Haldimand County Hydro

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July 18, 2012

Delivered By Courier and RESS

Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Attention: Kirsten Walli
Board Secretary

Re: Haldimand County Hydro Inc.
Smart Meter Cost Recovery Application (EB-2012-0272)

Dear Ms. Walli:

In accordance with the Board's Smart Meter Funding and Cost Recovery – Final Disposition Guideline (G-2011-0001) issued December 15, 2011, Haldimand County Hydro Inc. hereby submits its Smart Meter Cost Recovery Application (the "Application") for rates to be effective November 1, 2012.

Two hard copies of the Application are now enclosed. An electronic copy of the application in PDF format and the associated models in Excel format will be submitted through the Board's *Regulatory Electronic Submission System* ("RESS").

All of which is respectfully submitted for the Board's consideration.

Yours truly,
HALDIMAND COUNTY HYDRO INC.

Original signed by
Sherry Graham on behalf of

Jacqueline A. Scott
Finance Manager

IN THE MATTER OF the Ontario Energy Board Act, 1998, being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by Haldimand County Hydro Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates with respect to the recovery of smart meter costs, effective November 1, 2012.

Title of Proceeding:	An application by Haldimand County Hydro Inc. for an Order or Orders approving or fixing just and reasonable rates with respect to the recovery of smart meter costs, effective November 1, 2012.	
Applicant's Name:	Haldimand County Hydro Inc.	
Applicant's Address for Service:	1 Greendale Drive Caledonia, Ontario N3W 2J3	
	Attention:	Mr. Lloyd E. Payne, President & CEO
	Telephone:	905-765-5344
	Fax:	905-765-5316
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APPLICATION

1. Introduction

The Applicant is Haldimand County Hydro Inc. (referred to in this Application as the “Applicant” or “HCHI”). HCHI is a corporation incorporated pursuant to the Ontario *Business Corporations Act* with its head office in the community of Caledonia, ON. HCHI owns and operates the electricity distribution system in its licensed service area in Haldimand County, serving approximately 21,147 Residential, General Service, Street Lighting, Sentinel Lighting and Unmetered Scattered Load customers and one Embedded Distributor as at December 31, 2011.

HCHI filed a comprehensive Cost of Service (“COS”) rate application (EB-2009-0265) with the Ontario Energy Board (the “Board”) for rates effective May 1, 2010. HCHI’s rates were adjusted for 2011 and 2012 under the 3rd Generation Incentive Regulation Mechanism (“IRM3”) with approved rates effective May 1, 2011 (EB-2010-0086) and May 1, 2012 (EB-2011-0170) respectively.

Pursuant to EB-2010-0086, the existing Board-approved Smart Meter Funding Adder (“SMFA”) had a sunset date of April 30, 2012. HCHI noted in its 2011 IRM3 rate application (EB-2011-0170) that it would be filing a stand-alone application with the Board seeking final approval for the disposition and recovery of smart meter costs at a future date.

The Applicant hereby applies to the Board, pursuant to Section 78 of the *Ontario Energy Board Act, 1998* (the “OEB Act”) for an Order or Orders approving just and reasonable rates for the recovery of costs related to smart metering activities in its service territory. HCHI’s Smart Meter Cost Recovery Rate Application (the

"Application") has been informed by, and prepared in accordance with, the following documents:

(a) Chapter 3 of the Board's *Filing Requirements for Transmission and Distribution Applications* updated June 22, 2011 (the "Filing Requirements");

(b) *Guideline (G-2008-0002) Smart Meter Funding and Cost Recovery* – October 22, 2008*, and subsequently superseded by update Guideline (G-2011-0001) Smart Meter Funding and Cost Recovery – Final Disposition* issued on December 15, 2011 (collectively the "Guidelines");

(c) The Board's *Decision with Reasons (EB-2007-0063) to Combined Proceeding on Smart Meter Costs* (the "Combined Proceeding") issued on August 8, 2007;

(d) The Board's *Smart Meter Model, version 2.17, and instructions* issued on December 15, 2011 (the "Model"); and

(e) *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* issued on July 31, 2009 ("EDDVAR").

HCHI specifically requests the following approvals, all of which are to be effective November 1, 2012, or as soon as possible thereafter:

(a) The Board's determination that all Smart Meter capital and operating expenditures to December 31, 2011 are prudent;

(b) A Smart Meter Disposition Rider ("SMDR") for each of the Residential, General Service Less than 50 kW, and General Service 50 to 4,999 kW (non-interval metered) customer rate classes over an 18-month period from November 1, 2012 to April 30, 2014, to recover the deferred revenue requirements related to smart meters deployed as at December 31, 2011 for each rate class, net of the smart meter funding adder collected from May 1, 2006 to April 30, 2012 specific to each rate class;

(c) A Smart Meter Incremental Revenue Requirement Rate Rider (“SMIRR”) for each of the Residential, General Service Less than 50 kW, and General Service 50 to 4,999 kW (non-interval metered) customer rate classes to recover the annual revenue requirements associated with Smart Meters installed for each rate class from the inception of the Smart Meter program, to be in effect until HCHI’s next cost of service application when Smart Meter capital and operating costs will be incorporated into the rate base and revenue requirement;

(d) Foregone Revenue and associated Rate Rider for each of the Residential, General Service Less than 50 kW, and General Service 50 to 4,999 kW (non-interval metered) customer rate classes to recover six months of the 2012 incremental costs not recovered commencing May 1, 2012 due to the SMIRR implementation date of November 1, 2012; and

(e) The continuation of the inclusion of the stranded meter costs in rate base, as recommended by the Board in the Combined Proceeding as the Applicant is not requesting recovery of the stranded meters at this time. HCHI expects to seek recovery of the stranded meters at its next cost of service application as recommended in the Guidelines.

The Applicant requests that this Application be disposed of by way of a written hearing.

Contact information for this Application is as follows:

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MANAGER'S SUMMARY

2. Background

HCHI is a member of the Niagara Erie Power Alliance ("NEPA"), a cooperative arrangement of local distribution companies ("LDCs") in south central Ontario. Nine NEPA members developed a collective and collaborative approach to planning, as well as procurement of the Advanced Metering Infrastructure ("AMI") and installation services. HCHI, as part of the NEPA group, maintained its involvement in the Ontario Utilities Smart Meter ("OUSM") working group. This group consisted of approximately 46 LDCs that came together in an educational effort for a successful Smart Meter implementation.

The NEPA group also retained the services of an Ontario consulting firm, Util-Assist Inc. ("Util-Assist"), which provided guidance and direction in order to assist in the planning, implementation, testing, and complete back office integration for the Smart Meter Initiative ("SMI"). Included as Appendix D is a report "*Smart Meter Project Summary*" dated January 18, 2012, prepared by Util-Assist on behalf of the NEPA group, that outlines the details of each process, the Request for Proposals ("RFP") issued, evaluations completed, and the award of contracts. The consulting services proposal from Util-Assist was reviewed and accepted in December 2007 and has been included in Appendix L - "Confidential Materials Filed Separately with the Board"***.*** All RFP documents are included as appendices to this Application with the evaluations for each RFP and the service agreements included in Appendix L as confidential material.

3. Overview

HCHI has been actively installing Smart Meters in its service territory since 2009 under the Provincial government's mandate that all Residential and General

Service Less than 50 kW customers have a Smart Meter installed. The following Table 1 provides the timing of HCHI's Smart Meter installs by year.

Table 1 – Smart Meter Installs by Year

Customer Rate Class	2009	2010	2011	Total Installed at Dec.31/11	2012	Total to be Installed
Residential	16,583	1,703	238	18,524	11	18,535
General Service Less than 50 kW	1,275	758	316	2,349	12	2,361
% of Residential with Smart Meters Installed	89.47%	9.19%	1.28%	99.94%	0.06%	100.00%
% of General Service Less than 50 kW with Smart Meters Installed	54.00%	32.11%	13.38%	99.49%	0.51%	100.00%
General Service 50 to 4,999 kW			76	76	6	83
% of General Service 50 to 4,999 kW with Smart Meters Installed	0.00%	0.00%	91.57%	91.57%	7.23%	100.00%
% of Smart Meter Installs Complete	85.12%	96.85%	99.86%	99.86%	100.00%	

At the time of preparing this application, there remained one customer in the General Service Less than 50 kW rate class that required the installation of a Smart Meter. This one customer had a 240 volt, delta service which is the only one of its kind in HCHI's service territory. HCHI explored the possibility of upgrading this customers' service but due to the cost associated with this upgrade, the decision was made to purchase this one unique Smart Meter type. The Smart Meter was delivered to HCHI prior to the end of May 2012 and installed during the first week of June 2012. 100% completion of Smart Meter installs has been achieved for the Residential and General Service Less than 50 kW rate class at time of submission of this Application. There remains one customer in the General Service 50 to 4,999 kW customer class that requires a Smart Meter to be installed; however, currently HCHI does not have an expected timeline for the install of this Smart Meter.

On August 4, 2010 the Board issued a determination under Section 1.2.1 of the Standard Supply Service Code to require the implementation of time-of-use ("TOU") pricing for Regulated Price Plan ("RPP") consumers. The mandatory

TOU implementation date for HCHI was September 2011. HCHI commenced billing the majority of its customers by this date; that is, with the exception of approximately 416 General Service Less than 50 kW and 40 Residential customers. HCHI applied for an extension to its mandatory TOU implementation date to January 31, 2012 for these customers (EB-2011-0320). The extension was necessary due to an issue with Elster Alpha A3 three phase meters with FlexNet board firmware version 1.2.B that were delivering suspect interval data due to improper time-alignment of the consumption intervals. The Board approved the requested extension in a Decision and Order issued November 9, 2011. HCHI's TOU implementation dates are provided in Table 2 below.

Table 2 – Number of RPP Consumers Charged TOU by Period

Customer Rate Class	September 2011	October 2011	November 2011	December 2011	2012	Total to be Installed
Residential	18,381	67	42	17	28	18,535
General Service Less than 50 kW	1,853	10	12	122	364	2,361
Total RPP Consumers	20,234	77	54	139	392	20,896
% of Residential Charged TOU Pricing	99.17%	0.36%	0.23%	0.09%	0.15%	100.00%
% of General Service Less than 50 kW Charged TOU Pricing	78.48%	0.42%	0.51%	5.17%	15.42%	100.00%
% of Total RPP Consumers Charged TOU	96.83%	0.37%	0.26%	0.67%	1.88%	100.00%

HCHI began the registration of Smart Meters with the provincial Meter Data Management and Repository ("MDM/R"), part of the Independent Electricity System Operator ("IESO"), in April 2011 for the majority of its Smart Meter installations and continued with further registrations based on the IESO approved approach. Table 3 provides HCHI's installed Smart Meter registration periods with the IESO's MDM/R.

Table 3 – Registration of Installed Smart Meters with the MDM/R

Customer Rate Class	2nd Qtr. 2011	3rd Qtr 2011	4th Qtr 2011	Total Registered at Dec.31/11	2012	Total to be Registered
Residential	18,359	40	125	18,524	11	18,535
General Service Less than 50 kW	2,234	32	83	2,349	12	2,361
% of Residential - Smart Meters Registered MDM/R	99.05%	0.22%	0.67%	99.94%	0.06%	100.00%
% of General Service Less than 50 kW - Smart Meters Registered MDM/R	94.62%	1.36%	3.52%	99.49%	0.51%	100.00%

Currently there is no expectation of or capability for the General Service 50 to 4,999 kW customers Smart Meters being registered with the MDM/R. The required demand read component of these Smart Meters cannot be accepted by the MDM/R, as well as the Regional Network Interface ("RNI") does not have the capability to include demand reads in the "CMEP" file required by the MDM/R.

HCHI has received funding for the Smart Meter program through the collection of a Smart Meter Funding Adder ("SMFA") commencing in 2006 in conjunction with the Board's Generic Issues Decision (EB-2005-0529), issued March 21, 2006. This Decision provided that $0.30 per Residential customer per month be reflected in the Applicant's 2006 revenue requirement of its 2006 Rate Application (EB-2005-0373). The funding adder was to be allocated equally to all metered customers and recovered through the monthly service charge. For HCHI, this resulted in a SMFA of $0.26 per metered customer per month.

Table 4 summarizes the SMFAs approved to date by the Board for HCHI. These amounts have been charged monthly to all metered customers.

Table 4 – Smart Meter Funding Adders

Rate Period	Approved Rate	Board Decision and Order
May 1, 2006 to April 30, 2007	$ 0.26	EB-2005-0373
May 1, 2007 to April 30, 2008	$ 0.26	EB-2007-0535
May 1, 2008 to April 30, 2009	$ 0.26	EB-2007-0859
May 1, 2009 to April 30, 2010	$ 1.00	EB-2008-0181
May 1, 2010 to April 30, 2011	$ 1.87	EB-2009-0265
May 1, 2011 to April 30, 2012	$ 1.87	EB-2010-0086

In the Board's Decision approving the most recent SMFA (EB-2010-0086), the Board stated the following:

> *"… For those distributors that are scheduled to remain on IRM, the Board expects these distributors to file an application with the Board seeking final approval for smart meter related costs. I will approve the continuation of Haldimand County's SMFA of $1.87 per metered customer per month from May 1, 2011 to April 30, 2012. This SMFA adder will be reflected in the Tariff of Rates and Charges, and will cease on April 30, 2012…"*

HCHI is now filing its Application for approval of capital expenditures in the amount of $3,795,630 and operating costs in the amount of $729,190 related to its Smart Meter deployment as at December 31, 2011. All costs recorded in the Smart Meter deferral accounts as at December 31, 2011 have been audited as part of HCHI's annual year end audit by its external auditors, Millard, Rouse & Rosebrugh LLP. The Independent Auditors' Report, dated March 29, 2012, extracted from HCHI's audited financial statements as at and for the year ended December 31, 2011 is included in Appendix E.

The material costs, in the amount of $55,040, for the installation of the Smart Meters for the General Service 50 to 4,999 kW customer rate class have been included in the above capital expenditure amount of $3,795,630; however, they were not recorded in the Smart Meter capital deferral account until June 2012 as a result of this Application, having been previously reported in the regular meter capital account. Accordingly, HCHI's auditors have audited 93% or $50,945 of these material costs related to the General Service 50 to 4,999 kW customer class as part of HCHI's 2011 year end audit.

HCHI confirms that 99.8% of the total costs submitted for disposition are included in the audited financial statements as at December 31, 2011 with 98.7% represented by audited Smart Meter deferral account costs. The Guidelines state the following in section 3.5:

> *"… The Board expects that the majority (i.e. 90% or more) of the total program costs for which the distributor is seeking recovery will be audited…."*

The Smart Meter Disposition Rider ("SMDR") and the Smart Meter Incremental Revenue Requirement Rate Rider ("SMIRR") for each of the Residential, General Service Less than 50 kW, and General Service 50 to 4,999 kW customer rate classes have all been calculated individually using the Board's Model issued on December 15, 2011. Board-approved cost of capital parameters from HCHI's last COS rate application (EB-2009-0265) have been used for all years in each of the three Models. The actual capital installed costs by meter type have been input into each customer rate class Model. Operating costs have been allocated between each of the customer rate class Models on the basis of the number of installed meters by customer rate class. Each of the three Models have been included in as Appendices A, B, and C.

A rate rider has also been calculated for Foregone Revenue for each of the three customer classes. The Foregone Revenue is to recover six months of the Incremental Revenue Requirement for the 2012 Test Year that has been lost due to a November 1, 2012 implementation date versus a typical May 1, 2012 test year rate effective date. Section 26 of this Application provides details of this calculation which was completed outside of the Models.

The SMDRs, to be collected over an 18-month period commencing November 1, 2012 to April 30, 2014 inclusive, represent the Net Deferred Revenue Requirement by customer rate class from May 1, 2006 to December 31, 2011 as detailed in Table 5 below. The Net Deferred Revenue Requirement is the difference between (i) the Deferred Incremental Revenue Requirement from January 2007 (HCHI's first month of capital spending) to December 2011 plus interest on operating costs and amortization expense and (ii) the SMFA revenues collected from May 1, 2006 to April 30, 2012 plus interest for each customer class.

Table 5 – Net Deferred Revenue Requirement by Customer Rate Class

Customer Rate Class	Deferred Incremental Revenue Requirement	Smart Meter Funding Adder Revenues	Net Deferred Revenue Requirement
Residential	1,659,684	(1,253,014)	406,669
General Service Less than 50 kW	250,368	(160,613)	89,755
General Service 50 to 4,999 kW	8,265	(9,512)	(1,247)

The SMIRR is calculated based on the incremental revenue requirement associated with the recovery of capital related costs for the test year as at December 31, 2012 and related operating costs for the year then ended. The SMIRR is for 2012 and future years; that is, until HCHI's next cost of service rate application when Smart Meter capital and operating costs will be incorporated into the rate base and revenue requirement. The SMIRR will be collected from the Residential, General Service Less than 50 kW, and General Service 50 to 4,999 kW customers in a manner consistent with the investments in assets attributed to these customer rate classes.

With respect to the 2012 test year, HCHI has included actual unaudited costs up to and including May 31, 2012 and forecasted costs for June to December 2012 inclusive, in accordance with HCHI's 2012 Operating Budget approved by its Board of Directors on February 1, 2012. The following Table 6 details the 2012 incremental revenue requirement by customer rate class upon which the SMIRR is based.

Table 6 – Incremental Revenue Requirement for 2012 by Customer Rate Class

Customer Rate Class	Residential		General Service Less than 50 kW		General Service 50 to 4,999 kW	
Net Fixed Assets		2,407,155		637,639		53,121
Operating Expenses	376,588		47,954		1,704	
Working Capital Factor	15%		15%		15%	
Working Capital Allowance		56,489		7,194		256
Incremental Smart Meter Rate Base		$ 2,463,644		$ 644,833		$ 53,377
Deemed Short Term Debt	4%	98,546	4%	25,793	4%	2,135
Deemed Long Term Debt	56%	1,379,641	56%	361,107	56%	29,891
Deemed Equity	40%	985,458	40%	257,933	40%	21,351
Deemed Short Term Interest	2.07%	2,040	2.07%	534	2.07%	44
Deemed Long Term Interest	5.13%	70,775	5.13%	18,525	5.13%	1,533
Deemed Return on Equity	9.85%	97,068	9.85%	25,406	9.85%	2,103
Total Return on Capital		$ 169,883		$ 44,465		$ 3,680
Operating Expenses		376,588		47,954		1,704
Amortization Expenses		212,803		51,189		3,900
PIL's		32,281		7,323		506
Incremental Revenue Requirement		**$ 791,555**		**$ 150,931**		**$ 9,790**

Table 7 summarizes the applied-for monthly fixed charge rate riders for each of the SMDR, the SMIRR and the Foregone Revenue rate rider applicable to each of the three customer rate classes, and the net change to the prior SMFA rate riders.

Table 7 – Smart Meter Rate Riders by Customer Rate Class

Customer Rate Class	SMDR	SMIRR	Foregone Revenue	Subtotal	SMFA (Expired April 30/12)	Net Change
Residential	1.22	3.56	1.19	5.97	(1.87)	4.10
General Service Less than 50 kW	2.11	5.33	1.78	9.22	(1.87)	7.35
General Service 50 to 4,999 kW	(0.83)	9.83	3.28	12.28	(1.87)	10.41

The overall effect of the SMDR, the SMIRR and the Foregone Revenue rate rider will result in monthly bill impacts as provided in Table 8 below.

Table 8 – Bill Impacts by Customer Rate Class

Customer Rate Class	$ Distribution	% Distribution	$ Total Bill	% Total Bill
Residential (800 kWh)	4.10	10.3	4.17	3.2
General Service Less than 50 kW (2,000 kWh)	7.35	10.8	7.47	2.5
General Service 50 to 4,999 kW (50,000 kWh / 75 kW)	10.41	2.5	11.76	0.2

The above bill impacts have been calculated based on the combined related increase of the SMDR, SMIRR, and Foregone Revenue rate riders of $5.97 for Residential customers, $9.22 for General Service Less than 50 kW customers, and $12.28 for General Service 50 to 4,999 kW customers, each offset by the expiry of the monthly funding adder of $1.87 on April 30, 2012. Detailed bill impact calculations have been included in Section 27 of this Application.

4. Program Status

HCHI completed the mass deployment of Smart Meters in 2009 as illustrated in Table 1 and subsequently continued with the execution of the remainder of its

Smart Meter Investment Plan ("SMIP") that has been included as Appendix F. HCHI's SMIP was filed collectively with the NEPA group of LDCs.

By the end of 2009, HCHI had completed 16,583 Residential and 1,275 General Service Less than 50 kW Smart Meter installations. Collectively, this represented 85.46% of the total Smart Meters of 20,896 required to be installed in HCHI's service territory. Similarly, as at December 31, 2011, HCHI had achieved total Smart Meter installations of 20,873 or 99.89%.

In addition to the Residential and General Service Less than 50 kW customer rate classes, HCHI has been installing Smart Meters for the General Service 50 to 4,999 kW customers that do not have an interval meter which includes a total of 83 customers. This customer rate classification will have the ability to receive hourly electricity consumption data without the necessity of installing and maintaining a dedicated phone line service as is required for an interval meter. Table 1 illustrates that HCHI had completed 91.57% of these Smart Meter installations by the end of 2011. This Application includes the installed meter capital costs for this customer rate class and have been included in HCHI's Smart Meter deferral account 1555 as at June 30, 2012 and requested for disposition in this Application.

5. Procurement of Smart Meters and Installation Services

In 2004, the Ontario Government set out an objective for smart meter installation for all low volume consumers that are eligible for the RPP by the end of 2010. By 2007, legislation and regulations had defined minimum specifications for smart meters, authorized distributors to install smart meters and designated the IESO as the Smart Metering Entity ("SME").

Initially, thirteen LDCs were authorized by Ontario Regulation ("O.Reg.") 427/06 *"Smart Meters: Discretionary Metering Activity and Procurement Principles"* to conduct Smart Metering activities and participated in the Board's 2007 Combined Proceeding (EB-2007-0063) in order to determine the prudence and recovery of costs associated with these Smart Metering activities. These approved processes authorized the thirteen LDCs to move forward with the procurement and installation of Smart Meters.

The remaining LDCs in Ontario would be part of the consortium of LDCs working together as part of the authorized London Hydro AMI RFP process issued August 14, 2007. HCHI as part of the NEPA group was one of those remaining LDCs. The evaluation and selection phase of the RFP provided for the determination of the #1 and #2 ranked Proponents for each LDC. The highest ranked AMI proponent for the NEPA group was Sensus Metering Systems Inc. which is supported by the Attestation Letter of the Fairness Commissioner dated August 1, 2008 and included as Appendix G to this Application.

HCHI, as part of the NEPA group, proceeded with the Sensus FlexNet AMI system. An agreement with Sensus Metering Systems Inc. ("Sensus"), an AMI vendor, was completed and signed to acquire 100% of the smart meters required. This agreement has been included in Appendix L as part of the confidential material. The AMI purchased meets the minimum functionality adopted in O.Reg.425/06 *"Criteria and Requirements for Meters and Metering Equipment, Systems and Technology"* with the attachment *"Functional Specification for Advanced Metering Infrastructure – Version 2"* dated July 5, 2007. A letter dated August 15, 2009 from PRP International, Inc. provides further confirmation of the Fairness Commissioner for the negotiations and contracting phase and HCHI's administration of the contract awarded to its #1 ranked proponent, Sensus. A copy of this letter is included as Appendix H.

For HCHI, the purchased AMI included four Tower Gateway Base stations ("TGBs"). These four TGBs have been installed, one in May 2009 and the remaining three in June 2009, on existing (and leased) communications' towers, strategically located within Haldimand County, in order to ensure coverage requirements were achieved. The total service territory for HCHI is 1,252 km^2, consisting of rural area of 1,216 km^2 and six communities including Caledonia, Cayuga, Dunnville, Hagersville, Jarvis and Townsend representing an urban area of 36 km^2. A propagation study was completed in HCHI's service territory prior to determining the placement of these four TGBs in order to maximize coverage with the least amount of infrastructure.

The next stage was to select a vendor for the meter installation process. Util-Assist on behalf of the NEPA group prepared an Installation Services RFP, included as Appendix I, and invited seven vendors to respond. Requirements in the RFP were for the vendor to either meet or exceed strict safety policies and procedures as well as offer a turnkey solution that would have the vendor perform all site related services and workforce management; such as, customer communication, installation and commissioning, scheduling, dispatch and integration to back office systems. These operational considerations accounted for 45% of the weighting with the remaining 55% attributed to price. This weighting structure closely matched that used in the 2006 Coalition of Large Distributors RFP process which had been determined to be prudent by the Board, as detailed on pages 6 to 7 of the Guideline.

The evaluation process determined that Trilliant most closely met the requirements for the mass deployment of meters. Shortly after Trilliant was selected as the winning proponent, notice was received that Olameter Incorporated ("Olameter") had acquired Trilliant and thus Olameter would be providing the installation services to HCHI. The impact of this ownership change was evaluated, and based on the existing relationship between Olameter and the NEPA group of LDCs and their performance in the industry, awarding the contract was deemed appropriate. The evaluation document and the Advanced Metering Infrastructure Installation Services Agreement between Olameter and HCHI have both been included in Appendix L as part of the confidential material.

HCHI directed its efforts to minimize installation and meter purchase costs throughout the mass deployment of Smart Meters. Efficiencies and savings were achieved in the RFP development, evaluation process, and consultant costs.

HCHI developed an efficient installation process that was streamlined through the use of new technologies. Electronic service orders were dispatched through mobile hand-held devices which eliminated paper service orders and the need for manual processing. Efficiencies were also gained through automated uploading of Smart Metering installation files to the required systems, thereby reducing the potential for manual data entry errors and reducing the need for some back office manual functions.

Vendors for both Smart Meters and meter services were retained through competitive processes in order to help ensure optimal pricing while at the same time delivering required services and functionality.

HCHI's average installed capital cost per Smart Meter and average installed capital & operating cost per Smart Meter both compare favourably to the sector average costs as found in the Board's *"Sector Market Meter Audit Review Report"* dated March 31, 2010 and the *"Monitoring Report Smart Meter Investment – September 2010"* dated March 3, 2011. Table 9 below compares HCHI's average cost per Smart Meter with the reported sector averages. It should be noted that HCHI's capital expenditures in Table 9 include the $55,040 capital costs related to the installed Smart Meters for the General Service 50 to 4,999 kW customer rate class.

Table 9 – Comparison of Average Cost per Smart Meter

	HCHI	OEB Sector Market Report (March 31, 2010)	OEB Monitoring Report (March 3, 2011)
Capital Expenditures	$ 3,795,630	$ 570,339,200	$ 843,121,068
Total Smart Meters Installed	20,978	3,053,931	4,382,194
Capital Expenditures per Smart Meter	$ 180.93	$ 186.76	$ 192.40
Capital Expenditures plus Operating Costs	$ 4,524,821	$ 633,294,140	$ 994,426,187
Total Smart Meters Installed	20,978	3,053,931	4,382,194
Capital Expenditures plus Operating Costs per Smart Meter	$ 215.69	$ 207.37	$ 226.92

6. Operational Data Store Functionality

HCHI recognized the need for an Operational Data Store ("ODS"). The ODS introduces efficiencies through the use of the operational data available from the AMI system that is not stored by the MDM/R, such as enabling employees to audit and validate the meter data being collected, and interact with and gain valuable business information from this meter data.

The Advanced Metering Control Computer ("AMCC"), AMI network server, is limited to a maximum of 60 days of storage for the AMI data according to the Ministry of Energy's Functional Specification. An ODS system is capable of storing unlimited data and has the mechanisms in place to retain and archive data for analysis by HCHI.

Util-Assist on behalf of the NEPA group issued an RFP for an ODS in November 2008 included as Appendix J. The RFP was distributed to 30 vendors of which 6 chose to submit proposals. An evaluation criteria and scoring document was prepared in advance of the release of the RFP to ensure a consistent and fair approach in the evaluation of bids. HCHI formed part of the evaluation team of five NEPA LDCs in order to select the best-fit service provider for an ODS solution. Following the RFP process, the top two vendors, N. Harris Computer Corporation ("Harris") and Kinetiq Canada / Savage Data Systems ("Savage"), were invited to deliver software demonstrations, leading to the selection of Harris as the successful vendor. The evaluation document and the Software License, Implementation and Support and Maintenance Agreement between Harris and HCHI have been included as Appendix L as part of the confidential material.

The agreement with Harris was signed March 1, 2010. In January 2011 HCHI was experiencing issues with the performance of the ODS, such as the speed with which meter data and event files were processed and validated resulting in delays in producing the monthly meter reads causing issues with billing which could potentially result in unplanned and unnecessary expenses for manual meter reads. The ODS did not have the tools required to clear the MDM/R exceptions which resulted in a great deal of manual work. The "Read Interval Success" was also an issue with the Harris ODS which prevented the proper estimation of meter reads for the intervals that were not received. This was threatening to be a potential problem for HCHI meeting the time-of-use implementation date mandated by the Board. HCHI needed to take measures to ensure this would not happen. An agreement was then signed with Savage, attached as Appendix L part of the confidential material, as the ODS provider for HCHI commencing October 26, 2011. For a period of time from October 26, 2011 through to the end of the year, both ODS systems were operated in tandem to ensure Savage was operating and meeting HCHI's specification needs prior to giving the required 60 day notice to Harris. On December 30, 2011, HCHI notified Harris of the agreement termination, providing the 60 day "Notice of Termination of license term" to be effective February 29, 2012 in accordance with section 3.08 of the "Software License, Implementation and Support and Maintenance Agreement".

The primary requirements and features of the ODS are as follows:

a) **Dashboard of Field Issues Possibly Requiring Intervention** - Visibility to the real-time performance of the smart meter system to enable field staff to troubleshoot priorities such as non-communicating meters, non-communicating tower gateways / collectors, etc.

b) **AMI Service Level Agreements ("SLAs") Audit** – Audit and reporting / real-time notification capabilities to monitor AMI performance and therefore ensure that data collection and submission SLAs with the centralized MDM/R are consistently met.

c) **Read Re-submission** – The ODS provides a data repository to facilitate backfilling reads after a meter installation, front-filling reads after a meter removal, and replacing reads labeled as "Needs Verification or Edit (NVE)" by the IESO MDM/R system. It also provides a mechanism for meter data editing and "Validation, Estimation, and Editing (VEE)" processes (in keeping with the MDM/R specifications), allowing such data to then be re-submitted to the MDM/R. Features such as "register read validation failure resolution" are essential.

d) **IESO MDM/R Report Integration / Issue Resolution Automation** – The MDM/R produces a large volume of reports on a daily or regular basis, each potentially containing large amounts of information. The ODS will load the MDM/R reports and filter the information in order to provide manageable, meaningful action items that can be prioritized, investigated and resolved.

e) **Meter Event Monitoring** – Dashboard visibility to report meter events and indicators such as outages, restorations, tampers, voltage changes, etc., many of which will afford the opportunity to improve the safety and reliability of the distribution system.

f) **Revenue Protection** – HCHI will be able to identify and respond to meter tampers which historically would have resulted in unidentified theft of power.

g) **Outage Reporting** – Real-time outage information to facilitate faster response time, and therefore improved system reliability.

7. Business Process Redesign

During the latter half of 2010, HCHI participated in IESO workshops and Util-Assist education sessions covering the MDM/R design specifications, meter read data, VEE and other billing processes, and the design of a testing / cutover strategy. LDCs have widely recognized a number of business processes, some of which are new account setup, meter installations, meter changes, move-in / move-outs, and final billing that require analysis and procedural modifications to ensure that MDM/R integrations are optimized. HCHI completed the updates to their initial business process redesign in two stages, during April 2011 and September 2011, coinciding with the successful cutover to the MDM/R production environment and mandated TOU billing, respectively. HCHI realizes this is an ongoing activity and continues to update business process documentation as required to meet system and regulatory changes.

8. System Changes

HCHI converted to the Harris Northstar (“Northstar”) billing system in March 2009 after Advanced Utility Billing Systems announced in 2007 they would be leaving the Ontario market. HCHI’s conversion costs to Northstar have been previously included in its 2010 COS rate application (EB-2009-0265).

As part of the smart meter deployment and implementation of TOU billing, modifications and additional modules were required for Northstar. The fact that many other LDCs use this same billing system provided encouragement to HCHI that the implementation of TOU billing would be successful. The required software modules, modifications, and professional services for the existing system were negotiated and implemented to ensure the integration was completed in the defined regulatory timelines.

HCHI acquired the Harris Meter Exchange Workforce Management ("mCare") software in 2010 to automate the upload of meter change information into the Northstar billing system to accommodate the smart meter mass deployment. HCHI also required Harris to create a current transformer / potential transformer ("CT/PT") inventory database in Northstar to make-ready for MDM/R enrolment. This was completed towards the end of 2010. Extensive internal testing was completed by HCHI's smart meter team with favourable results that proved Northstar was capable of supporting MDM/R and TOU billing requirements.

9. Integration with MDM/R

HCHI filed registration paperwork and an integration project plan with the IESO on May 12, 2010. AS2 connectivity software, purchased from Cleo Communications was installed on August 5, 2010, in order to facilitate data integration with the MDM/R, and connectivity testing was completed with the IESO on August 30, 2010. To assist with the integration to the provincial MDM/R, HCHI employees attended relevant IESO training sessions beginning in 2010 through 2011 as well as ongoing training sessions provided by Util-Assist and MDM/R training workshops hosted by Harris. Successful integration to the MDM/R required months of education to prepare for the formalized enrolment testing run by the IESO. Dedicated resources were required to test and engage with the IESO during the 25 week enrolment timeframe leading up to the cutover to the MDM/R (flowing of all meter data).

HCHI commenced Unit Testing October 22, 2010 with completion February 4, 2011. System Integration Testing ("SIT") was then successfully completed March 4, 2011 followed by Qualification Testing ("QT") being entered into March 2011 and completed April 4, 2011. Cutover to the MDM/R production environment occurred on April 20, 2011 with all installed smart meters enrolled with the MDM/R.

From April 2011 until HCHI's mandated TOU billing, HCHI continued to bill from Northstar utilizing the register reads from the ODS. HCHI's smart meter team continued with internal testing on the billing information being received from the MDM/R in comparison to the actual customer billings generated from the ODS register reads right through to September 2011 to ensure the accuracy and reliability of the information being received from the MDM/R. Cutover to TOU billing using the MDM/R occurred in September 2011.

10. Transition to Time-of-Use Pricing

In mid-2009, the Ontario Government articulated an expectation that 1 million RPP customers would be billed using TOU pricing by the summer of 2010, increasing to 3.6 million customers by June 2011. On June 24, 2010, the Board issued a proposed determination regarding mandated TOU pricing for RPP customers (EB-2010-0218) suggesting that distributor-specific TOU dates would be the most appropriate approach, as it allows for the deadline to logically follow the date of commencement of meter enrolment with the MDM/R.

In a letter dated August 4, 2010, the Board provided direction to all LDCs on mandated dates by which each distributor must bill its RPP customers that have eligible TOU meters using TOU pricing. HCHI's mandated date for TOU billing was September 2011 for all Residential and General Service Less than 50 kW.

HCHI commenced billing the majority of its customers by this date with the exception of approximately 416 General Service Less than 50 kW and 40 Residential customers. HCHI applied for an extension to its mandatory TOU implementation date to January 31, 2012 for these customers (EB-2011-0320). The extension was necessary due to an issue with Elster Alpha A3 three phase meters with FlexNet board firmware version 1.2.B that were delivering suspect interval data due to improper time-alignment of the consumption intervals. The Board approved the requested extension in a Decision and Order issued November 9, 2011. HCHI's TOU implementation dates have been provided in Table 2.

11. Customer Education

HCHI carried out extensive education and information campaigns of HCHI's Smart Meter project status and TOU rollout schedule and impacts, and continues to educate its customers on TOU. The communication materials were designed to provide customers with an awareness and understanding of the installation of a Smart Meter at their location, the benefits of Smart Metering, TOU rates, and to inform customers of tools that are available to assist them. Such tools, including web presentment features as provided on HCHI's website, provide simple and helpful energy shifting and conserving tips and inform customers of the available conservation and demand management initiatives.

Beginning in March 2009, bill inserts were mailed to all of HCHI's Residential, General Service Less than 50 kW and General Service 50 to 4,999 kW customers as notification of their future smart meter installation. This notified the customer that their existing conventional meter would be removed and replaced with a Smart Meter noting that the Smart Meter would initially work just like their current conventional meter and that advance notice would be given when TOU pricing was available. HCHI also advertised in each of the local newspapers and on the local radio station for a period from July through December 2009 notifying customers of their future smart meter installation.

Throughout the installation period, a Smart Meter door hanger package, “Leave Behind Materials”, was left with each customer on the day of their specific installation. This package included a notice from HCHI that their smart meter had been installed, the Ministry of Energy booklet “*Getting Smart About Smart Meter’s Answer Book*”, and a TOU Peak Magnet identifying the mid-, on-, and off-peak periods. A Call Centre was also established during the Smart Meter mass deployment in 2009 to address any issues around the change-out of meters. This Call Centre was contracted out to the installation services vendor, Olameter.

HCHI also provided updates to their customers on Smart Meter activities in its regular bill insert entitled “*the Wire*”, which is published approximately three times a year. The cost of this bill insert was not included in the Smart Meter deferral accounts.

Prior to the implementation date of September 2011 for TOU pricing, HCHI mailed out additional bill inserts to make customers aware of the effective date for TOU pricing, and to remind them of energy shifting and conserving tips. HCHI also notified customers in August 2011 by way of a bill insert, as well as posted on its company website, of upcoming community information sessions to be held in three different locations of HCHI’s service territory in September 2011. These sessions provided HCHI and their customers with a face to face forum allowing HCHI to inform customers of upcoming TOU changes and explain the impact that these changes would have on their bill to be received commencing in

October 2011. Information was also provided at these sessions on energy conservation tips, safety tips, and open floor discussion to address any customer questions or concerns. HCHI provided customers at these sessions with "Peak O'Clocks" in order to assist the customer in determining each of the peak periods.

In September 2011, a direct mailing for TOU education was sent to all Residential and General Service Less than 50 kW customers to include TOU picture frame magnets and a TOU bill comparator that would calculate the customer's last RPP-tiered bill with TOU prices. TOU rate notifications were also advertised in each of the local newspapers and on the local radio station for the months of August and September 2011. A 2011 fall newsletter entitled "*Smart Meter Smarts*" was sent out to all customers as a bill insert to remind them of TOU rates, energy shifting and conservation tips, how to read the new TOU bill, and introduction to the internet-based eCare tool available to customers to view bills on-line, review and compare usage over a time period, and access to charts showing how they use their energy.

12. Web Presentment

The Ministry of Energy has indicated that electricity customers should ideally have web access to their hourly consumption data allowing them the opportunity to make informed decisions and adjust their usage accordingly. In order to accommodate this, HCHI implemented the Harris eCare software, a web presentment tool fully integrated with HCHI's Harris billing system. HCHI rolled out eCare in conjunction with TOU billing and encouraged customers, by way of bill inserts, to sign up for eCare access and informed them of the benefits. Some of these benefits being online access to hourly usage data with a one day lag period, web presentment of account status, balance of account, billing history, meter activity requests, etc.

The ODS has been a very useful and effective tool for the continuous, uninterrupted and reliable web presentment of hourly data to HCHI's customers. The ODS integration with the eCare web presentment module provides HCHI with a means for daily communication and education to its customers.

13. Annual Security Audit

With the mass deployment of the AMI system, security of the AMI network is critical to prevent LDCs from becoming susceptible to new levels of potential security breaches and to insure customer privacy and acceptance of the network. With the installation of network infrastructure in the field, there is now a requirement for additional security measures in order to ensure that LDC data and equipment are kept secure from manipulation or other forms of control. As networks are deployed throughout the world, cyber security articles with reports of the potential for smart-grid hacking are becoming commonplace in the media.

The minimum *"Functional Specification for an Advanced Metering Infrastructure"* issued July 14, 2006 identified the need for security within the AMI network in section 2.11 Security and Authentication as follows:

> *"2.11.1 The AMI shall have security features to prevent unauthorized access to the AMI and meter data and to ensure authentication to all AMI elements."*

Some of the privacy and network security infrastructure concerns that have been raised include the following:

a) Monitoring a customer's usage;

b) Modifying one's own, or another customer's usage;

c) Interrupting the power of one or more customers; and

d) Tampering with demand side management tools which can be controlled through smart meters.

Since early 2009, Ontario LDCs have been working with their Smart Meter providers to understand the security features of the networks, best practices for their deployment and new features that are being developed for future implementation within the Smart Meter networks. In November 2009, the Information and Privacy Commissioner of Ontario released the report "*Smart Privacy for the Smart Grid*" which identified areas of concern to be addressed in the area of Smart Meter and smart grid devices.

HCHI has participated as part of a group of 31 LDCs working with Util-Assist in the issuance of the May 2010 RFP, "Smart Meter Network Security Audit Services", included as Appendix K. The objective of the RFP was to select an audit partner who would perform a security audit of the Sensus AMI systems for the group members who had the Sensus technology in place, and to work with

Sensus towards the implementation of viable countermeasures to resolve all security concerns. The selected audit firm was to first complete an in-depth security review at one of the participating LDCs that has the Sensus AMI system. Once this initial review was complete, the audit firm would then review the technology at all remaining participating LDCs to confirm that their Sensus AMI systems were configured to the same standard as that declared as the standard for the group audit. Audits were to include end-to-end from the meter to LDC's systems and home area network. Bell Wurldtech ("Bell") was the vendor selected to provide the audit services for the Smart Meter network security. The Bell Statement of Work dated March 28, 2011 and Bell Services Agreement dated April 20, 2011 have been included in Appendix L as part of the confidential material.

The physical security audit would only take place at the location of the Regional Network Interface ("RNI"), which is controlled and managed by Sensus and housed centrally at PowerStream Inc. ("PowerStream"). Every other LDC of the audit group would complete a "Utility Checklist for Sensus AMI Threat Risk Assessment ("TRA")", attached in Appendix L as part of the confidential material, as provided by Bell to highlight internal policies where applicable and to verify comments provided by Sensus.

Moving forward, HCHI has budgeted for an annual security audit as a prudent approach to satisfying the due diligence requirements for protection not only of the customer information, but also to ensure that access to the infrastructure is properly protected, thereby securing against unwanted modifications to data collection and / or load-control functionality.

SMART METER COSTS

The following provides further analysis of audited expenditures associated with HCHI's Smart Meter implementation from 2007 to 2011 and unaudited / forecasted expenditures in 2012.

14. Capital and Operating Expenditures - 2007

Cost Summary: $90,565 (Capital); $0 (Operating)

In 2007, HCHI retained the services of the consulting firm Util-Assist who provided ongoing guidance and direction in order to assist in the planning, implementation, testing, and complete back office integration for the SMI. Util-Assist also assisted the NEPA group with the collective filing of their SMIP in 2007.

A portion of the capital costs in 2007 relate to the make-ready work that was necessary in order to commence the installation of Smart Meters, including the change-out of A-base meters which required installing the appropriate adapter to accept an S-base meter, all completed by HCHI employees.

15. Capital and Operating Expenditures - 2008

Cost Summary: $40,330 (Capital); $0 (Operating)

The capital expenditures during 2008 mirrored the type of spending from 2007; Util-Assist's ongoing consulting services continued throughout 2008 and the remaining make-ready work was completed in 2008.

16. Capital and Operating Expenditures - 2009

Cost Summary: $2,444,506 (Capital); $154,613 (Operating)

In 2009, HCHI commenced its mass deployment of Smart Meters resulting in 17,858 installations by the end of the year, representing 85.12% completion of the required total of 20,979.

Capital

In the first half of 2009, HCHI as part of the NEPA group, proceeded with the Sensus FlexNet AMI system. HCHI acquired 100% of its Smart Meters and the four TGBs from Sensus and proceeded with installation of these Smart Meters utilizing Olameter as the installation vendor. In order to accommodate the Smart Meter inventory, HCHI made the decision to rent two trailers which required slight modifications to its existing warehouse space, including the installation of a new garage door and removal of a loading dock leveler. HCHI rented the two trailers to house new Smart Meter inventory in 2009 at a cost of $300 per month per trailer, in addition to utilizing its existing available warehouse space. This was more cost effective than maintaining offsite storage. HCHI purchased three handheld devices and leased two handheld devices from Olameter to assist with the installation process and provide a smooth transfer of information for each install from the field back to the office. Implementation costs were spent in 2009 with Harris to bring the Smart Meter inventory into the billing system and to modify the existing billing system for integration with MDM/R.

Util-Assist consulting services continued through 2009, assisting with the installation vendor RFP and negotiations, the ODS contract review, and education sessions related to the MDMR.

Communications to customers commenced at the start of the mass deployment to prepare customers for their Smart Meter install. HCHI also provided information on its Smart Meter deployment progress by way of local newspapers and the local radio station. These costs were previously recorded in the deferred Operating account 1556 reported as part of the Distributor Quarterly Filings ("DQF") to the OEB "2.1.1 Deferral/Variance Accounts" and the "Smart Meter Cost Information" also filed quarterly with the OEB, but have now been reallocated to the deferred Capital account 1555 as part of this Application. The reallocation amount of $4,871 has been posted May 1, 2012 in HCHI's financial records and will be reported accordingly in the second quarter DQF as part of the Electricity Reporting & Record Keeping Requirements ("RRR").

Operating

The deployment of Smart Meters required additional incremental human resources resulting in a contract position in Customer Service. One of the existing Customer Service and Collections Clerk was assigned to the Smart Meter team. This position would be in place right through to the implementation of TOU billing at HCHI and a temporary employee was hired to backfill the temporarily assigned employee.

With the purchase of the four TGBs, additional property insurance was required.

For 2009, HCHI only incurred operational costs on the TGBs by way of a monthly base station service fee. A charge for the Flexnet monitoring services (i.e. a charge per meter installed per month) did not commence until 2010.

Third party contractors were required to make repairs to customer-owned meter bases that were found to be unsafe during the installation of the Smart Meter.

During 2009, communications regarding the benefits of Smart Meters were provided to customers by way of bill inserts. After each installation, a "Leave Behind" door hanger was provided to each customer that also provided information on the TOU rate periods.

17. Capital and Operating Expenditures - 2010

Cost Summary: $828,870 (Capital); $230,790 (Operating)

HCHI continued in 2010 with its deployment of smart meters, installing another 2,461 by the end of the year to bring the total installed to 20,319, representing 96.85% completion of the required 20,979. The more difficult meter installations took place in 2010 and continued into 2011.

Capital

The installation vendor contract for Olameter expired at the end of December 2009 and HCHI engaged a third party subcontractor, Rodan Energy Solutions, to continue with the more difficult installations in 2010. HCHI kept two trailers on site but only one was required to house new Smart Meter inventory whereas the second trailer was used to store the removed conventional meters until Green-Port Environmental was able to pick them up for scrap. The lease on the two handheld devices from Olameter continued through to November 2010 when they were no longer required. The purchase of AS2 software was required to accommodate the interface between the Northstar billing system and the MDM/R. HCHI also purchased Meter Exchange Workforce Management software from Harris in order to automate the upload of meter change information into the Northstar billing system. Seven tablets were purchased from Filbitron Marketing Corporation to communicate between the field and the workforce management software. Harris also provided a CT/PT inventory database in Northstar to make-ready for MDM/R enrolment.

Util-Assist monthly consulting costs continued for the NEPA group of LDCs including some specific items, such as the RFP for the IT Security Audit vendor, and contract review and legal fees related to the ODS vendor.

Operating

The ODS became functional in 2010 with HCHI incurring monthly service fees commencing June based on the number of communicating meters. Also in 2010, HCHI's employees would participate in a number of workshops and training sessions hosted by Harris, the IESO, and/or Util-Assist to ensure the interface with the MDM/R and HCHI's billing system was a smooth transition. The temporary position in Customer Service continued as the regular staff member was still an integral part of the Smart Meter team.

Third party contractor costs continued to be required in 2010 in order to make repairs to customer-owned meter bases that were found to be unsafe during the installation of the Smart Meter.

HCHI continued to incur costs on the TGBs by way of a monthly base station service fee and the commencement of the variable charge for the Flexnet monitoring services (i.e. charge per meter per month). The Flexnet monitoring service fee would only be charged from January through May due to meter communication issues. The performance did not meet the service level agreement "SLA" and the fee for June was waived and not charged for the balance of the year. HCHI would not see these Flexnet service fees again until January 2012 at which time they have been recorded in regular operations.

With the addition of the Harris mCare software, HCHI also incurred monthly operating costs related to support fees for this software commencing April 2010 and a prepayment for 2011.

18. Capital and Operating Expenditures - 2011

Cost Summary: $382,806 (Capital); $343,787 (Operating)

In 2011 HCHI continued with its deployment of smart meters, installing another 554 of the Residential and General Service Less than 50 kW more difficult meters and the commencement of the General Service 50 to 4,999 kW meters with 76 installed by the end of the year. This would now bring the total installed to 20,949 as at December 31, 2011, representing 99.86% completion of the required 20,979.

<u>Capital</u>

HCHI's third party subcontractor, Rodan Energy Solutions, continued with the Residential and General Service Less than 50 kW difficult installations in 2011. HCHI only required one trailer in 2011 to house only the new Smart Meter inventory. A tester tool for Smart Meters was required by HCHI, as the testers on hand would only be useful for meters other than a Smart Meter, and was purchased from Radian Research Inc. in 2011. Capital costs were also incurred in 2011 to modify HCHI's bill print for TOU pricing and to create the TOU bill comparator provided to customers in September.

Util-Assist consulting costs continued with the cutover to the MDM/R and the transition to TOU billing. These costs have been treated as capital through to the end of August 2011 becoming an operational cost commencing in September 2011, HCHI's mandated TOU date, and onwards. These costs were previously recorded in the deferred Operating account 1556 reported as part of the Distributor Quarterly Filings ("DQF") to the OEB "2.1.1 Deferral/Variance Accounts" and the "Smart Meter Cost Information" also filed quarterly with the OEB, but have now been reallocated to the deferred Capital account 1555 as part of this Application. The reallocation amount of $7,857 has been posted May

1, 2012 in HCHI's financial records and will be reported accordingly in the second quarter DQF as part of the Electricity Reporting & Record Keeping Requirements ("RRR").

Smart Meter material costs for HCHI's General Service 50 to 4,999 kW customer class were also incurred in 2011 with 76 of the total 83 meters having been installed. The material cost of $50,945 related to these 76 meters was previously recorded as part of HCHI's regular meter capital account 1860 and has now been reallocated to the Smart Meter deferred Capital account 1555 as part of this Application. The reallocation amount has been posted June 1, 2012 in HCHI's financial records and will be reported accordingly in the second quarter DQF, section "2.1.1 Deferral/Variance Accounts", as part of the Electricity Reporting & Record Keeping Requirements ("RRR").

Operating

The ODS monthly service fees continued throughout 2011 and the change was made from Harris to Savage late in the year as noted in section 6 above. Workshops and training would continue in 2011 for HCHI employees as it related to the MDM/R testing and cutover. As noted above, the temporary position in Customer Service continued right through until the end of 2011. Ongoing costs from third party contractors would continue in 2011 for repairs to meter bases with additional costs incurred from Rodan Energy Solutions ("Rodan") for the troubleshooting of Smart Meters. Some of the more difficult installations for the Residential and General Service Less than 50 kW customer classes as well as the General Service 50 to 4,999 kW customer class were required to be completed during regular hours and by HCHI's own employees. This caused a backlog in the duties and functions required by them on a daily basis for ongoing operations which would be back-filled by Rodan. The internal labour continued to be coded to regular operations with the incremental costs from the Rodan subcontractor invoices coded to Smart Meter operations. The Smart Meter security audit performed by Bell occurred in the latter part of 2011.

Costs were incurred for TOU notifications to customers via the local newspapers and radio, TOU flyers and bill inserts, TOU customer information sessions, and TOU web updates and development.

Util-Assist consulting costs continued as operating costs in 2011 including specific expenses related to the Sensus security audit.

The TGB monthly base station service fee was incurred at 100% of cost only from January to August in 2011 with no cost associated with the Flexnet monitoring services in 2011. The contractual service levels in the AMI Sales and Services agreement had not been achieved at all since the beginning of 2011. HCHI exercised its right in accordance with the contract to commence withholding a portion of the payment for the monthly TGB monitoring service fees to Sensus until the AMI performance met the contracted service levels. A letter dated August 29, 2011 to Sensus has been included in Appendix L as part of the confidential material.

Effective with the September 2011 invoice, amounts were withheld from Sensus as follows:

a) September Fees reduced by 25%
b) October Fess reduced by 50%
c) November Fess reduced by 75%
d) December Fees reduced by 100%

In 2012, HCHI has received invoices from Sensus for 100% of the costs for the monthly base station service fee and the Flexnet service fee commencing in

April. January through March 2012 were only partially paid. All of these costs have been recorded in regular operations.

19. Capital and Operating Expenditures – 2012 (Unaudited Actual)

Cost Summary: $8,553 (Capital); $0 (Operating)

Capital

A total of 29 or 0.14% of the total Smart Meter installations remained at the end of 2011. Some of the 29 were the more difficult installations for the Residential and General Service Less than 50 kW customer rate classes and the balance were installations in the General Service 50 to 4,999 kW customer rate class, all of which were completed during the first part of 2012 utilizing HCHI's own employees during regular hours. As already mentioned in this Application, there remains one customer in the General Service 50 to 4,999 kW customer rate class that requires a Smart Meter to be installed. Currently HCHI does not have an expected timeline for the installation of this Smart Meter.

20. Costs Beyond Minimum Functionality

Included in the above breakdown of capital and operating costs by year are costs related to "Beyond Minimum Functionality". HCHI has incurred Capital costs of $91,179 and Operating costs of $48,567 which meet the Board's criteria for being identified as expenditures beyond minimum functionality, as defined in the Combined Proceeding and identified in the section 3.4, *"Costs Beyond Minimum Functionality"*, of the Guidelines. The total of these expenditures represents 3% of total Smart Meter program spending. HCHI submits that these expenditures were necessary and is requesting these amounts be approved for recovery as being prudently incurred. A description and rationale for these costs is provided below.

Residential and General Service Less than 50 kW

Cost Summary: $35,995 (Capital); $48,374 (Operating)

<u>Capital</u>

It was necessary for HCHI to incur costs related to TOU rate implementation, web presentation, and integration with the MDM/R. These investments allowed HCHI to meet customer expectations and the Ontario government's mandate for TOU implementation.

Expenditures related to the creation of a user friendly web presentment tool for HCHI customers, CIS development and enhancements for TOU implementation, and the AS2 software to interface between CIS and MDM/R.

The web presentment services provide customers with useful information such as online real time access to hourly usage data, account status, balance of account, billing history, meter activity requests, etc. Web presentment has been a valuable education component for customers and employees, allowing customers to understand their usage patterns and to be used as a tool for queries about large bills. A security audit was completed on the customer web presentment tool to ensure the protection of HCHI's customers' privacy.

HCHI purchased AS2 communications software to interface between the Northstar billing system and the MDM/R. Enhancements were also required to the billing system to accommodate the TOU implementation, such as bill print modifications and the creation of a TOU bill comparator to educate the customer.

<u>Operating</u>

To maximize efficiencies and position HCHI for successful completion of the Smart Meter program, the project was undertaken as a single unified function.

HCHI only incurred operational costs related to the deployment of Smart Meters for the Residential and General Service Less than 50 kW customer rate classes.

HCHI has incurred operating costs related to the implementation of TOU rates, web presentation, and integration with the MDM/R. HCHI has successfully achieved the Ministry of Energy's mandate to bill customers with a Smart Meter on TOU rates. HCHI considers the entire customer education platform of Smart Metering materials, information regarding TOU rates, and web presentment to be part of a successful Smart Meter program.

The implementation of a robust and informative communications plan to educate customers regarding TOU rates will result in future customer value. HCHI's communication plan included web presentment, ongoing updates of information on company website, a series of bill inserts and brochures, information sessions, and media releases. HCHI's communications' materials provided customers with information on the installation of the Smart Meter, the value of understanding their household consumption, and the importance and ability to manage their future electricity bills on TOU rates. The constant flow of information has provided positive reinforcement to the Smart Meter program. Customer education and understanding of this initiative has been critical to its acceptance and to the realization of benefits of the Smart Meter program.

Ongoing support for the AS2 software interface between HCHI's Northstar billing system and the MDM/R has been included here as an operating cost.

General Service 50 to 4,999 kW

Cost Summary: $55,184 (Capital); $193 (Operating)

Capital

HCHI has also included capital costs for the installation of Smart Meters for its General Service 50 to 4,999 kW customers in order to maximize operational efficiencies through automated meter reading and enable accurate and timely customer rate classification reviews for customers with varying demand. The reclassification of a General Service 50 to 4,999 kW customer would be expedited as they would already have a Smart Meter prior to reclassification. The installation of a Smart Meter is also beneficial to the customer and is often preferred to the installation of an interval meter. A Smart Meter does not require the installation and maintenance of a dedicated telephone line service which is required for an interval meter, and the expense associated with the line is therefore avoided. The Smart Meter still provides valuable hourly data and enables the customer to make knowledgeable decisions regarding electricity usage. The installation of Smart Meters to this customer rate class is expected to lead to a reduction in meter reading costs due to automated meter reading processes. HCHI notes that the costs of providing meters to the General Service 50 to 4,999 kW customer class will be borne by only those customers in that rate class.

The capital costs for the General Service 50 to 4,999 kW customer class represent material only and were recorded in the regular meter capital account 1860 in 2011 and 2012 and not reported as part of the Distributor Quarterly Filings ("DQF") to the OEB "2.1.1 Deferral/Variance Accounts" and the "Smart Meter Cost Information" also filed quarterly with the OEB. They have now been properly reallocated to the deferred Capital account 1555 as part of this Application. The reallocation amount of $55,040 has been posted June 1, 2012 in HCHI's financial records and will be reported accordingly in the second quarter DQF as part of the Electricity Reporting & Record Keeping Requirements ("RRR").

21. 2012 Test Rate Year Operating Costs

Cost Summary: $157,607 (Unaudited Actual); $268,639 (Forecasted)

Test Year Operating Costs

HCHI will incur incremental operating costs due to the Smart Meter program implementation in various areas. The ongoing costs from third party contractor Rodan will continue into 2012 to assist with the backlog in the duties and functions of HCHI's regular employees caused by the Smart Meter implementation. HCHI's regular employees assisted with the installations of the more difficult meters as well as the General Service 50 to 4,999 kW customer rate class and were all completed during regular hours which put a back log on their daily duties.

HCHI will incur ongoing incremental monthly fees from the TGB's, Base Station service fees and Flexnet Monitoring services, as part of the Smart Meter program as well as the monthly service fee for the ODS. It should be noted that for the first three months of 2012, January to March, the service fees from the TGB's payable to Sensus have been reduced per the contract due to performance issues. A monthly fee is also required for the mobile tablets / data packs to communicate between the field and the mCare software.

Continued Smart Meter education to HCHI's customers is required to remind them of TOU rates, energy shifting and conservation tips. Additional costs now incurred by HCHI on account of Smart Meters are the incremental annual support fees for the new computer software for HCHI's billing system (MDM/R interface and mCare) and the annual security audit now required for the AMI system. An additional expense to be incurred moving forward in 2012 is security testing for the RNI as part of a shared cost with the other members of the NEPA group using PowerStream's Work Bench.

The incremental operating costs also include ongoing consulting services provided by Util-Assist on behalf of the NEPA group. It was also necessary for HCHI to include a new position of "Sync Operator" in 2012. During the Smart Meter deployment, the Sync Operator functions were completed by three internal positions which caused delays in day to day activities. Some of these Sync Operator functions include the following:

a) Synchronization between the AMI, the MDM/R, the ODS, and the Harris billing system;

b) Gatekeeper to critical service order activity that touches the Smart Meter, such as non-communicating meters;

c) Ensure accuracy of TOU meter data for billing purposes; and

d) Monitoring and verification that all Smart Meter data has been processed and meets MDM/R requirements.

During the implementation of Smart Meters HCHI hired a temporary position in its Customer Service department to accommodate some of the backlog of day to day activities as previously noted in this Application. This temporary position ended February 29, 2012 with the creation of the new position, Sync Operator, who was hired March 14, 2012.

One incremental operating cost included in HCHI's 2012 test year is the annual support fee required for the software interface between HCHI's billing system and the provincial MDM/R.

Table 10 provides the operating costs, as described above, included in HCHI's 2012 test rate year, separated between the unaudited actual amount, January to May inclusive, and the forecasted amount, June to December inclusive.

Table 10 – 2012 Test Rate Year Operating Costs
Unaudited Actual vs. Forecast

2012 Operating Costs	Unaudited Actual January to May	Forecast June to December	Total January to December
2.1 Advanced Metering Communication Device (AMCD)			
2.1.1 Maintenance			
Third Party Contractor Costs	$ 51,710	$ 68,290	$ 120,000
Total Incremental AMCD OM&A Costs	$ 51,710	$ 68,290	$ 120,000
2.2 Advanced Metering Regional Collector (AMRC)			
2.2.1 Maintenance			
Base Station Service Monthly Fees	$ 37,353	$ 83,670	$ 121,023
Flexnet Monitoring Services	7,893	17,688	25,581
Total Incremental AMRC OM&A Costs	$ 45,246	$ 101,358	$ 146,604
2.5 Other AMI OM&A Costs Related to Minimum Functionality			
2.5.2 Customer Communication			
TOU Customer Education Pieces	$ -	$ 9,000	$ 9,000
2.5.3 Program Management			
Util-Assist Consulting Services - NEPA group	6,013	8,030	14,043
ODS Monthly Service Fees	17,758	21,282	39,040
2.5.5 Administration Costs			
Temporary Position - Customer Service (Effective to Feb.29/12)	9,424	-	9,424
Sync Operator - New position (Effective from March 14/12)	17,211	40,159	57,370
2.5.6 Other AMI Expenses			
Security Audit - AMI Systems	-	13,000	13,000
Security Testing for RNI	-	5,000	5,000
Annual Support Fees (MDM/R & mCare)	7,416	-	7,416
Mobile Tablets / Data Packs - Monthly Fees	1,795	2,520	4,315
Total Other AMI OM&A Costs Related to Minimum Functionality	$ 59,617	$ 98,991	$ 158,608
2.6 OM&A Costs Related to Beyond Minimum Functionality			
2.6.3			
Annual Support Fees (CIS Interface to MDM/R	$ 1,034	$ -	$ 1,034
Total OM&A Costs Related to Beyond Minimum Functionality	$ 1,034	$ -	$ 1,034
Total Smart Meter Operating Costs for the 2012 Test Rate Year	**$ 157,607**	**$ 268,639**	**$ 426,246**

HCHI has not included any costs related to the IESO MDM/R operating fees as part of this Application. HCHI understands there is currently a proceeding before the Board (EB-2012-0100) for approval of a Smart Metering Charge ("SMC") and approval of the Smart Metering Agreement for Distributors by the IESO combined with the Board's proceeding (EB-2012-0211) to determine the appropriate recovery and allocation of the SMC.

22. Incremental Cost Savings

Although HCHI's operating costs have increased due to the installation of Smart Meters, it would be expected that certain cost savings have resulted due to the implementation of Smart Meters, with the most significant of these being the elimination of manual electric meter reading for those customers with an installed Smart Meter.

HCHI has not included the reduction of the manual electric meter reading costs as a result of the Smart Meter program in this Application. This reduction has already been reflected in HCHI's distribution rates, as part of the Board approved Settlement Agreement on February 18, 2010 in its 2010 COS Rate Application (EB-2009-0265). Specifically, the Settlement Agreement in section "4. Operating Costs (Exhibit 4)" states as follows:

> ***"a) Are the overall levels of OM&A budgets appropriate?***
> ***Status:*** *Complete Settlement*
>
> *The Parties have agreed that the overall level of HCHI's OM&A budget as proposed in the Application is appropriate, subject to the following:*
>
> - *A reduction of $84,000 related to meter reading costs of $168,000 in each of 2010 and 2011 normalized over the 4 year rate period. After 2011 these manual meter reading costs are expected to be replaced with automated meter*

> *reading costs, to be accumulated in the deferred smart meter operating costs."*

Therefore, all of HCHI's Smart Meter costs included in this Application are incremental.

23. Stranded Meter Costs

HCHI is not seeking disposition of the stranded costs of its conventional meters at this time. HCHI continues to recover these costs by including the net book value of stranded meters in its rate base for rate-making purposes and continues to amortize these stranded meters over the remaining amortization period.

As per the Board's Guidelines, section 3.7 "Stranded Meter Rate Rider ("SMRR"), HCHI will bring forward the remaining net book value of Stranded Meters for recovery at its next cost of service application.

24. Variance Analysis

The Guidelines require that distributors include a variance analysis comparing actual costs to previously approved costs if applicable. While HCHI has applied to the Board for approval of a utility-specific SMFA as part of its last COS filing, it has not applied to the Board for approval of its Smart Meter costs prior to this Application. Accordingly, a variance analysis comparing actual costs to previously approved costs is not included as part of this Application.

25. Cost Allocation

The Board's Guidelines recommend that class specific SMDRs should be calculated based on full cost causality, with the class specific SMFA revenues plus carrying costs directly offset to the incremental revenue requirement, to determine the SMDR for each specific customer class. The SMIRRs should also be calculated using the same cost allocation methodology as the SMDR calculations.

HCHI has completed separate Smart Meter Models for the Residential, General Service Less than 50 kW, and General Service 50 to 4,999 kW customer rate classes with class specific SMFAs collected, and class specific capital, and OM&A amounts. The primary basis of allocation to the customer rate classes is based on the actual capital cost of the Smart Meters installed for each customer rate class.

HCHI has tracked the installed cost of Smart Meters specifically by type of meter for each customer rate class by installed date through the use of its billing and financial systems. Output files from the billing system provided the service order installed dates and the type of meter installed for each customer. Cost information from the financial system provided material costs for each type of meter and labour costs by meter type for each third party contractor that was utilized for the Smart Meter installations.

Table 11 provides the details of installed Smart Meters by meter type for each of the Residential and General Service Less than 50 kW customer rate classes and Table 12 provides the details of the installed Smart Meters by meter type for the General Service 50 to 4,999 kW class.

Table 11 – Installed Cost by Meter Type

Residential and General Service Less than 50 kW

Meter Type	Unit Cost	Residential		General Service Less than50 kW	
	(labour + material)	Units	Dollars	Units	Dollars
Single Phase 200 Amp	$ 92.66	17,262	$ 1,599,438	1,455	$ 134,815
Single Phase Transformer Rated	$ 276.59	898	248,377	407	112,572
Single Phase Transformer Rated PMU	$ 601.80	-	-	5	3,009
Network Meter	$ 301.56	334	100,721	24	7,237
Three Phase 200 Amp	$ 657.56	37	24,330	270	177,541
Three Phase Transformer Rated	$ 761.73	3	2,285	142	108,166
Three Phase 600 Volt 200 Amp	$ 1,241.02	1	1,241	57	70,738
Three Phase 7 Jaw Meter - kVa	$ 620.09	-	-	1	620
Total Residential and General Service Less than 50 kW		**18,535**	**$ 1,976,392**	**2,361**	**$ 614,698**

Table 12 – Installed Cost by Meter Type

General Service 50 to 4,999 kW

Meter Type	Unit Cost	General Service 50 to 4,999 kW	
	(material only)	Units	Dollars
Single Phase Transformer Rated	$ 546.35	7	$ 3,824
Three Phase Transformer Rated	$ 682.57	70	47,780
Three Phase Transformer Rated Delta	$ 687.22	5	3,436
Total General Service 50 to 4,999 kW		**82**	**$ 55,040**

The balance of the costs in "1.1.2 Installation Costs", such as miscellaneous hardware, trailer rentals for storage of new meters, modifications to the garage door, call centre services, and media releases to name a few as discussed in Sections 14 through 20 of this Application, were allocated on the proportional basis of the number of Smart Meters installed to each of the three customer rate classes. Other capital costs have been allocated to the three customer rate classes based on the total number of customers in each rate class which represents 100% installation of Smart Meters completed at the time of filing this

Application. The other capital costs are similar for each Smart Meter and customer with no discernible differences between the types of Smart Meter and/or customer class. These costs are either driven by the number of Smart Meters and/or customers or each Smart Meter and/or customer receives similar benefits. The following Table 13 details the allocation of all capital costs to the three customer rate classes.

Table 13 – Allocation of Capital Costs by Customer Class

Description	Residential	General Service Less than 50 kW	General Service 50 to 4,999 kW	Total
Number of Smart Meters Installed	18,535	2,361	82	20,978
Smart Meters and Installation Costs	$ 2,219,715	$ 645,678	$ 56,141	$ 2,921,534
Workforce Automation (Hardware & Software)	84,937	10,815	385	96,137
Collectors (Tower Gateway Base Stations - TGBs)	499,390	63,590	2,261	565,241
Installation (Meter seals and Rings)	66,746	8,499	302	75,547
AMI Interface to CIS (MDM/R Integration)	6,570	836	30	7,436
Professional Fees	73,443	9,352	333	83,128
Integration (Operational Data Store Setup)	8,778	1,118	40	9,936
Other AMI Capital	470	60	2	532
Total Capital Costs Related to Minimum Functionality	**$ 2,960,049**	**$ 739,948**	**$ 59,494**	**$ 3,759,491**
Interface between CIS & MDM/R (FTP Site)	$ 4,298	$ 547	$ 19	4,864
Web Presentment (Security Audit)	5,999	764	27	6,790
TOU Rate Implementation (Bill Print Modifications / TOU Customer Comparator)	21,632	2,755	98	24,485
Total Capital Costs Beyond Minimum Functionality	**$ 31,929**	**$ 4,066**	**$ 144**	**$ 36,139**
Total Smart Meter Capital Costs	**$ 2,991,978**	**$ 744,014**	**$ 59,638**	**$ 3,795,630**
Average Capital Cost per Meter	**$ 161.42**	**$ 315.13**	**$ 727.29**	**$ 180.93**

HCHI has also tracked the SMFA revenues specific to the three customer rate classes since its first approved adder of $0.26 per metered customer with rates effective May 1, 2006. In order to calculate class specific disposition rate riders for the recovery of Smart Meter costs, HCHI has input the SMFA revenue collected from each rate class into each of the Models. Table 14 details the SMFA revenues collected from each specific customer rate class.

Table 14 – Allocation of Smart Meter Funding Revenue by Customer Class

Billing Period	Residential	General Service Less than 50 kW	General Service 50 to 4,999 kW	Total
May 1, 2006 to December 31, 2006	$ 32,189	$ 4,163	$ 267	$ 36,619
January 1, 2007 to December 31, 2007	56,338	7,234	457	64,029
January 1, 2008 to December 31, 2008	56,563	7,262	424	64,249
January 1, 2009 to December 31, 2009	151,500	19,511	1,136	172,147
January 1, 2010 to December 31, 2010	332,208	42,671	2,474	377,353
January 1, 2011 to December 31, 2011	409,237	51,979	3,121	464,337
January 1, 2012 to June 30, 2012	172,639	22,363	1,307	196,309
Total Smart Meter Funding Adder Revenue	**$ 1,210,674**	**$ 155,183**	**$ 9,186**	**$ 1,375,043**

HCHI has allocated the operating costs to each customer rate class based on the number of installed Smart Meters for each specific class. The 2012 Test Year operating costs have been allocated using the same method as the actual audited operating costs requested for disposition; by number of installed Smart Meters for each specific customer rate class.

Table 15 below provides the operating cost allocation by customer rate class only for those operating costs requested for disposition as part of the SMDR.

Table 15 – Allocation of Operating Costs by Customer Class (SMDR)

Description	Residential	General Service Less than 50 kW	General Service 50 to 4,999 kW	Total
Number of Smart Meters Installed	18,535	2,361	82	20,978
Maintenance (Third Party Contractors - repairs to unsafe meter bases found during installation of Smart Meter)	$ 35,758	$ 4,553	$ 162	$ 40,473
Maintenance (Third Party Contractors - incremental costs incurred during installation of more difficult Smart Meters)	69,491	8,849	315	78,655
Maintenance - TGB Base Station Service Fee	295,147	37,582	1,336	334,065
Maintenance - TGB Flexnet Monitoring Fee	9,425	1,200	43	10,668
Maintenance - TGB Additional Insurance	1,340	171	6	1,517
Customer Communication	32,667	4,160	148	36,975
Program Management - Professional Fees	4,593	585	21	5,199
Program Management - ODS Monthly Service Fee	46,077	5,867	209	52,153
Change Management - Employee Training	3,780	481	17	4,278
Administration Costs - Incremental Labour	78,571	10,005	356	88,932
Other AMI Capital - Smart Meter Security Audit (AMI)	8,200	1,044	37	9,281
Other AMI Capital - Incremental Software Support Fees	10,621	1,352	48	12,021
Other AMI Capital - Employee Training / Workshops	5,660	721	25	6,406
Total Operating Costs Related to Minimum Functionality	**$ 601,330**	**$ 76,570**	**$ 2,723**	**$ 680,623**
Interface between CIS & MDM/R (FTP Site) - Incremental Software Support Fees	$ 2,005	$ 255	$ 9	2,269
TOU Rate Implementation (TOU Customer Sessions, TOU Customer Comparator & Bill Inserts, Media Releases, etc.)	40,905	5,209	184	46,298
Total Operating Costs Beyond Minimum Functionality	**$ 42,910**	**$ 5,464**	**$ 193**	**$ 48,567**
Total Smart Meter Operating Costs	**$ 644,240**	**$ 82,034**	**$ 2,916**	**$ 729,190**
Total Smart Meter Capital & Operating Costs	**$ 3,636,218**	**$ 826,048**	**$ 62,554**	**$ 4,524,820**
Average Capital & Operating Cost per Meter	**$ 196.18**	**$ 349.87**	**$ 762.85**	**$ 215.69**

Table 16 provides the operating cost allocation by customer rate class for the 2012 Test Year.

Table 16 – Allocation of 2012 Test Year Operating Costs by Customer Class

Description	Residential	General Service Less than 50 kW	General Service 50 to 4,999 kW	Total
Number of Smart Meters Installed	18,535	2,361	82	20,978
Maintenance (Third Party Contractors - incremental costs incurred during installation of more difficult Smart Meters)	106,020	13,500	480	120,000
Maintenance - TGB Base Station Service Fee	106,923	13,615	484	121,022
Maintenance - TGB Flexnet Monitoring Fee	22,600	2,878	102	25,580
Customer Communication	7,952	1,013	36	9,001
Program Management - Professional Fees	12,407	1,580	56	14,043
Program Management - ODS Monthly Service Fee	34,492	4,392	156	39,040
Administration Costs - Incremental Labour	59,012	7,514	268	66,794
Other AMI Capital - Smart Meter Security Audit (AMI) & Smart Meter Security Testing for RNI	15,904	2,026	72	18,002
Other AMI Capital - Incremental Software Support Fees	10,365	1,320	46	11,731
Total Operating Costs Related to Minimum Functionality	**$ 375,675**	**$ 47,838**	**$ 1,700**	**$ 425,213**
Interface between CIS & MDM/R (FTP Site) - Incremental Software Support Fees	$ 913	$ 116	$ 4	1,033
Total Operating Costs Beyond Minimum Functionality	**$ 913**	**$ 116**	**$ 4**	**$ 1,033**
Total Smart Meter 2012 Test Year Operating Costs	**$ 376,588**	**$ 47,954**	**$ 1,704**	**$ 426,246**

Table 17 below provides the operating cost allocation by rate class for all operating costs; including audited costs requested for disposition as part of the SMDR calculation and unaudited actual plus forecast costs included as part of the 2012 Test Year revenue requirement for calculation of the SMIRR.

Table 17 – Allocation of Operating Costs by Customer Class
Inclusive of 2012 Test Year

Description	Residential	General Service Less than 50 kW	General Service 50 to 4,999 kW	Total
Number of Smart Meters Installed	18,535	2,361	82	20,978
Maintenance (Third Party Contractors - repairs to unsafe meter bases found during installation of Smart Meter)	$ 35,758	$ 4,553	$ 162	$ 40,473
Maintenance (Third Party Contractors - incremental costs incurred during installation of more difficult Smart Meters)	175,512	22,349	795	198,656
Maintenance - TGB Base Station Service Fee	402,069	51,197	1,820	455,086
Maintenance - TGB Flexnet Monitoring Fee	32,025	4,078	145	36,248
Maintenance - TGB Additional Insurance	1,340	171	6	1,517
Customer Communication	40,619	5,173	184	45,976
Program Management - Professional Fees	17,000	2,165	77	19,242
Program Management - ODS Monthly Service Fee	80,569	10,259	365	91,193
Change Management - Employee Training	3,780	481	17	4,278
Administration Costs - Incremental Labour	137,583	17,519	624	155,726
Other AMI Capital - Smart Meter Security Audit (AMI)	24,104	3,070	109	27,283
Other AMI Capital - Incremental Software Support Fees	20,986	2,672	94	23,752
Other AMI Capital - Employee Training / Workshops	5,660	721	25	6,406
Total Operating Costs Related to Minimum Functionality	**$ 977,005**	**$ 124,408**	**$ 4,423**	**$ 1,105,836**
Interface between CIS & MDM/R (FTP Site) - Incremental Software Support Fees	$ 2,918	$ 371	$ 13	3,302
TOU Rate Implementation (TOU Customer Sessions, TOU Customer Comparator & Bill Inserts, Media Releases, etc.)	40,905	5,209	184	46,298
Total Operating Costs Beyond Minimum Functionality	**$ 43,823**	**$ 5,580**	**$ 197**	**$ 49,600**
Total Smart Meter Operating Costs	**$ 1,020,828**	**$ 129,988**	**$ 4,620**	**$ 1,155,436**

26. Smart Meter Rate Rider Calculations (SMDR, SMIRR, and Foregone Revenue)

HCHI has used the Board’s Model, version 2.17 dated December 15, 2011, for calculating both the Smart Meter Disposition Rate Rider and the Smart Meter Incremental Revenue Requirement Rate Rider with a separate Model prepared for each of three customer rate classes; Residential, General Service Less than 50 kW, and General Service 50 to 4,999 kW.

As previously noted in Section 25, "Cost Allocation", actual capital installed costs for the three customer rate classes have been included in each of their respective Models as well as the SMFA revenues specifically collected from each of these three customer rate classes. The remaining costs have been allocated on the basis of number of installed Smart Meters.

As required in the Board's Model, HCHI has input it's previously Board-approved Weighted Average Capital Cost ("WACC") and Tax rates for the years 2006 through to 2012.

Table 18 provides the WACC and Tax Rates used in each of the three Models.

Table 18 – WACC and Tax Rate Inputs in Smart Meter Models

Year	2006 COS	2007 IRM	2008 IRM	2009 IRM	2010 COS	2011 IRM	2012 IRM
WACC	7.53%	7.53%	7.43%	7.33%	6.90%	6.90%	6.90%
Tax Rates	36.12%	36.12%	33.50%	33.00%	29.79%	28.25%	24.33%

HCHI proposes all three rate riders to be effective for 18 months commencing November 1, 2012 and expiring April 30, 2014, to coincide with its next cost of service application. At the time of rebasing, HCHI's Smart Meter capital and operating costs will be included in its regular operations and incorporated into the rate base and revenue requirement calculations for rates effective May 1, 2014.

The SMDR is based on the Net Deferred Revenue Requirement calculated in the Models as follows:

- Deferred Incremental Revenue Requirement from 2007 to December 31, 2011; Plus
- Interest on OM&A and Amortization expenses from 2007 to December 31, 2011; Less

- SMFA Revenues collected from May 1, 2006 to the 2012 Test Year inclusive plus Simple Interest on the SMFA Revenues from May 1, 2006 to December 31, 2012.

The interest on the SMFA Revenues collected should cease October 31, 2012 at the proposed time of disposition but due to the limitations of the Model, HCHI was not able to override the calculation for the months of November and December.

Table 19 provides the calculation of the SMDR for each customer rate class.

Table 19 – SMDR Summary Calculations

Customer Rate Class	Residential	General Service Less than 50 kW	General Service 50 to 4,999 kW
Revenue Requirement 2007	$ 6,434	$ 819	$ 29
Revenue Requirement 2008	15,005	1,911	68
Revenue Requirement 2009	326,392	35,633	941
Revenue Requirement 2010	572,534	79,851	1,470
Revenue Requirement 2011	721,575	129,779	5,685
Total Revenue Requirement	$ 1,641,940	$ 247,993	$ 8,193
Interest on OM&A and Amortization	17,744	2,375	72
Smart Meter Funding Adder Revenues	(1,210,674)	(155,183)	(9,186)
Interest on SMFA Revenues	(42,340)	(5,430)	(326)
Net Deferred Revenue Requirment	**$ 406,670**	**$ 89,755**	**$ (1,247)**
Number of Metered Customers	18,535	2,361	83
SMDR - Recovery Period November 1, 2012 to April 30, 2014	**$ 1.22**	**$ 2.11**	**$ (0.83)**

The SMIRR is based on the Incremental Revenue Requirement for the 2012 Test Year. Table 20 provides the calculation of the SMIRR for each customer rate class.

Table 20 – SMIRR Summary Calculations

Customer Rate Class	Residential		General Service Less than 50 kW		General Service 50 to 4,999 kW	
Net Fixed Assets		2,407,155		637,639		53,121
Operating Expenses	376,588		47,954		1,704	
Working Capital Factor	15%		15%		15%	
Working Capital Allowance		56,489		7,194		256
Incremental Smart Meter Rate Base		$ 2,463,644		$ 644,833		$ 53,377
Deemed Short Term Debt	4%	98,546	4%	25,793	4%	2,135
Deemed Long Term Debt	56%	1,379,641	56%	361,107	56%	29,891
Deemed Equity	40%	985,458	40%	257,933	40%	21,351
Deemed Short Term Interest	2.07%	2,040	2.07%	534	2.07%	44
Deemed Long Term Interest	5.13%	70,775	5.13%	18,525	5.13%	1,533
Deemed Return on Equity	9.85%	97,068	9.85%	25,406	9.85%	2,103
Total Return on Capital		$ 169,883		$ 44,465		$ 3,680
Operating Expenses		376,588		47,954		1,704
Amortization Expenses		212,803		51,189		3,900
PIL's		32,281		7,323		506
Incremental Revenue Requirement		**$ 791,555**		**$ 150,931**		**$ 9,790**
Number of Metered Customers		18,535		2,361		83
SMIRR - Recovery Period November 1, 2012 to April 30, 2014		**$ 3.56**		**$ 5.33**		**$ 9.83**

HCHI has included six months of Foregone Revenue as a separate rate rider in this Application. In the Model, the SMDR is to recover the Deferred Revenue Requirement as at December 31, 2011 and the SMIRR is to recover the Incremental Revenue Requirement for the 2012 Test Year with a rate effective date of May 1, 2012. The SMIRR would continue until HCHI rebases for rates effective May 1, 2014, a full two year (24 month) rate period. With this Application HCHI is requesting an implementation date of November 1, 2012 which would only result in 18 months collection of the SMIRR. Therefore HCHI is proposing a Foregone Revenue Rate Rider to recover the 6 months of unrecovered 2012 incremental costs.

The Foregone Revenue rate rider has been based on 6 months / 12 months, or one half of the SMIRRs calculated in each of the customer rate class Models as summarized in Table 20 above. Table 21 provides calculations of the Foregone Revenue rate riders for each customer rate class.

Table 21 – Foregone Revenue Rate Rider Calculations

Customer Rate Class	Residential	General Service Less than 50 kW	General Service 50 to 4,999 kW
Incremental Revenue Requirement	$ 791,555	$ 150,931	$ 9,790
Monthly Incremental Revenue Requirement	$ 65,963	$ 12,578	$ 816
Foregone Revenue (Equal to 6 Months of SMIRR)	**$ 395,778**	**$ 75,466**	**$ 4,895**
Number of Metered Customers	18,535	2,361	83
Foregone Revenue - Recovery Period November 1, 2012 to April 30, 2014	**$ 1.19**	**$ 1.78**	**$ 3.28**

HCHI is proposing that all three rate riders, SMDR, SMIRR, and Foregone Revenue, be collected as a fixed monthly charge from each of the three customer rate classes that have installed Smart Meters as detailed in Table 22.

Table 22 – Smart Meter Rate Riders by Customer Class

Customer Rate Class	SMDR	SMIRR	Foregone Revenue	Total
Residential	1.22	3.56	1.19	5.97
General Service Less than 50 kW	2.11	5.33	1.78	9.22
General Service 50 to 4,999 kW	(0.83)	9.83	3.28	12.28

27. Rate Change Summary and Bill Impacts

Table 23 summarizes the rate changes HCHI is seeking approval for in this Application. All charges are shown as monthly fixed charges.

Table 23 – Summary of Smart Meter Rate Changes by Customer Class

Customer Rate Class	SMDR	SMIRR	Foregone Revenue	Total Rate Riders	SMFA (Expired April 30/12)	Net Change
Residential	1.22	3.56	1.19	5.97	(1.87)	4.10
General Service Less than 50 kW	2.11	5.33	1.78	9.22	(1.87)	7.35
General Service 50 to 4,999 kW	(0.83)	9.83	3.28	12.28	(1.87)	10.41

The implementation of the SMDR, SMIRR, and Foregone Revenue rate riders after consideration for the discontinuation of the SMFA would result in a total bill impact increase of $4.17 or 3.2% for the Residential customers, $7.47 or 2.5% for the General Service Less than 50 kW customers, and $11.76 or 0.2% for the General Service 50 to 4,999 kW customers.

HCHI has used the May 1, 2012 Regulated Price Plan two-tiered pricing for commodity calculations and its currently approved rates effective May 1, 2012 in its bill impact calculations.

Detailed calculations are provided on the following three pages.

Name of LDC: **Haldimand County Hydro Inc.**
File Number: **EB-2012-0272**
Effective Date: **November 1, 2012**

Residential

Monthly Rates and Charges	Metric	Current Rate	Applied For Rate
Service Charge	$	16.16	16.16
Service Charge Rate Adder(s) / Rider(s)	$	1.87	5.97
Distribution Volumetric Rate	$/kWh	0.0289	0.0289
Low Voltage Volumetric Rate	$/kWh	0.0004	0.0004
Distribution Volumetric Rate Rider(s)	$/kWh	(0.0020)	(0.0020)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0067	0.0067
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0052	0.0052
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Standard Supply Service – Administration Charge (if applicable)	$	0.25	0.25

** Excludes Global Adjustment Rate Rider specific for Non-RPP Customers

Consumption	800	kWh	-	kW
RPP Tier One	600	kWh	***Load Factor***	

Loss Factor 1.0680

Residential	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	600	0.0750	45.00	600	0.0750	45.00	0.00	0.0%	30.00%
Energy Second Tier (kWh)	254	0.0880	22.39	254	0.0880	22.39	0.00	0.0%	14.92%
Sub-Total: Energy			**67.39**			**67.39**	**0.00**	**0.0%**	**44.92%**
Service Charge	1	16.16	16.16	1	16.16	16.16	0.00	0.0%	10.77%
Service Charge Rate Adder(s)	1	1.87	1.87	1	5.97	5.97	4.10	219.3%	3.98%
Distribution Volumetric Rate	800	0.0289	23.12	800	0.0289	23.12	0.00	0.0%	15.41%
Low Voltage Volumetric Rate	800	0.0004	0.32	800	0.0004	0.32	0.00	0.0%	0.21%
Distribution Volumetric Rate Rider(s)	800	(0.0020)	-1.60	800	(0.0020)	-1.60	0.00	0.0%	-1.07%
Total: Distribution			**39.87**			**43.97**	**4.10**	**10.3%**	**29.31%**
Retail Transmission Rate – Network Service Rate	854	0.0067	5.72	854	0.0067	5.72	0.00	0.0%	3.82%
Retail Transmission Rate – Line and Transformation Connection Service Rate	854	0.0052	4.44	854	0.0052	4.44	0.00	0.0%	2.96%
Total: Retail Transmission			**10.17**			**10.17**	**0.00**	**0.0%**	**6.78%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**50.04**			**54.14**	**4.10**	**8.2%**	**36.09%**
Wholesale Market Service Rate	854	0.0052	4.44	854	0.0052	4.44	0.00	0.0%	2.96%
Rural Rate Protection Charge	854	0.0011	0.94	854	0.0011	0.94	0.00	0.0%	0.63%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.17%
Sub-Total: Regulatory			**5.63**			**5.63**	**0.00**	**0.0%**	**3.75%**
Debt Retirement Charge (DRC)	800	0.0070	**5.60**	800	0.0070	**5.60**	**0.00**	**0.0%**	**3.73%**
Total Bill before Taxes			**128.66**			**132.76**	**4.10**	**3.2%**	**88.50%**
HST		13%	**16.73**		13%	**17.26**	**0.53**	**3.2%**	**11.50%**
Total Bill			**145.38**			**150.02**	**4.63**	**3.2%**	**100.00%**
Ontario Clean Energy Benefit (OCEB)		(10%)	**-14.54**		(10%)	**-15.00**			
Total Bill (less OCEB)			**130.84**			**135.01**	**4.17**	**3.2%**	

Name of LDC: Haldimand County Hydro Inc.
File Number: EB-2012-0272
Effective Date: November 1, 2012

General Service Less Than 50 kW

Monthly Rates and Charges	Metric	Current Rate	Applied For Rate
Service Charge	$	28.90	28.90
Service Charge Rate Adder(s) / Rider(s)	$	1.87	9.22
Distribution Volumetric Rate	$/kWh	0.0204	0.0204
Low Voltage Volumetric Rate	$/kWh	0.0003	0.0003
Distribution Volumetric Rate Rider(s)	$/kWh	(0.0021)	(0.0021)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0060	0.0060
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048	0.0048
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Standard Supply Service – Administration Charge (if applicable)	$	0.25	0.25

** Excludes Global Adjustment Rate Rider specific for Non-RPP Customers

Consumption	2,000	kWh	-	kW
RPP Tier One	600	kWh	*Load Factor*	

Loss Factor	1.0680

General Service Less Than 50 kW	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	600	0.0750	45.00	600	0.0750	45.00	0.00	0.0%	13.00%
Energy Second Tier (kWh)	1,536	0.0880	135.17	1,536	0.0880	135.17	0.00	0.0%	39.06%
Sub-Total: Energy			**180.17**			**180.17**	**0.00**	**0.0%**	**52.06%**
Service Charge	1	28.90	28.90	1	28.90	28.90	0.00	0.0%	8.35%
Service Charge Rate Adder(s)	1	1.87	1.87	1	9.22	9.22	7.35	393.0%	2.66%
Distribution Volumetric Rate	2,000	0.0204	40.80	2,000	0.0204	40.80	0.00	0.0%	11.79%
Low Voltage Volumetric Rate	2,000	0.0003	0.60	2,000	0.0003	0.60	0.00	0.0%	0.17%
Distribution Volumetric Rate Rider(s)	2,000	(0.0021)	-4.20	2,000	(0.0021)	-4.20	0.00	0.0%	-1.21%
Total: Distribution			**67.97**			**75.32**	**7.35**	**10.8%**	**21.76%**
Retail Transmission Rate – Network Service Rate	2,136	0.0060	12.82	2,136	0.0060	12.82	0.00	0.0%	3.70%
Retail Transmission Rate – Line and Transformation Connection Service Rate	2,136	0.0048	10.25	2,136	0.0048	10.25	0.00	0.0%	2.96%
Total: Retail Transmission			**23.07**			**23.07**	**0.00**	**0.0%**	**6.67%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**91.04**			**98.39**	**7.35**	**8.1%**	**28.43%**
Wholesale Market Service Rate	2,136	0.0052	11.11	2,136	0.0052	11.11	0.00	0.0%	3.21%
Rural Rate Protection Charge	2,136	0.0011	2.35	2,136	0.0011	2.35	0.00	0.0%	0.68%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.07%
Sub-Total: Regulatory			**13.71**			**13.71**	**0.00**	**0.0%**	**3.96%**
Debt Retirement Charge (DRC)	2,000	0.0070	**14.00**	2,000	0.0070	**14.00**	**0.00**	**0.0%**	**4.05%**
Total Bill before Taxes			**298.91**			**306.26**	**7.35**	**2.5%**	**88.50%**
HST		13%	**38.86**		13%	**39.81**	**0.96**	**2.5%**	**11.50%**
Total Bill			**337.77**			**346.08**	**8.31**	**2.5%**	**100.00%**
Ontario Clean Energy Benefit (OCEB)		(10%)	**-33.78**		(10%)	**-34.61**			
Total Bill (less OCEB)			**304.00**			**311.47**	**7.47**	**2.5%**	

Name of LDC: **Haldimand County Hydro Inc.**
File Number: **EB-2012-0272**
Effective Date: **November 1, 2012**

General Service 50 to 4,999 kW

Monthly Rates and Charges	Metric	Current Rate	Applied For Rate
Service Charge	$	103.56	103.56
Service Charge Rate Adder(s) / Rider(s)	$	1.87	12.28
Distribution Volumetric Rate	$/kW	4.8055	4.8055
Low Voltage Volumetric Rate	$/kW	0.1502	0.1502
Distribution Volumetric Rate Rider(s)	$/kW	(0.7765)	(0.7765)
Retail Transmission Rate – Network Service Rate	$/kW	2.4495	2.4495
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.8820	1.8820
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Standard Supply Service – Administration Charge (if applicable)	$	0.25	0.25

** Excludes Global Adjustment Rate Rider specific for Non-RPP Customers

Consumption	50,000	kWh	75.00	kW	***Loss Factor***	1.0680
RPP Tier One		kWh	***Load Factor***			

General Service 50 to 4,999 kW	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	53,400	0.0750	4,005.00	53,400	0.0750	4,005.00	0.00	0.0%	65.08%
Energy Second Tier (kWh)			0.00			0.00	0.00	0.0%	0.00%
Sub-Total: Energy			**4,005.00**			**4,005.00**	**0.00**	**0.0%**	**65.08%**
Service Charge	1	103.56	103.56	1	103.56	103.56	0.00	0.0%	1.68%
Service Charge Rate Adder(s)	1	1.87	1.87	1	12.28	12.28	10.41	556.7%	0.20%
Distribution Volumetric Rate	75	4.8055	360.41	75	4.8055	360.41	0.00	0.0%	5.86%
Low Voltage Volumetric Rate	75	0.1502	11.27	75	0.1502	11.27	0.00	0.0%	0.18%
Distribution Volumetric Rate Rider(s)	75	(0.7765)	-58.24	75	(0.7765)	-58.24	0.00	0.0%	-0.95%
Total: Distribution			**418.87**			**429.28**	**10.41**	**2.5%**	**6.98%**
Retail Transmission Rate – Network Service Rate	75	2.4495	183.71	75	2.4495	183.71	0.00	0.0%	2.99%
Retail Transmission Rate – Line and Transformation Connection Service Rate	75	1.8820	141.15	75	1.8820	141.15	0.00	0.0%	2.29%
Total: Retail Transmission			**324.86**			**324.86**	**0.00**	**0.0%**	**5.28%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**743.73**			**754.14**	**10.41**	**1.4%**	**12.25%**
Wholesale Market Service Rate	53,400	0.0052	277.68	53,400	0.0052	277.68	0.00	0.0%	4.51%
Rural Rate Protection Charge	53,400	0.0011	58.74	53,400	0.0011	58.74	0.00	0.0%	0.95%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.00%
Sub-Total: Regulatory			**336.67**			**336.67**	**0.00**	**0.0%**	**5.47%**
Debt Retirement Charge (DRC)	50,000	0.0070	**350.00**	50,000	0.0070	**350.00**	**0.00**	**0.0%**	**5.69%**
Total Bill before Taxes			**5,435.40**			**5,445.81**	**10.41**	**0.2%**	**88.50%**
HST		13%	**706.60**		13%	**707.96**	**1.35**	**0.2%**	**11.50%**
Total Bill			**6,142.00**			**6,153.77**	**11.76**	**0.2%**	**100.00%**
Ontario Clean Energy Benefit (OCEB)			**0.00**			**0.00**			
Total Bill (less OCEB)			**6,142.00**			**6,153.77**	**11.76**	**0.2%**	

CONCLUSION

HCHI respectfully submits that the costs incurred to fulfill its obligations under the provincially mandated Smart Meter initiative, as described in this Application, were necessary and prudently incurred in accordance with the Board's Guidelines. HCHI's costs per installed Smart Meter, both for capital and on a combined capital and operating basis are acceptable when compared to the sector averages; the proposed riders are just and reasonable; and the associated customer total bill impacts are acceptable. Accordingly, it is appropriate that the Board approve the disposition for recovery of costs for Smart Meter deployment and operation through the proposed SMDR, SMIRR and Foregone Revenue rate riders over an 18 month period effective November 1, 2012.

APPENDIX A

2012 Smart Meter Model

1. Residential Rate Class

V 2.17

Ontario Energy Board

Smart Meter Model

Choose Your Utility:

Haldimand County Hydro Inc.

Halton Hills Hydro Inc.

Application Contact Information

Name:	Jacqueline A. Scott
Title:	Finance Manager
Phone Number:	905-765-5211 ext. 2237
Email Address:	jscott@hchydro.ca
We are applying for rates effective:	November 1, 2012
Last COS Re-based Year	2010

Legend

DROP-DOWN MENU

INPUT FIELD

CALCULATION FIELD

Copyright

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results. The use of any models and spreadsheets does not automatically imply Board approval. The onus is on the distributor to prepare, document and support its application. Board-issued Excel models and spreadsheets are offered to assist parties in providing the necessary information so as to facilitate an expeditious review of an application. The onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Smart Meter Model

Haldimand County Hydro Inc.

Distributors must enter all incremental costs related to their smart meter program and all revenues recovered to date in the applicable tabs except for those costs (and associated revenues) for which the Board has approved on a final basis, i.e. capital costs have been included in rate base and OM&A costs in revenue requirement.

For 2012, distributors that have completed their deployments by the end of 2011 are not expected to enter any capital costs. However, for OM&A, regardless of whether a distributor has deployments in 2012, distributors should enter the forecasted OM&A for 2012 for all smart meters in service.

		2006	2007	2008	2009	2010	2011	2012 and later	Total
Smart Meter Capital Cost and Operational Expense Data		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
Smart Meter Installation Plan									
Actual/Planned number of Smart Meters installed during the Calendar Year									
Residential					16,583	1,703	238	11	18535
General Service < 50 kW									0
Actual/Planned number of Smart Meters installed (Residential and GS < 50 kW only)		0	0	0	16583	1703	238	11	18535
Percentage of Residential and GS < 50 kW Smart Meter Installations Completed		0.00%	0.00%	0.00%	89.47%	98.66%	99.94%	100.00%	100.00%
Actual/Planned number of GS > 50 kW meters installed									0
Other (please identify)									0
Total Number of Smart Meters installed or planned to be installed		0	0	0	16583	1703	238	11	18535
1 Capital Costs									
1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	**Asset Type** Asset type must be selected to enable calculations	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.1.1 Smart Meters *(may include new meters and modules, etc.)*	Smart Meter				1,342,524	280,231	41,092	889	$ 1,664,736
1.1.2 Installation Costs *(may include socket kits, labour, vehicle, benefits, etc.)*	Smart Meter		67,390	22,454	306,106	138,745	20,154	130	$ 554,979
1.1.3a Workforce Automation Hardware *(may include fieldwork handhelds, barcode hardware, etc.)*	Computer Hardware				3,743	36,801	4,597		$ 45,141
1.1.3b Workforce Automation Software *(may include fieldwork handhelds, barcode hardware, etc.)*	Computer Software				1,925	18,018	19,853		$ 39,796
Total Advanced Metering Communications Devices (AMCD)		$ -	$ 67,390	$ 22,454	$ 1,654,298	$ 473,795	$ 85,696	$ 1,019	$ 2,304,652
1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)	**Asset Type**	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.2.1 Collectors	Smart Meter				499,390				$ 499,390
1.2.2 Repeaters *(may include radio licence, etc.)*	Smart Meter								$ -
1.2.3 Installation *(may include meter seals and rings, collector computer hardware, etc.)*	Smart Meter				55,418	11,026	302		$ 66,746
Total Advanced Metering Regional Collector (AMRC) (Includes LAN)		$ -	$ -	$ -	$ 554,808	$ 11,026	$ 302	$ -	$ 566,136

1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.3.1 Computer Hardware	Computer Hardware								$ -
1.3.2 Computer Software	Computer Software								$ -
1.3.3 Computer Software Licences & Installation (includes hardware and software) *(may include AS/400 disk space, backup and recovery computer, UPS, etc.)*	Computer Software								$ -
Total Advanced Metering Control Computer (AMCC)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

1.4 WIDE AREA NETWORK (WAN)	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.4.1 Activiation Fees									$ -
Total Wide Area Network (WAN)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.5.1 Customer Equipment *(including repair of damaged equipment)*									$ -
1.5.2 AMI Interface to CIS	Computer Software				2,147	3,901	522		$ 6,570
1.5.3 Professional Fees	Smart Meter		12,624	13,178	22,719	15,416	9,506		$ 73,443
1.5.4 Integration	Computer Software					7,011	1,767		$ 8,778
1.5.5 Program Management									$ -
1.5.6 Other AMI Capital	Smart Meter					367	103		$ 470
Total Other AMI Capital Costs Related to Minimum Functionality		$ -	$ 12,624	$ 13,178	$ 24,866	$ 26,695	$ 11,898	$ -	$ 89,261
Total Capital Costs Related to Minimum Functionality		$ -	$ 80,014	$ 35,632	$ 2,233,972	$ 511,516	$ 97,896	$ 1,019	$ 2,960,049

1.6 CAPITAL COSTS BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06	Computer Software								$ -
1.6.2 Costs for deployment of smart meters to customers other than residential and small general service	Applications Software								$ -
1.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.	Smart Meter					3,765	28,163		$ 31,928
Total Capital Costs Beyond Minimum Functionality		$ -	$ -	$ -	$ -	$ 3,765	$ 28,163	$ -	$ 31,928
Total Smart Meter Capital Costs		$ -	$ 80,014	$ 35,632	$ 2,233,972	$ 515,281	$ 126,059	$ 1,019	$ 2,991,977

2 OM&A Expenses

	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)								
2.1.1 Maintenance *(may include meter reverification costs, etc.)*				25,219	10,539	69,491	106,020	$ 211,269
2.1.2 Other *(please specifiy)*								$ -
Total Incremental AMCD OM&A Costs	$ -	$ -	$ -	$ 25,219	$ 10,539	$ 69,491	$ 106,020	$ 211,269
2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)								
2.2.1 Maintenance				73,620	132,582	98,370	129,523	$ 434,095
2.2.2 Other *(please specifiy)* Additional Insurance re: Tower Gateway Base Stations				1,340				$ 1,340
Total Incremental AMRC OM&A Costs	$ -	$ -	$ -	$ 74,960	$ 132,582	$ 98,370	$ 129,523	$ 435,435
2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)								
2.3.1 Hardware Maintenance *(may include server support, etc.)*								$ -
2.3.2 Software Maintenance *(may include maintenance support, etc.)*								$ -
2.3.2 Other *(please specifiy)*								$ -
Total Incremental AMCC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.4 WIDE AREA NETWORK (WAN)								
2.4.1 WAN Maintenance								$ -
2.4.2 Other *(please specifiy)*								$ -
Total Incremental AMRC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY								
2.5.1 Business Process Redesign								$ -
2.5.2 Customer Communication (may include project communication, etc.)				26,921		5,746	7,952	$ 40,619
2.5.3 Program Management					16,862	33,808	46,899	$ 97,569
2.5.4 Change Management (may include training, etc.)					2,878	902		$ 3,780
2.5.5 Administration Costs				9,500	30,344	38,727	59,012	$ 137,583
2.5.6 Other AMI Expenses *(please specify)*					10,434	14,047	26,269	$ 50,750
Total Other AMI OM&A Costs Related to Minimum Functionality	$ -	$ -	$ -	$ 36,421	$ 60,518	$ 93,230	$ 140,132	$ 330,301
TOTAL OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY	$ -	$ -	$ -	$ 136,600	$ 203,639	$ 261,091	$ 375,675	$ 977,005
2.6 OM&A COSTS RELATED TO BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual		
2.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06								$ -
2.6.2 Costs for deployment of smart meters to customers other than residential and small general service								$ -
2.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.					263	42,647	913	$ 43,823
Total OM&A Costs Beyond Minimum Functionality	$ -	$ -	$ -	$ -	$ 263	$ 42,647	$ 913	$ 43,823
Total Smart Meter OM&A Costs	$ -	$ -	$ -	$ 136,600	$ 203,902	$ 303,738	$ 376,588	$ 1,020,828

3 Aggregate Smart Meter Costs by Category

3.1	**Capital**								
3.1.1	Smart Meter	$ -	$ 80,014	$ 35,632	$ 2,226,157	$ 449,550	$ 99,320	$ 1,019	$ 2,891,692
3.1.2	Computer Hardware	$ -	$ -	$ -	$ 3,743	$ 36,801	$ 4,597	$ -	$ 45,141
3.1.3	Computer Software	$ -	$ -	$ -	$ 4,072	$ 28,930	$ 22,142	$ -	$ 55,144
3.1.4	Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.5	Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.6	Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.7	**Total Capital Costs**	**$ -**	**$ 80,014**	**$ 35,632**	**$ 2,233,972**	**$ 515,281**	**$ 126,059**	**$ 1,019**	**$ 2,991,977**
3.2	**OM&A Costs**								
3.2.1	**Total OM&A Costs**	**$ -**	**$ -**	**$ -**	**$ 136,600**	**$ 203,902**	**$ 303,738**	**$ 376,588**	**$ 1,020,828**

Haldimand County Hydro Inc.

	2006	2007	2008	2009	2010	2011	2012 and later
Cost of Capital							
Capital Structure[1]							
Deemed Short-term Debt Capitalization					4.0%	4.0%	4.0%
Deemed Long-term Debt Capitalization	50.0%	50.0%	53.3%	56.7%	56.0%	56.0%	56.0%
Deemed Equity Capitalization	50.0%	50.0%	46.7%	43.3%	40.0%	40.0%	40.0%
Preferred Shares							
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Cost of Capital Parameters							
Deemed Short-term Debt Rate					2.07%	2.07%	2.07%
Long-term Debt Rate (actual/embedded/deemed)[2]	6.05%	6.05%	6.05%	6.05%	5.13%	5.13%	5.13%
Target Return on Equity (ROE)	9.0%	9.00%	9.00%	9.00%	9.85%	9.85%	9.85%
Return on Preferred Shares							
WACC	7.53%	7.53%	7.43%	7.33%	6.90%	6.90%	6.90%
Working Capital Allowance							
Working Capital Allowance Rate	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
(% of the sum of Cost of Power + controllable expenses)							
Taxes/PILs							
Aggregate Corporate Income Tax Rate	36.12%	36.12%	33.50%	33.00%	29.79%	28.25%	24.33%
Capital Tax (until July 1st, 2010)	0.30%	0.225%	0.225%	0.225%	0.075%	0.00%	0.00%
Depreciation Rates							
(expressed as expected useful life in years)							
Smart Meters - years	15	15	15	15	15	15	15
- rate (%)	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
Computer Hardware - years	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Computer Software - years	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Tools & Equipment - years	10	10	10	10	10	10	10
- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Other Equipment - years	10	10	10	10	10	10	10
- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
CCA Rates							
Smart Meters - CCA Class	47	47	47	47	47	47	47
Smart Meters - CCA Rate	8%	8%	8%	8%	8%	8%	8%
Computer Equipment - CCA Class	45	45	50	52	52	50	50
Computer Equipment - CCA Rate	45%	45%	55%	100%	100%	55%	55%
General Equipment - CCA Class	8	8	8	8	8	8	8
General Equipment - CCA Rate	20%	20%	20%	20%	20%	20%	20%
Applications Software - CCA Class	45	45	50	52	52	50	50
Applications Software - CCA Rate	45%	45%	55%	100%	100%	55%	55%

Assumptions

1 *Planned smart meter installations occur evenly throughout the year.*

2 *Fiscal calendar year (January 1 to December 31) used.*

3 *Amortization is done on a striaght line basis and has the "half-year" rule applied.*

Ontario Energy Board

Smart Meter Model

Haldimand County Hydro Inc.

Net Fixed Assets - Smart Meters

	2006	2007	2008	2009	2010	2011	2012 and later
Gross Book Value							
Opening Balance		$ -	$ 80,014	$ 115,646	$ 2,341,803	$ 2,791,353	$ 2,890,673
Capital Additions during year (from Smart Meter Costs)	$ -	$ 80,014	$ 35,632	$ 2,226,157	$ 449,550	$ 99,320	$ 1,019
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ 80,014	$ 115,646	$ 2,341,803	$ 2,791,353	$ 2,890,673	$ 2,891,692
Accumulated Depreciation							
Opening Balance		$ -	-$ 2,667	-$ 9,189	-$ 91,104	-$ 262,209	-$ 451,610
Amortization expense during year	$ -	-$ 2,667	-$ 6,522	-$ 81,915	-$ 171,105	-$ 189,401	-$ 192,746
Retirements/Removals (if applicable)							
Closing Balance	$ -	-$ 2,667	-$ 9,189	-$ 91,104	-$ 262,209	-$ 451,610	-$ 644,356
Net Book Value							
Opening Balance	$ -	$ -	$ 77,347	$ 106,457	$ 2,250,699	$ 2,529,144	$ 2,439,063
Closing Balance	$ -	$ 77,347	$ 106,457	$ 2,250,699	$ 2,529,144	$ 2,439,063	$ 2,247,336
Average Net Book Value	$ -	$ 38,673	$ 91,902	$ 1,178,578	$ 2,389,921	$ 2,484,103	$ 2,343,200

Net Fixed Assets - Computer Hardware

	2006	2007	2008	2009	2010	2011	2012 and later
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ 3,743	$ 40,544	$ 45,141
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 3,743	$ 36,801	$ 4,597	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ 3,743	$ 40,544	$ 45,141	$ 45,141
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	-$ 374	-$ 4,803	-$ 13,372
Amortization expense during year	$ -	$ -	$ -	-$ 374	-$ 4,429	-$ 8,569	-$ 9,028
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	-$ 374	-$ 4,803	-$ 13,372	-$ 22,400
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ 3,369	$ 35,741	$ 31,770
Closing Balance	$ -	$ -	$ -	$ 3,369	$ 35,741	$ 31,770	$ 22,741
Average Net Book Value	$ -	$ -	$ -	$ 1,684	$ 19,555	$ 33,755	$ 27,255

Net Fixed Assets - Computer Software (including Applications Software)

	2006	2007	2008	2009	2010	2011	2012 and later
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ 4,072	$ 33,002	$ 55,144
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 4,072	$ 28,930	$ 22,142	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ 4,072	$ 33,002	$ 55,144	$ 55,144
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	-$ 407	-$ 4,115	-$ 12,929
Amortization expense during year	$ -	$ -	$ -	-$ 407	-$ 3,707	-$ 8,815	-$ 11,029
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	-$ 407	-$ 4,115	-$ 12,929	-$ 23,958
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ 3,665	$ 28,887	$ 42,215
Closing Balance	$ -	$ -	$ -	$ 3,665	$ 28,887	$ 42,215	$ 31,186
Average Net Book Value	$ -	$ -	$ -	$ 1,832	$ 16,276	$ 35,551	$ 36,700

Net Fixed Assets - Tools and Equipment

	2006	2007	2008	2009	2010	2011	2012 and later
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Net Fixed Assets - Other Equipment

	2006	2007	2008	2009	2010	2011	2012 and later
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Ontario Energy Board

Smart Meter Model

Haldimand County Hydro Inc.

	2006	2007	2008	2009	2010	2011	2012 and Later
Average Net Fixed Asset Values (from Sheet 4)							
Smart Meters	$ -	$ 38,673	$ 91,902	$ 1,178,578	$ 2,389,921	$ 2,484,103	$ 2,343,200
Computer Hardware	$ -	$ -	$ -	$ 1,684	$ 19,555	$ 33,755	$ 27,255
Computer Software	$ -	$ -	$ -	$ 1,832	$ 16,276	$ 35,551	$ 36,700
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Net Fixed Assets	**$ -**	**$ 38,673**	**$ 91,902**	**$ 1,182,095**	**$ 2,425,752**	**$ 2,553,410**	**$ 2,407,155**
Working Capital							
Operating Expenses (from Sheet 2)	$ -	$ -	$ -	$ 136,600	$ 203,902	$ 303,738	$ 376,588
Working Capital Factor (from Sheet 3)	15%	15%	15%	15%	15%	15%	15%
Working Capital Allowance	$ -	$ -	$ -	$ 20,490	$ 30,585	$ 45,561	$ 56,488
Incremental Smart Meter Rate Base	**$ -**	**$ 38,673**	**$ 91,902**	**$ 1,202,585**	**$ 2,456,338**	**$ 2,598,970**	**$ 2,463,644**
Return on Rate Base							
Capital Structure							
Deemed Short Term Debt	$ -	$ -	$ -	$ -	$ 98,254	$ 103,959	$ 98,546
Deemed Long Term Debt	$ -	$ 19,337	$ 48,984	$ 681,865	$ 1,375,549	$ 1,455,423	$ 1,379,640
Equity	$ -	$ 19,337	$ 42,918	$ 520,719	$ 982,535	$ 1,039,588	$ 985,457
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capitalization	$ -	$ 38,673	$ 91,902	$ 1,202,585	$ 2,456,338	$ 2,598,970	$ 2,463,644
Return on							
Deemed Short Term Debt	$ -	$ -	$ -	$ -	$ 2,034	$ 2,152	$ 2,040
Deemed Long Term Debt	$ -	$ 1,170	$ 2,964	$ 41,253	$ 70,566	$ 74,663	$ 70,776
Equity	$ -	$ 1,740	$ 3,863	$ 46,865	$ 96,780	$ 102,399	$ 97,068
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Return on Capital	$ -	$ 2,910	$ 6,826	$ 88,118	$ 169,379	$ 179,215	$ 169,883
Operating Expenses	$ -	$ -	$ -	$ 136,600	$ 203,902	$ 303,738	$ 376,588
Amortization Expenses (from Sheet 4)							
Smart Meters	$ -	$ 2,667	$ 6,522	$ 81,915	$ 171,105	$ 189,401	$ 192,746
Computer Hardware	$ -	$ -	$ -	$ 374	$ 4,429	$ 8,569	$ 9,028
Computer Software	$ -	$ -	$ -	$ 407	$ 3,707	$ 8,815	$ 11,029
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Amortization Expense in Year	$ -	$ 2,667	$ 6,522	$ 82,696	$ 179,241	$ 206,784	$ 212,803
Incremental Revenue Requirement before Taxes/PILs	$ -	$ 5,577	$ 13,348	$ 307,414	$ 552,523	$ 689,737	$ 759,274
Calculation of Taxable Income							
Incremental Operating Expenses	$ -	$ -	$ -	$ 136,600	$ 203,902	$ 303,738	$ 376,588
Amortization Expense	$ -	$ 2,667	$ 6,522	$ 82,696	$ 179,241	$ 206,784	$ 212,803
Interest Expense	$ -	$ 1,170	$ 2,964	$ 41,253	$ 72,600	$ 76,815	$ 72,815
Net Income for Taxes/PILs	$ -	$ 1,740	$ 3,863	$ 46,865	$ 96,780	$ 102,399	$ 97,068
Grossed-up Taxes/PILs (from Sheet 7)	$ -	$ 856.44	$ 1,657.25	$ 18,978.02	$ 20,011.25	$ 31,838.15	$ 32,281.54
Revenue Requirement, including Grossed-up Taxes/PILs	$ -	$ 6,434	$ 15,005	$ 326,392	$ 572,534	$ 721,575	$ 791,555

Ontario Energy Board
Smart Meter Model

Haldimand County Hydro Inc.

For PILs Calculation

UCC - Smart Meters

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ 76,813.44	$ 104,875.08	$ 2,233,595.80	$ 2,486,476.13	$ 2,382,905.24
Capital Additions	$ -	$ 80,014.00	$ 35,632.00	$ 2,226,157.00	$ 449,550.00	$ 99,320.00	$ 1,019.00
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ 80,014.00	$ 112,445.44	$ 2,331,032.08	$ 2,683,145.80	$ 2,585,796.13	$ 2,383,924.24
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 40,007.00	$ 17,816.00	$ 1,113,078.50	$ 224,775.00	$ 49,660.00	$ 509.50
Reduced UCC	$ -	$ 40,007.00	$ 94,629.44	$ 1,217,953.58	$ 2,458,370.80	$ 2,536,136.13	$ 2,383,414.74
CCA Rate Class	47	47	47	47	47	47	47
CCA Rate	8%	8%	8%	8%	8%	8%	8%
CCA	$ -	$ 3,200.56	$ 7,570.36	$ 97,436.29	$ 196,669.66	$ 202,890.89	$ 190,673.18
Closing UCC	$ -	$ 76,813.44	$ 104,875.08	$ 2,233,595.80	$ 2,486,476.13	$ 2,382,905.24	$ 2,193,251.06

UCC - Computer Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ 3,907.50	$ 32,865.50	$ 34,175.25
Capital Additions Computer Hardware	$ -	$ -	$ -	$ 3,743.00	$ 36,801.00	$ 4,597.00	$ -
Capital Additions Computer Software	$ -	$ -	$ -	$ 4,072.00	$ 28,930.00	$ 22,142.00	$ -
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ -	$ -	$ 7,815.00	$ 69,638.50	$ 59,604.50	$ 34,175.25
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ 3,907.50	$ 32,865.50	$ 13,369.50	$ -
Reduced UCC	$ -	$ -	$ -	$ 3,907.50	$ 36,773.00	$ 46,235.00	$ 34,175.25
CCA Rate Class	45	45	50	52	52	50	50
CCA Rate	45%	45%	55%	100%	100%	55%	55%
CCA	$ -	$ -	$ -	$ 3,907.50	$ 36,773.00	$ 25,429.25	$ 18,796.39
Closing UCC	$ -	$ -	$ -	$ 3,907.50	$ 32,865.50	$ 34,175.25	$ 15,378.86

UCC - General Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class	8	8	8	8	8	8	8
CCA Rate	20%	20%	20%	20%	20%	20%	20%
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -

PILs Calculation

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
INCOME TAX							
Net Income	$ -	$ 1,740.30	$ 3,862.64	$ 46,864.72	$ 96,779.70	$ 102,399.43	$ 97,067.56
Amortization	$ -	$ 2,667.13	$ 6,522.00	$ 82,696.47	$ 179,241.30	$ 206,783.97	$ 212,802.50
CCA - Smart Meters	$ -	-$ 3,200.56	-$ 7,570.36	-$ 97,436.29	-$ 196,669.66	-$ 202,890.89	-$ 190,673.18
CCA - Computers	$ -	$ -	$ -	-$ 3,907.50	-$ 36,773.00	-$ 25,429.25	-$ 18,796.39
CCA - Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA - Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Change in taxable income	$ -	$ 1,206.88	$ 2,814.28	$ 28,217.40	$ 42,578.34	$ 80,863.26	$ 100,400.49
Tax Rate (from Sheet 3)	36.12%	36.12%	33.50%	33.00%	29.79%	28.25%	24.33%
Income Taxes Payable	$ -	$ 435.92	$ 942.78	$ 9,311.74	$ 12,684.09	$ 22,843.87	$ 24,427.44
ONTARIO CAPITAL TAX							
Smart Meters	$ -	$ 77,346.87	$ 106,456.87	$ 2,250,698.90	$ 2,529,143.70	$ 2,439,062.83	$ 2,247,336.33
Computer Hardware	$ -	$ -	$ -	$ 3,368.70	$ 35,741.00	$ 31,769.50	$ 22,741.30
Computer Software (Including Application Software)	$ -	$ -	$ -	$ 3,664.80	$ 28,887.40	$ 42,214.80	$ 31,186.00
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rate Base	$ -	$ 77,346.87	$ 106,456.87	$ 2,257,732.40	$ 2,593,772.10	$ 2,513,047.13	$ 2,301,263.63
Less: Exemption							
Deemed Taxable Capital	$ -	$ 77,346.87	$ 106,456.87	$ 2,257,732.40	$ 2,593,772.10	$ 2,513,047.13	$ 2,301,263.63
Ontario Capital Tax Rate (from Sheet 3)	0.300%	0.225%	0.225%	0.225%	0.075%	0.000%	0.000%
Net Amount (Taxable Capital x Rate)	$ -	$ 174.03	$ 239.53	$ 5,079.90	$ 1,945.33	$ -	$ -
Change in Income Taxes Payable	$ -	$ 435.92	$ 942.78	$ 9,311.74	$ 12,684.09	$ 22,843.87	$ 24,427.44
Change in OCT	$ -	$ 174.03	$ 239.53	$ 5,079.90	$ 1,945.33	$ -	$ -
PILs	$ -	$ 609.95	$ 1,182.31	$ 14,391.64	$ 14,629.42	$ 22,843.87	$ 24,427.44

Gross Up PILs

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Tax Rate	36.12%	36.12%	33.50%	33.00%	29.79%	28.25%	24.33%
Change in Income Taxes Payable	$ -	$ 682.41	$ 1,417.72	$ 13,898.12	$ 18,065.93	$ 31,838.15	$ 32,281.54
Change in OCT	$ -	$ 174.03	$ 239.53	$ 5,079.90	$ 1,945.33	$ -	$ -
PILs	$ -	$ 856.44	$ 1,657.25	$ 18,978.02	$ 20,011.25	$ 31,838.15	$ 32,281.54

Haldimand County Hydro Inc.

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP
2006 Q1		
2006 Q2	4.14%	4.68%
2006 Q3	4.59%	5.05%
2006 Q4	4.59%	4.72%
2007 Q1	4.59%	4.72%
2007 Q2	4.59%	4.72%
2007 Q3	4.59%	5.18%
2007 Q4	5.14%	5.18%
2008 Q1	5.14%	5.18%
2008 Q2	4.08%	5.18%
2008 Q3	3.35%	5.43%
2008 Q4	3.35%	5.43%
2009 Q1	2.45%	6.61%
2009 Q2	1.00%	6.61%
2009 Q3	0.55%	5.67%
2009 Q4	0.55%	4.66%
2010 Q1	0.55%	4.34%
2010 Q2	0.55%	4.34%
2010 Q3	0.89%	4.66%
2010 Q4	1.20%	4.01%
2011 Q1	1.47%	4.29%
2011 Q2	1.47%	4.29%
2011 Q3	1.47%	4.29%
2011 Q4	1.47%	4.29%
2012 Q1	1.47%	4.29%
2012 Q2	1.47%	4.29%
2012 Q3	1.47%	4.29%
2012 Q4	1.47%	4.29%

Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
Jan-06	2006	Q1	$ -		0.00%	$ -	$ -		
Feb-06	2006	Q1	$ -		0.00%	$ -	$ -		
Mar-06	2006	Q1	$ -		0.00%	$ -	$ -		
Apr-06	2006	Q2	$ -		4.14%	$ -	$ -		
May-06	2006	Q2	$ -	$ 356.72	4.14%	$ -	$ 356.72		$ 0.26
Jun-06	2006	Q2	$ 356.72	$ 4,128.28	4.14%	$ 1.23	$ 4,486.23		$ 0.26
Jul-06	2006	Q3	$ 4,485.00	$ 4,345.38	4.59%	$ 17.16	$ 8,847.54		$ 0.26
Aug-06	2006	Q3	$ 8,830.38	$ 5,273.58	4.59%	$ 33.78	$ 14,137.74		$ 0.26
Sep-06	2006	Q3	$ 14,103.96	$ 4,066.66	4.59%	$ 53.95	$ 18,224.57		$ 0.26
Oct-06	2006	Q4	$ 18,170.62	$ 4,669.60	4.59%	$ 69.50	$ 22,909.72		$ 0.26
Nov-06	2006	Q4	$ 22,840.22	$ 4,981.86	4.59%	$ 87.36	$ 27,909.44		$ 0.26
Dec-06	2006	Q4	$ 27,822.08	$ 4,366.44	4.59%	$ 106.42	$ 32,294.94	$ 32,557.92	$ 0.26
Jan-07	2007	Q1	$ 32,188.52	$ 4,693.78	4.59%	$ 123.12	$ 37,005.42		$ 0.26
Feb-07	2007	Q1	$ 36,882.30	$ 4,684.68	4.59%	$ 141.07	$ 41,708.05		$ 0.26
Mar-07	2007	Q1	$ 41,566.98	$ 5,002.40	4.59%	$ 158.99	$ 46,728.37		$ 0.26
Apr-07	2007	Q2	$ 46,569.38	$ 4,364.88	4.59%	$ 178.13	$ 51,112.39		$ 0.26
May-07	2007	Q2	$ 50,934.26	$ 5,008.12	4.59%	$ 194.82	$ 56,137.20		$ 0.26
Jun-07	2007	Q2	$ 55,942.38	$ 4,689.36	4.59%	$ 213.98	$ 60,845.72		$ 0.26
Jul-07	2007	Q3	$ 60,631.74	$ 4,704.70	4.59%	$ 231.92	$ 65,568.36		$ 0.26
Aug-07	2007	Q3	$ 65,336.44	$ 4,986.28	4.59%	$ 249.91	$ 70,572.63		$ 0.26
Sep-07	2007	Q3	$ 70,322.72	$ 4,079.40	4.59%	$ 268.98	$ 74,671.10		$ 0.26
Oct-07	2007	Q4	$ 74,402.12	$ 5,040.36	5.14%	$ 318.69	$ 79,761.17		$ 0.26
Nov-07	2007	Q4	$ 79,442.48	$ 4,997.20	5.14%	$ 340.28	$ 84,779.96		$ 0.26
Dec-07	2007	Q4	$ 84,439.68	$ 4,086.68	5.14%	$ 361.68	$ 88,888.04	$ 59,119.41	$ 0.26
Jan-08	2008	Q1	$ 88,526.36	$ 5,050.24	5.14%	$ 379.19	$ 93,955.79		$ 0.26
Feb-08	2008	Q1	$ 93,576.60	$ 4,384.64	5.14%	$ 400.82	$ 98,362.06		$ 0.26
Mar-08	2008	Q1	$ 97,961.24	$ 4,392.70	5.14%	$ 419.60	$ 102,773.54		$ 0.26
Apr-08	2008	Q2	$ 102,353.94	$ 4,890.08	4.08%	$ 348.00	$ 107,592.02		$ 0.26
May-08	2008	Q2	$ 107,244.02	$ 4,717.18	4.08%	$ 364.63	$ 112,325.83		$ 0.26
Jun-08	2008	Q2	$ 111,961.20	$ 4,720.56	4.08%	$ 380.67	$ 117,062.43		$ 0.26
Jul-08	2008	Q3	$ 116,681.76	$ 4,888.00	3.35%	$ 325.74	$ 121,895.50		$ 0.26
Aug-08	2008	Q3	$ 121,569.76	$ 4,570.28	3.35%	$ 339.38	$ 126,479.42		$ 0.26
Sep-08	2008	Q3	$ 126,140.04	$ 4,568.72	3.35%	$ 352.14	$ 131,060.90		$ 0.26
Oct-08	2008	Q4	$ 130,708.76	$ 5,068.70	3.35%	$ 364.90	$ 136,142.36		$ 0.26
Nov-08	2008	Q4	$ 135,777.46	$ 4,573.92	3.35%	$ 379.05	$ 140,730.43		$ 0.26
Dec-08	2008	Q4	$ 140,351.38	$ 4,737.72	3.35%	$ 391.81	$ 145,480.91	$ 61,008.67	$ 0.26
Jan-09	2009	Q1	$ 145,089.10	$ 4,745.00	2.45%	$ 296.22	$ 150,130.32		$ 0.26
Feb-09	2009	Q1	$ 149,834.10	$ 4,355.52	2.45%	$ 305.91	$ 154,495.53		$ 0.26
Mar-09	2009	Q1	$ 154,189.62	$ 4,296.87	2.45%	$ 314.80	$ 158,801.29		$ 0.26
Apr-09	2009	Q2	$ 158,486.49	$ 5,376.21	1.00%	$ 132.07	$ 163,994.77		$ 0.26
May-09	2009	Q2	$ 163,862.70	$ 5,096.04	1.00%	$ 136.55	$ 169,095.29		$ 1.00
Jun-09	2009	Q2	$ 168,958.74	$ 17,292.90	1.00%	$ 140.80	$ 186,392.44		$ 1.00
Jul-09	2009	Q3	$ 186,251.64	$ 18,969.97	0.55%	$ 85.37	$ 205,306.98		$ 1.00
Aug-09	2009	Q3	$ 205,221.61	$ 16,802.39	0.55%	$ 94.06	$ 222,118.06		$ 1.00
Sep-09	2009	Q3	$ 222,024.00	$ 19,099.17	0.55%	$ 101.76	$ 241,224.93		$ 1.00
Oct-09	2009	Q4	$ 241,123.17	$ 18,222.88	0.55%	$ 110.51	$ 259,456.56		$ 1.00
Nov-09	2009	Q4	$ 259,346.05	$ 18,264.70	0.55%	$ 118.87	$ 277,729.62		$ 1.00
Dec-09	2009	Q4	$ 277,610.75	$ 18,977.97	0.55%	$ 127.24	$ 296,715.96	$ 153,463.78	$ 1.00
Jan-10	2010	Q1	$ 296,588.72	$ 17,676.87	0.55%	$ 135.94	$ 314,401.53		$ 1.00
Feb-10	2010	Q1	$ 314,265.59	$ 16,903.98	0.55%	$ 144.04	$ 331,313.61		$ 1.00
Mar-10	2010	Q1	$ 331,169.57	$ 19,729.84	0.55%	$ 151.79	$ 351,051.20		$ 1.00
Apr-10	2010	Q2	$ 350,899.41	$ 18,963.57	0.55%	$ 160.83	$ 370,023.81		$ 1.00
May-10	2010	Q2	$ 369,862.98	$ 19,096.37	0.55%	$ 169.52	$ 389,128.87		$ 1.87
Jun-10	2010	Q2	$ 388,959.35	$ 33,187.60	0.55%	$ 178.27	$ 422,325.22		$ 1.87
Jul-10	2010	Q3	$ 422,146.95	$ 34,382.67	0.89%	$ 313.09	$ 456,842.71		$ 1.87
Aug-10	2010	Q3	$ 456,529.62	$ 34,433.33	0.89%	$ 338.59	$ 491,301.54		$ 1.87
Sep-10	2010	Q3	$ 490,962.95	$ 34,431.36	0.89%	$ 364.13	$ 525,758.44		$ 1.87
Oct-10	2010	Q4	$ 525,394.31	$ 33,255.74	1.20%	$ 525.39	$ 559,175.44		$ 1.87
Nov-10	2010	Q4	$ 558,650.05	$ 35,656.78	1.20%	$ 558.65	$ 594,865.48		$ 1.87
Dec-10	2010	Q4	$ 594,306.83	$ 34,489.92	1.20%	$ 594.31	$ 629,391.06	$ 335,842.58	$ 1.87
Jan-11	2011	Q1	$ 628,796.75	$ 33,305.46	1.47%	$ 770.28	$ 662,872.49		$ 1.87
Feb-11	2011	Q1	$ 662,102.21	$ 31,834.80	1.47%	$ 811.08	$ 694,748.09		$ 1.87
Mar-11	2011	Q1	$ 693,937.01	$ 37,214.66	1.47%	$ 850.07	$ 732,001.74		$ 1.87
Apr-11	2011	Q2	$ 731,151.67	$ 31,835.25	1.47%	$ 895.66	$ 763,882.58		$ 1.87
May-11	2011	Q2	$ 762,986.92	$ 34,540.70	1.47%	$ 934.66	$ 798,462.28		$ 1.87
Jun-11	2011	Q2	$ 797,527.62	$ 35,648.24	1.47%	$ 976.97	$ 834,152.83		$ 1.87
Jul-11	2011	Q3	$ 833,175.86	$ 33,475.51	1.47%	$ 1,020.64	$ 867,672.01		$ 1.87
Aug-11	2011	Q3	$ 866,651.37	$ 35,654.24	1.47%	$ 1,061.65	$ 903,367.26		$ 1.87
Sep-11	2011	Q3	$ 902,305.61	$ 34,594.70	1.47%	$ 1,105.32	$ 938,005.63		$ 1.87
Oct-11	2011	Q4	$ 936,900.31	$ 31,810.89	1.47%	$ 1,147.70	$ 969,858.90		$ 1.87
Nov-11	2011	Q4	$ 968,711.20	$ 36,409.77	1.47%	$ 1,186.67	$ 1,006,307.64		$ 1.87
Dec-11	2011	Q4	$ 1,005,120.97	$ 32,913.43	1.47%	$ 1,231.27	$ 1,039,265.67	$ 421,229.62	$ 1.87
Jan-12	2012	Q1	$ 1,038,034.40	$ 33,674.75	1.47%	$ 1,271.59	$ 1,072,980.74		$ 1.87
Feb-12	2012	Q1	$ 1,071,709.15	$ 34,611.89	1.47%	$ 1,312.84	$ 1,107,633.88		$ 1.87

Ontario Energy Board

Smart Meter Model

Haldimand County Hydro Inc.

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
			Mar-12	2012	Q1	$ 1,106,321.04	$ 34,770.81	1.47%	$ 1,355.24	$ 1,142,447.09		$ 1.87
			Apr-12	2012	Q2	$ 1,141,091.85	$ 33,094.66	1.47%	$ 1,397.84	$ 1,175,584.35		$ 1.87
			May-12	2012	Q2	$ 1,174,186.51	$ 32,573.44	1.47%	$ 1,438.38	$ 1,208,198.33		
			Jun-12	2012	Q2	$ 1,206,759.95	$ 3,914.08	1.47%	$ 1,478.28	$ 1,212,152.31		
			Jul-12	2012	Q3	$ 1,210,674.03		1.47%	$ 1,483.08	$ 1,212,157.11		
			Aug-12	2012	Q3	$ 1,210,674.03		1.47%	$ 1,483.08	$ 1,212,157.11		
			Sep-12	2012	Q3	$ 1,210,674.03		1.47%	$ 1,483.08	$ 1,212,157.11		
			Oct-12	2012	Q4	$ 1,210,674.03		1.47%	$ 1,483.08	$ 1,212,157.11		
			Nov-12	2012	Q4	$ 1,210,674.03		1.47%	$ 1,483.08	$ 1,212,157.11		
			Dec-12	2012	Q4	$ 1,210,674.03		1.47%	$ 1,483.08	$ 1,212,157.11	$ 189,792.28	
			Total Funding Adder Revenues Collected				**$ 1,210,674.03**		**$ 42,340.23**	**$ 1,253,014.26**	**$ 1,253,014.26**	

Ontario Energy Board

Smart Meter Model

Haldimand County Hydro Inc.

This worksheet calculates the interest on OM&A and amortization/depreciation expense, based on monthly data.

Prescribed Interest Rates	Approved Deferral and Variance Accounts	CWIP
2006 Q1	0.00%	0.00%
2006 Q2	4.14%	4.68%
2006 Q3	4.59%	5.05%
2006 Q4	4.59%	4.72%
2007 Q1	4.59%	4.72%
2007 Q2	4.59%	4.72%
2007 Q3	4.59%	5.18%
2007 Q4	5.14%	5.18%
2008 Q1	5.14%	5.18%
2008 Q2	4.08%	5.18%
2008 Q3	3.35%	5.43%
2008 Q4	3.35%	5.43%
2009 Q1	2.45%	6.61%
2009 Q2	1.00%	6.61%
2009 Q3	0.55%	5.67%
2009 Q4	0.55%	4.66%
2010 Q1	0.55%	4.34%
2010 Q2	0.55%	4.34%
2010 Q3	0.89%	4.66%
2010 Q4	1.20%	4.01%
2011 Q1	1.47%	4.29%
2011 Q2	1.47%	4.29%
2011 Q3	1.47%	4.29%
2011 Q4	1.47%	4.29%
2012 Q1	1.47%	4.29%
2012 Q2	1.47%	4.29%
2012 Q3	1.47%	4.29%
2012 Q4	1.47%	4.29%

Account 1556 - Sub-accounts Operating Expenses, Amortization Expenses, Carrying Charges

Date	Year	Quarter	Opening Balance (Principal)	OM&A Expenses	Amortization / Depreciation Expense	Closing Balance (Principal)	(Annual) Interest Rate	Interest (on opening balance)	Cumulative Interest
Jan-06	2006	Q1	$ -			-	0.00%	-	-
Feb-06	2006	Q1	-			-	0.00%	-	-
Mar-06	2006	Q1	-			-	0.00%	-	-
Apr-06	2006	Q2	-			-	4.14%	-	-
May-06	2006	Q2	-			-	4.14%	-	-
Jun-06	2006	Q2	-			-	4.14%	-	-
Jul-06	2006	Q3	-			-	4.59%	-	-
Aug-06	2006	Q3	-			-	4.59%	-	-
Sep-06	2006	Q3	-			-	4.59%	-	-
Oct-06	2006	Q4	-			-	4.59%	-	-
Nov-06	2006	Q4	-			-	4.59%	-	-
Dec-06	2006	Q4	-			-	4.59%	-	-
Jan-07	2007	Q1	-			-	4.59%	-	-
Feb-07	2007	Q1	-			-	4.59%	-	-
Mar-07	2007	Q1	-			-	4.59%	-	-
Apr-07	2007	Q2	-			-	4.59%	-	-
May-07	2007	Q2	-			-	4.59%	-	-
Jun-07	2007	Q2	-			-	4.59%	-	-
Jul-07	2007	Q3	-			-	4.59%	-	-
Aug-07	2007	Q3	-			-	4.59%	-	-
Sep-07	2007	Q3	-			-	4.59%	-	-
Oct-07	2007	Q4	-			-	5.14%	-	-
Nov-07	2007	Q4	-			-	5.14%	-	-
Dec-07	2007	Q4	-			-	5.14%	-	-
Jan-08	2008	Q1	-			-	5.14%	-	-
Feb-08	2008	Q1	-			-	5.14%	-	-
Mar-08	2008	Q1	-			-	5.14%	-	-
Apr-08	2008	Q2	-			-	4.08%	-	-
May-08	2008	Q2	-			-	4.08%	-	-
Jun-08	2008	Q2	-			-	4.08%	-	-
Jul-08	2008	Q3	-			-	3.35%	-	-
Aug-08	2008	Q3	-			-	3.35%	-	-
Sep-08	2008	Q3	-			-	3.35%	-	-
Oct-08	2008	Q4	-			-	3.35%	-	-
Nov-08	2008	Q4	-			-	3.35%	-	-
Dec-08	2008	Q4	-			-	3.35%	-	-
Jan-09	2009	Q1	-			-	2.45%	-	-
Feb-09	2009	Q1	-			-	2.45%	-	-
Mar-09	2009	Q1	-			-	2.45%	-	-
Apr-09	2009	Q2	-			-	1.00%	-	-
May-09	2009	Q2	-			-	1.00%	-	-
Jun-09	2009	Q2	-			-	1.00%	-	-
Jul-09	2009	Q3	-			-	0.55%	-	-
Aug-09	2009	Q3	-			-	0.55%	-	-
Sep-09	2009	Q3	-			-	0.55%	-	-
Oct-09	2009	Q4	-			-	0.55%	-	-
Nov-09	2009	Q4	-			-	0.55%	-	-
Dec-09	2009	Q4	-			-	0.55%	-	-
Jan-10	2010	Q1	-			-	0.55%	-	-
Feb-10	2010	Q1	-			-	0.55%	-	-
Mar-10	2010	Q1	-			-	0.55%	-	-
Apr-10	2010	Q2	-			-	0.55%	-	-
May-10	2010	Q2	-			-	0.55%	-	-
Jun-10	2010	Q2	-			-	0.55%	-	-
Jul-10	2010	Q3	-			-	0.89%	-	-
Aug-10	2010	Q3	-			-	0.89%	-	-
Sep-10	2010	Q3	-			-	0.89%	-	-
Oct-10	2010	Q4	-			-	1.20%	-	-
Nov-10	2010	Q4	-			-	1.20%	-	-
Dec-10	2010	Q4	-			-	1.20%	-	-
Jan-11	2011	Q1	-			-	1.47%	-	-
Feb-11	2011	Q1	-			-	1.47%	-	-
Mar-11	2011	Q1	-			-	1.47%	-	-
Apr-11	2011	Q2	-			-	1.47%	-	-
May-11	2011	Q2	-			-	1.47%	-	-
Jun-11	2011	Q2	-			-	1.47%	-	-
Jul-11	2011	Q3	-			-	1.47%	-	-
Aug-11	2011	Q3	-			-	1.47%	-	-
Sep-11	2011	Q3	-			-	1.47%	-	-
Oct-11	2011	Q4	-			-	1.47%	-	-
Nov-11	2011	Q4	-			-	1.47%	-	-
Dec-11	2011	Q4	-			-	1.47%	-	-
Jan-12	2012	Q1	-			-	1.47%	-	-
Feb-12	2012	Q1	-			-	1.47%	-	-
Mar-12	2012	Q1	-			-	1.47%	-	-
Apr-12	2012	Q2	-			-	1.47%	-	-
May-12	2012	Q2	-			-	1.47%	-	-
Jun-12	2012	Q2	-			-	1.47%	-	-
Jul-12	2012	Q3	-			-	1.47%	-	-
Aug-12	2012	Q3	-			-	1.47%	-	-
Sep-12	2012	Q3	-			-	1.47%	-	-
Oct-12	2012	Q4	-			-	1.47%	-	-
Nov-12	2012	Q4	-			-	1.47%	-	-
Dec-12	2012	Q4	-			-	1.47%	-	-
				$ -	$ -	$ -			

Ontario Energy Board

Smart Meter Model

Haldimand County Hydro Inc.

This worksheet calculates the interest on OM&A and amortization/depreciation expense, in the absence of monthly data.

Year	OM&A (from Sheet 5)	Amortization Expense (from Sheet 5)	Cumulative OM&A and Amortization Expense	Average Cumulative OM&A and Amortization Expense	Average Annual Prescribed Interest Rate for Deferral and Variance Accounts (from Sheets 8A and 8B)	Simple Interest on OM&A and Amortization Expenses
2006	$ -	$ -	$ -	$ -	4.37%	$ -
2007	$ -	$ 2,667.13	$ 2,667.13	$ 1,333.57	4.73%	$ 63.04
2008	$ -	$ 6,522.00	$ 9,189.13	$ 5,928.13	3.98%	$ 235.94
2009	$ 136,600.00	$ 82,696.47	$ 228,485.60	$ 118,837.37	1.14%	$ 1,351.78
2010	$ 203,902.00	$ 179,241.30	$ 611,628.90	$ 420,057.25	0.80%	$ 3,349.96
2011	$ 303,738.00	$ 206,783.97	$ 1,122,150.87	$ 866,889.88	1.47%	$ 12,743.28
2012	$ 376,588.00	$ 212,802.50	$ 1,711,541.37	$ 1,416,846.12	1.47%	$ 20,827.64
Cumulative Interest to 2011						$ 17,744.00
Cumulative Interest to 2012						$ 38,571.63

This worksheet calculates the Smart Meter Disposition Rider and the Smart Meter Incremental Revenue Requirement Rate Rider, if applicable. This worksheet also calculates any new Smart Meter Funding Adder that a distributor may wish to request. However, please note that in many 2011 IRM decisions, the Board noted that current funding adders will cease on April 30, 2011 and that the Board's expectation is that distributors will file for a final review of prudence at the earliest opportunity. The Board also noted that the SMFA is a tool designed to provide advance funding and to mitigate the anticipated rate impact of smart meter costs when recovery of those costs is approved by the Board. The Board observed that the SMFA was not intended to be compensatory (return on and of capital) on a cumulative basis over the term the SMFA was in effect. The SMFA was initially designed to fund future investment, and not fully fund prior capital investment. Distributors that seek a new SMFA should provide evidence to support its proposal. This would include documentation of where the distributor is with respect to its smart meter deployment program, and reasons as to why the distributor's circumstances are such that continuation of the SMFA is warranted. Press the "UPDATE WORKSHEET" button after choosing the applicable adders/riders.

Check if applicable		
	Smart Meter Funding Adder (SMFA)	
X	Smart Meter Disposition Rider (SMDR)	**The SMDR is calculated based on costs to December 31, 2011**
X	Smart Meter Incremental Revenue Requirement Rate Rider (SMIRR)	**The SMIRR is calculated based on the incremental revenue requirement associated with the recovery of capital related costs to December 31, 2012 and associated OM&A.**

	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012 and later**	**Total**
Deferred and forecasted Smart Meter Incremental Revenue Requirement (from Sheet 5)	$ -	$ 6,433.75	$ 15,005.40	$ 326,392.07	$ 572,533.77	$ 721,574.71	$ 791,555.04	$ 2,433,494.74
Interest on Deferred and forecasted OM&A and Amortization Expense (Sheet 8A/8B) (Check **one** of the boxes below)	$ -	$ 63.04	$ 235.94	$ 1,351.78	$ 3,349.96	$ 12,743.28		$ 17,744.00
Sheet 8A (Interest calculated on monthly balances)								$ -
X Sheet 8B (Interest calculated on average annual balances)	$ -	$ 63.04	$ 235.94	$ 1,351.78	$ 3,349.96	$ 12,743.28		$ 17,744.00
SMFA Revenues (from Sheet 8)	$ 32,188.52	$ 56,337.84	$ 56,562.74	$ 151,499.62	$ 332,208.03	$ 409,237.65	$ 172,639.63	$ 1,210,674.03
SMFA Interest (from Sheet 8)	$ 369.40	$ 2,781.57	$ 4,445.93	$ 1,964.16	$ 3,634.55	$ 11,991.97	$ 17,152.65	$ 42,340.23
Net Deferred Revenue Requirement	-$ 32,557.92	-$ 52,622.61	-$ 45,767.33	$ 174,280.07	$ 240,041.14	$ 313,088.37	$ 601,762.76	$ 1,198,224.48
Number of Metered Customers (average for 2012 test year)							18535	

Calculation of Smart Meter Disposition Rider (per metered customer per month)

Years for collection or refunding		1.5
Deferred Incremental Revenue Requirement from 2006 to December 31, 2011 plus Interest on OM&A and Amortization		$ 1,659,683.70
SMFA Revenues collected from 2006 to 2012 test year (inclusive) Plus Simple Interest on SMFA Revenues		$ 1,253,014.26
Net Deferred Revenue Requirement		$ 406,669.44
SMDR	November 1, 2012 to April 30, 2014	$ 1.22
Check: Forecasted SMDR Revenues		$ 407,028.60

Match

Calculation of Smart Meter Incremental Revenue Requirement Rate Rider (per metered customer per month)

Incremental Revenue Requirement for 2012	$ 791,555.04
SMIRR	$ 3.56
Check: Forecasted SMIRR Revenues	$ 791,815.20

Match

APPENDIX B

2012 Smart Meter Model

1. General Service Less than 50 kW Rate Class

V 2.17

Ontario Energy Board

Smart Meter Model

Choose Your Utility:

Haldimand County Hydro Inc.
Halton Hills Hydro Inc.

Application Contact Information

Name:	Jacqueline A. Scott
Title:	Finance Manager
Phone Number:	905-765-5211 ext. 2237
Email Address:	jscott@hchydro.ca
We are applying for rates effective:	November 1, 2012
Last COS Re-based Year	2010

Legend

DROP-DOWN MENU

INPUT FIELD

CALCULATION FIELD

Copyright

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results. The use of any models and spreadsheets does not automatically imply Board approval. The onus is on the distributor to prepare, document and support its application. Board-issued Excel models and spreadsheets are offered to assist parties in providing the necessary information so as to facilitate an expeditious review of an application. The onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Smart Meter Model

Haldimand County Hydro Inc.

Distributors must enter all incremental costs related to their smart meter program and all revenues recovered to date in the applicable tabs except for those costs (and associated revenues) for which the Board has approved on a final basis, i.e. capital costs have been included in rate base and OM&A costs in revenue requirement.

For 2012, distributors that have completed their deployments by the end of 2011 are not expected to enter any capital costs. However, for OM&A, regardless of whether a distributor has deployments in 2012, distributors should enter the forecasted OM&A for 2012 for all smart meters in service.

Smart Meter Capital Cost and Operational Expense Data

		2006	2007	2008	2009	2010	2011	2012 and later	Total
		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
Smart Meter Installation Plan									
Actual/Planned number of Smart Meters installed during the Calendar Year									
Residential									0
General Service < 50 kW					1,275	758	316	12	2361
Actual/Planned number of Smart Meters installed (Residential and GS < 50 kW only)		0	0	0	1275	758	316	12	2361
Percentage of Residential and GS < 50 kW Smart Meter Installations Completed		0.00%	0.00%	0.00%	54.00%	86.11%	99.49%	100.00%	100.00%
Actual/Planned number of GS > 50 kW meters installed									0
Other (please identify)									0
Total Number of Smart Meters installed or planned to be installed		0	0	0	1275	758	316	12	2361

1 Capital Costs

	Asset Type								
1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	Asset type must be selected to enable calculations	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.1.1 Smart Meters *(may include new meters and modules, etc.)*	Smart Meter				103,674	240,374	159,687	2,954	$ 506,689
1.1.2 Installation Costs *(may include socket kits, labour, vehicle, benefits, etc.)*	Smart Meter		8,582	2,859	29,185	60,344	37,535	484	$ 138,989
1.1.3a Workforce Automation Hardware *(may include fieldwork handhelds, barcode hardware, etc.)*	Computer Hardware				477	4,686	585		$ 5,748
1.1.3b Workforce Automation Software *(may include fieldwork handhelds, barcode hardware, etc.)*	Computer Software				245	2,294	2,528		$ 5,067
Total Advanced Metering Communications Devices (AMCD)		$ -	$ 8,582	$ 2,859	$ 133,581	$ 307,698	$ 200,335	$ 3,438	$ 656,493

	Asset Type								
1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.2.1 Collectors	Smart Meter				63,590				$ 63,590
1.2.2 Repeaters *(may include radio licence, etc.)*	Smart Meter								$ -
1.2.3 Installation *(may include meter seals and rings, collector computer hardware, etc.)*	Smart Meter				7,057	1,404	38		$ 8,499
Total Advanced Metering Regional Collector (AMRC) (Includes LAN)		$ -	$ -	$ -	$ 70,647	$ 1,404	$ 38	$ -	$ 72,089

1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.3.1 Computer Hardware	Computer Hardware								$ -
1.3.2 Computer Software	Computer Software								$ -
1.3.3 Computer Software Licences & Installation (includes hardware and software) *(may include AS/400 disk space, backup and recovery computer, UPS, etc.)*	Computer Software								$ -
Total Advanced Metering Control Computer (AMCC)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

1.4 WIDE AREA NETWORK (WAN)	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.4.1 Activiation Fees									$ -
Total Wide Area Network (WAN)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.5.1 Customer Equipment *(including repair of damaged equipment)*									$ -
1.5.2 AMI Interface to CIS	Computer Software				273	497	66		$ 836
1.5.3 Professional Fees	Smart Meter		1,608	1,678	2,893	1,963	1,210		$ 9,352
1.5.4 Integration	Computer Software					893	225		$ 1,118
1.5.5 Program Management									$ -
1.5.6 Other AMI Capital	Smart Meter					47	13		$ 60
Total Other AMI Capital Costs Related to Minimum Functionality		$ -	$ 1,608	$ 1,678	$ 3,166	$ 3,400	$ 1,514	$ -	$ 11,366
Total Capital Costs Related to Minimum Functionality		$ -	$ 10,190	$ 4,537	$ 207,394	$ 312,502	$ 201,887	$ 3,438	$ 739,948

1.6 CAPITAL COSTS BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06	Computer Software								$ -
1.6.2 Costs for deployment of smart meters to customers other than residential and small general service	Applications Software								$ -
1.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.	Smart Meter					479	3,587		$ 4,066
Total Capital Costs Beyond Minimum Functionality		$ -	$ -	$ -	$ -	$ 479	$ 3,587	$ -	$ 4,066
Total Smart Meter Capital Costs		$ -	$ 10,190	$ 4,537	$ 207,394	$ 312,981	$ 205,474	$ 3,438	$ 744,014

2 OM&A Expenses

		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)									
2.1.1 Maintenance *(may include meter reverification costs, etc.)*					3,211	1,342	8,849	13,500	$ 26,902
2.1.2 Other *(please specify)*									$ -
Total Incremental AMCD OM&A Costs		$ -	$ -	$ -	$ 3,211	$ 1,342	$ 8,849	$ 13,500	$ 26,902
2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)									
2.2.1 Maintenance					9,374	16,882	12,526	16,493	$ 55,275
2.2.2 Other *(please specify)*	Additional Insurance re: Tower Gateway Base Stations				171				$ 171
Total Incremental AMRC OM&A Costs		$ -	$ -	$ -	$ 9,545	$ 16,882	$ 12,526	$ 16,493	$ 55,446
2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)									
2.3.1 Hardware Maintenance *(may include server support, etc.)*									$ -
2.3.2 Software Maintenance *(may include maintenance support, etc.)*									$ -
2.3.2 Other *(please specify)*									$ -
Total Incremental AMCC OM&A Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.4 WIDE AREA NETWORK (WAN)									
2.4.1 WAN Maintenance									$ -
2.4.2 Other *(please specify)*									$ -
Total Incremental AMRC OM&A Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY									
2.5.1 Business Process Redesign									$ -
2.5.2 Customer Communication (may include project communication, etc.)					3,428		732	1,013	$ 5,173
2.5.3 Program Management						2,147	4,305	5,972	$ 12,424
2.5.4 Change Management (may include training, etc.)						366	115		$ 481
2.5.5 Administration Costs					1,210	3,864	4,931	7,514	$ 17,519
2.5.6 Other AMI Expenses *(please specify)*						1,329	1,788	3,346	$ 6,463
Total Other AMI OM&A Costs Related to Minimum Functionality		$ -	$ -	$ -	$ 4,638	$ 7,706	$ 11,871	$ 17,845	$ 42,060
TOTAL OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY		$ -	$ -	$ -	$ 17,394	$ 25,930	$ 33,246	$ 47,838	$ 124,408
2.6 OM&A COSTS RELATED TO BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual		
2.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06									$ -
2.6.2 Costs for deployment of smart meters to customers other than residential and small general service									$ -
2.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.						34	5,430	116	$ 5,580
Total OM&A Costs Beyond Minimum Functionality		$ -	$ -	$ -	$ -	$ 34	$ 5,430	$ 116	$ 5,580
Total Smart Meter OM&A Costs		$ -	$ -	$ -	$ 17,394	$ 25,964	$ 38,676	$ 47,954	$ 129,988

3 Aggregate Smart Meter Costs by Category

3.1	**Capital**								
3.1.1	Smart Meter	$ -	$ 10,190	$ 4,537	$ 206,399	$ 304,611	$ 202,070	$ 3,438	$ 731,245
3.1.2	Computer Hardware	$ -	$ -	$ -	$ 477	$ 4,686	$ 585	$ -	$ 5,748
3.1.3	Computer Software	$ -	$ -	$ -	$ 518	$ 3,684	$ 2,819	$ -	$ 7,021
3.1.4	Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.5	Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.6	Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.7	**Total Capital Costs**	**$ -**	**$ 10,190**	**$ 4,537**	**$ 207,394**	**$ 312,981**	**$ 205,474**	**$ 3,438**	**$ 744,014**
3.2	**OM&A Costs**								
3.2.1	**Total OM&A Costs**	**$ -**	**$ -**	**$ -**	**$ 17,394**	**$ 25,964**	**$ 38,676**	**$ 47,954**	**$ 129,988**

Ontario Energy Board

Smart Meter Model

Haldimand County Hydro Inc.

	2006	2007	2008	2009	2010	2011	2012 and later
Cost of Capital							
Capital Structure[1]							
Deemed Short-term Debt Capitalization					4.0%	4.0%	4.0%
Deemed Long-term Debt Capitalization	50.0%	50.0%	53.3%	56.7%	56.0%	56.0%	56.0%
Deemed Equity Capitalization	50.0%	50.0%	46.7%	43.3%	40.0%	40.0%	40.0%
Preferred Shares							
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Cost of Capital Parameters							
Deemed Short-term Debt Rate					2.07%	2.07%	2.07%
Long-term Debt Rate (actual/embedded/deemed)[2]	6.05%	6.05%	6.05%	6.05%	5.13%	5.13%	5.13%
Target Return on Equity (ROE)	9.0%	9.00%	9.00%	9.00%	9.85%	9.85%	9.85%
Return on Preferred Shares							
WACC	7.53%	7.53%	7.43%	7.33%	6.90%	6.90%	6.90%
Working Capital Allowance							
Working Capital Allowance Rate *(% of the sum of Cost of Power + controllable expenses)*	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Taxes/PILs							
Aggregate Corporate Income Tax Rate	36.12%	36.12%	33.50%	33.00%	29.79%	28.25%	24.33%
Capital Tax (until July 1st, 2010)	0.30%	0.225%	0.225%	0.225%	0.075%	0.00%	0.00%
Depreciation Rates *(expressed as expected useful life in years)*							
Smart Meters - years	15	15	15	15	15	15	15
- rate (%)	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
Computer Hardware - years	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Computer Software - years	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Tools & Equipment - years	10	10	10	10	10	10	10
- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Other Equipment - years	10	10	10	10	10	10	10
- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
CCA Rates							
Smart Meters - CCA Class	47	47	47	47	47	47	47
Smart Meters - CCA Rate	8%	8%	8%	8%	8%	8%	8%
Computer Equipment - CCA Class	45	45	50	52	52	50	50
Computer Equipment - CCA Rate	45%	45%	55%	100%	100%	55%	55%
General Equipment - CCA Class	8	8	8	8	8	8	8
General Equipment - CCA Rate	20%	20%	20%	20%	20%	20%	20%
Applications Software - CCA Class	45	45	50	52	52	50	50
Applications Software - CCA Rate	45%	45%	55%	100%	100%	55%	55%

Assumptions

1 *Planned smart meter installations occur evenly throughout the year.*
2 *Fiscal calendar year (January 1 to December 31) used.*
3 *Amortization is done on a striaght line basis and has the "half-year" rule applied.*

Net Fixed Assets - Smart Meters

	2006	2007	2008	2009	2010	2011	2012 and later
Gross Book Value							
Opening Balance		$ -	$ 10,190	$ 14,727	$ 221,126	$ 525,737	$ 727,807
Capital Additions during year (from Smart Meter Costs)	$ -	$ 10,190	$ 4,537	$ 206,399	$ 304,611	$ 202,070	$ 3,438
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ 10,190	$ 14,727	$ 221,126	$ 525,737	$ 727,807	$ 731,245
Accumulated Depreciation							
Opening Balance		$ -	-$ 340	-$ 1,170	-$ 9,032	-$ 33,927	-$ 75,712
Amortization expense during year	$ -	-$ 340	-$ 831	-$ 7,862	-$ 24,895	-$ 41,785	-$ 48,635
Retirements/Removals (if applicable)							
Closing Balance	$ -	-$ 340	-$ 1,170	-$ 9,032	-$ 33,927	-$ 75,712	-$ 124,347
Net Book Value							
Opening Balance	$ -	$ -	$ 9,850	$ 13,557	$ 212,094	$ 491,810	$ 652,095
Closing Balance	$ -	$ 9,850	$ 13,557	$ 212,094	$ 491,810	$ 652,095	$ 606,898
Average Net Book Value	$ -	$ 4,925	$ 11,704	$ 112,825	$ 351,952	$ 571,952	$ 629,496

Net Fixed Assets - Computer Hardware

	2006	2007	2008	2009	2010	2011	2012 and later
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ 477	$ 5,163	$ 5,748
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 477	$ 4,686	$ 585	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ 477	$ 5,163	$ 5,748	$ 5,748
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	-$ 48	-$ 612	-$ 1,703
Amortization expense during year	$ -	$ -	$ -	-$ 48	-$ 564	-$ 1,091	-$ 1,150
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	-$ 48	-$ 612	-$ 1,703	-$ 2,852
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ 429	$ 4,551	$ 4,045
Closing Balance	$ -	$ -	$ -	$ 429	$ 4,551	$ 4,045	$ 2,896
Average Net Book Value	$ -	$ -	$ -	$ 215	$ 2,490	$ 4,298	$ 3,470

Net Fixed Assets - Computer Software (including Applications Software)

	2006	2007	2008	2009	2010	2011	2012 and later
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ 518	$ 4,202	$ 7,021
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 518	$ 3,684	$ 2,819	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ 518	$ 4,202	$ 7,021	$ 7,021
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	-$ 52	-$ 524	-$ 1,646
Amortization expense during year	$ -	$ -	$ -	-$ 52	-$ 472	-$ 1,122	-$ 1,404
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	-$ 52	-$ 524	-$ 1,646	-$ 3,050
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ 466	$ 3,678	$ 5,375
Closing Balance	$ -	$ -	$ -	$ 466	$ 3,678	$ 5,375	$ 3,971
Average Net Book Value	$ -	$ -	$ -	$ 233	$ 2,072	$ 4,527	$ 4,673

Net Fixed Assets - Tools and Equipment

	2006	2007	2008	2009	2010	2011	2012 and later
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Net Fixed Assets - Other Equipment

	2006	2007	2008	2009	2010	2011	2012 and later
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Ontario Energy Board

Smart Meter Model

Haldimand County Hydro Inc.

	2006	2007	2008	2009	2010	2011	2012 and Later
Average Net Fixed Asset Values (from Sheet 4)							
Smart Meters	$ -	$ 4,925	$ 11,704	$ 112,825	$ 351,952	$ 571,952	$ 629,496
Computer Hardware	$ -	$ -	$ -	$ 215	$ 2,490	$ 4,298	$ 3,470
Computer Software	$ -	$ -	$ -	$ 233	$ 2,072	$ 4,527	$ 4,673
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Net Fixed Assets	**$ -**	**$ 4,925**	**$ 11,704**	**$ 113,273**	**$ 356,514**	**$ 580,777**	**$ 637,639**
Working Capital							
Operating Expenses (from Sheet 2)	$ -	$ -	$ -	$ 17,394	$ 25,964	$ 38,676	$ 47,954
Working Capital Factor (from Sheet 3)	15%	15%	15%	15%	15%	15%	15%
Working Capital Allowance	$ -	$ -	$ -	$ 2,609	$ 3,895	$ 5,801	$ 7,193
Incremental Smart Meter Rate Base	**$ -**	**$ 4,925**	**$ 11,704**	**$ 115,882**	**$ 360,409**	**$ 586,578**	**$ 644,833**
Return on Rate Base							
Capital Structure							
Deemed Short Term Debt	$ -	$ -	$ -	$ -	$ 14,416	$ 23,463	$ 25,793
Deemed Long Term Debt	$ -	$ 2,463	$ 6,238	$ 65,705	$ 201,829	$ 328,484	$ 361,106
Equity	$ -	$ 2,463	$ 5,466	$ 50,177	$ 144,164	$ 234,631	$ 257,933
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capitalization	$ -	$ 4,925	$ 11,704	$ 115,882	$ 360,409	$ 586,578	$ 644,833
Return on							
Deemed Short Term Debt	$ -	$ -	$ -	$ -	$ 298	$ 486	$ 534
Deemed Long Term Debt	$ -	$ 149	$ 377	$ 3,975	$ 10,354	$ 16,851	$ 18,525
Equity	$ -	$ 222	$ 492	$ 4,516	$ 14,200	$ 23,111	$ 25,406
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Return on Capital	$ -	$ 371	$ 869	$ 8,491	$ 24,852	$ 40,448	$ 44,465
Operating Expenses	$ -	$ -	$ -	$ 17,394	$ 25,964	$ 38,676	$ 47,954
Amortization Expenses (from Sheet 4)							
Smart Meters	$ -	$ 340	$ 831	$ 7,862	$ 24,895	$ 41,785	$ 48,635
Computer Hardware	$ -	$ -	$ -	$ 48	$ 564	$ 1,091	$ 1,150
Computer Software	$ -	$ -	$ -	$ 52	$ 472	$ 1,122	$ 1,404
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Amortization Expense in Year	$ -	$ 340	$ 831	$ 7,961	$ 25,931	$ 43,998	$ 51,189
Incremental Revenue Requirement before Taxes/PILs	$ -	$ 710	$ 1,700	$ 33,846	$ 76,748	$ 123,122	$ 143,608
Calculation of Taxable Income							
Incremental Operating Expenses	$ -	$ -	$ -	$ 17,394	$ 25,964	$ 38,676	$ 47,954
Amortization Expense	$ -	$ 340	$ 831	$ 7,961	$ 25,931	$ 43,998	$ 51,189
Interest Expense	$ -	$ 149	$ 377	$ 3,975	$ 10,652	$ 17,337	$ 19,059
Net Income for Taxes/PILs	$ -	$ 222	$ 492	$ 4,516	$ 14,200	$ 23,111	$ 25,406
Grossed-up Taxes/PILs (from Sheet 7)	$ -	$ 109.07	$ 211.05	$ 1,787.07	$ 3,103.36	$ 6,656.75	$ 7,322.60
Revenue Requirement, including Grossed-up Taxes/PILs	$ -	$ 819	$ 1,911	$ 35,633	$ 79,851	$ 129,779	$ 150,931

For PILs Calculation

UCC - Smart Meters

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ 9,782.40	$ 13,355.33	$ 210,429.94	$ 486,022.11	$ 641,127.54
Capital Additions	$ -	$ 10,190.00	$ 4,537.00	$ 206,399.00	$ 304,611.00	$ 202,070.00	$ 3,438.00
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ 10,190.00	$ 14,319.40	$ 219,754.33	$ 515,040.94	$ 688,092.11	$ 644,565.54
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 5,095.00	$ 2,268.50	$ 103,199.50	$ 152,305.50	$ 101,035.00	$ 1,719.00
Reduced UCC	$ -	$ 5,095.00	$ 12,050.90	$ 116,554.83	$ 362,735.44	$ 587,057.11	$ 642,846.54
CCA Rate Class	47	47	47	47	47	47	47
CCA Rate	8%	8%	8%	8%	8%	8%	8%
CCA	$ -	$ 407.60	$ 964.07	$ 9,324.39	$ 29,018.84	$ 46,964.57	$ 51,427.72
Closing UCC	$ -	$ 9,782.40	$ 13,355.33	$ 210,429.94	$ 486,022.11	$ 641,127.54	$ 593,137.81

UCC - Computer Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ 497.50	$ 4,185.00	$ 4,351.15
Capital Additions Computer Hardware	$ -	$ -	$ -	$ 477.00	$ 4,686.00	$ 585.00	$ -
Capital Additions Computer Software	$ -	$ -	$ -	$ 518.00	$ 3,684.00	$ 2,819.00	$ -
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ -	$ -	$ 995.00	$ 8,867.50	$ 7,589.00	$ 4,351.15
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ 497.50	$ 4,185.00	$ 1,702.00	$ -
Reduced UCC	$ -	$ -	$ -	$ 497.50	$ 4,682.50	$ 5,887.00	$ 4,351.15
CCA Rate Class	45	45	50	52	52	50	50
CCA Rate	45%	45%	55%	100%	100%	55%	55%
CCA	$ -	$ -	$ -	$ 497.50	$ 4,682.50	$ 3,237.85	$ 2,393.13
Closing UCC	$ -	$ -	$ -	$ 497.50	$ 4,185.00	$ 4,351.15	$ 1,958.02

UCC - General Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class	8	8	8	8	8	8	8
CCA Rate	20%	20%	20%	20%	20%	20%	20%
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -

PILs Calculation

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
INCOME TAX							
Net Income	$ -	$ 221.63	$ 491.90	$ 4,515.93	$ 14,200.11	$ 23,111.19	$ 25,406.40
Amortization	$ -	$ 339.67	$ 830.57	$ 7,961.27	$ 25,931.43	$ 43,998.20	$ 51,188.87
CCA - Smart Meters	$ -	-$ 407.60	-$ 964.07	-$ 9,324.39	-$ 29,018.84	-$ 46,964.57	-$ 51,427.72
CCA - Computers	$ -	$ -	$ -	-$ 497.50	-$ 4,682.50	-$ 3,237.85	-$ 2,393.13
CCA - Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA - Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Change in taxable income	$ -	$ 153.70	$ 358.39	$ 2,655.31	$ 6,430.21	$ 16,906.97	$ 22,774.41
Tax Rate (from Sheet 3)	36.12%	36.12%	33.50%	33.00%	29.79%	28.25%	24.33%
Income Taxes Payable	$ -	$ 55.52	$ 120.06	$ 876.25	$ 1,915.56	$ 4,776.22	$ 5,541.01
ONTARIO CAPITAL TAX							
Smart Meters	$ -	$ 9,850.33	$ 13,556.77	$ 212,094.00	$ 491,809.57	$ 652,094.77	$ 606,897.70
Computer Hardware	$ -	$ -	$ -	$ 429.30	$ 4,551.30	$ 4,045.20	$ 2,895.60
Computer Software (Including Application Software)	$ -	$ -	$ -	$ 466.20	$ 3,678.20	$ 5,374.90	$ 3,970.70
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rate Base	$ -	$ 9,850.33	$ 13,556.77	$ 212,989.50	$ 500,039.07	$ 661,514.87	$ 613,764.00
Less: Exemption							
Deemed Taxable Capital	$ -	$ 9,850.33	$ 13,556.77	$ 212,989.50	$ 500,039.07	$ 661,514.87	$ 613,764.00
Ontario Capital Tax Rate (from Sheet 3)	0.300%	0.225%	0.225%	0.225%	0.075%	0.000%	0.000%
Net Amount (Taxable Capital x Rate)	$ -	$ 22.16	$ 30.50	$ 479.23	$ 375.03	$ -	$ -
Change in Income Taxes Payable	$ -	$ 55.52	$ 120.06	$ 876.25	$ 1,915.56	$ 4,776.22	$ 5,541.01
Change in OCT	$ -	$ 22.16	$ 30.50	$ 479.23	$ 375.03	$ -	$ -
PILs	$ -	$ 77.68	$ 150.57	$ 1,355.48	$ 2,290.59	$ 4,776.22	$ 5,541.01

Gross Up PILs

	2006	2007	2008	2009	2010	2011	2012
Tax Rate	36.12%	36.12%	33.50%	33.00%	29.79%	28.25%	24.33%
Change in Income Taxes Payable	$ -	$ 86.91	$ 180.54	$ 1,307.84	$ 2,728.33	$ 6,656.75	$ 7,322.60
Change in OCT	$ -	$ 22.16	$ 30.50	$ 479.23	$ 375.03	$ -	$ -
PILs	$ -	$ 109.07	$ 211.05	$ 1,787.07	$ 3,103.36	$ 6,656.75	$ 7,322.60

Ontario Energy Board
Smart Meter Model

Haldimand County Hydro Inc.

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
2006 Q1			Jan-06	2006	Q1	$ -		0.00%	$ -	$ -		
2006 Q2	4.14%	4.68%	Feb-06	2006	Q1	$ -		0.00%	$ -	$ -		
2006 Q3	4.59%	5.05%	Mar-06	2006	Q1	$ -		0.00%	$ -	$ -		
2006 Q4	4.59%	4.72%	Apr-06	2006	Q2	$ -		4.14%	$ -	$ -		
2007 Q1	4.59%	4.72%	May-06	2006	Q2	$ -	$ 83.46	4.14%	$ -	$ 83.46		$ 0.26
2007 Q2	4.59%	4.72%	Jun-06	2006	Q2	$ 83.46	$ 525.72	4.14%	$ 0.29	$ 609.47		$ 0.26
2007 Q3	4.59%	5.18%	Jul-06	2006	Q3	$ 609.18	$ 557.18	4.59%	$ 2.33	$ 1,168.69		$ 0.26
2007 Q4	5.14%	5.18%	Aug-06	2006	Q3	$ 1,166.36	$ 686.14	4.59%	$ 4.46	$ 1,856.96		$ 0.26
2008 Q1	5.14%	5.18%	Sep-06	2006	Q3	$ 1,852.50	$ 509.34	4.59%	$ 7.09	$ 2,368.93		$ 0.26
2008 Q2	4.08%	5.18%	Oct-06	2006	Q4	$ 2,361.84	$ 600.08	4.59%	$ 9.03	$ 2,970.95		$ 0.26
2008 Q3	3.35%	5.43%	Nov-06	2006	Q4	$ 2,961.92	$ 642.20	4.59%	$ 11.33	$ 3,615.45		$ 0.26
2008 Q4	3.35%	5.43%	Dec-06	2006	Q4	$ 3,604.12	$ 558.48	4.59%	$ 13.79	$ 4,176.39	$ 4,210.92	$ 0.26
2009 Q1	2.45%	6.61%	Jan-07	2007	Q1	$ 4,162.60	$ 600.34	4.59%	$ 15.92	$ 4,778.86		$ 0.26
2009 Q2	1.00%	6.61%	Feb-07	2007	Q1	$ 4,762.94	$ 601.38	4.59%	$ 18.22	$ 5,382.54		$ 0.26
2009 Q3	0.55%	5.67%	Mar-07	2007	Q1	$ 5,364.32	$ 643.50	4.59%	$ 20.52	$ 6,028.34		$ 0.26
2009 Q4	0.55%	4.66%	Apr-07	2007	Q2	$ 6,007.82	$ 558.74	4.59%	$ 22.98	$ 6,589.54		$ 0.26
2010 Q1	0.55%	4.34%	May-07	2007	Q2	$ 6,566.56	$ 641.16	4.59%	$ 25.12	$ 7,232.84		$ 0.26
2010 Q2	0.55%	4.34%	Jun-07	2007	Q2	$ 7,207.72	$ 603.98	4.59%	$ 27.57	$ 7,839.27		$ 0.26
2010 Q3	0.89%	4.66%	Jul-07	2007	Q3	$ 7,811.70	$ 599.56	4.59%	$ 29.88	$ 8,441.14		$ 0.26
2010 Q4	1.20%	4.01%	Aug-07	2007	Q3	$ 8,411.26	$ 649.22	4.59%	$ 32.17	$ 9,092.65		$ 0.26
2011 Q1	1.47%	4.29%	Sep-07	2007	Q3	$ 9,060.48	$ 514.02	4.59%	$ 34.66	$ 9,609.16		$ 0.26
2011 Q2	1.47%	4.29%	Oct-07	2007	Q4	$ 9,574.50	$ 652.60	5.14%	$ 41.01	$ 10,268.11		$ 0.26
2011 Q3	1.47%	4.29%	Nov-07	2007	Q4	$ 10,227.10	$ 650.52	5.14%	$ 43.81	$ 10,921.43		$ 0.26
2011 Q4	1.47%	4.29%	Dec-07	2007	Q4	$ 10,877.62	$ 518.96	5.14%	$ 46.59	$ 11,443.17	$ 7,592.43	$ 0.26
2012 Q1	1.47%	4.29%	Jan-08	2008	Q1	$ 11,396.58	$ 653.64	5.14%	$ 48.82	$ 12,099.04		$ 0.26
2012 Q2	1.47%	4.29%	Feb-08	2008	Q1	$ 12,050.22	$ 565.24	5.14%	$ 51.62	$ 12,667.08		$ 0.26
2012 Q3	1.47%	4.29%	Mar-08	2008	Q1	$ 12,615.46	$ 514.02	5.14%	$ 54.04	$ 13,183.52		$ 0.26
2012 Q4	1.47%	4.29%	Apr-08	2008	Q2	$ 13,129.48	$ 648.44	4.08%	$ 44.64	$ 13,822.56		$ 0.26
			May-08	2008	Q2	$ 13,777.92	$ 604.76	4.08%	$ 46.84	$ 14,429.52		$ 0.26
			Jun-08	2008	Q2	$ 14,382.68	$ 612.82	4.08%	$ 48.90	$ 15,044.40		$ 0.26
			Jul-08	2008	Q3	$ 14,995.50	$ 665.60	3.35%	$ 41.86	$ 15,702.96		$ 0.26
			Aug-08	2008	Q3	$ 15,661.10	$ 554.58	3.35%	$ 43.72	$ 16,259.40		$ 0.26
			Sep-08	2008	Q3	$ 16,215.68	$ 571.22	3.35%	$ 45.27	$ 16,832.17		$ 0.26
			Oct-08	2008	Q4	$ 16,786.90	$ 704.08	3.35%	$ 46.86	$ 17,537.84		$ 0.26
			Nov-08	2008	Q4	$ 17,490.98	$ 555.62	3.35%	$ 48.83	$ 18,095.43		$ 0.26
			Dec-08	2008	Q4	$ 18,046.60	$ 611.52	3.35%	$ 50.38	$ 18,708.50	$ 7,833.32	$ 0.26
			Jan-09	2009	Q1	$ 18,658.12	$ 608.40	2.45%	$ 38.09	$ 19,304.61		$ 0.26
			Feb-09	2009	Q1	$ 19,266.52	$ 528.84	2.45%	$ 39.34	$ 19,834.70		$ 0.26
			Mar-09	2009	Q1	$ 19,795.36	$ 555.56	2.45%	$ 40.42	$ 20,391.34		$ 0.26
			Apr-09	2009	Q2	$ 20,350.92	$ 695.94	1.00%	$ 16.96	$ 21,063.82		$ 0.26
			May-09	2009	Q2	$ 21,046.86	$ 580.97	1.00%	$ 17.54	$ 21,645.37		$ 1.00
			Jun-09	2009	Q2	$ 21,627.83	$ 2,197.58	1.00%	$ 18.02	$ 23,843.43		$ 1.00
			Jul-09	2009	Q3	$ 23,825.41	$ 2,516.90	0.55%	$ 10.92	$ 26,353.23		$ 1.00
			Aug-09	2009	Q3	$ 26,342.31	$ 2,050.09	0.55%	$ 12.07	$ 28,404.47		$ 1.00
			Sep-09	2009	Q3	$ 28,392.40	$ 2,513.43	0.55%	$ 13.01	$ 30,918.84		$ 1.00
			Oct-09	2009	Q4	$ 30,905.83	$ 2,369.65	0.55%	$ 14.17	$ 33,289.65		$ 1.00
			Nov-09	2009	Q4	$ 33,275.48	$ 2,369.93	0.55%	$ 15.25	$ 35,660.66		$ 1.00
			Dec-09	2009	Q4	$ 35,645.41	$ 2,524.17	0.55%	$ 16.34	$ 38,185.92	$ 19,763.59	$ 1.00
			Jan-10	2010	Q1	$ 38,169.58	$ 2,210.35	0.55%	$ 17.49	$ 40,397.42		$ 1.00
			Feb-10	2010	Q1	$ 40,379.93	$ 2,069.66	0.55%	$ 18.51	$ 42,468.10		$ 1.00
			Mar-10	2010	Q1	$ 42,449.59	$ 2,652.72	0.55%	$ 19.46	$ 45,121.77		$ 1.00
			Apr-10	2010	Q2	$ 45,102.31	$ 2,517.41	0.55%	$ 20.67	$ 47,640.39		$ 1.00
			May-10	2010	Q2	$ 47,619.72	$ 2,385.46	0.55%	$ 21.83	$ 50,027.01		$ 1.87
			Jun-10	2010	Q2	$ 50,005.18	$ 4,292.39	0.55%	$ 22.92	$ 54,320.49		$ 1.87
			Jul-10	2010	Q3	$ 54,297.57	$ 4,428.59	0.89%	$ 40.27	$ 58,766.43		$ 1.87
			Aug-10	2010	Q3	$ 58,726.16	$ 4,431.52	0.89%	$ 43.56	$ 63,201.24		$ 1.87
			Sep-10	2010	Q3	$ 63,157.68	$ 4,428.83	0.89%	$ 46.84	$ 67,633.35		$ 1.87
			Oct-10	2010	Q4	$ 67,586.51	$ 4,140.38	1.20%	$ 67.59	$ 71,794.48		$ 1.87
			Nov-10	2010	Q4	$ 71,726.89	$ 4,700.62	1.20%	$ 71.73	$ 76,499.24		$ 1.87
			Dec-10	2010	Q4	$ 76,427.51	$ 4,413.16	1.20%	$ 76.43	$ 80,917.10	$ 43,138.39	$ 1.87
			Jan-11	2011	Q1	$ 80,840.67	$ 4,144.55	1.47%	$ 99.03	$ 85,084.25		$ 1.87
			Feb-11	2011	Q1	$ 84,985.22	$ 3,848.67	1.47%	$ 104.11	$ 88,938.00		$ 1.87
			Mar-11	2011	Q1	$ 88,833.89	$ 4,974.31	1.47%	$ 108.82	$ 93,917.02		$ 1.87
			Apr-11	2011	Q2	$ 93,808.20	$ 3,846.27	1.47%	$ 114.92	$ 97,769.39		$ 1.87
			May-11	2011	Q2	$ 97,654.47	$ 4,393.73	1.47%	$ 119.63	$ 102,167.83		$ 1.87
			Jun-11	2011	Q2	$ 102,048.20	$ 4,652.24	1.47%	$ 125.01	$ 106,825.45		$ 1.87
			Jul-11	2011	Q3	$ 106,700.44	$ 4,139.86	1.47%	$ 130.71	$ 110,971.01		$ 1.87
			Aug-11	2011	Q3	$ 110,840.30	$ 4,670.45	1.47%	$ 135.78	$ 115,646.53		$ 1.87
			Sep-11	2011	Q3	$ 115,510.75	$ 4,407.48	1.47%	$ 141.50	$ 120,059.73		$ 1.87
			Oct-11	2011	Q4	$ 119,918.23	$ 4,074.93	1.47%	$ 146.90	$ 124,140.06		$ 1.87
			Nov-11	2011	Q4	$ 123,993.16	$ 4,537.66	1.47%	$ 151.89	$ 128,682.71		$ 1.87
			Dec-11	2011	Q4	$ 128,530.82	$ 4,288.82	1.47%	$ 157.45	$ 132,977.09	$ 53,514.72	$ 1.87
			Jan-12	2012	Q1	$ 132,819.64	$ 4,326.97	1.47%	$ 162.70	$ 137,309.31		$ 1.87
			Feb-12	2012	Q1	$ 137,146.61	$ 4,396.74	1.47%	$ 168.00	$ 141,711.35		$ 1.87

Ontario Energy Board

Smart Meter Model

Haldimand County Hydro Inc.

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
			Mar-12	2012	Q1	$ 141,543.35	$ 4,453.85	1.47%	$ 173.39	$ 146,170.59		$ 1.87
			Apr-12	2012	Q2	$ 145,997.20	$ 4,256.99	1.47%	$ 178.85	$ 150,433.04		$ 1.87
			May-12	2012	Q2	$ 150,254.19	$ 4,286.41	1.47%	$ 184.06	$ 154,724.66		
			Jun-12	2012	Q2	$ 154,540.60	$ 641.93	1.47%	$ 189.31	$ 155,371.84		
			Jul-12	2012	Q3	$ 155,182.53		1.47%	$ 190.10	$ 155,372.63		
			Aug-12	2012	Q3	$ 155,182.53		1.47%	$ 190.10	$ 155,372.63		
			Sep-12	2012	Q3	$ 155,182.53		1.47%	$ 190.10	$ 155,372.63		
			Oct-12	2012	Q4	$ 155,182.53		1.47%	$ 190.10	$ 155,372.63		
			Nov-12	2012	Q4	$ 155,182.53		1.47%	$ 190.10	$ 155,372.63		
			Dec-12	2012	Q4	$ 155,182.53		1.47%	$ 190.10	$ 155,372.63	$ 24,559.80	
			Total Funding Adder Revenues Collected				**$ 155,182.53**		**$ 5,430.64**	**$ 160,613.17**	**$ 160,613.17**	

Haldimand County Hydro Inc.

This worksheet calculates the interest on OM&A and amortization/depreciation expense, based on monthly data.

Prescribed Interest Rates	Approved Deferral and Variance Accounts	CWIP
2006 Q1	0.00%	0.00%
2006 Q2	4.14%	4.68%
2006 Q3	4.59%	5.05%
2006 Q4	4.59%	4.72%
2007 Q1	4.59%	4.72%
2007 Q2	4.59%	4.72%
2007 Q3	4.59%	5.18%
2007 Q4	5.14%	5.18%
2008 Q1	5.14%	5.18%
2008 Q2	4.08%	5.18%
2008 Q3	3.35%	5.43%
2008 Q4	3.35%	5.43%
2009 Q1	2.45%	6.61%
2009 Q2	1.00%	6.61%
2009 Q3	0.55%	5.67%
2009 Q4	0.55%	4.66%
2010 Q1	0.55%	4.34%
2010 Q2	0.55%	4.34%
2010 Q3	0.89%	4.66%
2010 Q4	1.20%	4.01%
2011 Q1	1.47%	4.29%
2011 Q2	1.47%	4.29%
2011 Q3	1.47%	4.29%
2011 Q4	1.47%	4.29%
2012 Q1	1.47%	4.29%
2012 Q2	1.47%	4.29%
2012 Q3	1.47%	4.29%
2012 Q4	1.47%	4.29%

Account 1556 - Sub-accounts Operating Expenses, Amortization Expenses, Carrying Charges

Date	Year	Quarter	Opening Balance (Principal)	OM&A Expenses	Amortization / Depreciation Expense	Closing Balance (Principal)	(Annual) Interest Rate	Interest (on opening balance)	Cumulative Interest
Jan-06	2006	Q1	$ -			-	0.00%	-	-
Feb-06	2006	Q1	-			-	0.00%	-	-
Mar-06	2006	Q1	-			-	0.00%	-	-
Apr-06	2006	Q2	-			-	4.14%	-	-
May-06	2006	Q2	-			-	4.14%	-	-
Jun-06	2006	Q2	-			-	4.14%	-	-
Jul-06	2006	Q3	-			-	4.59%	-	-
Aug-06	2006	Q3	-			-	4.59%	-	-
Sep-06	2006	Q3	-			-	4.59%	-	-
Oct-06	2006	Q4	-			-	4.59%	-	-
Nov-06	2006	Q4	-			-	4.59%	-	-
Dec-06	2006	Q4	-			-	4.59%	-	-
Jan-07	2007	Q1	-			-	4.59%	-	-
Feb-07	2007	Q1	-			-	4.59%	-	-
Mar-07	2007	Q1	-			-	4.59%	-	-
Apr-07	2007	Q2	-			-	4.59%	-	-
May-07	2007	Q2	-			-	4.59%	-	-
Jun-07	2007	Q2	-			-	4.59%	-	-
Jul-07	2007	Q3	-			-	4.59%	-	-
Aug-07	2007	Q3	-			-	4.59%	-	-
Sep-07	2007	Q3	-			-	4.59%	-	-
Oct-07	2007	Q4	-			-	5.14%	-	-
Nov-07	2007	Q4	-			-	5.14%	-	-
Dec-07	2007	Q4	-			-	5.14%	-	-
Jan-08	2008	Q1	-			-	5.14%	-	-
Feb-08	2008	Q1	-			-	5.14%	-	-
Mar-08	2008	Q1	-			-	5.14%	-	-
Apr-08	2008	Q2	-			-	4.08%	-	-
May-08	2008	Q2	-			-	4.08%	-	-
Jun-08	2008	Q2	-			-	4.08%	-	-
Jul-08	2008	Q3	-			-	3.35%	-	-
Aug-08	2008	Q3	-			-	3.35%	-	-
Sep-08	2008	Q3	-			-	3.35%	-	-
Oct-08	2008	Q4	-			-	3.35%	-	-
Nov-08	2008	Q4	-			-	3.35%	-	-
Dec-08	2008	Q4	-			-	3.35%	-	-
Jan-09	2009	Q1	-			-	2.45%	-	-
Feb-09	2009	Q1	-			-	2.45%	-	-
Mar-09	2009	Q1	-			-	2.45%	-	-
Apr-09	2009	Q2	-			-	1.00%	-	-
May-09	2009	Q2	-			-	1.00%	-	-
Jun-09	2009	Q2	-			-	1.00%	-	-
Jul-09	2009	Q3	-			-	0.55%	-	-
Aug-09	2009	Q3	-			-	0.55%	-	-
Sep-09	2009	Q3	-			-	0.55%	-	-
Oct-09	2009	Q4	-			-	0.55%	-	-
Nov-09	2009	Q4	-			-	0.55%	-	-
Dec-09	2009	Q4	-			-	0.55%	-	-
Jan-10	2010	Q1	-			-	0.55%	-	-
Feb-10	2010	Q1	-			-	0.55%	-	-
Mar-10	2010	Q1	-			-	0.55%	-	-
Apr-10	2010	Q2	-			-	0.55%	-	-
May-10	2010	Q2	-			-	0.55%	-	-
Jun-10	2010	Q2	-			-	0.55%	-	-
Jul-10	2010	Q3	-			-	0.89%	-	-
Aug-10	2010	Q3	-			-	0.89%	-	-
Sep-10	2010	Q3	-			-	0.89%	-	-
Oct-10	2010	Q4	-			-	1.20%	-	-
Nov-10	2010	Q4	-			-	1.20%	-	-
Dec-10	2010	Q4	-			-	1.20%	-	-
Jan-11	2011	Q1	-			-	1.47%	-	-
Feb-11	2011	Q1	-			-	1.47%	-	-
Mar-11	2011	Q1	-			-	1.47%	-	-
Apr-11	2011	Q2	-			-	1.47%	-	-
May-11	2011	Q2	-			-	1.47%	-	-
Jun-11	2011	Q2	-			-	1.47%	-	-
Jul-11	2011	Q3	-			-	1.47%	-	-
Aug-11	2011	Q3	-			-	1.47%	-	-
Sep-11	2011	Q3	-			-	1.47%	-	-
Oct-11	2011	Q4	-			-	1.47%	-	-
Nov-11	2011	Q4	-			-	1.47%	-	-
Dec-11	2011	Q4	-			-	1.47%	-	-
Jan-12	2012	Q1	-			-	1.47%	-	-
Feb-12	2012	Q1	-			-	1.47%	-	-
Mar-12	2012	Q1	-			-	1.47%	-	-
Apr-12	2012	Q2	-			-	1.47%	-	-
May-12	2012	Q2	-			-	1.47%	-	-
Jun-12	2012	Q2	-			-	1.47%	-	-
Jul-12	2012	Q3	-			-	1.47%	-	-
Aug-12	2012	Q3	-			-	1.47%	-	-
Sep-12	2012	Q3	-			-	1.47%	-	-
Oct-12	2012	Q4	-			-	1.47%	-	-
Nov-12	2012	Q4	-			-	1.47%	-	-
Dec-12	2012	Q4	-			-	1.47%	-	-
				$ -	$ -	$ -			

Ontario Energy Board
Smart Meter Model

Haldimand County Hydro Inc.

This worksheet calculates the interest on OM&A and amortization/depreciation expense, in the absence of monthly data.

Year	OM&A (from Sheet 5)	Amortization Expense (from Sheet 5)	Cumulative OM&A and Amortization Expense	Average Cumulative OM&A and Amortization Expense	Average Annual Prescribed Interest Rate for Deferral and Variance Accounts (from Sheets 8A and 8B)	Simple Interest on OM&A and Amortization Expenses
2006	$ -	$ -	$ -	$ -	4.37%	$ -
2007	$ -	$ 339.67	$ 339.67	$ 169.83	4.73%	$ 8.03
2008	$ -	$ 830.57	$ 1,170.23	$ 754.95	3.98%	$ 30.05
2009	$ 17,394.00	$ 7,961.27	$ 26,525.50	$ 13,847.87	1.14%	$ 157.52
2010	$ 25,964.00	$ 25,931.43	$ 78,420.93	$ 52,473.22	0.80%	$ 418.47
2011	$ 38,676.00	$ 43,998.20	$ 161,095.13	$ 119,758.03	1.47%	$ 1,760.44
2012	$ 47,954.00	$ 51,188.87	$ 260,238.00	$ 210,666.57	1.47%	$ 3,096.80
Cumulative Interest to 2011						$ 2,374.51
Cumulative Interest to 2012						$ 5,471.31

Ontario Energy Board

Smart Meter Model

Haldimand County Hydro Inc.

This worksheet calculates the Smart Meter Disposition Rider and the Smart Meter Incremental Revenue Requirement Rate Rider, if applicable. This worksheet also calculates any new Smart Meter Funding Adder that a distributor may wish to request. However, please note that in many 2011 IRM decisions, the Board noted that current funding adders will cease on April 30, 2011 and that the Board's expectation is that distributors will file for a final review of prudence at the earliest opportunity. The Board also noted that the SMFA is a tool designed to provide advance funding and to mitigate the anticipated rate impact of smart meter costs when recovery of those costs is approved by the Board. The Board observed that the SMFA was not intended to be compensatory (return on and of capital) on a cumulative basis over the term the SMFA was in effect. The SMFA was initially designed to fund future investment, and not fully fund prior capital investment. Distributors that seek a new SMFA should provide evidence to support its proposal. This would include documentation of where the distributor is with respect to its smart meter deployment program, and reasons as to why the distributor's circumstances are such that continuation of the SMFA is warranted. Press the "UPDATE WORKSHEET" button after choosing the applicable adders/riders.

Check if applicable		
	Smart Meter Funding Adder (SMFA)	
X	Smart Meter Disposition Rider (SMDR)	**The SMDR is calculated based on costs to December 31, 2011**
X	Smart Meter Incremental Revenue Requirement Rate Rider (SMIRR)	**The SMIRR is calculated based on the incremental revenue requirement associated with the recovery of capital related costs to December 31, 2012 and associated OM&A.**

	2006	2007	2008	2009	2010	2011	2012 and later	Total
Deferred and forecasted Smart Meter Incremental Revenue Requirement (from Sheet 5)	$ -	$ 819.36	$ 1,910.91	$ 35,633.43	$ 79,851.15	$ 129,779.05	$ 150,930.54	$ 398,924.44
Interest on Deferred and forecasted OM&A and Amortization Expense (Sheet 8A/8B) (Check **one** of the boxes below)	$ -	$ 8.03	$ 30.05	$ 157.52	$ 418.47	$ 1,760.44		$ 2,374.51
[ ] Sheet 8A (Interest calculated on monthly balances)								$ -
[X] Sheet 8B (Interest calculated on average annual balances)	$ -	$ 8.03	$ 30.05	$ 157.52	$ 418.47	$ 1,760.44		$ 2,374.51
SMFA Revenues (from Sheet 8)	$ 4,162.60	$ 7,233.98	$ 7,261.54	$ 19,511.46	$ 42,671.09	$ 51,978.97	$ 22,362.89	$ 155,182.53
SMFA Interest (from Sheet 8)	$ 48.32	$ 358.45	$ 571.78	$ 252.13	$ 467.30	$ 1,535.75	$ 2,196.91	$ 5,430.64
Net Deferred Revenue Requirement	-$ 4,210.92	-$ 6,765.05	-$ 5,892.36	$ 16,027.36	$ 37,131.23	$ 78,024.77	$ 126,370.74	$ 240,685.78
Number of Metered Customers (average for 2012 test year)							2361	

Calculation of Smart Meter Disposition Rider (per metered customer per month)

Years for collection or refunding		1.5
Deferred Incremental Revenue Requirement from 2006 to December 31, 2011 plus Interest on OM&A and Amortization		$ 250,368.40
SMFA Revenues collected from 2006 to 2012 test year (inclusive) Plus Simple Interest on SMFA Revenues		$ 160,613.17
Net Deferred Revenue Requirement		$ 89,755.23
SMDR	November 1, 2012 to April 30, 2014	$ 2.11
Check: Forecasted SMDR Revenues		$ 89,670.78

Match

Calculation of Smart Meter Incremental Revenue Requirement Rate Rider (per metered customer per month)

Incremental Revenue Requirement for 2012	$ 150,930.54
SMIRR	$ 5.33
Check: Forecasted SMIRR Revenues	$ 151,009.56

Match

APPENDIX C

2012 Smart Meter Model

1. General Service 50 to 4,999 kW Rate Class

V 2.17

Ontario Energy Board

Smart Meter Model

Choose Your Utility:

Haldimand County Hydro Inc.
Halton Hills Hydro Inc.

Application Contact Information

Name:	Jacqueline A. Scott
Title:	Finance Manager
Phone Number:	905-765-5211 ext. 2237
Email Address:	jscott@hchydro.ca
We are applying for rates effective:	November 1, 2012
Last COS Re-based Year	2010

Legend

DROP-DOWN MENU

INPUT FIELD

CALCULATION FIELD

Copyright

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results. The use of any models and spreadsheets does not automatically imply Board approval. The onus is on the distributor to prepare, document and support its application. Board-issued Excel models and spreadsheets are offered to assist parties in providing the necessary information so as to facilitate an expeditious review of an application. The onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Smart Meter Model

Haldimand County Hydro Inc.

Distributors must enter all incremental costs related to their smart meter program and all revenues recovered to date in the applicable tabs except for those costs (and associated revenues) for which the Board has approved on a final basis, i.e. capital costs have been included in rate base and OM&A costs in revenue requirement.

For 2012, distributors that have completed their deployments by the end of 2011 are not expected to enter any capital costs. However, for OM&A, regardless of whether a distributor has deployments in 2012, distributors should enter the forecasted OM&A for 2012 for all smart meters in service.

Smart Meter Capital Cost and Operational Expense Data

	2006	2007	2008	2009	2010	2011	2012 and later	Total
	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
Smart Meter Installation Plan								
Actual/Planned number of Smart Meters installed during the Calendar Year								
Residential								0
General Service < 50 kW								0
Actual/Planned number of Smart Meters installed (Residential and GS < 50 kW only)	0	0	0	0	0	0	0	0
Percentage of Residential and GS < 50 kW Smart Meter Installations Completed	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Actual/Planned number of GS > 50 kW meters installed						76	6	82
Other (please identify)								0
Total Number of Smart Meters installed or planned to be installed	0	0	0	0	0	76	6	82

1 Capital Costs

1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)

	Asset Type Asset type must be selected to enable calculations	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.1.1 Smart Meters *(may include new meters and modules, etc.)*	Smart Meter						50,945	4,095	$ 55,040
1.1.2 Installation Costs *(may include socket kits, labour, vehicle, benefits, etc.)*	Smart Meter		306	101	490	172	32		$ 1,101
1.1.3a Workforce Automation Hardware *(may include fieldwork handhelds, barcode hardware, etc.)*	Computer Hardware				17	167	21		$ 205
1.1.3b Workforce Automation Software *(may include fieldwork handhelds, barcode hardware, etc.)*	Computer Software				9	81	90		$ 180
Total Advanced Metering Communications Devices (AMCD)		$ -	$ 306	$ 101	$ 516	$ 420	$ 51,088	$ 4,095	$ 56,526

1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)

	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.2.1 Collectors	Smart Meter				2,261				$ 2,261
1.2.2 Repeaters *(may include radio licence, etc.)*	Smart Meter								$ -
1.2.3 Installation *(may include meter seals and rings, collector computer hardware, etc.)*	Smart Meter				251	50	1		$ 302
Total Advanced Metering Regional Collector (AMRC) (Includes LAN)		$ -	$ -	$ -	$ 2,512	$ 50	$ 1	$ -	$ 2,563

1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.3.1 Computer Hardware	Computer Hardware								$ -
1.3.2 Computer Software	Computer Software								$ -
1.3.3 Computer Software Licences & Installation (includes hardware and software) *(may include AS/400 disk space, backup and recovery computer, UPS, etc.)*	Computer Software								$ -
Total Advanced Metering Control Computer (AMCC)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

1.4 WIDE AREA NETWORK (WAN)	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.4.1 Activiation Fees									$ -
Total Wide Area Network (WAN)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.5.1 Customer Equipment *(including repair of damaged equipment)*									$ -
1.5.2 AMI Interface to CIS	Computer Software				10	18	2		$ 30
1.5.3 Professional Fees	Smart Meter		57	60	103	70	43		$ 333
1.5.4 Integration	Computer Software					32	8		$ 40
1.5.5 Program Management									$ -
1.5.6 Other AMI Capital	Smart Meter					2	0		$ 2
Total Other AMI Capital Costs Related to Minimum Functionality		$ -	$ 57	$ 60	$ 113	$ 122	$ 53	$ -	$ 405
Total Capital Costs Related to Minimum Functionality		$ -	$ 363	$ 161	$ 3,141	$ 592	$ 51,142	$ 4,095	$ 59,494

1.6 CAPITAL COSTS BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06	Computer Software								$ -
1.6.2 Costs for deployment of smart meters to customers other than residential and small general service	Applications Software								$ -
1.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.	Smart Meter					17	127		$ 144
Total Capital Costs Beyond Minimum Functionality		$ -	$ -	$ -	$ -	$ 17	$ 127	$ -	$ 144
Total Smart Meter Capital Costs		$ -	$ 363	$ 161	$ 3,141	$ 609	$ 51,269	$ 4,095	$ 59,638

2 OM&A Expenses

	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)								
2.1.1 Maintenance *(may include meter reverification costs, etc.)*				114	48	315	480	$ 957
2.1.2 Other *(please specifiy)*								$ -
Total Incremental AMCD OM&A Costs	$ -	$ -	$ -	$ 114	$ 48	$ 315	$ 480	$ 957
2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)								
2.2.1 Maintenance				333	601	445	586	$ 1,965
2.2.2 Other *(please specifiy)* Additional Insurance re: Tower Gateway Base Stations				6				$ 6
Total Incremental AMRC OM&A Costs	$ -	$ -	$ -	$ 339	$ 601	$ 445	$ 586	$ 1,971
2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)								
2.3.1 Hardware Maintenance *(may include server support, etc.)*								$ -
2.3.2 Software Maintenance *(may include maintenance support, etc.)*								$ -
2.3.2 Other *(please specifiy)*								$ -
Total Incremental AMCC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.4 WIDE AREA NETWORK (WAN)								
2.4.1 WAN Maintenance								$ -
2.4.2 Other *(please specifiy)*								$ -
Total Incremental AMRC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY								
2.5.1 Business Process Redesign								$ -
2.5.2 Customer Communication (may include project communication, etc.)				122		26	36	$ 184
2.5.3 Program Management					76	154	212	$ 442
2.5.4 Change Management (may include training, etc.)					13	4		$ 17
2.5.5 Administration Costs				43	137	176	268	$ 624
2.5.6 Other AMI Expenses *(please specify)*					47	63	118	$ 228
Total Other AMI OM&A Costs Related to Minimum Functionality	$ -	$ -	$ -	$ 165	$ 273	$ 423	$ 634	$ 1,495
TOTAL OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY	$ -	$ -	$ -	$ 618	$ 922	$ 1,183	$ 1,700	$ 4,423
2.6 OM&A COSTS RELATED TO BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual		
2.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06								$ -
2.6.2 Costs for deployment of smart meters to customers other than residential and small general service								$ -
2.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.					1	192	4	$ 197
Total OM&A Costs Beyond Minimum Functionality	$ -	$ -	$ -	$ -	$ 1	$ 192	$ 4	$ 197
Total Smart Meter OM&A Costs	$ -	$ -	$ -	$ 618	$ 923	$ 1,375	$ 1,704	$ 4,620

3 Aggregate Smart Meter Costs by Category

3.1	**Capital**								
3.1.1	Smart Meter	$ -	$ 363	$ 161	$ 3,105	$ 311	$ 51,148	$ 4,095	$ 59,183
3.1.2	Computer Hardware	$ -	$ -	$ -	$ 17	$ 167	$ 21	$ -	$ 205
3.1.3	Computer Software	$ -	$ -	$ -	$ 19	$ 131	$ 100	$ -	$ 250
3.1.4	Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.5	Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.6	Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.7	**Total Capital Costs**	**$ -**	**$ 363**	**$ 161**	**$ 3,141**	**$ 609**	**$ 51,269**	**$ 4,095**	**$ 59,638**
3.2	**OM&A Costs**								
3.2.1	**Total OM&A Costs**	**$ -**	**$ -**	**$ -**	**$ 618**	**$ 923**	**$ 1,375**	**$ 1,704**	**$ 4,620**

Ontario Energy Board

Smart Meter Model

Haldimand County Hydro Inc.

	2006	2007	2008	2009	2010	2011	2012 and later
Cost of Capital							
Capital Structure[1]							
Deemed Short-term Debt Capitalization					4.0%	4.0%	4.0%
Deemed Long-term Debt Capitalization	50.0%	50.0%	53.3%	56.7%	56.0%	56.0%	56.0%
Deemed Equity Capitalization	50.0%	50.0%	46.7%	43.3%	40.0%	40.0%	40.0%
Preferred Shares							
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Cost of Capital Parameters							
Deemed Short-term Debt Rate					2.07%	2.07%	2.07%
Long-term Debt Rate (actual/embedded/deemed)[2]	6.05%	6.05%	6.05%	6.05%	5.13%	5.13%	5.13%
Target Return on Equity (ROE)	9.0%	9.00%	9.00%	9.00%	9.85%	9.85%	9.85%
Return on Preferred Shares							
WACC	7.53%	7.53%	7.43%	7.33%	6.90%	6.90%	6.90%
Working Capital Allowance							
Working Capital Allowance Rate	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
(% of the sum of Cost of Power + controllable expenses)							
Taxes/PILs							
Aggregate Corporate Income Tax Rate	36.12%	36.12%	33.50%	33.00%	29.79%	28.25%	24.33%
Capital Tax (until July 1st, 2010)	0.30%	0.225%	0.225%	0.225%	0.075%	0.00%	0.00%
Depreciation Rates							
(expressed as expected useful life in years)							
Smart Meters - years	15	15	15	15	15	15	15
- rate (%)	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
Computer Hardware - years	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Computer Software - years	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Tools & Equipment - years	10	10	10	10	10	10	10
- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Other Equipment - years	10	10	10	10	10	10	10
- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
CCA Rates							
Smart Meters - CCA Class	47	47	47	47	47	47	47
Smart Meters - CCA Rate	8%	8%	8%	8%	8%	8%	8%
Computer Equipment - CCA Class	45	45	50	52	52	50	50
Computer Equipment - CCA Rate	45%	45%	55%	100%	100%	55%	55%
General Equipment - CCA Class	8	8	8	8	8	8	8
General Equipment - CCA Rate	20%	20%	20%	20%	20%	20%	20%
Applications Software - CCA Class	45	45	50	52	52	50	50
Applications Software - CCA Rate	45%	45%	55%	100%	100%	55%	55%

Assumptions

1 *Planned smart meter installations occur evenly throughout the year.*

2 *Fiscal calendar year (January 1 to December 31) used.*

3 *Amortization is done on a striaght line basis and has the "half-year" rule applied.*

	2006	2007	2008	2009	2010	2011	2012 and later
Net Fixed Assets - Smart Meters							
Gross Book Value							
Opening Balance		$ -	$ 363	$ 524	$ 3,629	$ 3,940	$ 55,088
Capital Additions during year (from Smart Meter Costs)	$ -	$ 363	$ 161	$ 3,105	$ 311	$ 51,148	$ 4,095
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ 363	$ 524	$ 3,629	$ 3,940	$ 55,088	$ 59,183
Accumulated Depreciation							
Opening Balance		$ -	-$ 12	-$ 42	-$ 180	-$ 432	-$ 2,400
Amortization expense during year	$ -	-$ 12	-$ 30	-$ 138	-$ 252	-$ 1,968	-$ 3,809
Retirements/Removals (if applicable)							
Closing Balance	$ -	-$ 12	-$ 42	-$ 180	-$ 432	-$ 2,400	-$ 6,209
Net Book Value							
Opening Balance	$ -	$ -	$ 351	$ 482	$ 3,449	$ 3,508	$ 52,688
Closing Balance	$ -	$ 351	$ 482	$ 3,449	$ 3,508	$ 52,688	$ 52,974
Average Net Book Value	$ -	$ 175	$ 417	$ 1,966	$ 3,478	$ 28,098	$ 52,831
Net Fixed Assets - Computer Hardware							
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ 17	$ 184	$ 205
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 17	$ 167	$ 21	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ 17	$ 184	$ 205	$ 205
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	-$ 2	-$ 22	-$ 61
Amortization expense during year	$ -	$ -	$ -	-$ 2	-$ 20	-$ 39	-$ 41
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	-$ 2	-$ 22	-$ 61	-$ 102
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ 15	$ 162	$ 144
Closing Balance	$ -	$ -	$ -	$ 15	$ 162	$ 144	$ 103
Average Net Book Value	$ -	$ -	$ -	$ 8	$ 89	$ 153	$ 124
Net Fixed Assets - Computer Software (including Applications Software)							
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ 19	$ 150	$ 250
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 19	$ 131	$ 100	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ 19	$ 150	$ 250	$ 250
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	-$ 2	-$ 19	-$ 59
Amortization expense during year	$ -	$ -	$ -	-$ 2	-$ 17	-$ 40	-$ 50
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	-$ 2	-$ 19	-$ 59	-$ 109
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ 17	$ 131	$ 191
Closing Balance	$ -	$ -	$ -	$ 17	$ 131	$ 191	$ 141
Average Net Book Value	$ -	$ -	$ -	$ 9	$ 74	$ 161	$ 166
Net Fixed Assets - Tools and Equipment							
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Fixed Assets - Other Equipment							
Gross Book Value							
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value							
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Ontario Energy Board

Smart Meter Model

Haldimand County Hydro Inc.

	2006	2007	2008	2009	2010	2011	2012 and Later
Average Net Fixed Asset Values (from Sheet 4)							
Smart Meters	$ -	$ 175	$ 417	$ 1,966	$ 3,478	$ 28,098	$ 52,831
Computer Hardware	$ -	$ -	$ -	$ 8	$ 89	$ 153	$ 124
Computer Software	$ -	$ -	$ -	$ 9	$ 74	$ 161	$ 166
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Net Fixed Assets	**$ -**	**$ 175**	**$ 417**	**$ 1,982**	**$ 3,641**	**$ 28,412**	**$ 53,121**
Working Capital							
Operating Expenses (from Sheet 2)	$ -	$ -	$ -	$ 618	$ 923	$ 1,375	$ 1,704
Working Capital Factor (from Sheet 3)	15%	15%	15%	15%	15%	15%	15%
Working Capital Allowance	$ -	$ -	$ -	$ 93	$ 138	$ 206	$ 256
Incremental Smart Meter Rate Base	**$ -**	**$ 175**	**$ 417**	**$ 2,075**	**$ 3,780**	**$ 28,619**	**$ 53,377**
Return on Rate Base							
Capital Structure							
Deemed Short Term Debt	$ -	$ -	$ -	$ -	$ 151	$ 1,145	$ 2,135
Deemed Long Term Debt	$ -	$ 88	$ 222	$ 1,176	$ 2,117	$ 16,026	$ 29,891
Equity	$ -	$ 88	$ 195	$ 898	$ 1,512	$ 11,447	$ 21,351
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capitalization	$ -	$ 175	$ 417	$ 2,075	$ 3,780	$ 28,619	$ 53,377
Return on							
Deemed Short Term Debt	$ -	$ -	$ -	$ -	$ 3	$ 24	$ 44
Deemed Long Term Debt	$ -	$ 5	$ 13	$ 71	$ 109	$ 822	$ 1,533
Equity	$ -	$ 8	$ 18	$ 81	$ 149	$ 1,128	$ 2,103
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Return on Capital	$ -	$ 13	$ 31	$ 152	$ 261	$ 1,973	$ 3,681
Operating Expenses	$ -	$ -	$ -	$ 618	$ 923	$ 1,375	$ 1,704
Amortization Expenses (from Sheet 4)							
Smart Meters	$ -	$ 12	$ 30	$ 138	$ 252	$ 1,968	$ 3,809
Computer Hardware	$ -	$ -	$ -	$ 2	$ 20	$ 39	$ 41
Computer Software	$ -	$ -	$ -	$ 2	$ 17	$ 40	$ 50
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Amortization Expense in Year	$ -	$ 12	$ 30	$ 142	$ 289	$ 2,047	$ 3,900
Incremental Revenue Requirement before Taxes/PILs	$ -	$ 25	$ 61	$ 912	$ 1,473	$ 5,395	$ 9,285
Calculation of Taxable Income							
Incremental Operating Expenses	$ -	$ -	$ -	$ 618	$ 923	$ 1,375	$ 1,704
Amortization Expense	$ -	$ 12	$ 30	$ 142	$ 289	$ 2,047	$ 3,900
Interest Expense	$ -	$ 5	$ 13	$ 71	$ 112	$ 846	$ 1,578
Net Income for Taxes/PILs	$ -	$ 8	$ 18	$ 81	$ 149	$ 1,128	$ 2,103
Grossed-up Taxes/PILs (from Sheet 7)	$ -	$ 3.89	$ 7.51	$ 28.85	-$ 3.37	$ 290.37	$ 505.62
Revenue Requirement, including Grossed-up Taxes/PILs	$ -	$ 29	$ 68	$ 941	$ 1,470	$ 5,685	$ 9,790

Ontario Energy Board

Smart Meter Model

Haldimand County Hydro Inc.

For PILs Calculation

UCC - Smart Meters

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ 348.48	$ 475.16	$ 3,417.95	$ 3,443.07	$ 52,269.71
Capital Additions	$ -	$ 363.00	$ 161.00	$ 3,105.00	$ 311.00	$ 51,148.00	$ 4,095.00
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ 363.00	$ 509.48	$ 3,580.16	$ 3,728.95	$ 54,591.07	$ 56,364.71
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 181.50	$ 80.50	$ 1,552.50	$ 155.50	$ 25,574.00	$ 2,047.50
Reduced UCC	$ -	$ 181.50	$ 428.98	$ 2,027.66	$ 3,573.45	$ 29,017.07	$ 54,317.21
CCA Rate Class	47	47	47	47	47	47	47
CCA Rate	8%	8%	8%	8%	8%	8%	8%
CCA	$ -	$ 14.52	$ 34.32	$ 162.21	$ 285.88	$ 2,321.37	$ 4,345.38
Closing UCC	$ -	$ 348.48	$ 475.16	$ 3,417.95	$ 3,443.07	$ 52,269.71	$ 52,019.33

UCC - Computer Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ 18.00	$ 149.00	$ 154.78
Capital Additions Computer Hardware	$ -	$ -	$ -	$ 17.00	$ 167.00	$ 21.00	$ -
Capital Additions Computer Software	$ -	$ -	$ -	$ 19.00	$ 131.00	$ 100.00	$ -
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ -	$ -	$ 36.00	$ 316.00	$ 270.00	$ 154.78
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ 18.00	$ 149.00	$ 60.50	$ -
Reduced UCC	$ -	$ -	$ -	$ 18.00	$ 167.00	$ 209.50	$ 154.78
CCA Rate Class	45	45	50	52	52	50	50
CCA Rate	45%	45%	55%	100%	100%	55%	55%
CCA	$ -	$ -	$ -	$ 18.00	$ 167.00	$ 115.23	$ 85.13
Closing UCC	$ -	$ -	$ -	$ 18.00	$ 149.00	$ 154.78	$ 69.65

UCC - General Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)							
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class	8	8	8	8	8	8	8
CCA Rate	20%	20%	20%	20%	20%	20%	20%
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -

PILs Calculation

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
INCOME TAX							
Net Income	$ -	$ 7.90	$ 17.51	$ 80.84	$ 148.92	$ 1,127.57	$ 2,103.04
Amortization	$ -	$ 12.10	$ 29.57	$ 142.03	$ 289.30	$ 2,046.50	$ 3,900.03
CCA - Smart Meters	$ -	-$ 14.52	-$ 34.32	-$ 162.21	-$ 285.88	-$ 2,321.37	-$ 4,345.38
CCA - Computers	$ -	$ -	$ -	-$ 18.00	-$ 167.00	-$ 115.23	-$ 85.13
CCA - Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA - Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Change in taxable income	$ -	$ 5.48	$ 12.76	$ 42.66	-$ 14.66	$ 737.48	$ 1,572.57
Tax Rate (from Sheet 3)	36.12%	36.12%	33.50%	33.00%	29.79%	28.25%	24.33%
Income Taxes Payable	$ -	$ 1.98	$ 4.27	$ 14.08	-$ 4.37	$ 208.34	$ 382.61
ONTARIO CAPITAL TAX							
Smart Meters	$ -	$ 350.90	$ 482.33	$ 3,448.90	$ 3,507.60	$ 52,688.00	$ 52,973.97
Computer Hardware	$ -	$ -	$ -	$ 15.30	$ 162.20	$ 144.30	$ 103.30
Computer Software (Including Application Software)	$ -	$ -	$ -	$ 17.10	$ 131.20	$ 191.20	$ 141.20
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rate Base	$ -	$ 350.90	$ 482.33	$ 3,481.30	$ 3,801.00	$ 53,023.50	$ 53,218.47
Less: Exemption							
Deemed Taxable Capital	$ -	$ 350.90	$ 482.33	$ 3,481.30	$ 3,801.00	$ 53,023.50	$ 53,218.47
Ontario Capital Tax Rate (from Sheet 3)	0.300%	0.225%	0.225%	0.225%	0.075%	0.000%	0.000%
Net Amount (Taxable Capital x Rate)	$ -	$ 0.79	$ 1.09	$ 7.83	$ 2.85	$ -	$ -
Change in Income Taxes Payable	$ -	$ 1.98	$ 4.27	$ 14.08	-$ 4.37	$ 208.34	$ 382.61
Change in OCT	$ -	$ 0.79	$ 1.09	$ 7.83	$ 2.85	$ -	$ -
PILs	$ -	$ 2.77	$ 5.36	$ 21.91	-$ 1.52	$ 208.34	$ 382.61

Gross Up PILs

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 and later Forecast
Tax Rate	36.12%	36.12%	33.50%	33.00%	29.79%	28.25%	24.33%
Change in Income Taxes Payable	$ -	$ 3.10	$ 6.43	$ 21.01	-$ 6.22	$ 290.37	$ 505.62
Change in OCT	$ -	$ 0.79	$ 1.09	$ 7.83	$ 2.85	$ -	$ -
PILs	$ -	$ 3.89	$ 7.51	$ 28.85	-$ 3.37	$ 290.37	$ 505.62

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP
2006 Q1		
2006 Q2	4.14%	4.68%
2006 Q3	4.59%	5.05%
2006 Q4	4.59%	4.72%
2007 Q1	4.59%	4.72%
2007 Q2	4.59%	4.72%
2007 Q3	4.59%	5.18%
2007 Q4	5.14%	5.18%
2008 Q1	5.14%	5.18%
2008 Q2	4.08%	5.18%
2008 Q3	3.35%	5.43%
2008 Q4	3.35%	5.43%
2009 Q1	2.45%	6.61%
2009 Q2	1.00%	6.61%
2009 Q3	0.55%	5.67%
2009 Q4	0.55%	4.66%
2010 Q1	0.55%	4.34%
2010 Q2	0.55%	4.34%
2010 Q3	0.89%	4.66%
2010 Q4	1.20%	4.01%
2011 Q1	1.47%	4.29%
2011 Q2	1.47%	4.29%
2011 Q3	1.47%	4.29%
2011 Q4	1.47%	4.29%
2012 Q1	1.47%	4.29%
2012 Q2	1.47%	4.29%
2012 Q3	1.47%	4.29%
2012 Q4	1.47%	4.29%

Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
Jan-06	2006	Q1	$ -		0.00%	$ -	$ -		
Feb-06	2006	Q1	$ -		0.00%	$ -	$ -		
Mar-06	2006	Q1	$ -		0.00%	$ -	$ -		
Apr-06	2006	Q2	$ -		4.14%	$ -	$ -		
May-06	2006	Q2	$ -	$ 3.12	4.14%	$ -	$ 3.12		$ 0.26
Jun-06	2006	Q2	$ 3.12	$ 35.10	4.14%	$ 0.01	$ 38.23		$ 0.26
Jul-06	2006	Q3	$ 38.22	$ 36.14	4.59%	$ 0.15	$ 74.51		$ 0.26
Aug-06	2006	Q3	$ 74.36	$ 42.90	4.59%	$ 0.28	$ 117.54		$ 0.26
Sep-06	2006	Q3	$ 117.26	$ 34.84	4.59%	$ 0.45	$ 152.55		$ 0.26
Oct-06	2006	Q4	$ 152.10	$ 38.48	4.59%	$ 0.58	$ 191.16		$ 0.26
Nov-06	2006	Q4	$ 190.58	$ 40.04	4.59%	$ 0.73	$ 231.35		$ 0.26
Dec-06	2006	Q4	$ 230.62	$ 35.88	4.59%	$ 0.88	$ 267.38	$ 269.58	$ 0.26
Jan-07	2007	Q1	$ 266.50	$ 38.48	4.59%	$ 1.02	$ 306.00		$ 0.26
Feb-07	2007	Q1	$ 304.98	$ 39.26	4.59%	$ 1.17	$ 345.41		$ 0.26
Mar-07	2007	Q1	$ 344.24	$ 41.86	4.59%	$ 1.32	$ 387.42		$ 0.26
Apr-07	2007	Q2	$ 386.10	$ 36.14	4.59%	$ 1.48	$ 423.72		$ 0.26
May-07	2007	Q2	$ 422.24	$ 41.60	4.59%	$ 1.62	$ 465.46		$ 0.26
Jun-07	2007	Q2	$ 463.84	$ 39.26	4.59%	$ 1.77	$ 504.87		$ 0.26
Jul-07	2007	Q3	$ 503.10	$ 39.26	4.59%	$ 1.92	$ 544.28		$ 0.26
Aug-07	2007	Q3	$ 542.36	$ 40.04	4.59%	$ 2.07	$ 584.47		$ 0.26
Sep-07	2007	Q3	$ 582.40	$ 34.32	4.59%	$ 2.23	$ 618.95		$ 0.26
Oct-07	2007	Q4	$ 616.72	$ 38.74	5.14%	$ 2.64	$ 658.10		$ 0.26
Nov-07	2007	Q4	$ 655.46	$ 35.10	5.14%	$ 2.81	$ 693.37		$ 0.26
Dec-07	2007	Q4	$ 690.56	$ 33.02	5.14%	$ 2.96	$ 726.54	$ 480.09	$ 0.26
Jan-08	2008	Q1	$ 723.58	$ 36.66	5.14%	$ 3.10	$ 763.34		$ 0.26
Feb-08	2008	Q1	$ 760.24	$ 33.54	5.14%	$ 3.26	$ 797.04		$ 0.26
Mar-08	2008	Q1	$ 793.78	$ 33.28	5.14%	$ 3.40	$ 830.46		$ 0.26
Apr-08	2008	Q2	$ 827.06	$ 36.14	4.08%	$ 2.81	$ 866.01		$ 0.26
May-08	2008	Q2	$ 863.20	$ 35.36	4.08%	$ 2.93	$ 901.49		$ 0.26
Jun-08	2008	Q2	$ 898.56	$ 35.10	4.08%	$ 3.06	$ 936.72		$ 0.26
Jul-08	2008	Q3	$ 933.66	$ 36.66	3.35%	$ 2.61	$ 972.93		$ 0.26
Aug-08	2008	Q3	$ 970.32	$ 30.94	3.35%	$ 2.71	$ 1,003.97		$ 0.26
Sep-08	2008	Q3	$ 1,001.26	$ 35.36	3.35%	$ 2.80	$ 1,039.42		$ 0.26
Oct-08	2008	Q4	$ 1,036.62	$ 37.44	3.35%	$ 2.89	$ 1,076.95		$ 0.26
Nov-08	2008	Q4	$ 1,074.06	$ 35.88	3.35%	$ 3.00	$ 1,112.94		$ 0.26
Dec-08	2008	Q4	$ 1,109.94	$ 37.18	3.35%	$ 3.10	$ 1,150.22	$ 459.21	$ 0.26
Jan-09	2009	Q1	$ 1,147.12	$ 35.36	2.45%	$ 2.34	$ 1,184.82		$ 0.26
Feb-09	2009	Q1	$ 1,182.48	$ 33.80	2.45%	$ 2.41	$ 1,218.69		$ 0.26
Mar-09	2009	Q1	$ 1,216.28	$ 32.39	2.45%	$ 2.48	$ 1,251.15		$ 0.26
Apr-09	2009	Q2	$ 1,248.67	$ 38.32	1.00%	$ 1.04	$ 1,288.03		$ 0.26
May-09	2009	Q2	$ 1,286.99	$ 35.34	1.00%	$ 1.07	$ 1,323.40		$ 1.00
Jun-09	2009	Q2	$ 1,322.33	$ 133.93	1.00%	$ 1.10	$ 1,457.36		$ 1.00
Jul-09	2009	Q3	$ 1,456.26	$ 120.22	0.55%	$ 0.67	$ 1,577.15		$ 1.00
Aug-09	2009	Q3	$ 1,576.48	$ 153.17	0.55%	$ 0.72	$ 1,730.37		$ 1.00
Sep-09	2009	Q3	$ 1,729.65	$ 138.87	0.55%	$ 0.79	$ 1,869.31		$ 1.00
Oct-09	2009	Q4	$ 1,868.52	$ 139.00	0.55%	$ 0.86	$ 2,008.38		$ 1.00
Nov-09	2009	Q4	$ 2,007.52	$ 137.00	0.55%	$ 0.92	$ 2,145.44		$ 1.00
Dec-09	2009	Q4	$ 2,144.52	$ 139.00	0.55%	$ 0.98	$ 2,284.50	$ 1,151.78	$ 1.00
Jan-10	2010	Q1	$ 2,283.52	$ 136.10	0.55%	$ 1.05	$ 2,420.67		$ 1.00
Feb-10	2010	Q1	$ 2,419.62	$ 127.16	0.55%	$ 1.11	$ 2,547.89		$ 1.00
Mar-10	2010	Q1	$ 2,546.78	$ 146.14	0.55%	$ 1.17	$ 2,694.09		$ 1.00
Apr-10	2010	Q2	$ 2,692.92	$ 137.90	0.55%	$ 1.23	$ 2,832.05		$ 1.00
May-10	2010	Q2	$ 2,830.82	$ 142.61	0.55%	$ 1.30	$ 2,974.73		$ 1.87
Jun-10	2010	Q2	$ 2,973.43	$ 246.45	0.55%	$ 1.36	$ 3,221.24		$ 1.87
Jul-10	2010	Q3	$ 3,219.88	$ 258.46	0.89%	$ 2.39	$ 3,480.73		$ 1.87
Aug-10	2010	Q3	$ 3,478.34	$ 254.06	0.89%	$ 2.58	$ 3,734.98		$ 1.87
Sep-10	2010	Q3	$ 3,732.40	$ 255.57	0.89%	$ 2.77	$ 3,990.74		$ 1.87
Oct-10	2010	Q4	$ 3,987.97	$ 256.07	1.20%	$ 3.99	$ 4,248.03		$ 1.87
Nov-10	2010	Q4	$ 4,244.04	$ 259.24	1.20%	$ 4.24	$ 4,507.52		$ 1.87
Dec-10	2010	Q4	$ 4,503.28	$ 254.20	1.20%	$ 4.50	$ 4,761.98	$ 2,501.65	$ 1.87
Jan-11	2011	Q1	$ 4,757.48	$ 256.06	1.47%	$ 5.83	$ 5,019.37		$ 1.87
Feb-11	2011	Q1	$ 5,013.54	$ 241.08	1.47%	$ 6.14	$ 5,260.76		$ 1.87
Mar-11	2011	Q1	$ 5,254.62	$ 273.64	1.47%	$ 6.44	$ 5,534.70		$ 1.87
Apr-11	2011	Q2	$ 5,528.26	$ 245.66	1.47%	$ 6.77	$ 5,780.69		$ 1.87
May-11	2011	Q2	$ 5,773.92	$ 264.91	1.47%	$ 7.07	$ 6,045.90		$ 1.87
Jun-11	2011	Q2	$ 6,038.83	$ 277.01	1.47%	$ 7.40	$ 6,323.24		$ 1.87
Jul-11	2011	Q3	$ 6,315.84	$ 247.46	1.47%	$ 7.74	$ 6,571.04		$ 1.87
Aug-11	2011	Q3	$ 6,563.30	$ 276.82	1.47%	$ 8.04	$ 6,848.16		$ 1.87
Sep-11	2011	Q3	$ 6,840.12	$ 263.67	1.47%	$ 8.38	$ 7,112.17		$ 1.87
Oct-11	2011	Q4	$ 7,103.79	$ 247.15	1.47%	$ 8.70	$ 7,359.64		$ 1.87
Nov-11	2011	Q4	$ 7,350.94	$ 273.39	1.47%	$ 9.00	$ 7,633.33		$ 1.87
Dec-11	2011	Q4	$ 7,624.33	$ 254.51	1.47%	$ 9.34	$ 7,888.18	$ 3,212.21	$ 1.87
Jan-12	2012	Q1	$ 7,878.84	$ 256.01	1.47%	$ 9.65	$ 8,144.50		$ 1.87
Feb-12	2012	Q1	$ 8,134.85	$ 258.87	1.47%	$ 9.97	$ 8,403.69		$ 1.87

Haldimand County Hydro Inc.

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
			Mar-12	2012	Q1	$ 8,393.72	$ 267.47	1.47%	$ 10.28	$ 8,671.47		$ 1.87
			Apr-12	2012	Q2	$ 8,661.19	$ 257.81	1.47%	$ 10.61	$ 8,929.61		$ 1.87
			May-12	2012	Q2	$ 8,919.00	$ 247.09	1.47%	$ 10.93	$ 9,177.02		
			Jun-12	2012	Q2	$ 9,166.09	$ 19.94	1.47%	$ 11.23	$ 9,197.26		
			Jul-12	2012	Q3	$ 9,186.03		1.47%	$ 11.25	$ 9,197.28		
			Aug-12	2012	Q3	$ 9,186.03		1.47%	$ 11.25	$ 9,197.28		
			Sep-12	2012	Q3	$ 9,186.03		1.47%	$ 11.25	$ 9,197.28		
			Oct-12	2012	Q4	$ 9,186.03		1.47%	$ 11.25	$ 9,197.28		
			Nov-12	2012	Q4	$ 9,186.03		1.47%	$ 11.25	$ 9,197.28		
			Dec-12	2012	Q4	$ 9,186.03		1.47%	$ 11.25	$ 9,197.28	$ 1,437.36	
			Total Funding Adder Revenues Collected				**$ 9,186.03**		**$ 325.85**	**$ 9,511.88**	**$ 9,511.88**	

Ontario Energy Board

Smart Meter Model

Haldimand County Hydro Inc.

This worksheet calculates the interest on OM&A and amortization/depreciation expense, based on monthly data.

Prescribed Interest Rates	Approved Deferral and Variance Accounts	CWIP
2006 Q1	0.00%	0.00%
2006 Q2	4.14%	4.68%
2006 Q3	4.59%	5.05%
2006 Q4	4.59%	4.72%
2007 Q1	4.59%	4.72%
2007 Q2	4.59%	4.72%
2007 Q3	4.59%	5.18%
2007 Q4	5.14%	5.18%
2008 Q1	5.14%	5.18%
2008 Q2	4.08%	5.18%
2008 Q3	3.35%	5.43%
2008 Q4	3.35%	5.43%
2009 Q1	2.45%	6.61%
2009 Q2	1.00%	6.61%
2009 Q3	0.55%	5.67%
2009 Q4	0.55%	4.66%
2010 Q1	0.55%	4.34%
2010 Q2	0.55%	4.34%
2010 Q3	0.89%	4.66%
2010 Q4	1.20%	4.01%
2011 Q1	1.47%	4.29%
2011 Q2	1.47%	4.29%
2011 Q3	1.47%	4.29%
2011 Q4	1.47%	4.29%
2012 Q1	1.47%	4.29%
2012 Q2	1.47%	4.29%
2012 Q3	1.47%	4.29%
2012 Q4	1.47%	4.29%

Account 1556 - Sub-accounts Operating Expenses, Amortization Expenses, Carrying Charges

Date	Year	Quarter	Opening Balance (Principal)	OM&A Expenses	Amortization / Depreciation Expense	Closing Balance (Principal)	(Annual) Interest Rate	Interest (on opening balance)	Cumulative Interest
Jan-06	2006	Q1	$ -			-	0.00%	-	-
Feb-06	2006	Q1	-			-	0.00%	-	-
Mar-06	2006	Q1	-			-	0.00%	-	-
Apr-06	2006	Q2	-			-	4.14%	-	-
May-06	2006	Q2	-			-	4.14%	-	-
Jun-06	2006	Q2	-			-	4.14%	-	-
Jul-06	2006	Q3	-			-	4.59%	-	-
Aug-06	2006	Q3	-			-	4.59%	-	-
Sep-06	2006	Q3	-			-	4.59%	-	-
Oct-06	2006	Q4	-			-	4.59%	-	-
Nov-06	2006	Q4	-			-	4.59%	-	-
Dec-06	2006	Q4	-			-	4.59%	-	-
Jan-07	2007	Q1	-			-	4.59%	-	-
Feb-07	2007	Q1	-			-	4.59%	-	-
Mar-07	2007	Q1	-			-	4.59%	-	-
Apr-07	2007	Q2	-			-	4.59%	-	-
May-07	2007	Q2	-			-	4.59%	-	-
Jun-07	2007	Q2	-			-	4.59%	-	-
Jul-07	2007	Q3	-			-	4.59%	-	-
Aug-07	2007	Q3	-			-	4.59%	-	-
Sep-07	2007	Q3	-			-	4.59%	-	-
Oct-07	2007	Q4	-			-	5.14%	-	-
Nov-07	2007	Q4	-			-	5.14%	-	-
Dec-07	2007	Q4	-			-	5.14%	-	-
Jan-08	2008	Q1	-			-	5.14%	-	-
Feb-08	2008	Q1	-			-	5.14%	-	-
Mar-08	2008	Q1	-			-	5.14%	-	-
Apr-08	2008	Q2	-			-	4.08%	-	-
May-08	2008	Q2	-			-	4.08%	-	-
Jun-08	2008	Q2	-			-	4.08%	-	-
Jul-08	2008	Q3	-			-	3.35%	-	-
Aug-08	2008	Q3	-			-	3.35%	-	-
Sep-08	2008	Q3	-			-	3.35%	-	-
Oct-08	2008	Q4	-			-	3.35%	-	-
Nov-08	2008	Q4	-			-	3.35%	-	-
Dec-08	2008	Q4	-			-	3.35%	-	-
Jan-09	2009	Q1	-			-	2.45%	-	-
Feb-09	2009	Q1	-			-	2.45%	-	-
Mar-09	2009	Q1	-			-	2.45%	-	-
Apr-09	2009	Q2	-			-	1.00%	-	-
May-09	2009	Q2	-			-	1.00%	-	-
Jun-09	2009	Q2	-			-	1.00%	-	-
Jul-09	2009	Q3	-			-	0.55%	-	-
Aug-09	2009	Q3	-			-	0.55%	-	-
Sep-09	2009	Q3	-			-	0.55%	-	-
Oct-09	2009	Q4	-			-	0.55%	-	-
Nov-09	2009	Q4	-			-	0.55%	-	-
Dec-09	2009	Q4	-			-	0.55%	-	-
Jan-10	2010	Q1	-			-	0.55%	-	-
Feb-10	2010	Q1	-			-	0.55%	-	-
Mar-10	2010	Q1	-			-	0.55%	-	-
Apr-10	2010	Q2	-			-	0.55%	-	-
May-10	2010	Q2	-			-	0.55%	-	-
Jun-10	2010	Q2	-			-	0.55%	-	-
Jul-10	2010	Q3	-			-	0.89%	-	-
Aug-10	2010	Q3	-			-	0.89%	-	-
Sep-10	2010	Q3	-			-	0.89%	-	-
Oct-10	2010	Q4	-			-	1.20%	-	-
Nov-10	2010	Q4	-			-	1.20%	-	-
Dec-10	2010	Q4	-			-	1.20%	-	-
Jan-11	2011	Q1	-			-	1.47%	-	-
Feb-11	2011	Q1	-			-	1.47%	-	-
Mar-11	2011	Q1	-			-	1.47%	-	-
Apr-11	2011	Q2	-			-	1.47%	-	-
May-11	2011	Q2	-			-	1.47%	-	-
Jun-11	2011	Q2	-			-	1.47%	-	-
Jul-11	2011	Q3	-			-	1.47%	-	-
Aug-11	2011	Q3	-			-	1.47%	-	-
Sep-11	2011	Q3	-			-	1.47%	-	-
Oct-11	2011	Q4	-			-	1.47%	-	-
Nov-11	2011	Q4	-			-	1.47%	-	-
Dec-11	2011	Q4	-			-	1.47%	-	-
Jan-12	2012	Q1	-			-	1.47%	-	-
Feb-12	2012	Q1	-			-	1.47%	-	-
Mar-12	2012	Q1	-			-	1.47%	-	-
Apr-12	2012	Q2	-			-	1.47%	-	-
May-12	2012	Q2	-			-	1.47%	-	-
Jun-12	2012	Q2	-			-	1.47%	-	-
Jul-12	2012	Q3	-			-	1.47%	-	-
Aug-12	2012	Q3	-			-	1.47%	-	-
Sep-12	2012	Q3	-			-	1.47%	-	-
Oct-12	2012	Q4	-			-	1.47%	-	-
Nov-12	2012	Q4	-			-	1.47%	-	-
Dec-12	2012	Q4	-			-	1.47%	-	-
				$ -	$ -	$ -			

Ontario Energy Board
Smart Meter Model

Haldimand County Hydro Inc.

This worksheet calculates the interest on OM&A and amortization/depreciation expense, in the absence of monthly data.

Year	OM&A (from Sheet 5)	Amortization Expense (from Sheet 5)	Cumulative OM&A and Amortization Expense	Average Cumulative OM&A and Amortization Expense	Average Annual Prescribed Interest Rate for Deferral and Variance Accounts (from Sheets 8A and 8B)	Simple Interest on OM&A and Amortization Expenses
2006	$ -	$ -	$ -	$ -	4.37%	$ -
2007	$ -	$ 12.10	$ 12.10	$ 6.05	4.73%	$ 0.29
2008	$ -	$ 29.57	$ 41.67	$ 26.88	3.98%	$ 1.07
2009	$ 618.00	$ 142.03	$ 801.70	$ 421.68	1.14%	$ 4.80
2010	$ 923.00	$ 289.30	$ 2,014.00	$ 1,407.85	0.80%	$ 11.23
2011	$ 1,375.00	$ 2,046.50	$ 5,435.50	$ 3,724.75	1.47%	$ 54.75
2012	$ 1,704.00	$ 3,900.03	$ 11,039.53	$ 8,237.52	1.47%	$ 121.09
Cumulative Interest to 2011						$ 72.13
Cumulative Interest to 2012						$ 193.23

This worksheet calculates the Smart Meter Disposition Rider and the Smart Meter Incremental Revenue Requirement Rate Rider, if applicable. This worksheet also calculates any new Smart Meter Funding Adder that a distributor may wish to request. However, please note that in many 2011 IRM decisions, the Board noted that current funding adders will cease on April 30, 2011 and that the Board's expectation is that distributors will file for a final review of prudence at the earliest opportunity. The Board also noted that the SMFA is a tool designed to provide advance funding and to mitigate the anticipated rate impact of smart meter costs when recovery of those costs is approved by the Board. The Board observed that the SMFA was not intended to be compensatory (return on and of capital) on a cumulative basis over the term the SMFA was in effect. The SMFA was initially designed to fund future investment, and not fully fund prior capital investment. Distributors that seek a new SMFA should provide evidence to support its proposal. This would include documentation of where the distributor is with respect to its smart meter deployment program, and reasons as to why the distributor's circumstances are such that continuation of the SMFA is warranted. Press the "UPDATE WORKSHEET" button after choosing the applicable adders/riders.

Check if applicable		
	Smart Meter Funding Adder (SMFA)	
X	Smart Meter Disposition Rider (SMDR)	**The SMDR is calculated based on costs to December 31, 2011**
X	Smart Meter Incremental Revenue Requirement Rate Rider (SMIRR)	**The SMIRR is calculated based on the incremental revenue requirement associated with the recovery of capital related costs to December 31, 2012 and associated OM&A.**

	2006	2007	2008	2009	2010	2011	2012 and later	Total
Deferred and forecasted Smart Meter Incremental Revenue Requirement (from Sheet 5)	$ -	$ 29.19	$ 68.02	$ 940.89	$ 1,469.56	$ 5,685.28	$ 9,790.29	$ 17,983.23
Interest on Deferred and forecasted OM&A and Amortization Expense (Sheet 8A/8B) (Check **one** of the boxes below)	$ -	$ 0.29	$ 1.07	$ 4.80	$ 11.23	$ 54.75		$ 72.13
[ ] Sheet 8A (Interest calculated on monthly balances)								$ -
[X] Sheet 8B (Interest calculated on average annual balances)	$ -	$ 0.29	$ 1.07	$ 4.80	$ 11.23	$ 54.75		$ 72.13
SMFA Revenues (from Sheet 8)	$ 266.50	$ 457.08	$ 423.54	$ 1,136.40	$ 2,473.96	$ 3,121.36	$ 1,307.19	$ 9,186.03
SMFA Interest (from Sheet 8)	$ 3.08	$ 23.01	$ 35.67	$ 15.38	$ 27.69	$ 90.85	$ 130.17	$ 325.85
Net Deferred Revenue Requirement	-$ 269.58	-$ 450.62	-$ 390.12	-$ 206.10	-$ 1,020.87	$ 2,527.83	$ 8,352.93	$ 8,543.49
Number of Metered Customers (average for 2012 test year)							83	

Calculation of Smart Meter Disposition Rider (per metered customer per month)

Years for collection or refunding		1.5
Deferred Incremental Revenue Requirement from 2006 to December 31, 2011 plus Interest on OM&A and Amortization		$ 8,265.07
SMFA Revenues collected from 2006 to 2012 test year (inclusive) Plus Simple Interest on SMFA Revenues		$ 9,511.88
Net Deferred Revenue Requirement		-$ 1,246.81
SMDR	November 1, 2012 to April 30, 2014	-$ 0.83
Check: Forecasted SMDR Revenues		-$ 1,240.02

Match

Calculation of Smart Meter Incremental Revenue Requirement Rate Rider (per metered customer per month)

Incremental Revenue Requirement for 2012	$ 9,790.29
SMIRR	$ 9.83
Check: Forecasted SMIRR Revenues	$ 9,790.68

Match

APPENDIX D

Niagara Erie Power Association

Smart Meter Project Summary
January 18, 2012

util-assist

utility strategic operational assistance

NIAGARA ERIE POWER ASSOCIATION

(NEPA)

Smart Meter Project Summary

January 18, 2012

Prepared By:
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Executive Summary

In June of 2004, the Minister of Energy issued a Directive under Section 27.1 of the *Ontario Energy Board Act,* 1998 which required the Board to develop and, upon approval by the Minister of Energy, implement a plan to achieve the government's objectives for the deployment of smart electricity meters. In conjunction with the development of its implementation plan, the Directive also required the Board to examine the need for and effectiveness of time of use rates for non-commodity charges - in addition to season/time-based standard supply service commodity rates the Board is already in a position to establish - to complement the implementation of and maximize the benefits of smart meters.

The provincial Smart Meter Initiative would stem from this Directive and all Local Distribution Companies (LDCs) in Ontario would be heavily involved in creating a conservation culture in Ontario and making the Province a North American leader in energy efficiency. Key initiatives included the introduction of flexible, time-of-use pricing for electricity, and a targeted reduction in Ontario’s energy consumption of 5%.

The provincial initiative mandated the installation of a smart electricity meter in every Ontario home by December 31, 2010, with the interim goal of 800,000 meters being deployed by December 31, 2007. The underlying premise behind the mandate to install these meters was to educate customers on their consumption habits and to implement new rate structures that encouraged load shifting and conservation of energy, thereby reducing the requirement for increased power generation capabilities.

This was an enormous undertaking for all LDCs; a project that took months of planning and carefully managed execution. To accommodate the needs of the Ministry of Energy and Infrastructure, NEPA members installed approximately 178,000 meters to fulfill their requirements for the mandate. Combined with the magnitude of the metering project, members also had the challenge of choosing technologies and installation service providers that could accommodate the stated requirements within their diverse LDC service territories.

Other Ontario Regulations that applied to the initiative include:

Reg. 425/06 Criteria and Requirements For Meters and Metering Equipment, Systems and Technology
Reg. 426/06 Smart Meter: Costs Recovery
Reg. 427/06 Smart Meters: Discretionary Metering Activity and Procurement Principles
Reg. 235/08 Amending Reg. 427/06 Smart Meters: Discretionary Metering Activity and Procurement Principles Functional Specification for an Advanced Metering Infrastructure – July 5, 2007

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Education and Preparation for the Initiative

As indicated above, the SMI required preparation and execution for the selection and deployment of new technology on an unprecedented scale. As this initiative was new to Ontario utilities, the NEPA group members recognized that there was much to be learned about the new AMI technologies to ensure that the operational efficiencies that become available through AMI would be realized as part of the initiative.

NEPA member utilities had achieved great success when working together on previous initiatives and elected for a collaborative approach to the education required for a successful Smart Meter Implementation. In so doing, utilities were involved with the Ontario Utility Smart Metering (OUSM) working group starting with its inception in March of 2005. Through this involvement, much was learned regarding prominent AMI systems and the technologies associated with back office integration of meter data, as well as the vendors associated with the installation of these products.

OUSM Working Group Participation

To satisfy the due diligence requirements of a project of this magnitude, an all-inclusive process was undertaken. In order to become educated on all aspects of the AMI initiative, NEPA members maintained involvement in the Ontario Utilities Smart Meter (OUSM), a working group that consisted of over 50 utility members that came together in an educational effort.

NEPA members supported the concept of the OUSM from the outset, embracing the collaborative approach to acquiring the required education for a successful Smart Meter Implementation. Through their involvement much was learned regarding all prominent AMI technologies available to the North American marketplace by:

1. Sharing information on the success of AMI pilots installed in utilities across the province

2. Reporting on the testing of different AMI technologies and components related to the AMI initiative which was completed in 2005.

   a. Standard Test Scripts were created and used for testing all AMI technologies, helping to provide comfort and back-up documentation to justify future vendor selection to a utility's board members and the OEB.

   b. The testing of products ensured an understanding not only of the functionality of the products *available* in this market, but also to understand the functionality that would be *required* of the different components of the Smart Meter system in order to accomplish the needs of the regulators. Acquiring insight into how different products delivered such components as time stamping of intervals, synchronization of register reads, network diagnostic components, etc, ensured that the chosen products could deliver the requirements of the regulators as well as accomplish the unique requirements of individual members.

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c. The following AMI Systems were part of the testing completed by the OUSM and detailed reports are available on the Util-Assist Web Portal which provides test results and detailed information regarding functionality.

OUSM Tested AMI Systems

Elster	**Tantalus**	**EKA Systems**	**Trilliant**	**Cellnet**
Sensus	**Itron**	**SilverSpring**	**Quadlogic**	**SmartSynch**

By acting collaboratively with the OUSM, NEPA members were able to gain an understanding of the base functionality and advanced feature sets of these installed products, as well as the other prominent technologies available to the North American market.

NEPA Strategy

To cost-effectively plan for the deployment, and ensure due diligence was accommodated, NEPA members came together, and through a concerted effort, examined the benefits of a collaborative approach to planning, as well as procurement of AMI and Installation services. As part of this plan, the NEPA member utilities retained the services of Util-Assist Inc., an Ontario consulting firm who would provide guidance and direction to the group to assist in the preparation, deployment and back office integration for the SMI.

Satisfying NEPA's due diligence requirements entailed an all-encompassing process, accounting for:

1. Planning
2. Implementation
3. Testing, and
4. Complete Back Office Integration.

NEPA members worked together throughout the initiative, taking full advantage of the benefits that collaboration brings. The SMI project would touch every department in the utility and would touch every residential and small commercial customer in each LDC's service territory. All tasks had to be considered, from the selection and installation of the AMI infrastructure right down to the disposal of the redundant meters and ensuring that the recycling vendors were engaged so as to divert the meters from landfills. Benefits were found in on-going operational costs. By working together, the NEPA members drastically reduced the labour components associated with maintaining the health of the installed network, as well as the daily data collection requirements for the deployed system (i.e. 2 employees to maintain a NEPA AMI system vs. 9 employees to maintain an AMI system for each individual NEPA member).

By collaborating with Util-Assist to develop an extensive plan, NEPA Members were sufficiently prepared to accommodate the established timelines. A project of this magnitude is not without risk and within this document we have identified the potential problems and risks which may impede progress (Rate Recovery, Meter Base Repairs, etc).

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All aspects of the deployment were considered, including:

1. Rate recovery,
2. Regulatory requirements regarding AMI functionality
3. Strategic planning to minimize costs for deployment
4. Audit tools during deployment
5. Back office integration
6. Meter disposal
7. AMI security
8. WEB presentment
9. Sub-metering
10. Coordination with local municipalities
11. Change management and
12. most importantly, the continued dedication to Health and Safety;

Throughout the initiative, NEPA members stayed focused on mitigating associated risks, thereby ensuring the successful implementation of the Smart Meter Initiative.

Following is a brief timeline demonstrating the order of events that the NEPA group followed:

Timeline

1. 2007: Participation in Ministry of Energy and Infrastructure authorized London Hydro AMI RFP process (establishing best practice procurement procedures).
2. Q4 2008: release of ODS provider RFP (November 7, 2008)
3. Q4 2008: vendor submittal due date for responses to ODS RFP (December 5, 2008)
4. Q1 2009: release of Meter Disposal RFQ
5. Q3 2008: release of Installation Service Provider RFP
6. Q3 2008: vendor submittal due date for responses to RFP (September 26, 2008)
7. Q4 2008: evaluation of Installation vendor submittals
8. Q4 2008: vendor negotiation (secure best pricing, discuss associated risk)
9. Q1 2009: commence deployment of residential Smart Meters

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AMI Selection Process

As mass deployment rapidly approached, the strategy of the NEPA group was to work together and create a process that accomplished the goals of the Smart Meter Initiative, while controlling the risks to customers and share holders.

The phase one approved processes included the Coalition of Large Distributors (CLD) RFPQ in conjunction with the MOE and the Hydro One procurement process, through this process, 13 utilities would be authorized to move forward with the procurement and installation of smart meters.

The remaining LDCs in Ontario would be part of the consortium of utilities working together as part of the authorized London Hydro AMI RFP process (phase two) that is summarized below.

London Hydro Phase Two AMI RFP Process Summary

- A Request for Proposal procurement transaction was conducted by London Hydro Inc., as the lead sponsoring Local Distribution Company (LDC) and with a consortia of another 63 LDCs, during the period August 2007 to July, 2008;

- The evaluation and selection phase of the RFP provided for the determination of the #1 and #2 ranked Proponents for each LDC;

- RFP Provision 7.5.141 provides the framework (principle) for negotiations and contracting based on the principle of "first right to negotiation and execution of a contract" being accorded to the ranked order of Proponents commencing with the highest ranked Proponent and proceeding in a consecutive order thereafter; and

- Each LDC was provided the evaluation results for their #1 and #2 ranked Proponents supported by the Attestation Letter of the Fairness Commissioner as to those rankings.

From a final contract negotiation perspective the NEPA LDCs each initiated good faith contract negotiations with their identified "best value" bidder, KTI/Sensus Limited.

The Fairness Commissioner provided each NEPA LDC with a letter that stated "that the successful conclusion of negotiations between the NEPA LDCs and KTI/Sensus Limited, were undertaken in accordance with the principle for such negotiations and contract award set out in the RFP, issued in August 2007."

Ultimately the result for NEPA member utilities was that the NEPA group was awarded the Sensus' FlexNet™ AMI system. This evaluation process was termed as phase two in the Ontario market place and was the method by which AMI systems were selected for the vast majority of utilities in the province.

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Following the selection of an AMI provider, attention was turned to the selection of an Installation Vendor.

Install Vendor Selection Process

NEPA's involvement in the London Hydro Phase Two Procurement Process proved to be of great value as the experience formed a foundation that ensured a sound and prudent procurement path was followed. An Installation Services RFP was created and seven (7) vendors from across North America were invited to respond.

The invited vendors included Corix, Honeywell, Olameter, PowerQuest, (Keywell), VSI, Rodan Energy and Trilliant, representing both vendors with local representation as well as vendors with extensive experience in larger markets. NEPA was confident that the most qualified and successful vendors were given the opportunity to submit proposals in response to the RFP.

NEPA's clearly stated requirement for the highest possible standards with regards to Safety were evident in every stage of the procurement process. The Request for Proposal identified NEPA's stringent Safety requirements, and included a requirement for bidder's to state their ability to either meet or exceed NEPA's guidelines. In addition to comprehensive Safety policies and procedures, NEPA's preference for a turnkey solution with the successful vendor performing all site related services and workforce management (i.e. customer communication, installation and commissioning, scheduling, dispatch and integration to back office systems, etc) was expressed.

In total, the operational considerations accounted for 45% of weighting of the evaluation with the remaining 55% attributed to the pricing received. The weighting structure was chosen to closely match that used in the 2006 CLD RFPQ process which had been found to be prudent by the regulator.

At the close of financial and technology evaluations, it was determined that Trilliant most closely matched all of NEPA's requirements; providing clear and concise Safety protocols as well as strong managerial tools to ensure all communicated policies and procedures would be properly implemented by the staff utilized within each NEPA member's service territory. These strong functional components were to be provided at a highly competitive price, which in combination resulted in the best service package being provided at the best price. Shortly after Trilliant was selected as the winning proponent, the group received notice that Olameter had acquired Trilliant and thus Olameter would be providing the services to the group.

As many utilities had a relationship with Olameter for meter reading services and Olameter was quite active in the Ontario market, this worked in the group's favour. Olameter's operational score in the RFP evaluation was strong; however their pricing was not the most favourable which attributed to their ranking as number three in the evaluation model. Given the success being enjoyed by Olameter within Ontario, there was confidence that there was minimal risk in the decision to award Olameter with the installation of NEPA's residential Smart Meters.

ODS Vendor Selection Process

NEPA member utilities recognized early on that an Operational Data Store (ODS) would be of value to support their needs for the introduction of efficiencies which would become possible through the use of the operational data available from the AMI system as the MDM/R didn't store operational data.

According to the Ministry of Energy's Functional Specification, the Advanced Metering Control Computer (AMCC – AMI network server) is limited to a maximum of 60 days for the storage of AMI data. Whereas ODS systems act as a repository to store unlimited data and have the architecture with the mechanisms in place to retain and archive data for analysis by the utility.

Many benefits can be realized through the use of an ODS system, one of which is to use the ODS to audit the mass meter installation to prevent the situation of deploying the AMI network "blind". The AMI systems traditionally will indicate that the meters are communicating but the ODS will verify the quality of the data coming from the AMI system.

Other examples of the available functionality in ODS systems include verification of all data fields being transmitted from AMI, such as:

- Readings (kWh, kW)
- Alarm Filtering (Tamper, Outage)
- Power Quality Data (Voltage)
- Perform Data Gap Analysis
- SLA management of AMI system

Due to the possibility that the provincial centralized Meter Data Management and Repository (MDM/R) would one day accommodate operational needs in addition to the billing requirements, and in keeping with the desire to minimize duplication in utility infrastructure, the utilities chose to procure a system that was an Application Service Provider (ASP) model, allowing the system to grow with the needs of each utility, and also provide flexibility with regards to contract term.

To be prepared for the deployment of residential smart meters in each utility's service territory, the ODS RFP was developed focusing on data management functionality which would definitively determine a utility's compliance with the requirements of the Ministry of Energy's Functional Specification. Additionally, the ODS system would be required to store operational data which will allow utilities to implement operational efficiencies in the immediate future.

The ODS Request for Proposal (RFP) was distributed to selected vendors in North America with thirty (30) vendors invited to respond. Of the vendors invited to bid on the RFP, six (6) vendors chose to submit a written response for an ODS solution. These vendors included local representation as well as vendors with extensive experience in larger markets. NEPA was confident that the most qualified and successful vendors were given the opportunity to submit proposals in response to the RFP.

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The evaluation team consisted of representatives from five utilities in the NEPA group with resources from Brantford Power Inc., Canadian Niagara Power Inc., Haldimand County Hydro Inc., Norfolk Power Distribution Inc. and Welland Hydro Electric System Corp. volunteering to be part of the committee. This committee provided for a mixture of Elster and Sensus AMI users and a wealth of both technical and operational knowledge.

The evaluation criteria and scoring documents were prepared in advance of the release of the RFP to support a prudent process and identify scoring criteria that ensured a consistent and fair approach in the evaluation of the bids. Many of the ODS systems were considered new technology and to ensure that the written responses and functionality descriptions in the RFP matched the state of the actual technology released, vendor demonstrations were held allowing utilities the opportunity to see the actual software.

The team evaluated Bidders objectively with the end goal of selecting the best-fit service provider for an ODS solution, thereby allowing utilities to achieve their internal goals of maximizing the value from the assets in the field, while ensuring that the requirements of the provincial government are met. With financial and technology evaluations completed, it was originally determined that the Accenture ODS proposal most closely matched all of the requirements; providing strong support for the functionality requirements expressed through the RFP, as well as project management support tailored to the needs of each utility to ensure project success. During the implementation process, Accenture amended their offering so significantly that contract negotiations failed.

NEPA revisited the evaluations performed on the six vendors who had submitted a proposal and selected the second and third ranked vendors, Harris and Kinetiq, for re-evaluation. At the same time, changes also began to occur with Brantford Power Inc. and Niagara-on-the-Lake Hydro Inc. electing to work in collaboration with other utilities following the same procurement path for an ODS solution. Brantford Power Inc. and Niagara-on-the-Lake Hydro Inc. (NOTL) did not participate in the re-evaluation process and they opted to select Kinetiq as their vendor of choice.

Westario Power Inc. and Orillia Power Distribution Corporation, originally part of the CHEC group (Cornerstone Hydro Electric Consortium), joined the NEPA group in their efforts to secure a suitable ODS solution. Both Westario Power Inc. and Orillia Power Distribution Corporation participated in the re-evaluation of the second and third ranked vendors.

There were a number of technology changes that occurred during this time period and in order to gain an understanding of any new differences between these vendor offerings, NEPA invited both Harris and Kinetiq to demonstrate their solutions and submit revised pricing. NEPA re-evaluated both vendors resulting in Harris becoming the new vendor of choice.

Supplied documentation reflects the analysis that went into this important decision by noting the functionality provided by the bidders as well as the pricing and associated risk of the different vendors. The decision making process regarding ODS solutions has been well documented and conclusive, to provide each utility's Executive Management team with the confidence to support the decision made by

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the committee. The well organized approach has ensured that the proper decisions have been made and documented with the end goal of achieving all SMI related timelines.

MDM/R Integration Process Project planning

Ontario Regulation 393/07: Designation of Smart Metering Entity would authorize the Independent Electricity System Operator (IESO) as the Smart Metering Entity responsible for processing all meter read interval data to provide billing quantity data to all LDCs in Ontario. This centralized system is termed as the Provincial Centralized MDM/R (MDM/R).

Having made such tremendous progress in the acquisition and implementation of systems, NEPA recognized the value in collaboration and continued to work together with Util-Assist to complete the necessary steps required to integrate their systems into the MDM/R.

As part of this strategy, Util-Assist developed and presented a series of MDM/R Education Sessions in which the NEPA members were educated about the MDM/R and the Business Process changes that would be required to effectively integrate and interact with the MDM/R on an enduring basis.

Standard processes were provided to members allowing them to tailor the processes for their own situations. Several members elected to have Util-Assist provide a more in-depth analysis of their processes and ultimately assist the LDCs in the design and development of specific processes unique to their utility.

Successfully integrating to the MDM/R would require months of education to prepare for the formalized enrolment testing run by the IESO. Dedicated resources would be required from each utility to be the test lead and engage with the IESO during the 8 week enrolment timeframe leading up to the cutover to the MDM/R (flowing all meter data). The flowing of all residential and small commercial customers' meter data to the MDM/R would be required in order for utilities to successfully implement the new time-of-use rate structures.

On June 24, 2010, the Board issued for comment a Proposed Determination (the "June Proposed Determination") to mandate time-of-use ("TOU") pricing for RPP consumers by establishing the "mandatory TOU date" for each electricity distributor as contemplated in section 1.2.1 of the Standard Supply Service Code (the "SSS Code"). In the June Proposed Determination, the Board proposed that a distributor's mandatory TOU date will be one of two dates, depending on the distributor's progress to date against the schedule set out in its baseline plan (updated to the date of the June Proposed Determination, where applicable).

This would require the NEPA member utilities to implement time-of-use rates in their service territory based on the dates provided in the OEB determination. As of the writing of this report, approximately 65% of the NEPA member utilities have implemented time-of-use pricing in their service territories while all other members are on a path to successfully fulfill their requirements to the regulator.

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Conclusion

The NEPA group members are confident that a comprehensive process has been undertaken and successfully completed, and that the due diligence requirements for all decisions related to this initiative have been satisfied.

Through the process of working together with other LDCs, NEPA has realized the true value of collaboration, having received support as well as operational and pricing efficiencies that were not possible had each LDC gone through the process on their own.

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Appendix A

a) Ontario Regulation 425/06
b) Functional Specifications document

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ONTARIO REGULATION 425/06

made under the

ELECTRICITY ACT, 1998

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CRITERIA AND REQUIREMENTS FOR METERS AND METERING EQUIPMENT, SYSTEMS AND TECHNOLOGY

Adoption of criteria and requirements

1. For residential and small general service consumers, the prescribed criteria and requirements for meters, metering equipment, systems and technology and any associated equipment, systems and technologies are the criteria and requirements specified in the document entitled "Functional Specification for Advanced Metering Infrastructure" dated July 14, 2006 and available at the Ministry of Energy, 4th Floor, Hearst Block, 900 Bay Street, Toronto, Ontario or at http://www.energy.gov.on.ca/english/pdf/electricity/smartmeters/Functional_Specification_for_Advanced_Metering_Infrastructure.pdf.

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FUNCTIONAL SPECIFICATION

FOR AN

ADVANCED METERING INFRASTRUCTURE

JULY 14, 2006

FUNCTIONAL SPECIFICATION

FOR AN ADVANCED METERING INFRASTRUCTURE

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FUNCTIONAL SPECIFICATION

FOR AN ADVANCED METERING INFRASTRUCTURE

1.0 APPLICATION OF SPECIFICATION

This Specification sets the required minimum level of functionality for AMI in the Province of Ontario for residential and small general service consumers where the metering of demand is not required. This Specification is not intended to apply to net metering applications.

2.0 FUNCTIONAL SPECIFICATION

2.1 Deployment

This Specification shall be met regardless of the size or scope of the AMI deployment by a distributor.

2.2 Minimum Functionality

2.2.1 As a minimum:

2.2.1.1 AMI shall collect Meter Reads on an hourly basis from all AMCDs deployed by a distributor and transmit these same Meter Reads to the AMCC and MDM/R, as required, in accordance with these Specifications; and

2.2.1.2 A Meter Read shall be collected, dated and time stamped at the end of each hour (i.e. midnight as represented by 24:00).

2.2.2 The date and time stamping of Meter Reads shall be recorded as year, month, day, hour, minute (i.e. YYYY-MM-DD hh:mm).

2.2.3 All meters shall have a meter multiplier of one (1).

2.2.4 Distributors shall provide the MDM/R with the service multiplier for transformer-type meters.

2.3 Performance Requirements

2.3.1 Collection and Transmission of Meter Reads:

2.3.1.1 AMI shall successfully collect and transmit to the AMCC and MDM/R at least 98.0% of the Meter Reads from all AMCDs deployed by a distributor in any Daily Read Period.

2.3.1.2 Meter Reads unsuccessfully collected or transmitted shall not be due to the same AMI component (including, without limitation, any AMCD) during any three (3) month consecutive time period.

2.3.1.3 AMI shall be able to collect and transmit Meter Reads during its operating life without requiring a field visit.

2.3.2 Transmission Accuracy: Over the Daily Read Period, 99.9% of the Meter Reads received by the AMCC shall contain the same information as that collected by all AMCDs deployed by the distributor.

2.3.3 AMI shall be capable of providing Meter Reads with a precision of at least 10 Watt-hours (0.01 kWh).

2.4 Technical Requirements

2.4.1 When an AMI includes AMRCs, the AMRCs shall have the ability to store meter data to accommodate the performance requirements in section 2.3.1.

2.4.2 Time Synchronization:

2.4.2.1 AMI shall be operated and synchronized to Official Time, as set by the National Research Council of Canada.

2.4.2.2 AMI shall have the capability of adjusting for changes due to local daylight savings time.

2.4.2.3 AMI installed within a distributor's service area shall have the capability of accommodating more than one (1) time zone.

2.4.2.4 Time synchronization shall be maintained in the AMI to the specified accuracy parameters set out in section 2.4.3.1 following a loss of power.

2.4.2.5 All Meter Reads shall adhere to accurate time synchronization processes to ensure an accurate accounting of electricity consumption at each meter.

2.4.3 Time Accuracy:

2.4.3.1 At all times, time accuracy in the AMI shall not exceed a ±1.5 minute variance from the time established in section 2.4.2.1.

2.4.3.2 AMI shall be able to prove that time accuracy does not exceed the permitted time variance identified in section 2.4.3.1.

2.4.4 Loss and Restoration of Power:

2.4.4.1 AMI shall detect and identify the interval in which a loss of power occurred during a Daily Read Period.

2.4.4.2 AMI shall detect and identify the interval in which power was restored following a loss of power.

2.4.5 Environmental Tolerances: All AMI components (except the AMCC) shall operate and meet the requirements in these Specifications within a temperature range of minus thirty degrees Celsius (–30° C) to positive sixty-five degrees Celsius (+65° C), and within a humidity range of zero percent (0%) to ninety-five percent (95%) non-condensing.

2.5 Advanced Metering Communication Device (AMCD)

2.5.1 Installation Within the Meter:

2.5.1.1 The AMCD shall not impair the ability of the meter to be visually read.

2.5.1.2 Meters in which an AMCD is installed shall be able to be installed in existing meter sockets or enclosures.

2.5.1.3 AMCD shall meet or exceed ANSI standards to withstand electrical surges and transients.

2.5.2 Labelling:

2.5.2.1 The AMCD shall be permanently labelled with:

(1) Legally required labelling;

(2) Manufacturer's name;

(3) Model number;

(4) AMCD identification number;

(5) Input/output connections;

(6) Date of manufacture; and

(7) Bar code for tracking and inventory management.

2.5.3 When installed at a consumer's location, the meter shall visibly display, as a minimum, the AMCD identification number, meter serial number and LDC badge number for the meter.

2.5.4 The AMCD shall be able to be initialized or programmed during, or prior to, field installation.

2.6 Transmission of Meter Reads

2.6.1 All Meter Reads collected during the Daily Read Period shall be received by the AMCC and transferred to the MDM/R no later than 5:00 a.m. local time following the Daily Read Period.

2.6.2 Meter Reads are not required to be transmitted in a single transmission and may be transmitted as frequently as necessary in order to meet the requirements in section 2.6.1.

2.6.3 AMCC shall transfer the information identified in section 2.6.1 using an approved protocol and file structure.

2.7 Advanced Metering Regional Collectors (AMRC)

2.7.1 LAN Communication Infrastructure:

2.7.1.1 The spectrum allocation and wattage of the radio signal used by an AMI shall not impede neighbouring frequencies.

2.7.2 When an AMI includes AMRCs:

2.7.2.1 The AMI shall provide for the continuous powering of AMRCs regardless of their location and placement.

2.7.2.2 All AMCDs shall be able to collect and transmit Meter Reads when one or more AMRC has a loss of power.

2.7.2.3 Memory and software parameters shall be maintained at all AMRC during a loss of power, whether by the provision of backup/alternate power or other solution.

2.8 Advanced Metering Control Computer (AMCC)

2.8.1 Each AMCC shall have the ability to store a rolling sixty (60) days of Meter Reads.

2.8.2 A distributor shall not aggregate Meter Reads into rate periods or calculate consumption data from the Meter Reads collected through its AMI either in its AMCC or any other component.

2.8.3 The AMCC shall be able to perform basic operational verification of Meter Reads received before transmitting these Meter Reads to the MDM/R.

2.9 Customer Account Information

2.9.1 Distributors shall provide initial information associated with customer accounts to the MDM/R on a date to be determined.

2.9.2 On an ongoing basis, distributors shall provide information associated with any change to the initial information identified in section 2.9.1 to the MDM/R at a frequency to be determined.

2.9.3 Information to be provided to the MDM//R pursuant to sections 2.9.1 and 2.9.2 is to be determined.

2.10 Monitoring & Reporting Capability

2.10.1 The AMI shall have non-critical reporting functionality and critical reporting functionality as required in this section 2.10. Information generated from this reporting functionality shall be available to the MDM/R.

2.10.2 Non-critical reporting:

2.10.2.1 At the completion of every Daily Read Period and following a transmission of Meter Reads, the AMCC shall generate a status report that includes information regarding anomalies and issues affecting the integrity of the AMI or any component of the AMI including information related to any foreseeable impact that such anomalies or issues might have on the AMI's ability to collect and transmit Meter Reads.

2.10.2.2 In addition to section 2.10.2.1, the AMCC shall generate reports:

(1) Confirming successful initialization of the AMCD's installed in the field;

(2) Confirming data linkages among an AMCD identification number, LDC badge number, serial number and customer account;

(3) Confirming that the MDM/R has successfully received notification of any changes to customer account information;

(4) Confirming that the AMCC has successfully made changes to customer account information following receipt of same from the MDM/R;

(5) Confirming the successful collection and transmission of Meter Reads or logging all unsuccessful attempts to collect and transmit Meter Reads, identifying the cause, and indicating the status of the unsuccessful attempt(s) pursuant to section 2.3.1;

(6) Confirming the accuracy of the Meter Reads received by the AMCC pursuant to section 2.3.2;

(7) Confirming that all Meter Reads have a precision of at least 10 Watt-hours (0.01 kWh) pursuant to section 2.3.3;

(8) Confirming whether the Meter Reads acquired within the Daily Read Period are in compliance with the time accuracy levels identified in section 2.4.3;

(9) Confirming whether time synchronization within the AMI or any components of the AMI has been reset within the Daily Read Period;

(10) Identifying the intervals in which a loss of power occurred and at which power was restored, following a loss of power;

(11) Addressing the functionality of the AMCD communication link, including status indicators related to the AMCD and AMRC;

(12) Identifying suspected instances of tampering, interference and theft;

(13) Flagging potential network, meter and AMCD issues; and

(14) Identifying any other instances that impact or could potentially impact the AMI's ability to collect and transmit Meter Reads to the AMCC and/or MDM/R on a daily basis.

2.10.2.3 Following a transmission of Meter Reads or at the completion of every Daily Read Period, the information in section 2.10.2.2 (5) shall be stored and used by the AMCC to assess compliance with the requirement specified in section 2.3.1.2.

2.10.2.4 The reports generated in sections 2.10.2.1 and 2.10.2.2 shall be made available to the MDM/R with a frequency to be determined.

2.10.3 Critical reporting:

Critical events are defined to include any AMI operational issue that could adversely impact the collection and transmission of Meter Reads during any Daily Read Period.

2.10.3.1 The AMI shall identify and report the following to the distributor:

(1) AMCD failures;

(2) AMRC failures;

(3) Issues related to the storage capacity of any component of the AMI;

(4) Communication links failures;

(5) Network failures; and

(6) Loss of power and restoration of power.

2.10.3.2 The reports generated in section 2.10.3.1 shall be made available to the MDM/R.

2.11 Security and Authentication:

2.11.1 The AMI shall have security features to prevent unauthorized access to the AMI and meter data and to ensure authentication to all AMI elements.

2.12 Proven Technology

2.12.1 No distributor shall install more than five hundred (500) units of a particular model of electricity AMCD if a minimum of five thousand (5,000) units of the same model of electricity AMCD that is to be installed by the distributor is not currently functioning in the field as part of one or more functioning AMI.

2.13 Regulatory Requirements

2.13.1 The AMI shall meet all applicable federal, provincial and municipal laws, codes, rules, directions, guidelines, regulations and statutes (including any requirements of any applicable regulatory authority, agency, board, or department including Industry Canada, the Canadian Standards Association, the Ontario Energy Board and the Electrical Safety Authority) (collectively, "**Laws**"). For greater certainty, the AMI shall meet all applicable Laws that are necessary for the measurement of data and/or the transmission of data to and from the consumers within the Province of Ontario, including Laws applicable to metering, safety and telecommunications.

2.14 Water or Natural Gas Meter Reads

2.14.1 The AMI should be capable of supporting an increased number of Meter Reads associated with the reading and transmission of water and/or natural gas meters through additional ports on the AMCD, through optionally available multi-port AMCDs, or through additional AMCD/AMRC devices that are compatible with operating on the AMI. When procuring AMI, distributors shall obtain an indication of the capabilities of the proposed AMI to read water and natural gas meters, indicating the makes and models of such meters that can be read, and any requirements for retrofitting them.

3.0 DEFINITIONS

Within this Specification the following words and phrases have the following meanings:

"AMCC" is an advanced metering control computer that is used to retrieve or receive and temporarily store Meter Reads before or as they are being transmitted to the MDM/R. The information stored in the AMCC is available to log maintenance and transmission faults and issue reports on the overall health of the AMI to the distributor.

"AMCD" is an advanced metering communication device that is housed either under the meter's glass or outside the meter. It transmits Meter Reads from the meter directly or indirectly to the AMCC.

"AMI" means an advanced metering infrastructure. It includes the meter, AMCD, LAN, AMRC, AMCC, WAN and related hardware, software and connectivity required for a fully functioning system that complies with this Specification. With some technologies, an AMI does not include AMRCs. An AMI does not include the MDM/R.

"AMRC" is an advanced metering regional collector that collects Meter Reads over the LAN from the AMCD and transmits these Meter Reads to the AMCC.

"consumer" or "customer" means a person who uses, for the person's own consumption, electricity that the person did not generate.

"distributor" has the meaning provided in the *Ontario Energy Board Act, 1998*.

"Daily Read Period" means the 24-hour period for collecting Meter Reads, subject to the two periods annually during which changes to and from daylight savings time take place. The Daily Read Period ends at 12:00 midnight of each day.

“LAN” means a local area network, the communication network that transmits Meter Reads from the AMCD to the AMRC.

“meter multiplier” is the factor by which the register reading must be multiplied to obtain the registration in the stated units.

“Meter Read” is a number generated by a meter that reflects cumulative electricity consumption at a specific point in time.

“MDM/R” means the meter data management and meter data repository functions within which Meter Reads are processed to produce rate-ready data and are stored for future use.

“Specification” means these functional specifications.

“transformer-type meter” means a meter designed to be used with instrument transformers.

“WAN” means a wide area network, the communication network that transmits Meter Reads from the AMRC to the AMCC or, in some systems from the AMCD directly to the AMCC, and from the AMCC to the MDM/R.

Appendix B

a) Ontario Regulation 426/06

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Ontario Energy Board Act, 1998
Loi de 1998 sur la commission de l'énergie de l'Ontario

ONTARIO REGULATION 426/06

SMART METERS: COST RECOVERY

Consolidation Period: From June 25, 2008 to the e-Laws currency date.

Last amendment: O. Reg. 234/08.

This Regulation is made in English only.

Cost recovery, general

1. (1) In relation to the acquisition of smart meters, a distributor may recover its costs relating to functionality that does not exceed the minimum functionality adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the *Electricity Act, 1998,* subject to final approval by the Board and the Board's review and determination that the agreement entered into for the acquisition is economically prudent and cost effective. O. Reg. 234/08, s. 1 (1).

(1.01) In determining whether an agreement referred to in subsection (1) is economically prudent and cost effective, the Board's review shall take into consideration, but not be limited to,

(a) all costs associated with the agreement; and

(b) the costs of the agreement relative to any agreements entered into by the distributor and other distributors for comparable acquisitions. O. Reg. 234/08, s. 1 (1).

(1.1) Subject to final approval of the Board, a distributor may recover the costs it prudently incurred to comply with the enrolment requirements and technical interface requirements of the Smart Metering Entity. O. Reg. 441/07, s. 1; O. Reg. 234/08, s. 1 (2).

(2) In relation to the acquisition of smart meters, a distributor may not recover its costs relating to functionality that exceeds the minimum functionality adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the *Electricity Act, 1998* unless the costs are approved by the Board. O. Reg. 426/06, s. 1 (2); O. Reg. 234/08, s. 1 (3).

(3) In reaching a decision under subsection (2), the Board may consider the matters that it considers appropriate, including evidence that the functionality that exceeds the minimum functionality adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the *Electricity Act, 1998* benefits the distributor's consumers. O. Reg. 426/06, s. 1 (3).

(4) In this section,

"smart meters" includes smart meters, metering equipment, systems and technology and any associated equipment, systems and technologies. O. Reg. 234/08, s. 1 (4).

Cost recovery, meter data functions

2. (1) No distributor shall recover any costs associated with meter data functions to be performed by the Smart Metering Entity. O. Reg. 426/06, s. 2 (1).

(2) Despite subsection (1), distributors may recover costs associated with functions related to meter data that are contemplated to be performed by distributors by the criteria and requirements adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the *Electricity Act, 1998*. O. Reg. 426/06, s. 2 (2).

(3) Subsection (1) does not prevent distributors from recovering costs that are approved by the Board pursuant to section 1 that are associated with functions related to meter data that relate to a distributor's operation of its distribution system, but only if those functions are not meter data functions to be performed by the Smart Metering Entity. O. Reg. 426/06, s. 2 (3).

(4) Subsection (1) does not apply to distributors with service areas identified as priority installations in Ontario Regulation 428/06 (Priority Installations) made under the *Electricity Act, 1998*. O. Reg. 426/06, s. 2 (4).

(4.1) Subsection (1) does not prevent a distributor from recovering costs, if approved by the Board, that the distributor incurred as a result of supporting the IESO with finalizing the design of the requirements and processes for the interface and integration of the Smart Metering Entity's system with the distributor's billing and metering systems. O. Reg. 392/07, s. 1.

(4.2) The distributor's cost recovery under subsection (4.1) is subject to the Board receiving confirmation from the IESO that the distributor supported the IESO as described in subsection (4.1) and that the distributor was one of the first five distributors whose billing and metering systems were integrated with the Smart Metering Entity's system. O. Reg. 392/07, s. 1.

(5) In this section,

"meter data functions" means those functions for which the Smart Metering Entity has the exclusive authority to carry out pursuant to Ontario Regulation 393/07 (Smart Metering Entity) made under the *Electricity Act, 1998*. O. Reg. 426/06, s. 2 (5); O. Reg. 234/08, s. 2.

Cost recovery, replaced meter assets

3. (1) Subject to Board order, to ensure that distributors are not financially disadvantaged by the implementation of the smart metering initiative, distributors may recover the costs associated with meters owned before, on or after January 1, 2006 being replaced because of the smart metering initiative if,

(a) the meter being replaced was not acquired in contravention of section 53.18 of the *Electricity Act, 1998*; and

(b) the meter is replaced with a smart meter authorized for installation under the *Electricity Act, 1998*. O. Reg. 441/07, s. 2.

(2) The Board shall determine the period of time over which the costs referred to in subsection (1) may be recovered, in order to protect the interests of consumers with respect

to prices. O. Reg. 441/07, s. 2.

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Appendix C

a) Ontario Regulation 427/06
b) Ontario Regulation 235/08

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Electricity Act, 1998
Loi de 1998 sur l'électricité

ONTARIO REGULATION 427/06

SMART METERS: DISCRETIONARY METERING ACTIVITY AND PROCUREMENT PRINCIPLES

Consolidation Period: From June 25, 2008 to the e-Laws currency date.

Last amendment: O. Reg. 235/08.

This Regulation is made in English only.

Definition

0.1 In this Regulation,

"smart meters" includes smart meters, metering equipment, systems and technology and any associated equipment, systems and technologies. O. Reg. 235/08, s. 1.

Authorized discretionary metering activity

1. (1) The following activities are authorized discretionary metering activities for the purposes of section 53.18 of the Act:

1. Metering activities conducted pursuant to the distributor's Conservation and Demand Management Plan approved by a Board order referenced as RP - 2004 - 0203, including pursuant to a reallocation of funds within an approved Conservation and Demand Management Plan as authorized by the Board order approving the Conservation and Demand Management Plan or that is otherwise approved by the Board.

2. If not otherwise authorized by this subsection, a distributor may utilize funds to conduct metering activities that are for the purpose of testing smart meter technology if,

    i. the distributor has the prior approval of the Board, and

    ii. the funds that are utilized were collected pursuant to the Board's approval to include capital and operating costs related to smart meters in distributors' revenue requirements for 2006, as set out in the Board's Generic Issues decision, dated March 21, 2006 and referenced as RP - 2005 - 0020, as is incorporated into each distributor's 2006 electricity distribution rate order provided by the Board pursuant to section 78 of the *Ontario Energy Board Act, 1998*.

3. Metering activities conducted by Enersource Corporation, Powerstream Inc., Hydro Ottawa Limited, Horizon Utilities Corporation, Toronto Hydro-Electric System

Limited and Veridian Connections Inc. pursuant to the process initiated in the Request for Pre-Qualification for Advanced Metering Infrastructure Procurement and Installation issued by Enersource Corporation on behalf of itself and the other referenced utilities and dated May 2, 2006.

3.1 Metering activities conducted by a distributor listed in paragraph 3, if the smart meters were procured subsequent to the process referred to in paragraph 3.

4. Metering activities conducted by a distributor that has had its smart meters procured on its behalf by one or more of Enersource Corporation, Powerstream Inc., Hydro Ottawa Limited, Horizon Utilities Corporation, Toronto Hydro-Electric System Limited or Veridian Connections Inc. pursuant to the process referred to in paragraph 3.

5. Metering activities conducted pursuant to the Request for Proposal for Smart Metering Services issued by Hydro One Networks Inc. and dated March 4, 2005.

6. Metering activities conducted by a distributor that has had its smart meters procured on its behalf by Hydro One Networks Inc. pursuant to the process referred to in paragraph 5.

7. Metering activities conducted by distributors if the activities meet the following criteria:

   i. the activities are for service areas identified as priority installations by Ontario Regulation 428/06 (Priority Installations) made under the Act, and

   ii. smart meter deployment plans have been filed with the Minister by the distributor.

8. Metering activities conducted by a distributor that has procured its smart meters pursuant to and in compliance with the parameters and process established by the Request for Proposal for Advanced Metering Infrastructure (AMI) – Phase 1 Smartmeter Deployment dated August 14, 2007, together with any amendments to it, issued by London Hydro Inc. O. Reg. 427/06, s. 1 (1); O. Reg. 153/07, s. 1 (1); O. Reg. 235/08, s. 2 (1-4).

(2) The smart meters used in relation to activities authorized as discretionary metering activities in subsection (1) shall comply with the criteria and requirements adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the Act. O. Reg. 427/06, s. 1 (2); O. Reg. 153/07, s. 1 (2); O. Reg. 235/08, s. 2 (5).

(2.1) Despite subsection (2), the smart meters used in relation to activities authorized as discretionary metering activities in paragraph 1 of subsection (1) that were conducted before the day this subsection comes into force are not required to comply with the criteria and requirements adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the Act. O. Reg. 153/07, s. 1 (3); O. Reg. 235/08, s. 2 (6).

(3) Any procurement associated with the activities authorized as discretionary metering activities under subsection (1), other than activities referenced in paragraphs 1 and 2 of subsection (1), shall comply with the procurement requirements set out in section 2. O. Reg. 427/06, s. 1 (3); O. Reg. 153/07, s. 1 (4).

(4) The activities authorized as discretionary metering activities in subsection (1) are subject to the cost recovery requirements set out in Ontario Regulation 426/06 (Smart

Meters: Cost Recovery) made under the *Ontario Energy Board Act, 1998*. O. Reg. 427/06, s. 1 (4).

Procurement

2. (1) When a distributor enters into a procurement process in relation to the smart metering initiative, the distributor shall ensure,

(a) that the procurement process complies with the principles set out in subsection (2); and

(b) that any agreement entered into as a result of the procurement is economically prudent and cost effective, taking into consideration, but not limited to,

(i) all costs associated with the agreement, and

(ii) the costs of the agreement relative to any prior agreement entered into by the distributor for comparable acquisitions. O. Reg. 427/06, s. 2 (1); O. Reg. 235/08, s. 3 (1).

(2) Distributors shall ensure that a procurement process in relation to the smart metering initiative complies with the following principles:

1. The procurement process, including the procedures used in the process and the selection criteria, must be fair, open and accessible to a range of interested bidders.
2. The procurement process must be competitive.
3. Conflicts of interest, both actual and potential, of bidders must be disclosed in the bidders' proposals and the process must ensure that,

   i. the selected bidder will not have a conflict of interest in respect of the deliverables under the agreement entered into as a result of the procurement, or

   ii. the selected bidder will be required to comply with requirements established by the distributor to address an actual or potential conflict of interest.
4. There must be no unfair advantage in the procurement process. O. Reg. 427/06, s. 2 (2).

(3) A distributor may only procure or utilize smart meters from an affiliate, if the affiliate is the selected bidder in a procurement process that satisfies the requirements of this section. O. Reg. 427/06, s. 2 (3); O. Reg. 235/08, s. 3 (2).

(4) The Minister or the Board may on notice require that a distributor provide to the Minister or the Board, as the case may be,

(a) information relating to the procurement or installation of smart meters including information concerning pricing, contractual arrangements, and status of installations; and

(b) information relating to a procurement, which information was obtained or developed during the procurement, including information concerning the selection of the successful bidder. O. Reg. 153/07, s. 2; O. Reg. 235/08, s. 3 (3).

(5) The notice in subsection (4),

(a) shall be in writing;

(b) shall set out a time frame in which the distributor must reply; and

(c) shall specify the information that the distributor must supply. O. Reg. 427/06, s. 2 (5).

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ONTARIO REGULATION 235/08

made under the

ELECTRICITY ACT, 1998

Made: June 17, 2008
Filed: June 25, 2008
Published on e-Laws: June 26, 2008
Printed in *The Ontario Gazette*: July 12, 2008

Amending O. Reg. 427/06

(Smart Meters: Discretionary Metering Activity and Procurement Principles)

Note: Ontario Regulation 427/06 has previously been amended. Those amendments are listed in the Table of Current Consolidated Regulations – Legislative History Overview which can be found at www.e-Laws.gov.on.ca.

1. Ontario Regulation 427/06 is amended by adding the following section:

Definition

0.1 In this Regulation,

"smart meters" includes smart meters, metering equipment, systems and technology and any associated equipment, systems and technologies.

2. (1) Subsection 1 (1) of the Regulation is amended by adding the following paragraph:

3.1 Metering activities conducted by a distributor listed in paragraph 3, if the smart meters were procured subsequent to the process referred to in paragraph 3.

(2) Paragraph 4 of subsection 1 (1) of the Regulation is amended by striking out "meters, metering equipment, systems and technology and any associated equipment, systems and technologies" and substituting "smart meters".

(3) Paragraph 6 of subsection 1 (1) of the Regulation is amended by striking out "meters, metering equipment, systems and technology and any associated equipment, systems and technologies" and substituting "smart meters".

(4) Subsection 1 (1) of the Regulation is amended by adding the following paragraph:

8. Metering activities conducted by a distributor that has procured its smart meters pursuant to and in compliance with the parameters and process established by the Request for Proposal for Advanced Metering Infrastructure (AMI) – Phase 1 Smartmeter Deployment dated August 14, 2007, together with any amendments to it, issued by London Hydro Inc.

(5) Subsection 1 (2) of the Regulation is amended by striking out "meters, metering equipment, systems and technology and any associated equipment, systems and technologies" and substituting "smart meters".

(6) Subsection 1 (2.1) of the Regulation is amended by striking out "meters, metering equipment, systems and technology and any associated equipment, systems and technologies" and substituting "smart meters".

3. (1) Clause 2 (1) (b) of the Regulation is revoked and the following substituted:

(b) that any agreement entered into as a result of the procurement is economically prudent and cost effective, taking into consideration, but not limited to,

(i) all costs associated with the agreement, and

(ii) the costs of the agreement relative to any prior agreement entered into by the distributor for comparable acquisitions.

(2) Subsection 2 (3) of the Regulation is amended by striking out "metering equipment, systems and technology and any associated equipment, systems and technologies".

(3) Clause 2 (4) (a) of the Regulation is amended by striking out "metering equipment, systems and technology and any associated equipment, systems and technologies".

4. This Regulation comes into force on the day it is filed.

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Appendix D

a) Ontario Regulation 393/07

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ONTARIO REGULATION 393/07

made under the

ELECTRICITY ACT, 1998

Made: March 28, 2007
Filed: July 26, 2007
Published on e-Laws: July 27, 2007
Printed in *The Ontario Gazette*: August 11, 2007

DESIGNATION OF SMART METERING ENTITY

Designation of IESO

1. The IESO is designated as the Smart Metering Entity.

Non-application of *Business Corporations Act*

2. Other than as prescribed in Ontario Regulation 610/98 (The IMO) made under the Act, the *Business Corporations Act* does not apply to the IESO.

Exemption, s. 53.10 of Act

3. The IESO is exempt from section 53.10 of the Act.

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APPENDIX E

Millard, Rouse & Rosebrugh LLP

Independent Auditors' Report For the Fiscal Year Ended December 31, 2011

Millard, Rouse & Rosebrugh LLP
Chartered Accountants
P.O. Box 57, 91 Main Street South
Hagersville, Ontario N0A 1H0
Telephone: (905) 768-5883
Facsimile: (905) 768-5843

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Haldimand County Hydro Inc.

We have audited the accompanying financial statements of Haldimand County Hydro Inc., which comprise the statement of financial position as at December 31, 2011, and the statements of income, retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Haldimand County Hydro Inc. as at December 31, 2011, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Millard, Rouse & Rosebrugh LLP

March 29, 2012

CHARTERED ACCOUNTANTS
Licensed Public Accountants

APPENDIX F

Niagara Erie Power Alliance

Smart Meter Investment Plans
Board File Number EB-2006-0246
December 15, 2006

Smart Meter Investment Plans

Board File Number EB 2006-0246

December 15th, 2006

NIAGARA ERIE POWER ALLIANCE

Prepared in conjunction with util-assist Inc.

NIAGARA ERIE POWER ALLIANCE

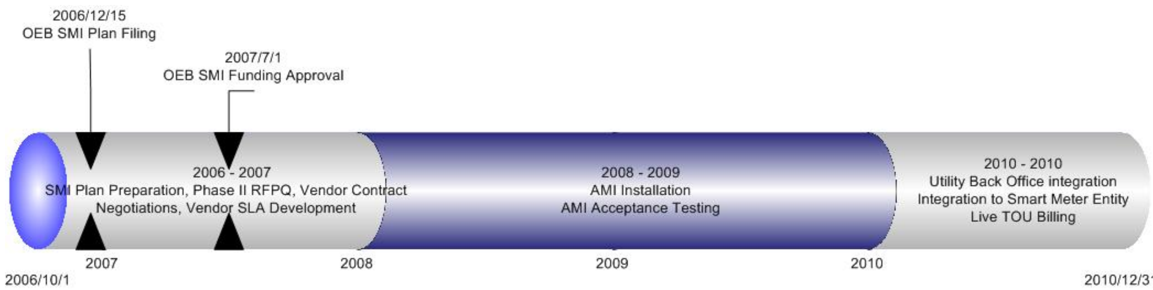
Executive Summary

The Niagara Erie Power Alliance (NEPA) members are pleased to provide the Ontario Energy Board (OEB) our plans for smart meter investment in the 2006 rate year (May 1, 2006 to April 30, 2007). Our association is working together to collectively prepare and fulfill the requirements of the OEB and the Ministry of Energy regarding the Smart Meter Implementation Plan.

This is an enormous undertaking for all Local Distribution Companies (LDCs); a project that will take months of planning and carefully managed execution. To accommodate the needs of the Ministry of Energy (MOE) and the Ontario Energy Board, NEPA members will have to install approximately 155,000 meters by the end of 2010.

The required network is new to this market, and the rules that will be established will also be unique. Clearly the Smart Meter Initiative (SMI) is an all-encompassing program, with implications for every utility system. Many of the components of the SMI fall under the responsibility and control of the utility, while others will be in the hands of regulatory bodies. Regardless of who is in control of each component, a comprehensive, effective, and achievable implementation plan will need to consider all aspects. For NEPA members to seamlessly integrate their chosen Smart Meters; their planning will need to take into consideration the functionality of all required systems, so that preparation for future integration has been properly considered.

Specific to the OEB filing requirements relating to smart meter investment plans, **No NEPA members have plans to procure and install smart meter infrastructure in the 2006 rate year (May 1, 2006 to April 30, 2007)**; with each NEPA member developing the details of their multi year plan in 2007 and following the implementation timeline below.



The following pages contain a carefully considered process, which identifies generic steps that will be followed by NEPA members at utility specific time intervals. We feel the structure of this document will allow the OEB to understand the direction each NEPA member intends to follow in the development and completion of their smart meter investment plan for current and future rate years. This group process will allow members to partner with and learn from each others deployments helping mitigate deployment risks to the rate payers in our service territories.

Introduction

The provincial government has mandated installing a smart electricity meter in every Ontario home by December 31, 2010, The Ontario Energy Board in its decision on generic issues (EB-2005-0529) related to the smart meter initiative filed its decision, dated March 21, 2006 which stated:

> "In addition, as a condition of granting the rate applications, all utilities will be required to file with the Board within 90 days of this Decision their plan for smart meter investment in the 2006 rate year."

The subsequent Regulations were issued on September 16, 2006. Accordingly, the Board will require distributors to file their plans (File No. EB-2006-0246) for smart meter investment in the 2006 rate year (May 1, 2006 to April 30, 2007) by December 15, 2006 (within 90 days of the issuance of the Regulations).

In order for Ontario LDCs to develop these investment plans they will need to understand how all of the AMI systems that have been pre-qualified work, and how they should be structured to meet the needs of the Ontario government. The business case for supplementary functionality will need to be created so utilities can make decisions on AMI systems qualified within the selection framework, as recovery of the asset will be based on the minimum Functional Specification requirements. Proper analysis will help minimize risk from both an operational and financial perspective.

Upon selection of an AMI provider, and confirmation of final pricing for each NEPA service territory, the installation process will need to be properly addressed. Plans will need to include acceptance testing of installed technology to ensure that the deployed product achieves the performance goals and that the asset is properly integrated into all departments within the utility.

The 3rd Party Installation vendor which utilities may select for this process will represent the utility in the eyes of the public, and must perform this task at the highest level of quality and safety. In making this important decision, Best Practice installation procedures must be considered (recording of GIS coordinates, digital image of off-reads, etc), utilization of Workforce Management systems (WFM), disposal of old meters, and most importantly the investigation into safety requirements for the associated field services. By working together with neighboring utilities, and through working group relationships, NEPA members are in the ideal position to understand and properly address any potential scheduling conflicts that could alter the quality of the service provided by vendors. Carefully controlled analysis will help minimize risk from both an operational and financial perspective. The process enlisted by the NEPA group would ensure that the best possible staff is utilized for each installation, and that each individual utility is properly represented to their end consumer.

The decision making process regarding the Smart Meter Initiative needs to be well documented. Documentation will reflect the analysis that go into this important decision by noting the service available, as well as the pricing and associated risk of short-listed vendors. A well organized approach will ensure the proper decisions are made, and that the approval to move forward is achieved.

NIAGARA ERIE POWER ALLIANCE

Niagara Erie Power Alliance (NEPA)

NEPA is a cooperative venture of 11 Local Distribution Companies (LDC's) in south eastern Ontario with the common goals of addressing industry issues, sharing resources, increasing efficiencies, reducing operation costs and where possible, providing a substantial, uniform voice to the government, regulator, media and the public. The members of NEPA included in this filing are Brant Country Power Inc., Canadian Niagara Power Inc., Haldimand County Hydro Inc., Niagara Falls Hydro Holding Co. Inc., Niagara-on-the-Lake Hydro Inc., Grimsby Power Inc., Norfolk Power Distribution Inc., Peninsula West Utilities Ltd., and Welland Hydro-Electric System Corp. Collectively, this group distributes to approximately 155,000 customers.

The mission of the NEPA Group is to be recognized as the premier LDC Cooperative in the province, by meeting or exceeding member expectations through the sharing of opportunities, knowledge and resources. The values of the NEPA Group include the sharing of resources, both intellectual and technical, enabling members to deliver value to their customers and shareholders ensuring competitiveness in the marketplace. Together the mission and value statements represent lofty but attainable goals for the NEPA Group.

To accommodate the needs of the Ministry of Energy, the NEPA group will need to install approximately 155,000 meters by the end of 2010. Combined with the sheer magnitude of the Smart Meter Initiative, the NEPA group (in keeping with the philosophy of a cooperative) also has the challenge of choosing technologies for deployment over varied terrain, all the while trying to achieve savings through shared infrastructure wherever possible.

Comprised of LDC's from across south eastern Ontario the target audience of NEPA Group initiatives are wide ranging and fully represent the diversity in Ontario economically, geographically and culturally. Diversity of the NEPA Group has been given full consideration in the development of this Smart Meter Plan.

Member LDC's will benefit from this joint effort in planning through the pooling of volumes in procurement processes for services such as Installation and Meter Disposal, and potentially through purchases of ancillary products like meter bases, and adaptors which may be required to accommodate the large volume of installations.

This report represents a joint submission on the issue of Smart Meter Initiative planning by the members of the NEPA Group in consideration of our collective responsibility to act as agents of change in creating and promoting a conservation culture.

Assumptions

The NEPA group has created the following plan under the assumption that the costs described herein will be recoverable. If the costs as described are not going to be recoverable, some components of this plan may change.

NEPA Strategy

With the need for mass deployment rapidly approaching, the strategy of the NEPA group is to work together and create a process that accomplishes the goals of the Smart Meter Mandate, while controlling the risks to our customers and share holders.

The path that will be followed by the NEPA members is to procure the AMI infrastructure through an approved process identified by the following Ontario Regulations regarding the Electricity Act, 1998;

> **Reg. 425/06** Criteria and Requirements For Meters and Metering Equipment, Systems and Technology,
> **Reg. 426/06** Smart Meter: Costs Recovery and,
> **Reg. 427/06** Smart Meters: Discretionary Metering Activity and Procurement Principles, AMI Functionality

These approved processes include the Coalition of Large Distributors (CLD) RFPQ in conjunction with the MOE, the Hydro One procurement process, or any future MOE approved procurement processes.

For the purposes of this filing the deployment strategy identified by the group can be segmented into the following generic steps;

> **Planning**
> **Procurement Process / Vendor Selection**
> **OEB Rate Approval**
> **Negotiation with Qualified Vendors**
> **Customer Communication**
> **Implementation**
> **Meter Disposal**
> **Acceptance Testing**
> **Security and Authentication**
> **Back Office Integration**
> **Customer Presentment**

Planning

During this stage the approach by NEPA members will be to produce detailed project plans regarding the smart meter initiative, identifying all tasks that need to be completed as well as the resources required to achieve these tasks. Part of this planning process will include understanding and collecting the information required by the qualified AMI (meter types, propagation studies) and installation vendors (location types i.e. inside outside, rural, etc). With this information utilities will be well positioned to gather budgetary numbers that will be used for rate approvals (for those members that have yet to file their smart meter rate request). This approach ensures all costs are properly understood to help verify the funding requirements of each NEPA member. By identifying the technical requirements, timelines, and estimated costing, the main goal of this section is accomplished by ensuring realistic timelines are created and an achievable plan presented.

Procurement Process / Vendor Selection

NEPA member's selection and procurement process can identify and take advantage of the opportunities of price offerings by Phase One utilities or procure a technology that has yet to be selected in the Ontario Market (forthcoming Phase 2 procurement process). If the latter is the process required by the MOE and NEPA members, a thorough procurement process will take place, potentially including the involvement of consultants and fairness commissioners to create a seamless process. The end goal of such a process would be to produce a list of qualified vendors with which NEPA members could enter into final vendor negotiations and subsequent selection.

OEB Rate Approval

During the Procurement / Vendor Selection stage each NEPA member will make their detailed rate filing with the OEB. This filing will have costs associated with approved technologies based on information made available from vendors and phase one utilities. It is critical that NEPA members completely understand the rate approval process and the associated recovery allocation before they enter into final negotiations and contract signing with qualified smart meter vendor(s). This process is expected to take four months to complete from the time the file is submitted to the OEB. Without rate approval, the next stages of the smart meter implementation process will be delayed.

Negotiation with Qualified Vendors

Having acquired a level of comfort regarding the functionality of the qualified vendors considered appropriate for mass deployment, NEPA members will invite these vendors into a final negotiation session. In this meeting, final pricing relating to the specific deployment details of each NEPA member are addressed. This process will also identify the risks associated with each company. These meetings are considered extremely important as they will result in true costing of the AMI system as well as the opportunity to identify all deliverables which will help finalize the Implementation deployment plan that each Member is managing.

Customer Communication

The success of the smart metering implementation and the switch to TOU rates may be more dependent on the effectiveness of our communications planning than any other portion of our strategy. First and foremost, all of our staff must be educated ambassadors for smart metering and TOU. We must be able to explain how this new technology will assist in managing current and future residential energy consumption practices and be aware of the status of the implementation and deployment progress.

All employees will need to attend Smart Meter Information Sessions to learn about the purpose of smart meters, the way in which the meters operate, details of our Smart Meter Communications Plan, and time-of-use rates. Customer service representatives may need to receive more in-depth training than other employees as they will be required to respond to questions from the public.

During mass deployment, materials for our customers must be consistent with messaging from the MOE, and the OEB. A selection of smart meter materials need to be designed and purchased by LDCs for use in two stages: pre-smart meter installation and post-smart meter installation. The purpose is to ensure consistent messaging on the topic of smart meters.

Implementation

The first priority will be to ensure that all field processes and safety procedures are well documented; ensuring implementation is performed safely and without incident. NEPA members will maximize the value of the site visit while maintaining the highest level of quality to help control the need for return visits which will increase overall costs. Any opportunities that are presented which can improve the installation process should be strongly considered, once it is determined what the priorities are with respect to this process.

Other considerations that are affected by the anticipated time for deployment include the method of data entry for the meter changes that are performed, and possible ways of avoiding potential customer disputes regarding "off-reads". Workforce Management systems and Digital Images (for storage of "off-reads") are just two examples of how this process can be controlled, with supplementary benefits such as improved safety procedures through the use of these solutions.

NEPA members will jointly develop the plans that will see tasks grouped by associated departments (Metering, Customer Service, IT, Procurement, and Executive Management teams). This format will prove valuable in managing the hundreds of tasks required of the Smart Meter Initiative. Buying pools will be researched, and financial options will be investigated to determine applicability to the NEPA members.

Meter Disposal

Accompanying the challenges of determining the right technology fit, labour considerations, and back office integration, is the problem of disposing of the redundant meters. Perhaps more importantly than the cost of the disposal of the meters, is the environmental and political considerations associated with this process. The new technology is required to accommodate the end goals of the government, but dumping millions of meters into landfill sites is not necessary, and therefore not considered an option by the NEPA group. By researching alternative avenues of disposal, NEPA has found that the potential environmental and political backlash associated with the projected 27 million pounds of scrap (produced through the Smart Meter Initiative) can also be avoided through recycling processes.

Acceptance Testing

During the later stages of implementation, test scripts will be executed on the systems as they are deployed to ensure that the proper amount of infrastructure has been installed to accommodate the performance requirements of the industry. Acceptance testing will be initiated to ensure that the infrastructure is operating according to the requirements, thereby minimizing the risk associated with mass deployments.

Security and Authentication

With the introduction of AMI systems, utilities will become susceptible to new levels of potential security breaches. By installing network infrastructure in the field, there is now a requirement for additional security measures in order to ensure that utility data, and equipment, are kept secure from manipulation, or other forms of control. Industry reports show a worldwide trend in cyber security breaches from "hacking" where the utilities are the recipients of extortion threats.

The minimum Functional Specification for an Advanced Metering Infrastructure (AMI) released in July 2006 identified the need for security within the AMI network - Section 2.11 Security and Authentication: "The AMI shall have security features to prevent unauthorized access to the AMI and meter data and to ensure authentication to all AMI elements."

As members of the OUSM working group, NEPA utilities have embarked upon an educational process which has included partnering with Industry experts to provide qualified, objective, third party security viewpoints. The goal thus far has been to gain the knowledge required to build security into smart meter systems at the foundational level, which is a fundamental Best Practice. Standard test scripts performed by an approved third party will provide an annual evaluation of the security assessment to NEPA members AMI systems.

Back Office Integration

The integration of the data being acquired from the chosen AMI system(s) into daily processes is a critical component in ensuring that operational efficiencies are maximized by the chosen system. Clearly the Meter Data Management/Repository (MDM/R) will become an integral piece of technology; interfacing with the CIS for the purposes of billing as well as to other operational entities that may be interested in using the information acquired from the AMI network. The NEPA group understands that the Meter Data Repository will be a centralized entity. It will be important for NEPA members to work with AMI Operational Verification Tools for the purpose of evaluating the performance of the AMI network until the AMI infrastructure is live within the centralized MDM/R. As part of their commitment to the successful implementation of the Smart Meter deployment and systems integration, the NEPA group has a representative working with and on the IESO Smart Meter System Implementation Plan workgroup.

The time line followed by each NEPA member in going live with TOU billing takes into consideration the timing required for system set-ups, configuration and testing associated with TOU billing each members CIS system.

Customer Presentment

With the drastic changes in our energy market, there is a growing emphasis on conservation and consumer education. Traditionally, the problem faced by the end consumers is the lack of information regarding the daily use of electricity.

To effectively educate end users on their consumption habits, a technology infrastructure will need to be implemented that will provide granular information regarding consumer usage over the course of a day. This new information combined with innovative pricing structures such as time of use will help motivate changes to a consumers usage patterns.

The concept of conservation is not restricted to WEB presentment of information. Multiple technology solutions will be required to effectively communicate the message that is being advocated through this initiative. WEB presentment is not the only way to communicate this message, but should instead be considered one of many tools to be implemented in the network. IVR systems and bill print modifications should be explored and other forms of media will be required to ensure the message is communicated effectively to all customers.

Every consumer has the right to conservation. While the end result should be an easy to use tool that will present this concept to the consumers in a logical format, the functionality that will be required in presentment products has yet to be determined, as well as any minimum specifications upon which recovery may be based.

Conclusion

This report was prepared for the NEPA group by Util-Assist (www.util-assist.com).

Should you have any concerns or questions please do not hesitate to call.

Yours truly,

util-assist

James Douglas
President

tel: (905) 967-0770 ext 201
email: jdouglas@util-assist.com

Schedule A1 - LDC Authorization – Brant County Power Inc.

Brant County Power Inc.
65 Dundas St. East
Paris, Ontario
N3L 3H1

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Brant County Power Inc. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Brant County Power Inc.
   Glen Fuller, Operations Manager
   phone: (519) 442-2215
   e-mail: gfuller@brantcountypower.com

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much of this is being recovered from your customers?**

$0.30 of the monthly service charge per customer is currently being collected except for the following rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

NIAGARA ERIE POWER ALLIANCE

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	2007	2008	2009	2010
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	2007	2008	2009	2010
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**
   - **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
   - **the capital expenditures and amortization by class and by year;**
   - **the operation expenses by class and by years;**
   - **the effect of the SMIP on the level of the allowance for PILs.**

   We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation quantities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 9,233 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

   N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

   May 1/06 to Apr. 30/07 - collect $0.30 per customer per month for approved customer classes
   May 1/07 to Apr. 30/08 - to be determined
   May 1/08 to Apr. 30/09 - to be determined
   May 1/09 to Apr. 30/10 - to be determined
   2010 and beyond - continue to collect until costs recovered, amount to be determined

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that recovery of the procured assets will be possible. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout.

Signature

Dec 12/06

Date

Schedule A2 - LDC Authorization – Canadian Niagara Power Inc.

Canadian Niagara Power Inc.
1130 Bertie Street
PO Box 1218
Fort Erie, ON
L2A 5Y2

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Canadian Niagara Power Inc. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures for its service territories in Fort Erie, Port Colborne and Gananoque. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Canadian Niagara Power Inc.
   Douglas Bradbury, Director Regulatory Affairs
   phone: (905) 871-0330
   e-mail: doug.bradbury@cnpower.com

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   Not applicable

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much of this is being recovered from your customers?**

   $0.30 per residential customer is currently being collected through the monthly service charge of all metered customers.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

NIAGARA ERIE POWER ALLIANCE

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	2007	2008	2009	2010
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	2007	2008	2009	2010
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**
- **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
- **the capital expenditures and amortization by class and by year;**
- **the operation expenses by class and by years;**
- **the effect of the SMIP on the level of the allowance for PILs.**

We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation quantities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 9,233 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

Not applicable

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

May 1/06 to Apr. 30/07 - collect $0.30 per customer per month for approved customer classes
May 1/07 to Apr. 30/08 - to be determined
May 1/08 to Apr. 30/09 - to be determined
May 1/09 to Apr. 30/10 - to be determined
2010 and beyond - continue to collect until costs recovered, amount to be determined

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

    The development of these plans has been based on the understanding that recovery of the procured assets will commence just prior to procurement and deployment. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout.

Signature
Canadian Niagara Power Inc.

Date

Schedule A3 - LDC Authorization – Grimsby Power Incorporated

Grimsby Power Incorporated
231 Roberts Rd
Grimsby, Ontario
L3M 5N2

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Grimsby Power Incorporated is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Grimsby Power Incorporated
   Brian Weber, President
   phone: (905) 945-5437 ext 221
   e-mail: brianw@grimsbypower.com

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much of this is being recovered from your customers?**

   $0.30 of the monthly service charge per customer is currently being collected except for the following rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

NIAGARA ERIE POWER ALLIANCE

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	2007	2008	2009	2010
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	2007	2008	2009	2010
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**
   - **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
   - **the capital expenditures and amortization by class and by year;**
   - **the operation expenses by class and by years;**
   - **the effect of the SMIP on the level of the allowance for PILs.**

   We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation quantities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 9,555 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

   N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

   May 1/06 to Apr. 30/07 - collect $0.30 per customer per month for approved customer classes
   May 1/07 to Apr. 30/08 - to be determined
   May 1/08 to Apr. 30/09 - to be determined
   May 1/09 to Apr. 30/10 - to be determined
   2010 and beyond - continue to collect until costs recovered, amount to be determined

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that recovery of the procured assets will commence just prior to procurement and deployment. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout. Grimsby Power sees this risk as being significant and we expect delays in procurement and deployment as indicated in the above schedule without additional funds being forthcoming in advance. Further, we need to be assured that additional funds as required for the completion and sustaining of the SMIP are guaranteed.

Brian Weber
Signature
Grimsby Power Incorporated

12/13/06
Date

Schedule A4 - LDC Authorization – Haldimand County Hydro Inc.

Haldimand County Hydro Inc.
1 Greendale Drive
Caledonia, Ontario
N3W 2J3

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Haldimand County Hydro Inc. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Haldimand County Hydro Inc.
   Ed Galinski, P.Eng., Engineering Manager
   phone: (905) 765-5211 ext 243
   e-mail: egalinski@hchydro.ca

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much of this is being recovered from your customers?**

    $0.30 of the monthly service charge per customer is currently being collected except for the following rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

    2006 – No Plan
    2007 – Planning, Procurement (See Generic Section in Main Document)
    2008 – Implement Plan (See Generic Section in Main Document)
    2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

    2006 – No Plan
    2007 – Planning, Procurement (See Generic Section in Main Document)
    2008 – Implement Plan (See Generic Section in Main Document)
    2009 – Back Office Integration (See Generic Section in Main Document)

NIAGARA ERIE POWER ALLIANCE

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	2007	2008	2009	2010
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	2007	2008	2009	2010
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**
   - **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
   - **the capital expenditures and amortization by class and by year;**
   - **the operation expenses by class and by years;**
   - **the effect of the SMIP on the level of the allowance for PILs.**

   We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation quantities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 20,464 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

   N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

   May 1/06 to Apr. 30/07 - collect $0.30 per customer per month for approved customer classes
   May 1/07 to Apr. 30/08 - to be determined
   May 1/08 to Apr. 30/09 - to be determined
   May 1/09 to Apr. 30/10 - to be determined
   2010 and beyond - continue to collect until costs recovered, amount to be determined

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that recovery of the procured assets will be possible. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout.

December 15, 06

Signature
Haldimand County Hydro Inc.

Date

Schedule A5 - LDC Authorization – Niagara Falls Hydro Inc.

Niagara Falls Hydro Inc.
7447 Pin Oak Drive
Niagara Falls, Ontario
L2E 6S9

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Niagara Falls Hydro Inc. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Niagara Falls Hydro Inc.
   Brian Wilkie, President
   phone: (905) 356-2681
   e-mail: brianwilkie@niagarafallshydro.on.ca

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much of this is being recovered from your customers?**

   $0.30 of the monthly service charge per customer is currently being collected except for the following rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2008 – Implement Plan (See Generic Section in Main Document)
   2009 – Back Office Integration (See Generic Section in Main Document)

NIAGARA ERIE POWER ALLIANCE

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	2007	2008	2009	2010
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	2007	2008	2009	2010
Consulting Services	X	X	X	
Legal for RFPQ’s	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**
   - **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
   - **the capital expenditures and amortization by class and by year;**
   - **the operation expenses by class and by years;**
   - **the effect of the SMIP on the level of the allowance for PILs.**

   We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation quantities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 33,188 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

   N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

   May 1/06 to Apr. 30/07 - collect $0.30 per customer per month for approved customer classes
   May 1/07 to Apr. 30/08 - to be determined
   May 1/08 to Apr. 30/09 - to be determined
   May 1/09 to Apr. 30/10 - to be determined
   2010 and beyond - continue to collect until costs recovered, amount to be determined

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that recovery of the procured assets will be possible. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout.

Dec 13, 2006

Signature
Niagara Falls Hydro Inc.

Date

Schedule A6 - LDC Authorization – Niagara-on-the-Lake Hydro Inc.

Niagara-on-the-Lake Hydro Inc.
8 Henegan Rd.
Virgil, Ontario
L0S 1T0

Niagara-on-the-Lake Hydro Inc.

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Niagara-on-the-Lake Hydro Inc. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Niagara-on-the-Lake Hydro Inc.
   Jim Huntingdon, President
   phone: (905) 468-4235
   e-mail: jhuntingdon@notlhydro.com

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much of this is being recovered from your customers?**

$0.30 of the monthly service charge per customer is currently being collected except for the following rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2009 – Implement Plan (See Generic Section in Main Document)
2010 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2009 – Implement Plan (See Generic Section in Main Document)
2010 – Back Office Integration (See Generic Section in Main Document)

NIAGARA ERIE POWER ALLIANCE

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	2007	2008	2009	2010
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	2007	2008	2009	2010
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**
   - **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
   - **the capital expenditures and amortization by class and by year;**
   - **the operation expenses by class and by years;**
   - **the effect of the SMIP on the level of the allowance for PILs.**

   We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation quantities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2009 with a total customer base of 7,638 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

   N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

   May 1/06 to Apr. 30/07 - collect $0.30 per customer per month for approved customer classes
   May 1/07 to Apr. 30/08 - to be determined
   May 1/08 to Apr. 30/09 - to be determined
   May 1/09 to Apr. 30/10 - to be determined
   2010 and beyond - continue to collect until costs recovered, amount to be determined

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that recovery of the procured assets will be possible. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout.

Signature
Niagara-on-the-Lake Hydro Inc.

December 12/06
Date

Schedule A7 - LDC Authorization – Norfolk Power Distribution Inc.

Norfolk Power Distribution Inc.
70 Victoria St.
Simcoe, Ontario
N3Y 4N6

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Norfolk Power Distribution Inc. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Norfolk Power Distribution Inc.
   Cheryl Elliott, Manager of Customer Service
   phone: (519) 426-4440
   e-mail: celliott@norfolkpower.on.ca

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much of this is being recovered from your customers?**

$0.30 of the monthly service charge per customer is currently being collected except for the following rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

2006 – No Plan
2007 – Planning, Procurement (See Generic Section in Main Document)
2008 – Implement Plan (See Generic Section in Main Document)
2009 – Back Office Integration (See Generic Section in Main Document)

NIAGARA ERIE POWER ALLIANCE

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	2007	2008	2009	2010
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	2007	2008	2009	2010
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**
   - **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
   - **the capital expenditures and amortization by class and by year;**
   - **the operation expenses by class and by years;**
   - **the effect of the SMIP on the level of the allowance for PILs.**

   We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation quantities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2008 with a total customer base of 18,329 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

   N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

   May 1/06 to Apr. 30/07 - collect $0.30 per customer per month for approved customer classes
   May 1/07 to Apr. 30/08 - to be determined
   May 1/08 to Apr. 30/09 - to be determined
   May 1/09 to Apr. 30/10 - to be determined
   2010 and beyond - continue to collect until costs recovered, amount to be determined

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that recovery of the procured assets will be possible. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout.

December 15, 06

Signature

Date

Norfolk Power Distribution Inc.

Schedule A8 - LDC Authorization – Peninsula West Utilities Ltd.

Peninsula West Utilities Ltd.
4548 Ontario St.
Unit 2
Beamsville, Ontario
L0R 1B5

PEN WEST Utilities
"Providing power for the future"

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Peninsula West Utilities Ltd. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

    Peninsula West Utilities Limited
    Brad Randall, Director of Engineering and Operations
    phone: (905) 563-5550
    e-mail: brad@penwest.on.ca

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

    No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

    N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much of this is being recovered from your customers?**

   $0.30 of the monthly service charge per customer is currently being collected except for the following rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2009 – Implement Plan (See Generic Section in Main Document)
   2010 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2009 – Implement Plan (See Generic Section in Main Document)
   2010 – Back Office Integration (See Generic Section in Main Document)

NIAGARA ERIE POWER ALLIANCE

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation			X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors	X			
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	2007	2008	2009	2010
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	2007	2008	2009	2010
Consulting Services	X	X	X	
Legal for RFPQ's		X		
Legal for AMI Contracts		X		
Legal for Installation Contract		X		
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits			X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**
   - **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
   - **the capital expenditures and amortization by class and by year;**
   - **the operation expenses by class and by years;**
   - **the effect of the SMIP on the level of the allowance for PILs.**

   We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation quantities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2009 with a total customer base of 15,228 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

   N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

   May 1/06 to Apr. 30/07 - collect $0.30 per customer per month for approved customer classes
   May 1/07 to Apr. 30/08 - to be determined
   May 1/08 to Apr. 30/09 - to be determined
   May 1/09 to Apr. 30/10 - to be determined
   2010 and beyond - continue to collect until costs recovered, amount to be determined

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

Based on system impact, we believe the installation of interval and "smart" meters in commercial and industrial sites should be the primary focus. As deployment is considered for the remaining residential customers, funding should be considered to automate order processing otherwise the paper transactions used currently will overwhelm the customer service and billing reps.

B Randall

December 12, 06

Signature
Peninsula West Utilities Ltd.

Date

Schedule A9 - LDC Authorization – Welland Hydro Electric System Corp.

Welland Hydro Electric System Corp.
950 East Main St.
Box 280
Welland, Ontario
L3B 5P6

RE: EB-2006-0246 - Filing of Smart Meter Investment Plan for the 2006 Rate Year

Welland Hydro Electric System Corp. is pleased to submit an application to the OEB to establish an accrual/deferral account to monitor and record Smart Meter Investment Plan (SMIP) expenditures. This application is in response to correspondence from the Ontario Energy Board (File Number EB-2006-0246) advising utilities of the requirement to file their Smart Meter Investment Plan as part of their 2006 rate application by December 15, 2006.

1. **Distributor identification (name, name of contact person and contact information).**

   Welland Hydro Electric System Corp.
   Kevin Bailey, Operations & Meter Department Supervisor
   phone: (905) 732-1381
   e-mail: kbailey@wellandhydro.com

2. **Did you submit a Smart Meter Investment Plan ("SMIP") as part of your 2006 EDR rate application? If yes, please provide the specific place(s) in your application that outline your plan.**

   No

3. **If you have made any significant changes to your SMIP subsequent to your application please provide details of the changes (both here in general terms and as a component of the following questions).**

   N/A

4. **For the 2006 rate year, how much money has been included in the Board approved revenue requirement for the SMIP? How much of this is being recovered from your customers?**

   $0.30 of the monthly service charge per customer is currently being collected except for the following rate classes: sentinel lights, street lights and un-metered scattered load.

5. **What is your SMIP in the 2006 rate year? If you do not have a SMIP in the 2006 rate year, what are your intentions for future years?**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2009 – Implement Plan (See Generic Section in Main Document)
   2010 – Back Office Integration (See Generic Section in Main Document)

6. **Is your SMIP in the 2006 rate year a component of a multi-year plan? If so, please provide details of the total plan, broken down by year, as completely as possible.**

   2006 – No Plan
   2007 – Planning, Procurement (See Generic Section in Main Document)
   2009 – Implement Plan (See Generic Section in Main Document)
   2010 – Back Office Integration (See Generic Section in Main Document)

NIAGARA ERIE POWER ALLIANCE

Smart Meter Expenses over the next four years

Please note that this is NOT an exhaustive list and will be expanded on over the next few months through planning sessions.

OPERATIONS	2007	2008	2009	2010
Repair of unsafe meter bases	X	X		
Costs for Detailed Propagation Studies	X			
Work Force Management System	X	X	X	X
Smart Meter Network (AMCD, AMRC, AMCC)		X	X	X
Smart Meter WAN		X	X	X
Smart Meter Installation		X	X	
Meter Seals		X	X	
Meter Rings		X	X	
Meter Adaptors		X	X	
AMI Installation of Operational Verification Tools		X	X	X
Staff Training and Department Integration		X	X	
Measurement Canada Re-Verification Accrual Account		X	X	X
BILLING / CUSTOMER SERVICE	2007	2008	2009	2010
CIS Automated Meter Change Package	X	X		
Smart Meter Customer Presentment Tools (Web, IVR)	X	X	X	X
Smart Meter Entity MDM/R		X	X	X
Storage Costs for Old Meter Off Read Image Files		X	X	X
Bill Print Modifications		X	X	
Customer Education Packages		X	X	X
CIS TOU Modifications and MDM/R Integration		X	X	
Staff Training and Department Integration		X	X	
FINANCE / CORPORATE	2007	2008	2009	2010
Consulting Services	X	X	X	
Legal for RFPQ's	X			
Legal for AMI Contracts	X			
Legal for Installation Contract	X			
Legal for Old Meter Recycling Contract	X			
AMI Annual Security Audits		X	X	X

7. **Specifically, and in as much detail as possible, please provide the following information for you planned implementation of the SMIP:**
   - **the number of meters installed by class and by year, both in absolute terms and as a percentage of the class;**
   - **the capital expenditures and amortization by class and by year;**
   - **the operation expenses by class and by years;**
   - **the effect of the SMIP on the level of the allowance for PILs.**

   We are committed to investing the funds to developing and implementing the above noted programs in conjunction with the Ministry of Energy's Smart Meter Initiative. As we move forward into the procurement and implementation stages of the initiative, specific budget allocations, meter class installation quantities, capital expenditures, amortization, operational expenses will be established to achieve the mandate. Full deployment is planned to start in 2009 with a total customer base of 21,493 (not including Street and Sentinel Lighting Connections). At the time of this submission it is unknown as to the effect of the SMIP on the level of allowance for PILS, this will be determined at a later date.

8. **If you previously submitted a plan and have made changes to it, please provide a similar set of responses to question 7 for both the original plan and the changes between plans.**

   N/A

9. **With respect to funding for the SMIP, please provide comments as to whether you consider that the existing funding recovered through the 2006 rates and/or the proposed adjustment for 2007 rates is sufficient, or indicate why that funding and timing is not sufficient for your SMIP needs and what action you consider necessary to ameliorate the situation. Please ensure that these comments are as detailed and specific as possible, both with respect to the level of the funding and the timing of such a revision.**

   May 1/06 to Apr. 30/07 - collect $0.30 per customer per month for approved customer classes
   May 1/07 to Apr. 30/08 - to be determined
   May 1/08 to Apr. 30/09 - to be determined
   May 1/09 to Apr. 30/10 - to be determined
   2010 and beyond - continue to collect until costs recovered, amount to be determined

10. **Please provide any additional comments that you believe would be helpful to the Board in its understanding of your SMIP and what you consider to be the requirements for the efficient and effective implementation of this government sponsored initiative.**

The development of these plans has been based on the understanding that recovery of the procured assets will be possible. Without this indicator there is risk associated with finalizing the procurement phase and beginning mass rollout.

Signature
Welland Hydro Electric System Corp.

Dec 13th 2006
Date

APPENDIX G

PRP International Inc.
Fairness Advisory Services

Attestation Letter of the Fairness Commissioner dated August 1, 2008

PRP International, Inc.

Fairness Advisory Services

August 1, 2008

Mr. Lloyd Payne
President & CEO
Haldimand County Hydro Inc.
1 Greendale Drive
Caledonia, ON N3W 2J3

Dear Mr. Payne:

Subject: Attestation of the Fairness Commissioner
Advanced Metering Infrastructure RFP, August-July 2008
London Hydro, Consortium & Add-On LDCs Smartmetering Project

PRP International, Inc. is pleased to submit its letter report of the Fairness Commissioner for the noted Request for Proposal (RFP) evaluation and selection phase. This judgment is being provided for the information and use of each Add-On LDC Sponsor, in their consideration of the report from the Evaluation Phase, for this competitive transaction.

"It is the judgment of PRP International, Inc., as the Fairness Commissioner, that the determinations of the two (2) highest ranked Proponents for the ***NEPA Collective of LDCs (Brant County Power Inc., Brantford Power Inc., Canadian Niagara Power Inc. (Fortis), Grimsby Power Incorporated, Haldimand County Hydro Inc., Niagara-on-the-Lake Hydro Inc., Niagara Peninsula Energy Inc., Norfolk Power Distribution Inc., and Welland Hydro Electric System Corp.)*** *requirements are:*

- *KTI/ Sensus Limited, as the recommended Preferred Proponent, based on its highest ranking, and*
- *Elster Metering being the second ranked Proponent.*

These determinations were made in a fair (objective and competent) manner and consistent with the evaluation and selection processes set out in the RFP, issued August 14, 2007."

A detailed report for your records will be submitted to you, by August 31, 2008. Should you have any questions or require clarification of any matter contained in this letter report, please contact the undersigned.

Yours truly,

Peter Sorensen
President
cc: Mr. Gary Rains, RFP Project Director

203 - 8 QUEEN STREET, SUMMERSIDE, PEI C1N 0A6
TELEPHONE: 902.436.3930 FAX: 604-677-5409
EMAIL: fairness@telus.net

APPENDIX H

PRP International Inc.
Fairness Advisory Services

Attestation Letter of the Fairness Commissioner dated August 15, 2009

9S.

RECEIVED

AUG 1 8 2009

PRP International, Inc.

Fairness Advisory Services

August 15, 2009

Mr. Lloyd Payne
President & CEO
Haldimand County Hydro Inc.
1 Greendale Drive
Caledonia, ON N3W 2J3

Dear Mr. Payne:

Subject: Confirmation of the Fairness Commissioner
Haldimand County Hydro Inc.
– KTI/Sensus Limited Contract Award
Advanced Metering Infrastructure RFP, August 2007
London Hydro & Consortium of LDCs Smartmetering Project

PRP International, Inc. is pleased to submit its Confirming Letter of the Fairness Commissioner for the noted negotiations and contracting phase of the LH AMI Request for Proposal (RFP) procurement. This judgment is being provided for the information and use of Haldimand County Hydro Inc. ("HCHI"), in its administration of the contract awarded to its #1 ranked Proponent, KTI/Sensus Limited.

"It is the judgment of PRP International, Inc., as the Fairness Commissioner engaged by HCHI *for the phase of negotiations and contract award pursuant to the Fairness Protocols issued August 2008, that the successful conclusion of negotiations and contract between* Haldimand County Hydro Inc. *and* KTI/Sensus Limited, *were undertaken in accordance with the principle for such negotiations and contract award set out in the RFP, issued August 14, 2007."*

A backgrounder and summary of the Fairness Protocols is attached and forms part of this Confirming Letter.

Yours truly,

Peter Sorensen.

Peter Sorensen
President

Attachment: Negotiations and Contract Phase Backgrounder

203 - 8 Queen Street, Summerside, PEI C1N 0A6
Direct telephone: 902.436.3930 Fax: 604-677-5409
Email: fairness@telus.net

BACKGROUNDER TO FAIRNESS CONFIRMATION / ATTESTATION
Advanced Metering Infrastructure Procurement

TO WHOM IT MAY CONCERN:

Background:

- A Request for Proposal procurement transaction was conducted by London Hydro Inc., as the lead sponsoring Local Distribution Company (LDC) and with a consortia of another 63 LDCs, during the period August 2007 to July, 2008;
- The evaluation and selection phase of the RFP provided for the determination of the #1 and #2 ranked Proponents for each LDC;
- RFP Provision 7.5.14[1] provides the framework (principle) for negotiations and contracting based on the principle of "first right to negotiation and execution of a contract" being accorded to the ranked order of Proponents commencing with the highest ranked Proponent and proceeding in a consecutive order thereafter; and
- Each LDC was provided the evaluation results for their #1 and #2 ranked Proponents supported by the Attestation Letter of the Fairness Commissioner as to those rankings.

Fairness Coverage Objective:

Normally, fairness coverage terminates with the determination of the ranked Proponents following the evaluation and selection phase of the RFP; however, certain LDCs expressed a wish to secure additional fairness coverage during the subsequent phase of negotiations and contract award. The objective for this second phase fairness coverage is to assure that LDCs undertook a phase of negotiations and contracting that meets the RFP provisions of consecutive negotiations where required, e.g. with their top two ranked Proponents and in the event of unsuccessful negotiations with the #1 ranked Proponent, a subsequent contract award to the next ranked Proponent would be on an equitable basis as was the requirements in the negotiations with the #1 ranked Proponent.

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1 7.5.14 **Final Contract Negotiations**

Any conditions and provisions that a bidder seeks shall be a part of this proposal. Notwithstanding, nothing herein shall be interpreted to prohibit London Hydro from introducing or modifying contract terms and conditions during negotiation of the final contract.

London Hydro has scheduled no more than two weeks for contract negotiations (if necessary), and expects the successful bidder to maintain a prompt and responsive negotiation to accomplish and complete final contract agreement within that time period. If contract negotiations exceed an interval acceptable to London Hydro, London Hydro retains the option to terminate negotiations and continue to the next apparent successful bidder, at the sole discretion of London Hydro. Said interval shall in no event be less than three weeks.

BACKGROUNDER TO FAIRNESS CONFIRMATION / ATTESTATION
Advanced Metering Infrastructure Procurement

Fairness Protocols:

- A Fairness Protocol was developed and issued to all LDCs, in August 2008 that set forth the best practices for fair consecutive-based negotiations and contract award.
  - The fundamental principle of the Protocol was the requirement for the LDC to establish the negotiations agenda for their top ranked Proponents and submit a copy to the Fairness Commissioner prior to engagement of their #1 ranked Proponent, i.e. the agenda would demonstrate a common statement of work, a LDC standard for pass/fail in their negotiations and the negotiation issues would only differ to the extent of the respective Proponent's technical solution being offered.

Form of Fairness Confirmation / Attestation[2]:

1. A confirmation of fair negotiations and contract award would be issued if the LDC's #1 ranked Proponent was awarded a contract; the original Attestation Letter remains in effect.

2. An Attestation of fair negotiations and contract award would be issued if the LDC determined that their #1 Proponent was to be set aside and the LDC successfully contracted with their next ranked Proponent, e.g. their #2; the original Attestation Letter is thus superseded by the Negotiations and Contract Award Attestation Letter.

Local Distribution Company:

Haldimand County Hydro Inc.

Mr. Lloyd Payne
President & CEO
Haldimand County Hydro Inc.
1 Greendale Drive
Caledonia, ON N3W 2J3

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[2] Conditions on the rendering of this Confirmation / Attestation.

- The two Negotiations Agenda were provided by HCHI, via its agent Util-Assist;
- Fairness Commissioner undertook no direct participation or oversight in the negotiations between HCHI and their #1 ranked Proponent;
- The successful contract award was based on the HCHI criteria and no independent analysis nor any comparison with the evaluation results of the RFP process was carried out by the Fairness Commissioner; and
- The confirmation of the Fairness Commissioner was based on the progress report(s) provided by HCHI, via its agent Util-Assist.

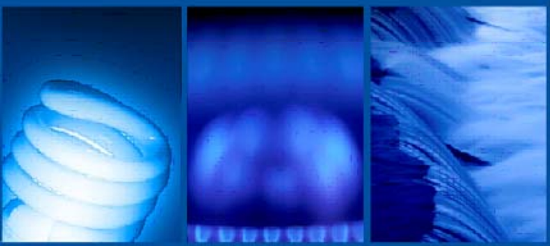
APPENDIX I

Niagara Erie Power Association

Request for Proposal
Smart Meter Installation Services
RFP#: 2008-926
September 26, 2008

util-assist

utility strategic operational assistance



Niagara Erie Power Association (NEPA)

Request for Proposal

Smart Meter Installation Services
RFP#: 2008-926

September 26, 2008

Section 1: Introduction

1.1 Background

Niagara Erie Power Association (NEPA) members have been working collaboratively through the planning and preparation stages for the Smart Meter Initiative. The NEPA Group consists of ten electricity distribution utilities who have found great benefit in sharing resources and proficiencies through many past collaborative efforts.

Collectively the NEPA group represents over 180,000 endpoints in Ontario and is comprised of the following member utilities:

Brant County Power Inc.
Brantford Power Inc.
Canadian Niagara Power Inc.
Grimsby Power Incorporated
Haldimand County Hydro Inc.
Niagara-on-the-Lake Hydro Inc.
Niagara Peninsula Energy Inc.
Norfolk Power Distribution Inc.
Welland Hydro Electric System Corp.

NEPA members wish to procure Installation Services from a qualified Bidder at a firm, fixed price; this documentation sets out the procedural and technical requirements of NEPA for its Advanced Metering Infrastructure (AMI) System Installation service requirements.

1.1.1 Provincial Mandate

As part of its energy conservation effort, the Ontario government has made a commitment to replace all existing meters (5 million) with smart meters by 2010. Phase One utilities have fulfilled their commitments to install 1 million smart meters by Dec 31, 2007 which assisted the government in exceeding their interim goal of 800,000 by Dec 31, 2007. Focus now shifts to the Phase Two implementation of a Smart Meter Network.

The underlying premise behind the provincial mandate to install these meters is to educate customers on their consumption habits and implement new rate structures that will encourage load shifting, and the conservation of energy.

1.1.2 The NEPA Approach to Smart Metering

With respect to the Provincial government's Smart Metering Initiative, Niagara Erie Power Association (NEPA) has taken a collaborative approach to becoming educated on this mandate by working with other Ontario utilities and advocacy groups. NEPA hopes to evaluate Bidders as objectively as possible with the end goal of selecting the best-fit service provider for implementation services, thereby allowing NEPA to achieve their goals, as well as those of the provincial Smart Meter mandate.

Along with satisfying the provincial mandate of measuring "how much electricity a customer uses each hour of the day, and to use that data to charge customers an energy price that varies depending on when the electricity was consumed" (OEB Smart Meter Plan; January 26, 2005; page i); NEPA will also implement the Smart Meter Network to improve overall efficiency within the associated service territories.

Real time connectivity with the end use consumer through the installed networks will allow for improvements in the maintenance and management of the distribution network (i.e. improved outage management and restoration) and the utilization of existing infrastructure (e.g. Fiber) where available will allow for cost effective implementation of these systems.

1.1.3 AMI Terminology

For the purposes of this procurement process, NEPA has opted to utilize the terminology as defined by the Ministry of Energy in their *Functional Specification for an Advanced Metering Infrastructure Version 2* (dated July 5, 2007), Section 3, *Definitions.* For reference, this document has been included herein as Appendix "A". Any additional terms that have been utilized in this document, which have not been defined in the aforementioned document, which may require clarification, have been defined in Section 1.1.4 *Other Terms*.

1.1.4 Other Terms

1. ***Route Acceptance*** shall refer to the process by which NEPA accepts an existing meter reading route as having been 100% saturated with the AMI being procured through this RFP. Route Acceptance is the process which definitively determines whether the responsibilities of the Installation Vendor (being procured through this document) have been achieved.
2. ***Bidder*** shall mean those vendors which submit a Proposal.
3. ***Costs*** *and* ***Price***. Within this document, the terms "Costs" and "Price" are used interchangeably, and should be interpreted as including conversion costs, life-cycle costs, etc. Vendors should be sure to provide details regarding the amount charged for the given commodity or service.
4. ***Proposal*** shall mean the Vendor's written response provided to NEPA in accordance with this RFP. The Proposal shall include all written material submitted by Vendor as of the date set forth in the Key Dates (Section 2.1 *Key Dates*).
5. ***Unsafe Meter*** shall mean meters, meter bases, or other infrastructure which creates an electrically unsafe situation for the meter installer or for the general public. This can include situations where access to the meter for the purpose of meter exchange poses a safety risk (i.e. confined spaces). The manner in which Unsafe Meters are to be dealt with has been detailed in Section 3.2.2 *Unsafe Meter Bases*.
6. ***Refused Access*** shall refer to situations where the customer is present at the location where a meter exchange is required, but refuses access to the meter. It is expected that the Installer would accommodate unique situations such as Refused Access through the policies and procedures which NEPA have requested in Section 7: *Customer Communications*.
7. ***Non Installable Account*** is the "Comment Code" or "Note" that will be used by the Bidder to indicate that a meter installer has visited a premise three (3) times and utilized telephone scheduling attempts two (2) times, and has not been successful at installing a meter. In this case the meter exchange service order can be returned to NEPA for resolution with no associated implications for not meeting installation targets.
8. ***Installer*** shall refer to the successful Bidder. The term Installer will be used when stating future requirements, to be performed only by the successful Bidder.
9. ***Field Service Representative*** or ***Field Service Personnel*** shall refer to the employees of the Installer which are actually performing the work, and which are monitored by the Installer to ensure proper protocols are followed.
10. ***Contractor*** shall refer to the Electrical Contractor retained by NEPA for upgrading infrastructure, and performing any other services beyond the scope of this document.

1.2 Description of Environment

Please refer to NEPA_InstallationRFP_PricingSheet_Sept08.xls for details regarding customer count, meter count, etc.

For reference, we have also included the following information pertaining to NEPA's back office systems.

Customer Information Systems (CIS):	**Advanced, APPX, Daffron, Harris Northstar, SAP**

Section 2: Instructions to Bidders

This Request for Proposals (RFP), establishes the system products and services that the NEPA group wish to acquire. This bid document is the basis upon which NEPA seeks firm proposals from selected Bidders and upon which proposals will be evaluated. The documents are:

- This RFP (a pdf document), including Appendices that are integral to it.
- NEPA_InstallationRFP_PricingSheet_Sept08.xls, a Microsoft Excel workbook. This file contains scoring criteria, the compliancy signoff sheet that is to be printed and included with the response, and tabs that allow for entry of pricing information. This workbook will heretofore be referred to as the Pricing and Compliancy spreadsheet.

2.1 Key Dates

Below is the expected timeline that NEPA will be following during the evaluation of submitted proposals. As can be seen, it is the intention of NEPA to make its decision by November 28th, 2008. This time line will allow for contract negotiation and signing, so that installation can begin according to the anticipated start date of March 2, 2009.

Installation Services RFP released by NEPA :	**September 26th, 2008**
Intention to bid:	**October 3rd, 2008**
Final Questions Due:	**October 8th, 2008**
Answers to Questions:	**October 13th, 2008**
Closing Time (Proposals Due):	**3:00 PM EST October 24th, 2008**
Proposal Decision:	**November 28th, 2008**
Anticipated Start Date:	**March 2, 2009**
Required Project Completion Date:	**July 30, 2010**

2.2 Intention to Bid

Recipients of this RFP are asked to inform NEPA of their intention to bid, by completing the template form found in Section 2.15 *Proposal Forms*, and by submitting this form by the date shown in Section 2.1 *Key Dates*. Recipients that express intention to bid will be included in all correspondence (if any) during the bidding process. Please provide full contact information and expression of intention via the provided form to the NEPA contact named in Section 2.4 *Submission of Bids*.

2.3 Components of Service

It is the intent of NEPA to procure a turn-key solution. Strategic alliances may be formed to provide a turn-key solution, or Bidders may be interested in performing only certain components of the project. Bidders are asked to clearly indicate which components of the Project are being bid.

NEPA reserves the right to award some, none, or all of the components through this process to one or many Bidders.

2.4 Submission of Bids

Proposals submitted in response to this RFP will be submitted by 3:00 PM Eastern Time on October 24th, 2008 (the due date, as per Section 2.1 *Key Dates*) to:

Mr. Jim Huntingdon
Niagara-on-the-Lake Hydro Inc.
8 Henegan Road, PO Box 460
Virgil, ON L0S 1T0
905-468-4235
Email: NEPA@util-assist.com

Bidders are requested to submit bids that are complete and unambiguous without the need for additional explanation or information. NEPA reserves the right to make a final determination as to whether a bid is acceptable or unacceptable solely on the basis of the bid as submitted, and proceed with bid evaluation without requesting further information from any Bidder. If NEPA deems it desirable and in its best interest, NEPA may, in its sole discretion, request from any Bidder or Bidders additional information clarifying or supplementing any submitted bid.

Proposals received after the due date will remain unopened and will not be considered for selection. NEPA does not currently plan to grant extensions of the proposal due date, but reserves the right to do so. In the unlikely case that an extension is granted, notice of such extension will be provided to all Bidders at least one week prior to due date. Proposals will be submitted in hard copy to the street address above. All Proposals will remain the property of NEPA.

2.4.1 Submission Requirements

1) A complete Proposal will consist of one (1) original and ten (10) copies complete with all supporting data, and one (1) electronic soft copy complete with all supporting data.
2) Accompanying the Bidder's response document should be the Proposal Form provided in Section 2.15 *Proposal Forms*.
3) The required format of the Bidder's response document is outlined in Section 2.4.3 *Proposal Format Instructions*.
4) The Pricing and Compliancy spreadsheet will allow for the Bidder to enter their pricing information in a standard format, as well as allow the Bidders to attest to their company's compliancy with the appropriate Health and Safety Requirements. Failure to properly complete this document is grounds for disqualification, as highlighted in Section 2.4.4 *Grounds for Disqualification*.
5) The original hard copy shall be clearly identified as "ORIGINAL"; the remainder (i.e. ten) shall be marked as "COPY". In the event of discrepancy between the copies of the Proposal Submission, the one marked "ORIGINAL" shall prevail. Each Bidder's submission shall consist of the required documents with the required number of copies of all commercial information, including pricing, terms and conditions and exceptions (if applicable). Faxed or late Proposals will not be accepted. Proposals must be sealed and marked clearly quoting the Proposal Number referred to on the cover sheet of the Proposal Documents. The use of any means of delivery of a Proposal shall be at the risk of the Bidder.
6) Any Bidder wishing to provide additional information other than what is requested in the RFP Document must place such additional information in a separate envelope marked Additional Information attached to the outside of the Proposal envelope. Any Additional Information or any unsolicited value-added alternatives may, in NEPA's absolute discretion, be given due consideration, or not.

7) NEPA shall not be liable for, nor shall it reimburse any Bidder for costs incurred in the preparation of Proposals, or any other services or samples that may be requested as part of the evaluation process.
8) The Proposal Forms shall be signed under the Corporate Seal of the Bidder, by the duly authorized signing officer(s). All submitted pages of the original document shall be initialled by such officer(s).

2.4.2 Pricing and Compliancy Spreadsheet

A Microsoft Excel workbook has been provided with this pdf document (entitled NEPA_InstallationRFP_PricingSheet_Sept08.xls). The following tabs are included within this Pricing Spreadsheet:

i) NEPA_BidderCompliancy: This tab requires completion by the Bidder, and will act as their compliancy statement according to the requirements of Section 2.4.4 *Grounds for Disqualification*

ii) Pricing_Option1: This tab requires completion by the Bidder, and is the pricing for the Bidder to provide installation services as outlined within this RFP.

iii) Pricing_Option2: This tab is optional and allows the Bidder to provide pricing in an alternative format, should they desire to do so, and are of the opinion that their services are better represented with pricing apart from that outlined on the Pricing_Option1 tab. Bidders are free to add additional pricing tabs as required should they feel that there are more than on alternative option which may allow for more competitive pricing (i.e. according to a more or less aggressive timeline, holding off project commencement until a different time of year (i.e. spring vs. winter, etc.)).

Note: Pricing_Option1 is mandatory, Pricing_Option2 is optional.

iv) Eval_Criteria: this tab is for reference, it is a copy of the table that is shown in Section 2.9 *Proposal Evaluation*.

v) WFM_Functionality: This tab requires completion by the Bidder, and will demonstrate the functionality inherent to the WFM system being utilized to provide installation services.

2.4.3 Proposal Format Instructions

Each Bidder's response will be organized as per the following:

a) Section 1 of the proposal will contain the Bidder's Executive Summary, no more than two pages in length that introduces the Bidder and highlights key features of the proposal.
b) Section 2 of the proposal will contain the statement of compliance that is included within the Pricing and Compliancy Spreadsheet, and which is described in Section 2.4.2 *Pricing and Compliancy Spreadsheet*, subsection i).
c) Section 3 of the Bidder's proposal will contain the requirements of Section 3 of this RFP Document (Section 3: *Health and Safety*), in the order presented in this document, with the numbering used in this document.
d) Section 4 of the Bidder's proposal will contain a statement of recognition that the Bidder understands NEPA's schedule for deployment and the deployment territories, and that they are providing a bid response with the intention of performing the required services for NEPA. Given the diverse nature of the service territories, and that there are Smart Meter Deployments occurring across the province, Bidders have the opportunity within this section to demonstrate, through submitted documentation/statements, how they will be able to accommodate the unique requirements of NEPA (i.e. staffing across the area, for the timelines projected).

e) Section 5 of the Bidder's proposal will contain the requirements of Section 5 of this RFP Document (Section 5: *Bidder Information*), in the order presented in this document, with the numbering used in this document.
f) Section 6 of the Bidder's proposal will contain the requirements of Section 6 of this RFP Document (Section 6: *Installation Services*), in the order presented in this document, with the numbering used in this document.
g) Section 7 of the Bidder's proposal will contain the requirements of Section 7 of this RFP Document (Section 7: *Customer Communications*), in the order presented in this document, with the numbering used in this document.
h) Section 8 of the Proposal will contain the summary pages pertaining to the Price Offer, contained within the Pricing and Compliancy Spreadsheet. The Bidder's detailed itemized pricing information for all goods or services is to be contained within the Pricing and Compliancy Spreadsheet which is to be included with the response in its entirety as well as within this section. Any alternative pricing offers may also be included within the Pricing and Compliancy Spreadsheet (tab Pricing_Option2 is included for this purpose, as described in Section 2.4.2 *Pricing and Compliancy Spreadsheet*). All pricing shall be expressed in Canadian currency, exclusive of taxes.

2.4.3.1 Sample Responses to Demonstrate Format

Within the section or subsection heading an indicator has been included to specify whether the Bidder should provide information pertaining to the functionality of their product/service (with regards to the section requirements), or a statement of compliancy AND information pertaining to the functionality of their product with respect to the requirement of the section. Where no indicator is included, a response is not required.

(I) When an (I) has been included with the section heading, NEPA requires Information regarding the proposed system's functionality, and the methodology utilized to satisfy the RFP requirement.

(C) When a (C) has been included with the section heading, NEPA requires a statement of compliancy from the Bidder. Within the proposal documentation, the Bidder is required to state the compliancy with the requirement by stating Fully Compliant, Partially Complaint, or Not Compliant.

(CI) When a (CI) has been included with the section heading, NEPA requires both a statement of compliancy, and Information regarding the proposed functionality, and the methodology utilized to satisfy the RFP requirement.

The method with which the Bidder provides information and compliancy statements is detailed within the individual sections, as well as within the Pricing and Compliancy Spreadsheet.

In Section 2.4.3 Proposal Format Instructions, subsections c) through g) it has been specified that the order and numbering used within this document be utilized. A sample has been provided here.

5.2 Company Size and Location (I)

What is the current size (number of employees), turnover rates for last three (3) years, and location(s) of the Bidder's company?

Bidder's Functionality Statement: Vendor X currently employs 600 employees. 500 of these employees are Field Service Representatives. Of the 100 remaining office and management staff, 37 are within the Operations division providing ample redundancy and support to effectively manage this project. Vendor X's head office is located in Alabama, with satellite offices in Toronto, London, and Ottawa. This project will be managed from the Toronto office. Turnover, while generally higher in the field service industry, is considered low at 3%. We attribute this to an effective Safety and Training program (1 week) in which employees receive ample safety training as well as introduction to the company incentive program which has been seen to improve morale amongst field service employees.

SAMPLES of response for Section 6: *Installation Services*, demonstrating that the section numbering from this document is to be retained, and that each section should be included, and where required shall include a statement of compliance.

6.1.1 Minimum Competencies (C)

Before installing meters the Installer shall ensure the Field Service Personnel are customer service oriented, have flexible work hours and are bonded, and the Installer shall maintain a process to ensure these requirements are met.

The Installer shall operate within specific procedures and operating conditions in adherence with procedures and training that NEPA will provide. Upon conclusion of the NEPA training, it will be the Installer's responsibility to ensure that new employees receive the same level of training as those employees which receive the training through NEPA.

Bidder's declaration of compliance: **Fully Compliant**

6.5.6 GPS (CI)

In addition to installing the meter, capturing the LAN ID and Meter ID data from the barcode on the installed meter, and the start read, NEPA members desire to update service location information by having the Bidder capture the GPS co-ordinates of the installed endpoint. Where meters are located in basements or in areas where satellite signal may not be possible, the closest co-ordinates will be collected once communication has been established.

Bidder's declaration of compliance: **Fully Compliant**

Bidder's Functionality Statement: The WFM system is capable of automatically capturing the GPS location of the installed meter, and this information is automatically recorded within the assigned service order. The GPS device is integrated (i.e. not a separate device), and is accurate to within 3m (10 feet).

2.4.4 Grounds For Disqualification

It is a requirement of this RFP document that the Bidders submitting proposals for evaluation complete a compliancy statement within the Pricing and Compliancy spreadsheet which will attest to the Bidder's compliance with the Health and Safety Policies and Procedures as outlined in Section 3.1 *NEPA Health and Safety Policies and Procedures*. In addition to having read this section, and all applicable subsections, the Bidder agrees that their company's own Health and Safety Policies will, at minimum, meet NEPA's Safety Policies, and that their bid response will provide the information to properly satisfy the requirements of Section 3.2 *Safety* (and applicable subsections), and that the content of the response is consistent with the policies being agreed to here.

NOTE: Failure to complete these compliancy documents (found within the Pricing and Compliancy Spreadsheet; tab named "NEPA_BidderCompliancy", or where compliancy has been misrepresented, NEPA reserves the right to disqualify the Bidder from contention of the RFP process.

2.5 Clarifications

Upon the issuance of this RFP to Bidders, and continuing through the submission date, all questions or other communications with NEPA shall be by email only, with NEPA's authorized representative, whose contact information is provided in Section 2.4 *Submission of Bids*.

NEPA will respond to the question in writing, with both the question and response provided to each Bidder that has declared intention to bid according to Section 2.2 *Intention to Bid*. No response will be made to questions submitted after October 8, 2008 (as per Section 2.1 *Key Dates*).

2.6 Modifications or Withdrawals of Bids

A Bidder may modify or withdraw its bid by written declaration, provided that the declaration is received by NEPA's authorized representative prior to the time specified for the submission of bids (the due date). Following withdrawal of its bid, a Bidder may submit a new bid, provided that such new bid is received by NEPA prior to the due date. The last bid received by NEPA shall supersede and invalidate all bids previously submitted by the Bidder.

NEPA may modify any provision of the Request for Proposal at any time prior to the due date. Such modifications may be made in the form of addenda, which will be issued simultaneously to all prospective Bidders that have declared their intention to bid. No addenda will be issued within five calendar days of the due date.

2.7 Bid Inconsistencies

Any provisions in Bidder's proposal that are inconsistent with the provisions of this Request for Proposals, unless expressly described in the proposal as being exceptions or alternates in the Table of Compliance, are deemed waived by the Bidder. In the event the Order is awarded to Bidder, any claim of inconsistency between the proposal and this RFP will be resolved in favour of this RFP unless otherwise agreed to in writing by NEPA.

2.8 Post-Bid Meeting

NEPA reserves the right to invite any or all Bidders to make an in-person presentation on the proposed smart meter installation services.

2.9 Proposal Evaluation

NEPA will evaluate proposals using an internal scoring method that weights various parameters to give the NEPA team insight into the strengths of each proposal relative to the NEPA group's needs.

Answers to sections 3 through 7 will represent 45% of the total weighting of the RFP. Pricing submitted will represent 55% of the total weighting of the RFP. Bidders will be selected for further discussion based on the Team's judgment, developed using the scoring method. NEPA reserves the rights to alter its internal scoring method and to exercise whatever judgment it deems is in the best interest of NEPA in selecting an Installation Service Provider.

NEPA's internal scoring method values the following proposal attributes (order of presentation does not reflect priority):

Figure 1: Proposal Evaluation Criteria

Proposal Evaluation Criteria	Section	% Total Points
Safety	3	
Project Overview	4	
Bidder Information	5	
Installation Services	6	
Service Offering / Capability		
Inventory Control		
Scheduling and Coordination		
Reporting		
Used Meter Disposal Handling		
A to S Adaptor Installation		
Meter Base Repairs		
Tamper / Theft		
Customer Communications	7	
Call Centre		
Pre Canvas		
Perspectives expressed by reference utilities		
Section 3 through 7 inclusive:		45%
Pricing Weighting:		55%
Total		100%

2.10 Award or Rejection

Issuance of this RFP does not constitute a commitment by NEPA to award a winning Bidder or purchase products or services offered in response to this RFP. NEPA reserves the right to reject any or all bids. NEPA will not reimburse Bidders' costs to respond to this RFP.

2.11 Execution of the Order

If requested by NEPA, the successful Bidder must assist NEPA in preparing the Purchase Order, which will be governed by the Terms and Conditions set out herein, or others as mutually agreed by the parties. The successful Bidder must duly execute the Purchase Order within ten (10) days after receipt and return it to NEPA. Failure of the successful Bidder to duly execute and return the Order, together with any other required documents will constitute a breach of contract by such Bidder and entitle NEPA to award the Order to any other Bidder, in addition to all other rights and remedies of NEPA.

2.12 Freedom of Information

Proposals submitted to NEPA become the property of NEPA and, as such, are subject to the *Freedom of Information and Protection of Privacy Act*, R.S.O. 1990, c. F.31, as amended.

2.13 Ownership of Data

NEPA shall own all data used and/or collected by any systems being utilized to perform the services. Data shall not be used for any purpose without the approval of NEPA.

2.14 Conflict of Interest

The Bidder is required to disclose in its Submission and on an ongoing basis thereafter any conflict of interest, real or perceived, that exists now or may exist in the future, with respect to this RFP, any resulting contract, or in relation to NEPA or their affiliates.

2.15 Proposal Forms

Within this section, there are two (2) forms required for submission. The first form is found in Section 2.15.1 *Intention to Bid Form*; the intention of this form is to allow the Bidder to provide a standard email response to NEPA to notify NEPA of the Bidder's intent to respond to the RFP.

2.15.1 Intention to Bid Form

Bidders intending to respond to this RFP should notify the contact, using the contact information provided in Section 2.4 *Submission of Bids*, according to the time line as established by Section 2.1 *Key Dates,* by sending an email with the following content inserted:

INTENTION TO BID NOTIFICATION FORM

PROPOSAL NO. 2008-926

Intention to Bid:
Please allow this email to represent "__ Insert Company Name Here __" intention to respond to NEPA RFP#: 2008-926.

Contact for communication regarding bid: ______________________________
Contact phone number: ______________________________
Contact email address: ______________________________

We acknowledge the requirement that our company meets the minimum Safety Requirements as outlined in Section 3. Our proposal will include the required compliance statements and documents to properly express our ability to meet these requirements. We also acknowledge the Submission Deadline is 3:00 pm Eastern Time on October 24, 2008.

2.15.2 RFP Submission Form

The procedure to be utilized for the RFP Submission form is to print the following pages, and include them with the RFP submission, which should be addressed to the contact listed in Section 2.4 *Submission of Bids*, and which should be submitted according to the time line as established by Section 2.1 *Key Dates*.

RFP SUBMISSION FORM

Niagara Erie Power Association (NEPA group of utilities)

Proposal Number: **RFP# 2008-926**

FOR: Installation Services

THIS PROPOSAL IS SUBMITTED BY:____________________

ADDRESS:

TELEPHONE: FAX NO.:

BIDDER G.S.T. No.:

PERSON(S) SIGNING ON BEHALF:____________________________(print)

POSITION(S) OF THE PERSON(S):___________________________________(print)

To Niagara Erie Power Association, Hereafter called "Owner":

I/WE ____________________________________ the undersigned declare:

1. THAT no Person(s), Firm or Corporation other than the one whose signature(s) of whose proper officers and the seal is or are attached below has any interest in this Proposal or in the contract proposed to be taken.

2. THAT this Proposal is made without any connections, knowledge, comparison of figures or arrangements with any other company, firm or person making a Proposal for the same work and is in all respects fair and without collusion or fraud.

   THE Bidder insures that no Owner and or employee of the NEPA group, is, or has become interested, directly or indirectly, as a Contracting Party, Partner, Stockholder, surety or otherwise howsoever in or on the performance of the said contract, or in the supplies, work or business in connection with the said contract, or in any portion of the profits thereof, or of any supplies to be used therein, or in any monies to be derived there-from.

3. THAT the several matters stated in the said Proposal are in all respects true.

4. THAT I/WE have carefully examined the requirement(s), as well as all sections of the document including Instruction to Bidders, Project Overview, Installation Services, Proposal Forms, and Appendices relating thereto, prepared, submitted and rendered available by NEPA and hereby acknowledge the same to be part and parcel of any contract to be let for the work therein described or defined.

5. THAT I/WE do hereby Propose and offer to enter into a contract to deliver all work as described or implied therein including in every case freight, duty, exchange, G.S.T. and P.S.T. in effect on the date of the acceptance of Proposal, and all other charges on the provisions therein set forth and to accept in full payment therefore, the sums calculated in accordance with the actual measured quantities and unit prices set forth in the Proposal herein.

6. THAT Addendum/Addenda No. ___ to ___ inclusive relate to the said contract and Bidder hereby accepts and agrees to the same as forming part and parcel of the said contract.

7. THAT additions or alterations to or deductions from the said contract, if any, shall be made in accordance with the prices stated in the Schedule of Items of Unit Prices in strict conformity with the requirements of the Contract.

8. THAT this offer is irrevocable and open to acceptance until the formal contract is executed by the awarded Bidder for the said requirement(s) or Sixty (60) working days, and unit prices for as long as stated elsewhere in the document, whichever event first occurs and that NEPA may at any time within that period without notice, accept this Proposal whether any other Proposal has been previously accepted or not.

9. THAT the awarding of the contract, by NEPA is based on this submission which shall be an acceptance of this Proposal.

10. THAT I/WE also understand that NEPA reserves the right to accept or reject all or part of this Proposal or any other and also reserves the right to accept other than the lowest Proposal.

<u>The undersigned affirms that he/she is duly authorized to execute this Proposal.</u>

BIDDER'S SIGNATURE AND SEAL: ______________________

NAME: ______________________
(Please Print)

POSITION: ______________________

WITNESS SIGNATURE: ______________________

WITNESS NAME: ______________________
(Please Print)

POSITION: ______________________

(If Corporate Seal is not available, documentation should be witnessed)

DATED AT THE ______________________ THIS ________
(City/Town) (Day)

DAY OF ______________________ 2008.
(Month)

Section 3: Health and Safety

3.1 NEPA Health and Safety Policies and Procedures

Sections 3.1.1 *NEPA Health and Safety Policy* through Section 3.1.6 *Health and Safety Legislation that Applies* are requirements for which compliance are required in order for any external contractors to be permitted to provide services to NEPA. As such, a Statement of Compliancy pertaining to each section is required, and a form has been provided within the Pricing and Compliancy Spreadsheet as outlined in Section 2.4.2 *Pricing and Compliancy Spreadsheet*.

Section 3.2 *Safety* is where the Bidder is provided the opportunity to demonstrate, through the submitted documents, that their own internal Health and Safety Policies, either meet, or exceed those outlined in Section 3.1 *NEPA Health and Safety Policies and Procedures*. Bidders that cannot meet, or exceed those requirements outlined in Section 3.1 *NEPA Health and Safety Policies and Procedures*, or that do not (or cannot) provide a completed Compliancy statement is eligible for disqualification from the evaluation process.

3.1.1 NEPA Health and Safety Policy (C)

NEPA members proclaim that the Health & Safety of each employee is of vital importance in the successful operation of the utility.

Our objective is to develop a keen sense of health & safety awareness in each and every employee and thereby prevent personal illness/injury and damage to property and equipment.

Management is responsible for providing a healthy and safe work environment and for training employees to ensure that they can perform their duties safely.

It is the duty and responsibility of every employee to work safely with equal concern for themselves, co-workers and the public.

It is our collective responsibility to ensure compliance with legislated requirements of Occupational Health & Safety Act.

It is our commitment to provide a safe and healthy work environment by reducing hazards that cause accidents and injuries.

3.1.2 NEPA Field Service Personnel Health and Safety Conditions (C)

Based on the nature of the work being procured through this RFP, and in accordance with the NEPA Health and Safety Policy, the following items shall be received prior to the start of work:

- Acknowledgement from the contractor that they are aware of and agree to adhere to the terms and conditions.
- WSIB Certificate
- NEER firm summary statement
- Liability Insurance
- Health & Safety Policy / Program
- Staff Competency List
- Confirmation of applicable EUSA training

- Documentation of injury experience
- WHMIS MSD documentation for any hazardous materials used in the job
- Equipment Fitness List

3.1.3 NEPA Field Service Personnel Health and Safety Policy (Basic Procedures) (C)

In accordance with NEPA Operating Policies and Procedures, all installers performing work such as that being procured through this RFP shall:

- Wear rubber gloves, Category 2 Fire Retardant Clothing or better
- Class 'O' rubbers for voltage checks
- Hard Hats
- Flash glasses
- Face Shields (must be Arc rated, Category 2 or better)
- Safety boots
- Ensure meter voltage and type is correct (utilizing Cat 4 voltmeters with fused leads)
- Observe safe limits of approach
- Observe wiring to determine if a back feed could be present, e.g. capacitors, standby generator, co-generator
- Not remove meter if meter base is damaged or not secure
- Use meter puller

3.1.4 NEPA Health and Safety Policy: Field Service Personnel (C)

In accordance with NEPA Operating Policies and Procedures, all installers performing field service work shall be:

- Responsible for knowing, understanding and working in compliance with the appropriate safety legislation, EUSA rules, NEPA rules, policies, procedures and safe work practices that apply to the work.
- Responsible for using and wearing at all times the appropriate personal protective and safety equipment required for the work.
- Responsible for using the equipment, materials, protective devices in the proper and safe manner.
- Responsible for participating in, and holding tailboard conferences as required in order to safely complete the work.
- Responsible to participate in any coaching sessions, training, safety meetings, and company general meetings in order to ensure continued competence in the most up-to-date rules, policies, procedures and safe work practices.
- Responsible for reporting all hazardous conditions or equipment defects to the supervisor immediately, fill out the proper documentation and assist with corrective action.
- Responsible to ensure loss incidents and potential loss incidents are reported to the supervisor immediately. Provide preliminary details, fill out the proper documentation and participate in the incident investigation as required.
- Responsible to follow the Internal Responsibility System.
- Responsible to take every precaution reasonable in the circumstances for the protection of the safety of fellow employees.

3.1.5 NEPA Health and Safety Policy: Supervisor/Manager (C)

In accordance with NEPA Operating Policies and Procedures, all Supervisors and/or Managers of Field Personnel shall be:

- Responsible for knowing, understanding and ensuring that work is done in compliance with the appropriate safety legislation, EUSA rules, NEPA members' rules, policies, procedures and safe work practices that apply to the work.
- Responsible for identifying the job hazards, determining the solutions or barriers required to provide safe working conditions and communicating this information to all workers under their supervision.
- Responsible for ensuring all job information such as tailboard conference sheets, traffic plans, vehicle and equipment inspection sheets are filled out properly and returned to the office as appropriate.
- Responsible for holding documented tailboard conferences as required and ensuring appropriate worker participation in order to complete the work safely. Responsible for directing the work in a safe manner.
- Responsible for using and ensuring all crew members use and wear at all times the appropriate personal protective and safety equipment required for the work.
- Responsible for using and ensuring all crew members use the equipment, materials, and protective devices in a proper and safe manner.
- Responsible to ensure loss incidents and potential loss incidents are reported to NEPA immediately. Provide preliminary details, fill out the proper documentation and participate in the incident investigation as required.
- Responsible to report workers who do not comply with their health and safety responsibility, for corrective action by their supervisor.

3.1.6 Health and Safety Legislation That Applies (C)

The Provincial, Federal and Municipal acts & regulations that must be adhered to include, but are not necessarily limited to, the following:

- Bill C45
- Transportation of Dangerous Goods Act , 1992
- Ontario Occupational Health & Safety Act & Regulations
- Ontario Regulation 632/05 – Confined Spaces
- Ontario Regulation 213/91 – Construction Projects
- Ontario Regulation 835-846 – Designated Substances
- Ontario Regulation 851 – Industrial Establishments
- Ontario Regulation 860 – WHMIS
- Ontario Highway Traffic Act & Regulations
- Ontario Regulation 595 – Commercial Motor Vehicle Inspections
- Ontario Regulation 4/93 – Hours of Service
- Ontario Traffic Manual
- Ontario Regulation 22/04 – Electrical Distribution Safety
- Electrical NEPA Operations Rule Book (EUSA Rules)
- NEPA Work Protection Code
- Electrical Safety Code

3.2 Safety (CI)

NEPA's number one requirement will always remain the health and safety of its employees and customers. In addition to stating compliance to NEPA Health and Safety Policies as outlined in Sections 3.1 *NEPA Health and Safety Policies and Procedures*, the Contractor shall ensure that all installation personnel complete all required training for meter installation, meter testing, and for the installation and testing of any other endpoint devices to be installed. NEPA will be expected to work with the Contractor to identify specific gaps in training and testing. The Contractor will communicate to NEPA how it will complete all training in advance of any installations taking place. The Bidder's ability to provide the required training (according to NEPA's requirements) for successful on-time deployment must be approved and properly documented by both NEPA's Project Manager and Health and Safety Officer.

To reflect a similar commitment to Health and Safety, all contracted vendor's policies and procedures manuals will contain comprehensive documentation (as a complement to Completed Training Programs) regarding On-The-Job Safety, Emergency Plans, Accident/Investigation Procedures, and Contact Numbers for any possible incident occurrences, as well as Hazard Assessment Identification and Control, (including (but not limited to) Dangerous Animals, Slips/Trips/Falls, Workplace Violence, Confined Spaces and Unsafe Meter Bases).

Included with the Bidder's response document should be current documentation regarding WSIB clearance.

Additionally, all contracted field service employees will provide to NEPA's Health and Safety Officer (prior to commencement of services), proof that contracted employees:

- Hold a valid drivers license,
- Hold valid drivers insurance,
- Have provided a Driver's Abstract to their employer,
- Have provided a Criminal Background Check to their employer.
- Provide proof of WSIB CAD Experience (WSIB Clearance Certificate)
- Provide proof of EUSA Electrical Safety and Awareness Course
- Provide proof of EUSA Electric Power Meters Course
- Health and Safety Training Program
- Environmental Management System Training
- Utilize Tailboard Conference/Tailgate Safety Talks
- Conform to Technical, Quality Assurance, and other NEPA specific training requirements
- Have received WHMIS Training
- Have any necessary First Aid Training/CPR Training
- Have received Customer Service Training
- Have completed In-field Training
- Comply with NEPA Contractor Checklist

Note: There is a requirement (as per Section 2.4.4 *Grounds For Disqualification*) for Bidders to declare compliancy with the appropriate safety regulations. Failure to do so will make the Bidder's response eligible for disqualification from the remainder of the evaluation.

3.2.1 Safety Policies (I)

NEPA believes that none of its meter sites presents a threat to the personal safety of field workers. It is the responsibility of the Bidder to ensure the safety of their staff, and to ensure that the necessary precautions are taken to ensure the security of any required tools.

i. Bidders shall describe their training and safety program.

ii. Bidder will provide their Health and Safety Policies and Procedures manual, complete with listing of assigned equipment, and required PPE. Documentation on the competency of staff utilizing PPE will also be provided.
iii. Bidder will provide the Emergency procedures that are provided to their installation staff; and indication that relevant staff have been trained on the procedures.
iv. Bidder should provide their Joint Health and Safety Committee meeting schedule/frequency, and membership.
v. Bidder should provide details on the number of staff that meet the safety requirements as outlined.

NEPA reserves the right to review and approve training materials and methods before the start of deployment. Bidders should note that NEPA Safety committee members will be conducting their own random audit process on installation staff.

3.2.2 Unsafe Meter Bases (I)

Bidders should provide details on their procedures for the handling of meter sites where installation is delayed by unforeseen circumstances such as required infrastructure upgrade, accident, or customer objection. Bidders will describe notification procedures and method for tracking the status of such sites.

Acceptable security precautions are to be maintained during all installation activities. The Installer will identify, report and resolve unsafe conditions on a daily basis or as they are identified according to established safety policies. In the case of electrical or mechanical hazards, these shall be reported to NEPA immediately.

Some meter bases have been deemed unsafe. The Contractor shall not attempt, at any time, to remove a meter that has been deemed unsafe. When encountered, the Contractor will be required to identify unsafe meter bases in the WFM handheld device using the appropriate codes and notify NEPA's Installation coordinator. Bidders shall include, within their response, a description of the procedures that are invoked upon discovery of an unsafe meter base, as well as description of the pre-installation inspection protocols which may result in the discovery of an unsafe meter base.

Section 4: Project Overview

Section 4 of the Bidder's proposal shall contain a statement of recognition that the Bidder understands NEPA's schedule for deployment and the deployment territories, and that they are providing a bid response with the intention of performing the required services for NEPA. Given the diverse nature of the service territories, and that there are Smart Meter Deployments occurring across the province, Bidders have the opportunity within this section to demonstrate, through submitted documentation/statements, how they will be able to accommodate the unique requirements of NEPA (i.e. staffing across the area, for the timelines projected).

4.1 NEPA Anticipated Schedule for Deployment (C)

Section 2.1 *Key Dates* shows the anticipated start date for deployment, and the end date required by NEPA. Within this time frame, the successful Bidder will be required to install the quantity of Smart Meters documented in Section 4.4 *NEPA Installation Volumes*. (The statement of recognition that is required for Section 4: *Project Overview* should include recognition of these timelines, and the Bidder's ability to accommodate them.)

4.2 Approved Hours of Installation (C)

Meter installations are to take place between the hours of 8:30 a.m. to 4:30 p.m., Monday to Friday. In special circumstances, extended hours of 8:00 a.m. to 8:00 p.m. and/or Saturday work may be considered by NEPA if required to accommodate the timelines as communicated within Section 2.1 *Key Dates*. No Meter installation is to take place on statutory holidays observed by NEPA.

The Installer shall develop and maintain an installation schedule to ensure installations are completed on time and on budget without interfering with the meter-reading schedule. The Installer can modify the work schedule with permission of NEPA to best meet installation goals and project milestones.

4.3 NEPA Deployment Territories (C)

Maps for NEPA's service territories have been provided within Appendix "B" to better illustrate the service territories within which the residential Smart Meter deployment will take place. It is anticipated that all smart meter installations being procured through this RFP will take place within these territories.

4.4 NEPA Installation Volumes (C)

NEPA projects that all of the required 180,000+ residential smart meter installations, with the exception of any reported safety concerns, will be installed by the successful Bidder.

Service territory details for each NEPA member are provided within Appendix "B".

The chart below depicts the meter volumes for the NEPA Group.

Type	Volume
Inside Residential	8,495
Outside Residential	135,249
Semi-Urban Residential	500
Rural Residential	34,195

4.4.1 Electrical Contractor

NEPA shall provide a qualified Electrical Contractor to complete repairs to customer plant deemed necessary installations based on the identified safety concerns.

4.5 NEPA Meter Depot (C)

For the duration of this deployment, meter installers will be required to pick up, and drop off, their inventory at the following addresses, between the hours specified in the following chart:

NEPA Member Utility	Meter Depot	Hours of Access
Brant County Power Inc.	65 Dundas St. E. Paris, ON N3L 3H1	7:30am – 5:00 PM
Brantford Power Inc.	84 Market Street P.O. Box 308 Brantford ON N3T 5N8	7:30am – 5:00 PM
Canadian Niagara Power Inc.	1130 Bertie Street Fort Erie ON L2A 5Y2 OR 380 Elm Street Port Colborne, ON L3K 4P2	7:30am – 5:00 PM
Grimsby Power Incorporated	231 Roberts Road Grimsby, Ontario L3M 5N2	8:30am - 4:00pm
Haldimand County Hydro Inc.	1 Greendale Drive Caledonia, ON N3W 2J3	7:30am – 5:00 PM
Niagara-on-the-Lake Hydro Inc.	8 Henegan Road, PO Box 460 Virgil, ON L0S 1T0	7:30am – 5:00 PM
Niagara Peninsula Energy Inc.	7447 Pin Oak Drive, P.O. Box 120 Niagara Falls, ON L2E 6S9 - 2nd phase of installation depot location TBA	8:00am – 4:00pm
Norfolk Power Distribution Inc.	70 Victoria St., PO Box 588 Simcoe, ON N3Y 4N6	7:30am – 4:30pm
Welland Hydro Electric System Corp.	950 East Main St., PO Box 280 Welland, ON L3B 5P6	7:30am – 3:30pm

Each utility has provided a location for pick up and drop off of meters and supply of other related equipment required for the installation of the meters. All pick up and delivery of meters by the Installer shall be at the warehouse facility for the term of this contract unless otherwise agreed upon. Field Service Personnel shall pick up new meters and equipment and return the removed meters, in the new cartons, once daily to the designated locations provided by NEPA. No meter shall be returned without an associated transaction record and must be in actual cartons from new installs duly marked.

The Installer will be responsible for all meters from time of signing out of inventory/warehouse until successfully installed. Information regarding inventory in the Installer's custody shall be provided to NEPA upon request.

Note: For deployment within the outlying areas, arrangements will be made between the successful Bidder, and NEPA members, to minimize travel time for the Installers. For pricing purposes, Bidders should assume minimal impact to the work day (i.e. meter pick-up and drop-off will not impact the 8:30 am to 4:30 pm work day).

Section 5: Bidder Information

5.1 Experience (I)

i. How many years has the Bidder been in business?
ii. How long has the Bidder been providing installation services?
iii. The Bidder should describe their primary line of business and the percentage of business derived from the installation of meters.
iv. The Bidder should describe the organization and provide an organization chart of the team or department that would have specific resources used in the deployment of AMI. (Include the number of personnel assigned to installation services and project management of the AMI installation.)
v. Identify and describe any AMI/AMR project where the delivery schedule has been delayed as compared to the original Statement of Work per the contract when signed and describe the causes, current status and plans to address the delay(s). (If you lack AMI experience please provide the most comparable projects you have completed to date).

5.2 Company Size and Location (I)

What is the current size (number of employees), turnover rates for last three (3) years, and location(s) of the Bidder's company?

5.3 Financial Statement (I)

What is the current financial condition of the Bidder's company? Provide supporting documentation and annual reports for the last three years. If the company is privately held, supply sufficient information to document the company's financial status.

5.4 Subcontractors (I)

Does the Bidder intend to subcontract any component, service or support requested in this RFP? If so, indicate which components, services or support and identify the subcontractors.

5.5 References (I)

Provide a list of at least three (3) references (contact names and phone numbers) from companies that have used the Bidder's proposed services in the past three (3) years. Please indicate the number of meters installed and type (gas, water or electric).

5.6 Litigation (I)

Bidder will indicate if there are any anticipated or pending lawsuits or any litigation within the past five (5) years or bankruptcy filings within the past ten (10) years.

5.7 Environmental Policy (I)

NEPA recognizes environmental protection as a guiding principle and key component of sound business performance. NEPA is committed to providing quality customer service in a manner that ensures a safe and healthy workplace for our employees and minimizes our potential impact on the environment. We not only operate in compliance with, but also strive to exceed all relevant federal, provincial, and municipal environmental legislation; and we will strive to use pollution prevention and environmental best practices in all we do.

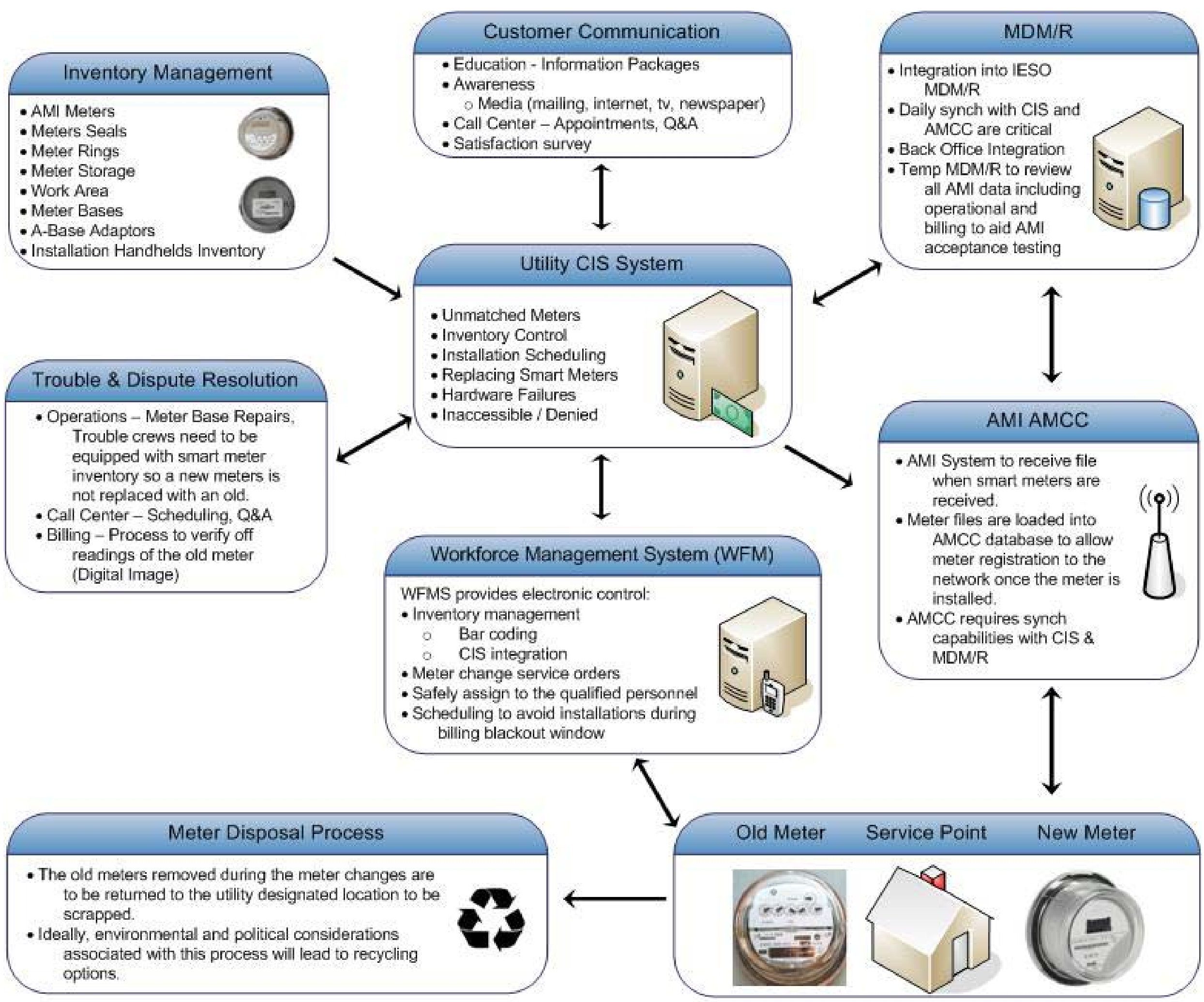
Bidders should indicate if they have a written environmental policy statement, whether the policy statement includes a commitment to continual improvement of environmental performance, whether the company has documented environmental performance objectives/targets and implementation plans, and what their three most significant environmental performance objectives/targets are. In addition, Bidders should describe the extent to which employees understand, accept, and share the environmental values of the company, and how the company uses environmentally friendly products in its day-to-day operations.

Section 6: Installation Services

With the execution of this province wide mandate, we would stress the importance of providing our customers with the highest level of customer service possible. **Figure 2** is a high level view of the work flow process that encompasses the Smart Meter Installation process. Bidders will note the requirements for:

- Proper receipt and inventory of meters
- Change out order creation
- Change out order completion
- Workforce management system to update CIS when orders are completed
- Inventory update to MDR system
- Need for bar coding or digital image of changed meter to prevent disputes
- Ongoing reading of Smart Meter system
- Ongoing maintenance of inventory in MDR

Figure 2: High Level Work Flow of Installation Process



6.1 Installation Overview (C)

The Smart Meter Installer will be responsible for installing Smart Meters on all single phase, network and self contained meter installations for all residential and General Service under 50 kW locations. The Contractor will not be required to install any transformer rated installations or polyphase meters. The total number of non-transformer rated customer electric meter installations being procured through this RFP can be found in Section 4: *Project Overview*.

NEPA will perform upgrade or repair to electric services found to require this during the Smart meter inspection or installation process. Installer will notify NEPA as rapidly as practical when such requirement poses a hazard to field workers. Bidders will describe notification procedures and method for tracking the status of such sites.

- **All Field Personnel must be well groomed, and in full uniform with the required NEPA member utility photo identification.** Installer will not issue daily assignments to Field Personnel who do not comply with this policy, and the appropriate disciplinary action should follow.
- All Field Personnel will strictly adhere to NEPA inventory control processes, including the proper use of any associated Workforce Management System.
- All Field Personnel will ensure that any required ancillary meter supplies (seals, rings, etc) are acquired prior to beginning the days' work (to ensure travel time is minimized).
- Meter installations are to take place between the hours of 8:30 am to 4:30 pm Monday to Friday, between March 2, 2009 and July 30, 2010. No meter installations are to take place on statutory holidays observed by NEPA.
- NEPA will provide meter seals and other security hardware to be placed on the meter by the Contractor when installing the meter. A-to-S Base meter adapters will be provided by NEPA for A-Base meter change outs.
- As part of providing exemplary customer service, the Bidder is expected to handle customer complaints that are related to installation services and provide customer assistance to resolve issues resulting from installation negligence to the satisfaction of NEPA, ensuring all claims are reported to NEPA. Claims not resolved after 10 days should be reported to NEPA for resolution.

6.1.1 Minimum Competencies (C)

Before installing meters the Installer shall ensure the Field Service Personnel are customer service oriented, have flexible work hours and are bonded, and the Installer shall maintain a process to ensure these requirements are met.

The Installer shall operate within specific procedures and operating conditions in adherence with procedures and training that NEPA will provide. Upon conclusion of the NEPA training, it will be the Installer's responsibility to ensure that new employees receive the same level of training as those employees which receive the training through NEPA.

6.1.2 Suggested Installation Procedure (CI)

The Installer shall follow the following process for the installation of all Smart Meters:

i. The Field Service Representative (FSR), as a minimum, will visit the site as the first attempt to install the Smart Meter.
ii. Prior to installation, FSR will knock on the door prior to removing the meter to advise the customer of the work to be performed and pending power outage.

iii. If the first attempt is not successful due to inability to access the meter, the FSR shall visit the customer site a second time on a different day, at a time of day at least (2) hours different from the first visit, to perform the Smart Meter installation.
iv. If necessary, a third visit attempt shall be made by the FSR.
v. If necessary, the Contractor shall also attempt to reach the customer by telephone, to schedule access to the meter.
vi. If necessary, a second telephone attempt shall be made.
vii. If (3) visits and (2) phone contacts have been exhausted without successful access to the meter, the Installer may declare the account non-installable and refer it to NEPA for resolution.
viii. All customer contact, interaction and communications shall meet NEPA standards.
ix. The customer shall be accommodated with a scheduled appointment with a specific day and time within a 1 hour window arranged and scheduled by the Installer, through their call centre which will be open between the hours of 8:00 am and 7:00 pm.
x. The utility will provide a list of known customers on Medic Alert as per the Control Centre list.
xi. Installer will deliver upon completion of meter change an information “Drop” package for the customer.
xii. Installer will ensure the install site is left “clean” (i.e. under no circumstances is the customer site to be left littered with any installation associated debris)
xiii. Should an incident occur at the property (i.e. Broken meter jaws), the contractor shall remain at the property until the contract electrician or NEPA staff can arrive at the property.

When every meter on a route has either passed the field installation operating test or been declared non-installable by Installer, that route will be declared ready for Route Acceptance.

With regards to the installation procedure above, Bidders are requested to discuss:

a) concurrence with suggested procedure
b) concurrence with suggested definition of non-installable account
c) PPE utilized by Field Service Personnel (i.e. in addition to the equipment required, does the Installer assign any additional equipment such as meter pullers?)

6.1.3 Installer Vehicles (C)

Installer will provide Field Personnel a vehicle to be used for installation services. The requirement for a uniform fleet of vehicles is to minimize the call centre traffic associated with customer inquiries related to the appearance of Field Service Personnel. Field Service Personnel are expected to maintain vehicles in respectable condition (i.e. reasonably clean, presentable and without excessive damage) as well as perform and document a daily vehicle safety check. Vehicles will be properly marked to indicate the company providing services. The meter installation vehicles are to be capable of carrying a minimum of 60 boxed meters (15 boxes). Removed meters are to be placed in the boxes that the new meters were shipped in and returned to the NEPA designated facility.

The Installer shall be responsible for all related parking fines and parking fees through the course of the Agreement.

NEPA member utilities shall provide their corporate logo and “Under Contract” signage, which must be affixed to all vehicles used by the Contractor. The Contractor may display its own corporate logo as approved by NEPA. Preference will be given to vehicles that are otherwise unmarked (ie. Display no other significant signs or marking such as a rental agency logo).

6.2 Pre-Installation Inspection (CI)

The pre-installation inspection shall include knocking on the door of the customer premise to determine if the site is occupied, and to inform occupants of the imminent, brief power interruption. Meter Installers will utilize the appropriate PPE and Equipment (including, but not limited to, arc/flame resistant uniforms (Category 2), meter installer identification, etc.) at all times.

The pre-installation inspection shall discern whether:

- The work site is unsafe to complete the assigned task (unsafe meter base, confined space, etc.)
- There is tampering or energy diversion evident at the meter site
- The existing physical equipment and installation do not conform to applicable codes
- The existing meter base is a Murray Jensen style. (Note: Faulty type of meter base to be identified; not all Murray Jensen meter bases are a problem)
- The existing meter and installation is transformer rated
- An electrical hazard may arise upon installation of the Smart Meter

If ANY of the above (6) conditions exist, the Contractor shall perform no work at the site, but shall notify the Installer Project Manager, who shall notify the NEPA Contract Administrator. It is possible that the pre-installation will fail to detect a hazard, such as tension (frost pull) on the underground secondary service conductor that will move broken meter socket jaws when the meter is removed. The Installer shall comply with NEPA procedures that apply if, at any time during the Smart Meter process, a serious hazard arises.

6.2.1 Tampering (C)

The Installer is responsible for reviewing electric metering facilities for obvious signs of tampering and interference, including jumpers, stopped meters (if not disconnected), un-metered load on the line side of the meter, damage caused by apparent attempts to open the meter, or any other situation where tampering/interference appears to have been involved. If the Installer suspects tampering or diversion, no work (or further work) shall be performed at that site. The Installer shall notify NEPA on a daily basis of all power diversion, tampering or interference-related situations that might impact revenues to NEPA.

Any meters that are scheduled to be replaced and are disconnected using disconnect sleeves or have a Programmable Service Interrupter unit installed will be re-installed by the Installer after the meter change unless the utility directs otherwise. All meters that are disconnected with sleeves, must be installed on the new smart meter with tabs on the bottom lugs only to ensure the meter will continue to act as a communication hop.

6.2.2 Power Diversion (I)

During the process of installing Smart Meters, NEPA wishes to discover meter installations (if any) where there is meter tampering and/or energy diversion. As such, a financial incentive of an agreed to amount per proven occurrence will be paid to the Installer for each verified instance of meter tampering and/or power diversion.

Bidders are requested to provide any information pertaining to this or other incentive programs which are thought to ensure high service levels from Field Service Personnel.

6.3 Scheduling & Coordination (I)

Coordination among the flow of materials, installer labour, customer response/acceptance, and NEPA data updates is a principal determinant of whether the smart meter installation proceeds on-time and within budget. A well-coordinated project can run smoothly and finish on time. No unusual mandatory work rules or wage constraints apply to the work solicited in this RFP.

The Bidder should propose normal work hours to NEPA for its approval. Installers are to be available for work on evenings and weekends and for special-need installations. The Bidder should be prepared to modify the work schedule to best meet installation goals and project milestones set by NEPA.

Bidders are requested to provide information regarding the manner in which work is assigned, including such details as number of outside installs per day assigned, number of indoor installs assigned per day, and the capabilities of the Bidder's WFM system with regards to routing, personnel qualifications to avoid assigning work to the wrong people/trucks, etc. The Installer shall provide a detailed deployment schedule that accomplishes NEPA's meter installation targets. The Installer is responsible to manage the installation schedule to ensure the satisfaction of NEPA. The Installer is responsible to design, propose, and possibly implement a plan to advance the installation services timeframe in the event that the project schedule is delayed in any way.

The Installer is responsible for responding to calls from NEPA regarding the loss of service and other high priority problems associated with installations on an expedited basis. NEPA will do everything within its control to aid the progress of the Installer in meeting the goals of this Agreement. However, minor delays in productivity due to day-to-day operational issues management will occur and are considered typical and normal in the course of regular business. (ie. Software irregularities, computer downtime, wireless communications gaps or emergencies.)

6.4 Project Management (CI)

The Contractor shall designate a Project Manager who shall have the authority to handle and resolve any disputes or contractual issue with NEPA.

The Project Manager is expected to spend sufficient time on the project and the project site to identify any areas that are not fully meeting the stated requirements, and manage corrective actions to bring the results within said requirements.

The Project Manager's role will be to coordinate activities among the Contractor, the Smart Meter provider and the various functional parts of NEPA. Problem resolution will be high on the Manager's agenda. The Project Manager will maintain clearly defined levels of installation problem categories and associated escalation levels to facilitate quick recognition and resolution of problems. The Project Manager will involve NEPA on appropriate issues in a timely manner.

Section 3.2 *Safety* and Section 6.1.1 *Minimum Competencies* requires that the meter installer's meet certain qualifications, and that the installation service provider provide NEPA with certain documentation. The Project Manager will facilitate satisfaction of these requirements,

Bidders should provide suggested procedures for Problem Resolution / Problem Escalation.

6.4.1 Quality Assurance (I)

The Installer's policies/procedures shall include an integrated quality control / quality assurance program:

Bidders will describe the proposed approach to staffing the field deployment, including:

a. Positions to be filled by permanent employees of Bidder
b. Positions to be filled by temporary employees or contractors
c. Qualifications of employees or contractors
d. Training of employees or contractors
e. Strategy for monitoring the work quality of employees or contractors and correcting any encountered deficiencies

NEPA understands that there may be several AMI deployments occurring concurrently across Ontario to accommodate the Provincial mandate, and requires the Bidders written acknowledgement that the appropriate staff will be dedicated to the requirements of NEPA deployment.

6.4.2 Installation Field Audit (CI)

The Installer's Project Manager / Supervisor will conduct random audits of staff in the field to check for safety compliance as well as for the quality of work completed by the meter installers. The Contractor's Project Manager / Supervisor will, on a weekly basis, randomly check a minimum of 2% of sites for quality control. All results are to be reported to NEPA on a weekly basis. Items to be audited include at minimum:

- Proper line and load wiring associations on bottom connected installations
- Identification of hot metering installations when a main switch exists at a service entrance and is supposed to provide isolation to the meter and it is actually on the load side of the meter
- Validation of crossed units, on multi-unit dwellings
- Work order data validation and transfer to NEPA systems

6.4.3 Service Quality Standard (C)

All work shall be completed according to the agreed schedule using milestones. Checkpoints and corrective action on slipped timelines shall be assessed on an interval of duration no longer than (2) weeks.

In keeping with the stringent safety requirements of NEPA, as communicated herein, Bidders will strive for no less than zero preventable safety incidents and accidents.

Failure to report any safety incident or accident to NEPA will put the Contractor in breach of the Agreement and may disqualify them from competing for future service contracts and may result in the termination of the present Agreement without a notification period.

6.5 Workforce Management (WFM) System

The Workforce Management (WFM) system plays an integral role in the success of the project acting as the main system responsible for work order completion, project reporting and task management, and ensuring safety for meter installations. Due to the critical nature of the WFM, it is imperative that the 3rd party installation service provider be comfortable with the functionality of the WFM system. For this reason, NEPA will require that the Bidder provide their own WFM as part of their service package.

It is a fundamental requirement that this system is in place with functional interfaces to the NEPA CIS systems prior to the start of deployment. NEPA is interested in the functionality provided as part of the WFM system; information will be requested as part of Section 6.5 *Workforce Management (WFM) System* and associated subsections. A compliancy statement is required which will have Bidder's acknowledge proficiency with an electronic WFM system, and a commitment to ensuring integration with NEPA's back office systems prior to project commencement (as per Section 2.1 *Key Dates*).

NEPA will provide to the vendor, in electronic format, information concerning the locations that will require meter changes / installations (i.e. customer name and contact information, service location address and location number along with an expected completion date). By way of electronic WFM the Installer will add to this record, the final meter read from the mechanical meter at the time of removal. The Installer will also take a photograph of the old meter, showing its dials prior to removal. This photo will be date and time stamped and the file name recorded in the data record associated with the specific installation.

As there are multiple CIS Systems in use within the NEPA member service territories, Bidders should provide their output format requirements to ensure that the CIS Systems can accommodate this format.

6.5.1 WFM System Overview (I)

Within the Pricing and Compliancy spreadsheet, NEPA has provided a tab labelled WFM_Functionality, within which Bidders are requested to submit information pertaining to their WFM system, specific to the different devices that may be utilized with the system.

Below we have provided an example of a completed the NEPA WFM system functionality matrix. Bidders are requested to complete this spreadsheet for all devices that are compatible with the WFM software platform. In addition to acquiring the information regarding a variety of functionality, NEPA looks to understand any potential functionality differences between devices being offered as part of a solution. If multiple devices are possible, NEPA members may opt to purchase more than one type of device. In this case it would be important to understand if any functionality is lost in moving from one device to another.

Completion of the chart may satisfy some of the following sections. However the following sections provide Bidders with the opportunity to supply additional supporting information which may differentiate their product.

Workforce Management (WFM) Functionality

WFM Functionality	WFM Bidder: Sample (S/O)	Add-On Cost
Devices		
Handheld	S	
Tablet	O	$1200/tablet
Signature tool	O	Standard with tablet
Touch Screen	O	Standard with tablet
Printing Capabilities	O	$600/print device
Connectivity		
Real Time	O	cost to interface
Batch upload (offline storage)	S	
Carriers		
Bell	S	
Rogers	S	
Telus	S	
Multiple Network Roaming	O	$300/comm card
Utility RF	NA	
Other	NA	
Existing Utility Interfaces		
T&W	S	
SAP	S	
SPL	O	cost to interface
Other	S	
Forms		
Template only	S	
Customized	S	
Other	NA	
Reporting		
Fat Client	No	
Thin Client	Yes	
Canned	S	
Customized	S	
Safety	S	
Inventory	S	
Completed vs. Schedule	S	
Route Summary	S	
Problem Installs	S	
Other	S	programming fees
Operational Tools*		
Bar Code Scanner	S	
GPS Recording	S	
Camera	NA	
GPS Tracking of Workers	NA	
Scheduling		
Automated dispatch	S	
Dispatching based on qualifications & Equipment	S	
Map based dispatching	O	
Street level routing	O	
Other	NA	

Bidders are required to complete chart for their WFM product. If more than one product is offered, copy the columns as required.

Bidders are required to specify an S or an O to represent standard functionality vs. optional functionality. If the optional functionality is available only at an incremental cost, this must be specified.

NA may be used to represent Not Available.

*For Operational Tools, please indicate in the associated documentation whether this functionality is integrated with the WFM device, or whether they are separate tools.

6.5.2 Dispatching (CI)

In support of the priority which NEPA places on safety, NEPA is interested in the ability to assign worker qualifications to their field staff to assist in the dispatching of orders to only the personnel with the qualifications required to complete the work. This may be achieved through assigning qualifications to staff, or toolsets to trucks, or any other of a variety of methods. Details should be provided regarding all the safety features inherent to the WFM system.

Bidders are asked to provide detailed information regarding the dispatching of work orders. The manner in which work orders are sorted/listed (i.e. by customer, location, schedule, etc) is critical in realizing efficiencies with the assignment of field services.

If GPS capabilities are inherent to the system, and are integrated into the dispatch process, Bidders are asked to provide explanation, and screen shots of the views that are possible for the dispatcher. In addition to the mapping of orders, NEPA is interested in accessing the real time location of their workers to assist in the completion of on demand requests (i.e. service disconnect / reconnect, outage restoration, etc). Details regarding this functionality are requested.

In addition to the manner in which the dispatcher accesses information, Bidders are asked to explain the ease with which the field service worker (and any associated options) can sort work. If GPS capabilities exist, and are integrated with the sorting of work while in the field, screen shots of the views possible for the field service worker are requested.

6.5.3 Data Management & Integrity (I)

The Installer shall record and retain the meter identification information and the register read of the removed meter, the meter identification information and the register read of the installed Smart Meter using a handheld WFM system equipped with a barcode reader.

The Installer shall maintain an effective process to assure the quality of the electronic data records and transactions. All field data shall be pre-filled on orders. The Installer shall place emphasis on quality data management from the beginning of the training, and will remain responsible for correcting errors in data collected during the installation process.

Data quality (including Meter Reads) shall be accurate 99.9% of the time over the course of the project. The Installer shall collect data from specified collection locations and transfer data in a specified electronic file format for use by NEPA in accordance with a schedule that will be provided by the utility.

6.5.4 WFM Handheld Device (I)

NEPA would like to understand the device being utilized by the contractor. Information should include format of device (tablet, PDA, laptop, phone, etc.), how many orders per day the handheld device can manage (i.e. how many can be downloaded), and what the expected daily battery life is of the device.

6.5.5 Installation Hours (i.e. WFM Charging) (CI)

NEPA's policy for installation hours are that installations should be occurring between the hours of 8:30 am and 4:30 pm. NEPA prefers that there are no evening installs. Saturday installs are acceptable with proper planning (minimum 1 week notice) and staffing of the call center. This should be a last resort / catch up for installation backlog, so as not to inconvenience customers. Installer would be required to provide a minimum number of installers in this instance to ensure that it is a productive day (i.e. NEPA will have to pay overtime to warehouse staff).

6.5.6 Digital Imaging (CI)

The handheld Workforce Management Equipment must be able to take a picture with a resolution no less than 3 Mp of the removed meter. The Installer will take a photograph of the old meter, showing its dials. This photo will be date and time stamped and the file name recorded in the data record associated with the specific installation.

Digital imaging is performed to mitigate the risk associated with Dispute Resolution. If the WFM system allows for read validation which might be used in conjunction with the Digital Imaging process, Bidder should provide details.

6.5.7 GPS (CI)

In addition to installing the meter, capturing the LAN ID and Meter ID data from the barcode on the installed meter, and the start read, NEPA desires to update service location information by having the Bidder capture the GPS co-ordinates of the installed endpoint. Where meters are located in basements or in areas where satellite signal may not be possible, the closest co-ordinates will be collected once communication has been established.

6.5.8 Inventory Control (CI)

Given the volume of daily meter installations that will be performed, maintaining accurate control of inventory will be critical. All sealed meter deliveries will be sent to the NEPA location and loaded into inventory via an import into CIS.

Daily workflows will need to be established that have an assigned point of contact for the installation vendor to verify and sign-out the meters required each day for installation in the field. At the end of each day or at the start of the next shift, the same point of contact will verify the meters that were not installed are recorded in inventory ensuring adequate controls are in place to manage the assets.

Managing the inventory of essential hardware is an important step in keeping the installation process moving while controlling costs.

i. The Workforce Management system will be capable of utilizing bar code scanning for recording newly deployed meters.
ii. Bidders will describe methods used to track inventory of all essential ancillary supplies needed to support the deployment including any associated smart meter devices and installation tools, meter seals, meter rings, meter adaptors, security devices, etc. Vendors should provide details on how their company will ensure that accurate data is provided back to NEPA and their back office systems.

6.6 Reporting Requirements (CI)

The NEPA Project Manager will hold weekly meetings together with the Installer's Project Manager to review status, identify problems, and plan resolution. The Installer shall provide reporting (as per following subsections) to support these meetings. Where possible, reports should be generated from the WFM system, made possible by the daily data transfers identifying sites visited and completed.

Following is a sample of items that might be included in these reports:

i. Safety Issues;
ii. Bidders will describe installation problem categories and escalation levels, identifying the point at which the NEPA Project Manager will become involved;

iii. Inventory status;
iv. Installers will provide daily data transfers identifying sites visited and completed and providing work order data;
v. Bidders should supply automated reports regarding success/failure of daily installation targets;
vi. The Installer shall report progress, including numbers and percentages of meters installed, attempts to complete the installation process, appointments scheduled and completed and other pertinent installation data to NEPA on a weekly basis (if project plan timeline has been affected, Bidders will provide their plan which will put them back on schedule according to the originally submitted schedule);
vii. It is expected that the successful Bidder will invoice based on the data in the WFM system.

Bidders should provide detailed information regarding the reporting functions that are possible through their WFM or other systems.

The Installer will provide all required equipment, along with the trained staff. The Installer shall be required to report all relevant data from the field to the NEPA Installation Coordinator. This includes, but is not limited to meter exchanges that cannot be completed because of access, physical space limitations, or safety reasons.

6.6.1 Reporting: Beginning of the Project (C)

In addition to any other data and reporting requirements outlined, the following report / information will be required at project commencement:

The Bidder will provide NEPA with a Project Plan that indicates the number of meter installers per week for the duration of the project as well as the meters to be installed per week. The Plan shall include contingency plans in the event the installation numbers fall behind the milestone schedule.

6.6.2 Reporting: Daily Reports (C)

In addition to any other data and reporting requirements outlined, the following reports and information will be required on a daily basis through the duration of the project:

The Bidder will identify, report and resolve unsafe conditions on a daily basis or as they are identified according to established safety policies, and report all tampering / interference related situations that might impact revenues, to NEPA on a daily basis.

6.6.3 Reporting: Weekly Reports (C)

In addition to any other data and reporting requirements outlined, the following reports and information will be required at weekly interval through the duration of the project:

The Bidder will provide NEPA with Project Plan Update which includes number of meters installed to date, and number of meters remaining to be installed. If behind schedule, Action Plans will be identified that are being used to bring the installation schedule back on track.

In addition, the Bidder shall provide details related to any identified unsafe conditions, safety issues, customer diversions, tampering.

6.6.4 Reporting: Bi-Weekly Reports (C)

In addition to any other data and reporting requirements outlined, the following reports and information will be required at bi-weekly intervals through the duration of the project:

The Bidder will provide NEPA with an invoice indicating: The number of meters installed, the number of identified and NEPA validated power diversions, the number of identified and NEPA validated unsafe meter installation sites, the month end invoice shall indicate the number of meters that didn't comply with the month-end target milestone installations.

6.7 Service Level Agreements (I)

Bidders should provide their standard Service Level Agreements, citing such measurable performance indicators as:

i. Outside Urban installation per week
ii. Inside Urban installation per week
iii. Installation Error rate
iv. Customer Claim rate

6.8 Installation Warranties (I)

The Bidder must state term on guarantee of workmanship for all installation work performed under this contract.

6.9 Meter Disposal (I)

NEPA will be utilizing a Meter Disposal Vendor to properly, and in an environmentally sound manner, discard of the redundant meters. Should the Bidder desire to provide a Meter Disposal Labour rate, a line item has been added to Pricing Option 1 for this purpose. The Labour that would be required for this service would potentially be for the separation of glass covers from meters, and organization of meter packing supplies (cardboard, Styrofoam packing etc) into the appropriate bins that would be provided by the Meter Disposal Vendor. NEPA would provide the work space for this service to be performed.

Section 7: Customer Communications

7.1 Call Centre Services (I)

Installer will be responsible for customer communications associated with gaining access to the customer's meter. NEPA recognizes that some accounts, despite extensive effort by Installer, may be non-installable for any of many reasons. NEPA accepts responsibility for installing smart meters at these non-installable accounts. Bidders will describe the customer communications plan, including;

i. Call Centre Services Overview (including hours of operation, and policies/procedures)
ii. Customer contact methods/strategies
iii. Appointment management (management of multiple sequential (unsuccessful until the last) customer contacts)
iv. Steps in achieving successful completion of Smart Meter installation
v. Definition of an non-installable account
vi. Customer claims administration
vii. Record keeping and coordination with NEPA Customer Service (NEPA member utilities are interested in understanding the tracking of Service Quality Indicators (SQIs) which may include (but not limited to) such indicators as inbound/outbound calls, appointments attempted/made, complaints, call waiting period, etc.)

Call operations shall be maintained from 8:00 a.m. to 7:00 p.m., Monday to Friday, and shall have a provision for taking calls using an automated method outside of the regular operating hours. NEPA recognizes that their agents may take calls, other than those for the purpose of appointments, once a phone number is provided to the customer. NEPA wishes the Contractor to transact only those calls related to the appointments to be fielded by their staff, and the operator for disposition shall direct all others to NEPA.

The Contractor shall provide in detail:

- The scripting for communicating with customers by phone
- A means of managing the collected customer information and appointments (i.e. managing ongoing coordination and customer communications related to the appointment and meter exchange by the Contractor)
- The fee structure for managing customer communications for the purpose of collecting appointment data

7.1.1 Communications Materials (I)

NEPA requires that communications materials provided to the customer by their meter installers when the meter is inaccessible contain the phone number of the Contractor for future follow-up. The Contractor shall manage inbound phone communication to secure appointments for Smart Meter installations using a professional and courteous protocol that shall be approved by NEPA.

7.1.2 Customer Contact (I)

Each meter installer shall be responsible for customer communications associated with gaining access to customer meter. Meter installers will be provided with communications materials to be distributed to customers as part of the meter installation process.

Prior to beginning the meter exchange, each meter installer shall attempt to notify each customer by knocking on the front door and/or ringing the doorbell and waiting a minimum of (1) minute for a response. If the customer does respond, the Installer shall inform the customer of the meter exchange and short power interruption according to the standardized script. If the customer does not respond, the Installer shall proceed with the installation of the Smart Meter.

7.1.3 Customer Information (CI)

Each meter installer shall provide each customer with communication materials as provided by NEPA, either in person, in the mailbox or through the mail slot. These materials are not to be left where they are readily visible to passers-by or may blow away or damaged (i.e. rain damage)

7.1.4 Customer Complaints and Claims Administration (CI)

The Installer shall have a procedure to process and manage customer claims, arising from the provision of the Services pursuant to this Agreement, which will successfully resolve issues in a timely manner. All claims shall be reported to NEPA once the Installer has been made aware of the incidence. Claims outstanding for (10) days or greater are to be reported to NEPA for resolution. The Installer shall have full accountability for customer claims and complaints, especially for the response to initial reports of half or full power outage following a Smart Meter change. This accountability applies regardless of the time of call and may fall outside business and work hours. NEPA crews and resources are prepared to aid the Installer in a resolution based on the initial findings of Field Staff if the call ends up being systemic rather than an oversight on the part of the Contractor. Additional compensation shall not be provided by NEPA to meet the Installer's obligations for after-hour response and site visits that are required to mitigate customer complaints.

7.2 Pre-Canvassing Service (I)

Pre-Installation Customer Information Packages are to be delivered to customers approximately 2 weeks before the scheduled meter replacement date. Customer Contact and Information Packages would be provided by NEPA.

As an option, Bidders that are able to provide input based on experience regarding suggested processes for Customer Communications that may take place prior to deployment are requested to do so. If possible, the Bidder should provide any marketing material that they may have used in the past that was found to be effective.

Section 8: Contract Terms and Conditions

8.1 General

This Agreement covers the general conditions under which the work shall be performed.

Bidder shall be aware and acknowledges that the work to be performed may be on or within close proximity to electrical apparatus that may be energized at normal potential and with normal current carrying capacity during the course of the work. This may involve the equipment or facilities being worked on directly, or equipment or facilities adjacent to the actual devices and location being worked on.

Bidder will under no circumstances replace anything except single phase meters.

8.2 Information to Contractors

Bidder represents that it has carefully examined the specifications and requirements of the municipality(s) having jurisdiction in the work location(s) and any other authorities having jurisdiction, and has thoroughly familiarized themselves with all permit, inspection and other requirements of all of these agencies and authorities.

Bidder will not rely solely upon any information or representations made or furnished by NEPA respecting the nature of the site conditions, the work to be performed or the quality of any materials to be used.

8.3 Approvals

Bidder shall work closely with the authorities having jurisdiction. Bidder shall satisfy all authorities on specific concerns on work permits. No permit costs have been included in this Agreement. Should the need for any permits arise, Bidder will invoice NEPA for the costs thereof.

8.4 Sub-Contractors

Bidder shall set out herein, all Sub-Contractors to be employed in the performance of the Agreement. No other Sub-Contractor shall be employed without the approval of NEPA.

8.5 Officials in Charge, Personnel, Employment Conditions

Bidder shall identify in Schedule “A”, prior to commencing work, a work site manager (the person on the job) who will be in charge of the work and all work sites, as well as an office official (officer, principle, or senior manager) at his central place of business who will be responsible for the work.

NEPA’s key contacts are also identified in Schedule “A”.

Bidder shall take every step to minimize a change of site manager during the course of the work, but when necessary, Bidder will make such change with an individual of similar or greater capability.

Bidder will provide conditions of employment in accordance with the Occupational Health and Safety Act, and the Employment Standards Act and their latest revisions, and any other statutory requirements in force and effect.

Bidder hereby agrees that no person shall be employed who is unfit to do the work or anyone unskilled to do the work assigned to him. Persons under the influence of intoxicating drugs or beverages shall be declared unfit.

Bidder agrees that for the purpose of the work to be undertaken, they will not discriminate in the hiring and implementation of labour against any person's gender, race, national origin, colour or religion.

8.6 Work Protection

Work protection from electrical hazards, where required, shall be applied for prior to beginning work and shall be consistent with the Electric & Utilities Safety Association's Protection Code, and upon review and acceptance by Bidder, NEPA requirements. Protections shall be surrendered at the end of each working day. In general, daily requests shall be available during NEPA normal working hours only.

Signalling and traffic protection shall be done according to the Occupational Health and Safety Act, the Highway Traffic Act, and NEPA requirements.

Only competent personnel shall work within the ten feet limit of approach for apparatus energized over 750 volts. NEPA Manager of Engineering and Maintenance shall have the sole discretion to determine such competence, but Bidder will assume full liability in respect of any such personnel, even if approved of by NEPA. Equipment, tools, and protective clothing shall be in accordance with the Electric Utilities Safety Act, the Occupational Health and Safety Act, and other authorities having jurisdiction.

8.7 Site Housekeeping

During the performance of the work, Bidder shall ensure that the work site is kept as neat and orderly as possible, in keeping with the nature of the work in progress. When work is interrupted for any length of time, or at the completion of the work, all waste material shall be removed and tools, equipment and surplus material shall be removed or stored or secured in a neat and safe fashion.

8.8 Term

The Agreement will terminate as per the agreed to date in the contract. The Agreement may be extended on terms mutually agreeable to the parties.

8.9 Training and Safety

Before beginning installation of smart meters, all Bidder installers must receive the following training:

- EUSA Training for residential smart meter changes. Proof of training must be provided and approved by NEPA.
- NEPA Health and Safety orientation
- Work procedures and workforce management orientation

Bidder shall comply with all NEPA safety rules, when Bidder has reviewed and accepted such rules.

8.10 Schedule

Bidder shall submit, at such times as may reasonably be requested by NEPA, schedules which shall show the order in which it is proposed to do the work, with dates showing commencement and completion of the various parts of the work.

8.11 Public Relations

Bidder shall respect private property and do whatever necessary to prevent damage to landscaping, buildings, fences and other appurtenances on private property and where damage results will make restoration to the pre-damaged state. Public lands on rights of way shall be restored to the satisfaction of the authority having jurisdiction.

8.12 Identification

Bidder vehicles must be properly identified with the company name. Bidder employees must carry proper identification at all times.

8.13 Materials and Labour

Unless otherwise stipulated, the lump sum price or prices quoted in this Agreement shall include the furnishing of all of the Bidder designated supplied materials, supplies and equipment and the providing of all labour, construction tools and equipment, utility and transportation services necessary to perform and complete all the work required under this Agreement.

All designated material, major or minor, supplied by Bidder must be approved by NEPA prior to its installation. Any material supplied by Bidder and installed without NEPA approval will be replaced at Bidder's expense. Co-ordination of the delivery of materials shall be by Bidder. No claims will be considered due to late deliveries.

8.14 Working Hours

Unless otherwise stated, all labour and services under this Agreement will be performed during the hours of 8:30 am - 4:30 pm local time Monday through Friday, excluding statutory holidays (except for telephone call answer services). If for any reason NEPA requests Bidder to furnish any such labour or services outside of the hours of 8:30 am - 4:30 pm local time Monday through Friday, or on statutory holidays, any overtime or other additional expense occasioned thereby, such as repairs or material costs not included in this Agreement, will be billed to and paid by NEPA.

8.15 Taxes

NEPA agrees to pay the amount of any new or increased Canadian taxes or governmental charges upon labour or the production, shipment, sale, installation, or use of equipment or software which become effective after the date of this Agreement. If NEPA claims any such taxes do not apply to transactions covered by this Agreement, NEPA will provide Bidder with a tax exemption certificate acceptable to the applicable taxing authorities. NEPA to the extent required by applicable law may retain and remit any withholding taxes on behalf of Bidder and provide evidence of that to Bidder. NEPA shall not be required to make any "gross up" payment to Bidder to compensate Bidder for such withholding.

8.16 Insurance Obligations

Bidder shall, at its own expense, carry and maintain in force at all times from the effective date of the Contract through final completion of the work the following insurance. It is agreed, however, that Bidder has the right to insure or self-insure any of the insurance coverage's listed below:

(a) Commercial General Liability Insurance to include contractual liability, products/completed operations liability with a combined single limit of CDN $5,000,000 per occurrence. Such policy will be written on an occurrence form basis.

(b) If automobiles are used in the execution of the Contract, Automobile Liability Insurance with a minimum combined single limit of CDN $5,000,000 per occurrence. Coverage will include all owned, leased, non-owned and hired vehicles.
(c) Where applicable, "All Risk" Property Insurance, including Builder's Risk insurance, for physic damage to property which is assumed in the Contract.
(d) Workers Safety Insurance Board (WSIB) clearance certificates are to be provided to NEPA.

Prior to the commencement of the Contract, Bidder will furnish evidence of said insurance coverage in the form of a Memorandum of Insurance, and warrants that such coverage will be maintained for the duration of the Agreement, and that proof of maintenance will be routinely supplied.

Bidder will not issue coverage on a per project basis.

8.17 Hazardous Substances, Mould and Unsafe Working Conditions

8.17.1

NEPA has not observed or received notice from any source (formal or informal) of (a) Hazardous Substances or Mould, either airborne or on or within the walls, floors, ceilings, heating, ventilation and air conditioning systems, plumbing systems, structure, and other components of the Site, or within furniture, fixtures, equipment, containers or pipelines in a Site; or (b) conditions that, to NEPA's knowledge, might cause or promote accumulation, concentration, growth or dispersion of Hazardous Substances or Mould on or within such locations.

8.17.2

If any such materials, situations or conditions, whether disclosed or not, are in fact discovered by Bidder or others and provide an unsafe condition for the performance of the work or Services, the discovery of the condition will constitute a cause beyond Bidder's reasonable control and Bidder will have the right to cease the work or Services until the area has been made safe by NEPA or NEPA's representative, at NEPA's expense. Bidder will have the right to terminate this Agreement if NEPA has not fully remediated the unsafe condition within sixty (60) days of discovery.

8.17.3

NEPA represents that NEPA has not retained Bidder to discover, inspect, investigate, identify, prevent or remediate Hazardous Substances or Mould or conditions caused by Hazardous Substances or Mould.

8.18 Warranty and Limitation of Liability

8.18.1

Bidder will have all work performed by appropriately trained and experienced personnel in a workmanlike manner consistent with industry standards and applicable law. Bidder will replace or repair any work Bidder provides under this Agreement that fails within the warranty period (one) 1 year because of defective workmanship or Bidder supplied materials, except to the extent the failure results from NEPA negligence, or from fire, lightning, water damage, or any other cause beyond the control of Bidder. This warranty applies to all work Bidder provides under this Agreement, whether or not manufactured by Bidder. The warranty is effective as of the date of installation.

8.18.2

The warranties set forth herein are exclusive, and Bidder expressly disclaims and NEPA expressly waives all other warranties, whether written or oral, implied or statutory, including but not limited to, any warranty of workmanship, construction, merchantability or fitness for a particular purpose, with respect to the services, equipment, and materials provided hereunder. Bidder will not be liable for any property damage, personal injury, loss of income, emotional distress, death, loss of use, loss of value, adverse health effect or any special, incidental, indirect, speculative, remote, consequential, punitive, or exemplary damages, arising from, or relating to, this limited warranty or its breach.

8.18.3

Bidder makes no representation or warranty, express, implied or otherwise, regarding Hazardous Substances or Mould. Bidder will have no duty, obligation or liability, all of which NEPA expressly waives, for any damage or claim, whether known or unknown, including but not limited to property damage, personal injury, loss of income, emotional distress, death, loss of use, loss of value, adverse health effect or any special, consequential, punitive, exemplary or other damages, regardless of whether such damages may be caused by or otherwise associated with defects in the Services, in whole or in part due to or arising from any investigation, testing, analysis, monitoring, cleaning, removal, disposal, abatement, remediation, decontamination, repair, replacement, relocation, loss of use of building, or equipment and systems, or personal injury, death or disease in any way associated with Hazardous Substances or Mould.

8.19 Indemnity

Bidder agrees to indemnify and hold NEPA and its agents and employees harmless from all claims for bodily injury and property damages to the extent such claims result from or arise under Bidder's negligent actions or willful misconduct in its performance of the work required under this Agreement, provided that such indemnity obligation is valid only to the extent (i) NEPA gives Bidder prompt notice in writing of any such claims and permits Bidder, through counsel of its choice and Bidder's sole cost and expense, to answer the claims and defend any related suit and (ii) NEPA gives Bidder the authority and reasonable assistance and access to all applicable information in its possession, at Bidder's expense, to enable Bidder to defend such suit. Bidder will not be responsible for any settlement without its written consent, which consent shall not be unreasonably withheld or delayed. Bidder will not be liable for loss or damage caused by the negligence of NEPA or any other party or such party's employees or agents. This obligation will survive termination of this Agreement. Notwithstanding the foregoing, NEPA agrees that Bidder will not be responsible for any damages caused by Mould or any other fungus or biological material or agent, including but not limited to property damage, personal injury, loss of income, emotional distress, death, loss of use, loss of value, adverse health effect or any special, consequential, punitive, exemplary or other damages, regardless of whether such damages may be caused by or otherwise associated with defects in the Services.

8.20 Limitation of Liability

8.20.1

Subject to: (1) Bidder's obligations under the above indemnity (s. 8.19), (ii) a breach of its confidentiality or privacy obligations, (iii) breach of applicable law; or (iv) intentional or willful misconduct, in no event will Bidder be liable for any special, incidental, indirect, speculative, remote, consequential, punitive or exemplary damages, whether arising out of or as a result of breach of contract, warranty, tort (including negligence), strict liability, mould, moisture, indoor air quality, or otherwise, arising from, relating to, or connected with the services, equipment, materials, or any goods provided hereunder.

8.20.2

Notwithstanding anything to the contrary herein, Bidder's total liability arising out of or as a result of its performance under this agreement will not exceed the amount of this agreement.

8.21 Excusable Delays

Bidder will not be liable for damages caused by delay or interruption in Services due to fire, flood, corrosive substances in the air, strike, lockout, dispute with workmen, inability to obtain material or services, commotion, war, acts of God, the presence of Hazardous Substances or Mould, or any other cause beyond Bidder's reasonable control (the "Force Majeure Event") provided that Bidder: (i) promptly notifies the other Party immediately and in detail of the commencement and nature of such a cause; (ii) promptly develops a workaround strategy if one is reasonably available; and (iii) uses all commercially reasonable efforts to render performance in a timely manner utilizing to such end all resources reasonably required in the circumstances, including obtaining supplies or services from other sources if same are reasonably available and to otherwise resume service to the applicable standard. A failure by a sub-contractor or other agent to perform shall only be considered a Force Majeure Event if the failure by that sub-contractor or agent to perform is due to a Force Majeure Event suffered by that sub-contractor or agent and such sub-contractor or agent is taking the same actions as are required by Bidder under this Section in respect of a Force Majeure Event. The benefit of this section shall not apply to the performance or an obligation which is thirty (30) or more days in default. In the event of any such delay, date of shipment or performance will be extended by a period equal to the time lost by reason of such delay.

8.22 Dispute Resolution

With the exception of any controversy or claim arising out of or related to the installation, monitoring, and/or maintenance of fire and/or security systems, the Parties agree that any controversy or claim between Bidder and NEPA arising out of or relating to this Agreement, or the breach thereof, will be settled by arbitration, conducted in accordance with the Arbitration Rules of the Canadian Commercial Arbitration Center. Any award rendered by the arbitrator will be final, and judgment may be entered upon it in accordance with applicable law in any court having jurisdiction thereof. Either party can terminate for cause without the obligation to engage in dispute resolution, mediation or arbitration.

8.23 Acceptance of Contract

This proposal and the pages attached will become an Agreement upon signature above by Bidder and NEPA. The terms and conditions are expressly limited to the provisions hereof, including Bidder's General Terms and Conditions attached hereto, notwithstanding receipt of, or acknowledgment by, Bidder of any purchase order, specification, or other document issued by NEPA. Any additional or different terms set forth or referenced in NEPA's purchase order are hereby objected to by Bidder and will be deemed a material alteration of these terms and will not be a part of any resulting order.

8.24 Miscellaneous

8.24.1

This Agreement represents the entire Agreement between NEPA members and Bidder for the work described herein and supersedes all prior negotiations, representations or Agreements between the Parties related to the work described herein.

8.24.2

None of the provisions of this Agreement will be modified, altered, changed or voided by any subsequent Purchase Order or other document unilaterally issued by NEPA that relates to the subject matter of this Agreement. This Agreement may be amended only by written instrument signed by both Parties.

8.24.3

This Agreement will be governed by the law of the province where the work is to be performed.

8.24.4

Any provision or part of this Agreement held to be void or unenforceable under any laws or regulations will be deemed stricken, and all remaining provisions will continue to be valid and binding upon Bidder and NEPA, who agree that this Agreement will be reformed to replace such stricken provision or part thereof with a valid and enforceable provision that comes as close as possible to expressing the intention of the stricken provision.

8.24.5

NEPA may not assign its rights or delegate its obligations under this Agreement, in whole or in part, without the prior written consent of Bidder. Bidder may assign its right to receive payment to a third party.

8.24.6

Bidder will provide services in accordance with the attached work scope documents and the terms and conditions herein, which form a part of this Agreement.

8.24.7

The parties are independent contractors and no other relationship is intended. Nothing herein shall be deemed to constitute either party as an agent, representative or employee of the other party, or both parties as joint venturers or parties for any purpose to create a fiduciary relationship between the parties. Neither party shall act in a manner that expresses or implies a relationship other than that of an independent contractor. Each party shall act solely as an independent contractor and shall not be responsible to third parties for the acts or omissions of the other party. Neither party will have the authority or right to represent or obligate the other party in any way except as expressly authorized by this agreement.

8.24.8

If Bidder is delayed in its performance of the work due to the delayed performance or non-performance of NEPA or its suppliers, NEPA shall notify Bidder one (1) week in advance. In the event Bidder is notified (1) one week in advance, Bidder shall relieve NEPA of all costs except for the following: In the event Bidder incurs any costs in retaining staff or recruiting and staffing a new position as a result of the delay then NEPA will reimburse Bidder at its actual documented costs incurred plus 10%. Bidder shall invoice NEPA no more than weekly for such reimbursement and NEPA shall pay such invoices within the terms of this Agreement. All such invoices will itemize the costs incurred and proof will be provided to the extent possible.

8.25 Terms of Payment

Subject to Bidder's approval of each NEPA member utility's credit, payment terms are as follows:

Progress Payments: Bidder will invoice monthly for all materials delivered to the job site or to an off-site storage facility and for all installation, labour, and services performed, both on and off the job site. NEPA agrees to pay the full amounts invoiced, less holdback, upon receipt of the invoice at the address specified by NEPA. Invoices not paid within thirty (30) days of the invoice date are past due and accrue interest from the invoice date to the date of payment at the rate of one percent (1%) per month, compounded monthly.

Holdback: NEPA will not withhold, as holdback, a greater percentage than is withheld from NEPA under a prime contract, if applicable. NEPA will pay all holdback to Bidder within 30 days after Bidder's work is substantially complete.

Suspension of work: If Bidder, having performed work per Agreement requirements, does not receive payment within thirty (30) days after submission of a Bidder invoice, Bidder may suspend work until NEPA provides remedy unless NEPA provides evidence disputing such amount is owing.

8.26 Work by Others

8.26.1

Unless otherwise indicated, the following items are to be furnished and installed by others: electric wiring and accessories, all in-line devices (including but not limited to flow tubes, hand valves, orifice plates, orifice flanges, etc.), pipe and pipe penetrations including flanges for mounting pressure and level transmitters, temperature sensors, vacuum breakers, gauge glasses, water columns, equipment foundations, riggings, steam tracings, and all other items and work of like nature. Automatic valve bodies and dampers furnished by Bidder are to be installed by others.

8.26.2

Services Bidder will provide under this Agreement specifically exclude professional services which constitute the practice of architecture or engineering unless specifically set forth by NEPA. NEPA or Owner will specify all performance and design criteria that Bidder will follow in performing work under this Agreement. If professional design services or certifications by a design professional related to systems, materials, or equipment is required, such services and certifications are the responsibility of others.

8.27 Delivery

Delivery of equipment not agreed on the face hereof to be installed by or with the assistance of Bidder will be F.O.B. at Bidder's factory, warehouse, or office selected by Bidder. Delivery of equipment agreed on the face hereof to be installed by or with the assistance of Bidder will be C.I.F. at site of installation.

8.28 Damage or Loss

Bidder will not be liable for damage to or loss of equipment and software after installation.

8.29 Termination

A party may terminate this Agreement for cause if the other party defaults in the performance of any material term of this Agreement, or fails or neglects to carry forward the work (in the case of Bidder) in accordance with this Agreement, after giving the other party written notice of its intent to terminate. If the defaulting party has not, within seven (7) business days after receipt of such notice, remedied such deficiencies, the other party may terminate this Agreement.

8.30 Changes in the Work

NEPA, without invalidating the Agreement, may direct the Contractor to perform extra work or make changes in the work, provided that all changes or additions form an inseparable part of the contracted work. The contractor shall make such changes or additions only after receipt of written instructions to do so from NEPA. If such changes or additions cause an increase or decrease in the cost of the Agreement, or in the time required to complete the Agreement, an equitable adjustment shall be made and the Agreement shall be modified accordingly by a Change Order in writing.

When a change is ordered, NEPA and the Contractor shall execute a change order before any change order work is performed. Any increase or decrease in the contract price and the time required for the completion of the contract work due to a change order shall be specifically set out in the change order. All terms and conditions contained in the Agreement shall be applicable to change order work. The amount of any increase or decrease shall be added to or subtracted from the contract price as appropriate.

8.30.1

A Change Order is a written order signed by NEPA and Bidder authorizing a change in the work.

8.30.2

NEPA may request Bidder to submit proposals for changes in the work, subject to acceptance by Bidder. If NEPA chooses to proceed, such changes in the work will be authorized by a Change Order.

8.31 Acceptance of the Work

NEPA designated representative will determine if any work has not been performed in accordance with this Agreement.

Upon receipt of notice by Bidder that the work is ready for final inspection and acceptance, NEPA will make such final inspection and issue acceptance within five (5) business days (except for work performed in the first thirty (30) days of the Agreement, in which case it shall be ten (10) business days). Acceptance will be in a form provided by Bidder, stating that to the best of NEPA's knowledge, information and belief, and on the basis of NEPA's on-site visits and inspections, the work has been fully completed in accordance with the terms and conditions of this Agreement. If NEPA finds the work unacceptable due to non-compliance with a material element of this Agreement, which non-compliance is due solely to the fault of Bidder, NEPA will notify Bidder in writing within the five (5) business days (or ten (10) business days, as applicable) setting forth the specific reasons for non-acceptance. Failure to respond shall result in cancellation of the Agreement. Any payment then made will be based on proration, per unit, quantities of acceptable work performed, less costs assessed by NEPA for correction of deficiencies and noted issues.

Nothing in this Section 8.31 will be construed to require that NEPA indemnify and hold harmless the Bidder from claims and costs resulting from Bidder's negligent actions or wilful misconduct.

8.32 Confidentiality and Privacy

"Confidential Information" means all information relating to either Party or to such Party's business, products, sales, customers, trade secrets, technology or financial position to which access is obtained or granted hereunder, which when disclosed to the other Party is marked or otherwise designated as confidential, provided, however, that Confidential Information shall not include any data or information which: (i) is or becomes publicly available through no fault of the other Party; (ii) is already in the rightful possession of the other Party prior to its receipt from the other Party as evidenced by documentation; (iii) is independently developed by the other Party as evidenced by documentation; (iv) is rightfully obtained by the other Party from a third party whose lawful right to provide such data or information is evidenced by documentation; (v) is disclosed with the written consent of the Party whose information it is; or (vi) is disclosed pursuant to a Canadian court order or other Canadian legal compulsion.

8.33 Definitions

8.33.1

"Hazardous substance" includes all of the following, and any by-product of or from any of the following, whether naturally occurring or manufactured, in quantities, conditions or concentrations that have, are alleged to have, or are believed to have an adverse effect on human health, habitability of a Site, or the environment: (a) any dangerous, hazardous or toxic pollutant, contaminant, chemical, material or substance defined as hazardous or toxic or as a pollutant or contaminant under state or federal law, and (b) any petroleum product, nuclear fuel or material, carcinogen, asbestos, urea formaldehyde, foamed-in-place insulation, polychlorinated biphenyl (PCBs), and (c) any other chemical or biological material or organism, that has, is alleged to have, or is believed to have an adverse effect on human health, habitability of a Site, or the environment.

8.33.2

"Mould" means any type or form of fungus or biological material or agent, including mould, mildew, moisture, yeast and mushrooms, and any mycotoxins, spores, scents, or by-products produced or released by any of the foregoing. This includes any related or any such conditions caused by third parties.

8.33.3

"Covered Equipment" means the equipment covered by the Services to be performed by Bidder under this Agreement, and is limited to the equipment included in the respective work scope attachments.

Appendix A

Ministry of Energy

Functional Specification for an Advanced Metering Infrastructure Version 2

(dated July 5, 2007)

Appendix B

NEPA Member
Service Territory Maps
and
Supplemental Information

APPENDIX J

Niagara Erie Power Alliance

Request for Proposal
Operational Data Store
RFP#: 2008-0711
November 7, 2008

Request for Proposal

Operational Data Store
RFP 2008-0711

November 7, 2008

Niagara Erie Power Alliance

Table of Contents

Section 1: Background

1.1 Introduction

To create a conservation culture in Ontario and make the Province a North American leader in energy efficiency, the Government has taken action to facilitate a number of key initiatives, including the introduction of flexible, time-of-use pricing for electricity, and a target reduction in Ontario's energy consumption of 5% by 2007.

The attached documentation sets out the procedural and technical requirements for the submission of proposals to Niagara Erie Power Alliance (NEPA), for its Operational Data Storage (ODS) requirements as per the enclosed specifications; as well as the substantive contractual terms that govern the relationship between parties upon award of the contract.

NEPA members have been working collaboratively through the planning and preparation stages for the Smart Meter Initiative. The NEPA Group consists of nine electricity distribution utilities who have found great benefits in sharing resources and proficiencies through many past collaborative efforts.

Collaboratively NEPA represents over 180,000 residential end points in Ontario and is comprised of the following member utilities:

Brant County Power Inc.
Brantford Power Inc.
Canadian Niagara Power Inc.
Grimsby Power Incorporated
Haldimand County Hydro Inc.
Niagara-on-the-Lake Hydro Inc.
Niagara Peninsula Energy Inc.
Norfolk Power Distribution Inc.
Welland Hydro Electric System Corp.

1.2 Provincial Context for Project

As part of its energy conservation effort, the Ontario government has made a commitment to replace all existing meters (5 million) with smart meters by 2010. Phase One utilities have fulfilled their commitments to install 1 million smart meters by Dec 31, 2007 which assisted the government in exceeding their interim goal of 800,000 by Dec 31, 2007. Focus now shifts to the Phase Two implementation of a Smart Meter Network.

The underlying premise behind the provincial mandate to install these meters is to educate customers on their consumption habits and implement new rate structures that will encourage load shifting and conservation of energy, thereby reducing the requirement for increased power generation capabilities. To this end, the province, by way of the Independent Electricity System Operator (IESO), will be implementing a centralized Meter Data Management / Repository to aggregate utility data from the multiple AMI systems being implemented across Ontario. The IESO has created validation rules, and synchronization processes to control data and ensure that data is complete and suitable for billing.

It should be noted that NEPA members fully support this endeavour on behalf of the IESO and the province of Ontario, and that the interests of the RFP document are not related to those of the IESO and the centralized MDM/R. The Operational Data Storage requirements discussed herein are for the purpose of storing AMI Data being collected by NEPA's AMI systems, for which there is no provision in the centralized system to store and further utilize to implement operational efficiencies that will now become possible through the implementation of this new metering infrastructure.

1.3 NEPA's Approach to Smart Metering

With respect to the Provincial government's Smart Metering Initiative, NEPA has taken a collaborative approach to becoming educated on this mandate by working with other Ontario utilities and advocacy groups. NEPA hopes to evaluate Bidders as objectively as possible with the end goal of selecting the best-fit provider for an ODS, thereby allowing NEPA members to achieve their goals, as well as those of the provincial Smart Meter mandate.

Along with satisfying the provincial mandate of measuring "how much electricity a customer uses each hour of the day, and to use that data to charge customers an energy price that varies depending on when the electricity was consumed" (OEB Smart Meter Plan; January 26, 2005; page i); NEPA members will also implement the Smart Meter Network to improve overall efficiency within each members respective service territory.

NEPA would like to reiterate their support for the IESO MDM/R system that is being implemented, and that the utilities will look to the ODS to support their needs for the introduction of efficiencies that become possible through the use of Operational data that is available through the AMI system. Due to the possibility that the centralized system may one day accommodate these needs, and in keeping with the utility's desire to minimize duplication in utility infrastructure, combined with the relative infancy of Operational Data Storage systems, the utilities will procure a system that is established in the Application Service Provider (ASP) model, allowing the system to grow with the utility needs, but also provide flexibility with regards to term; in the event that the centralized system is able to accommodate the operational needs as well as billing requirements, the utilities would support (and move to) the IESO model.

1.4 Smart Meter Terminology

For the purposes of this procurement process, and within this Request for Proposal document, NEPA has opted to utilize the terminology as defined by the Ministry of Energy in their *Functional Specification for an Advanced Metering Infrastructure Version 2* (dated July 5, 2007), Section 3, *Definitions.* For reference, this document has been included herein as Appendix "A".

1.5 Other Terms

1) ***MDM/R:*** Within this document the acronym MDM/R has been used in reference to the centralized Meter Data Management / Repository that is owned and operated by the Independent Electricity System Operator (IESO). Currently the IESO is working to integrate Smart Meter Data from systems that were installed in Phase One of the Ontario Smart Meter Initiative.
2) ***ODS:*** Within this document the acronym ODS will be used in reference to the Operational Data Storage Services being sought in (potentially) a temporary capacity for the purposes of auditing and validating smart meter data until such time that the centralized repository is in place. At that time NEPA members will make a business decision whether or not to continue utilizing the ODS based on the functionality that is available in ODS compared to that currently in place with the MDM/R. For example, at this time it is not clear whether MDM/R will be used to store operational information. If NEPA members are able to implement efficiencies as a result of the operational data being received from the installed AMI systems, it may be in NEPA members' best interests to continue utilizing ODS.
3) ***Bidder*** shall refer to the vendor proposing a solution to this RFP document.
4) ***Vendor*** shall refer to the successful Bidder. The term Vendor will be used when stating future requirements, to be performed only by the successful Bidder.

1.6 Key Dates

Below is the expected timeline that NEPA will be following during the evaluation of available ODS solutions. NEPA reserves the right to adjust these dates as needed. All Bidders will be notified if any of the following dates are altered. As can be seen, it is the intention of NEPA members to make their decision by February 6, 2009.

Dates of Significance

RFP released by NEPA:	**November 7, 2008**
Bidder Response with Intention to Bid:	**November 14, 2008**
Final Questions Due:	**November 21, 2008**
Answers to Questions:	**November 28, 2008**
Closing Time (RFP Due):	**3:00 pm EST December 5, 2008**
Vendor Presentations:	**January 19 - 23**
RFP Decision:	**February 6, 2009**

Section 2: Instruction to Bidders

2.1 Bid Documents

This Request for Proposals (RFP), establishes the system products and services that NEPA members wish to acquire. This bid document is the basis upon which NEPA seeks firm proposals from selected Bidders and upon which proposals will be evaluated. The documents are:

1) This RFP (a .pdf document), including Appendices that are integral to it.
2) NEPA-ODS_RFPPricingFunctionality_Nov2008.xls, a Microsoft Excel workbook. This file allows for entry of pricing information, as well as confirmation of product functionality and will heretofore be referred to as the Pricing and Functionality Spreadsheet.

2.1.1 Pricing Spreadsheet

The Pricing spreadsheet will allow for the Bidder to enter their pricing information in a standard format, as well as allow the Bidder to attest to their product's functionality. As per Section 2.4 *Proposal Format Instructions*, any hard copies of the pricing submission should be submitted in a separate envelope, marked "PRICE OFFER".

The following tabs are included within the Pricing and Compliancy Spreadsheet:

1) ODS_Functionality: This tab requires completion by the Bidder, and will act as their product functionality statement providing detailed information on product capabilities.
2) Pricing_Option1_ASP: This tab requires completion by the Bidder
3) Pricing_Option2: This tab is optional. If the Bidder feels that a pricing format apart from that provided in the Pricing_Option1_ASP tab will better represent their product offering, they may complete the Option 2 tab. **NOTE: In the event that the bidder chooses to complete Pricing Option 2, the utilities will still require a completed Option 1 tab.**

2.2 Intention to Bid

Recipients of this RFP are asked to inform NEPA of their intention to bid by completing the template form found in Section 2.19 *Proposal Forms*, and by submitting this form by the date shown in Section 1.6 *Key Dates*. Recipients that express intention to bid will be included in all correspondence (if any) during the bidding process. Please provide full contact information and expression of intention via the provided form to the NEPA member contact as per instruction in Section 2.19.1 *Intention to Bid Form*.

2.3 Submission Requirements

1) A complete proposal will consist of an original and nine (9) copies of each of
   a) The proposal forms,
   b) The Bidder's Response document (including all associated attachments),
   c) Pricing spreadsheet: NEPA-ODS_RFPPricingFunctionality_Nov2008.xls; a Microsoft Excel workbook,
   d) Accompanying the Bidder's Response document should be the proposal forms provided in Section 2.19 *Proposal Forms*,
   e) The required format of the Bidder's Response document is outlined in Section 2.4 *Proposal Format Instructions*,
   f) A soft copy of all of the above forms and documents should also be provided on one CD.
2) The original hard copy shall be clearly identified as "ORIGINAL"; the remainder (i.e. nine copies) shall be marked as "COPY". In the event of discrepancy between the copies of the Response, the one marked "ORIGINAL" shall prevail. Each Bidder's Response shall consist of the required documents with the required

number of copies of all commercial information, including pricing, terms and conditions and exceptions (if applicable). Faxed or late proposals will not be accepted. Proposals must be sealed and marked clearly quoting the proposal number referred to on the cover sheet of the proposal documents. The use of any means of delivery of a proposal shall be at the risk of the Bidder.

3) Any Bidder wishing to provide additional information other than what is requested in the proposal documents must place such additional information in a separate section marked Supplementary Information, as per Section 2.4 *Proposal Format Instructions*. Any Additional Information or any unsolicited value-added alternatives may, in NEPA's absolute discretion, be given due consideration, or not.
4) NEPA member utilities shall not be liable for, nor shall they reimburse any Bidder for costs incurred in the preparation of proposals, or any other services or samples that may be requested as part of the evaluation process.
5) The Proposal Forms shall be signed under the Corporate Seal of the Bidder, by the duly authorized signing officer(s). All submitted pages shall be initialled by such officer(s).

2.4 Proposal Format Instructions

Where information has been requested through this RFP, the Bidder's Response should clearly indicate the RFP section number that the Response pertains to. The Bidder's Response should be organized according to the following sections:

1) Section 1 of the proposal will contain the Bidder's Executive Summary, no more than two pages in length that introduces the Bidder and highlights key features of the proposal.
2) Section 2 of the Proposal **should be provided in a separate envelope which has been clearly marked "PRICE OFFER".** This section will contain the summary pages pertaining to the Price Offer, contained within the Pricing and Compliancy Spreadsheet. The Bidder's detailed itemized pricing information for all goods or services is to be contained within the Pricing Spreadsheet which is to be included with the Response in its entirety as well as within this section. Any alternative pricing offers may also be included within the Pricing Spreadsheet, by adding tabs as needed. All pricing shall be expressed in Canadian currency, exclusive of taxes. If your originating currency is not Canadian, the currency exchange that was used to calculate the price in Canadian currency is to be provided.
3) Section 3 of the proposal will contain the functionality tab that is included within the Pricing Spreadsheet as the following tab: ODS_Functionality.
4) Section 4 of the proposal will contain all requested information regarding the Bidder (NEPA RFP Section 4: *Bidder Company Information*) in the order presented in this document, with the numbering used in this document.
5) Section 5 of the Bidder's proposal will contain the requirements of Section 5 of this RFP Document (Section 5: *ODS Solution Technical Requirements*), in the order presented in this document, with the numbering used in this document.
6) Section 6 of the Bidder's proposal will contain any additional documentation that the Bidder decides to provide regarding their offering.

2.4.1 Proposal Format Example: Section 5

Within Section 5: *ODS Solution Technical Requirements* of the RFP, an indicator has been included with the subsection heading to indicate the requirement of the Bidder to provide information pertaining to the functionality of their product (with regards to the section requirements), or a statement of compliancy AND information pertaining to the functionality of their product with respect to the requirement of the section.

(I) When an (I) has been included with the section heading, NEPA members require Information regarding the proposed system's functionality, and the methodology utilized to satisfy the RFP requirement.

(C) When a (C) has been included with the section heading, NEPA members require a statement of compliancy from the Bidder. Within the Submission documentation, the Bidder is required to state the proposed product's compliancy with the requirement by stating Fully Compliant, Partially Compliant, or Not Compliant. In instances where the product is Partially Compliant, or Not Compliant, the Bidder is required to state their plans (complete with development time line) to bring their product into compliancy.

(CI) When a (CI) has been included with the section heading, NEPA members require both a statement of compliancy, and Information regarding the proposed system's functionality, and the methodology utilized to accommodate the RFP requirement.

The method with which the Bidder provides information and compliancy statements is detailed within the individual sections, as well as within the Pricing and Functionality Spreadsheet.

SAMPLES of response for Section 5: *ODS Solution Technical Requirements*, demonstrating that the section numbering from this document is to be retained, and that each section should be included, and shall include within it a statement of compliance (which is also included in spreadsheet form in the Pricing and Functionality Spreadsheet).

5.5.6 Reporting: Custom Queries (C)

The ODS will be capable of executing custom queries to accommodate any areas where standard reports are not available.

Vendor's declaration of compliance: **Fully Compliant**

5.9 Scalability (CI)

The Bidder must describe its proposed ODS data model demonstrating the model's flexibility and scalability to deliver cumulative and interval metering over the next ten years. The system should be designed for a minimum of 250,000 customers, assuming 2 years of online interval data and 7 years off-line data storage. Please specify the methodology for data storage and retrieval.

Vendor's declaration of compliance: **Fully Compliant**

Vendor's Functionality Statement: The ODS system being proposed has been implemented in several deployments (in other markets) of 300,000+ meters, with the largest deployment being 500,000 meters. In addition to these live deployments, the system has been volume tested to more than 1.5 million meters. While these large deployments are all electric AMI deployments, we have deployed the system in some smaller cooperatives 80,000+ meters which are multi-commodity (electric, water, and gas). We believe that together, these experiences demonstrate the scalability required to be successful in the Ontario marketplace. References have been included which can speak to these experiences.

2.5 Adjustments / Substitutions

1) A proposal may be altered by a Bidder only by submitting another proposal at any time up to the Closing Time. Adjustments by telephone, facsimile, telegram or letter to a proposal already submitted will not be considered. The last proposal received by NEPA's designee shall supersede and invalidate all proposals previously submitted by the Bidder for this RFP.
2) During the period prior to the Closing Time, changes made by NEPA members to the proposal documents will be issued by NEPA to the Bidders as written addenda. The Bidder shall list in its proposal all addenda that

were considered in the preparation of its proposal.

3) No substitutions or deviation from the Specifications, Proposal Form or General Conditions of Contract will be permitted without NEPA's approval in writing.

2.6 Complete Bid

Bidders are requested to submit bids that are complete and unambiguous without the need for additional explanation or information. NEPA members reserve the right to make a final determination as to whether a bid is acceptable or unacceptable solely on the basis of the bid as submitted, and proceed with bid evaluation (or not) without requesting further information from any Bidder. If NEPA members deem it desirable and in their best interest, NEPA may, in its sole discretion, request from any Bidder or Bidders additional information clarifying or supplementing any submitted bid.

2.7 Clarifications

Upon the issuance of this RFP to Bidders, and continuing through the submission date, all questions or other communications with NEPA shall be by email only:

nepa@util-assist.com

NEPA members will respond to the question in writing, with both the question and response provided to each Bidder that has declared intention to bid. No response will be made to questions submitted after November 21st, 2008.

2.8 Grounds for Disqualification

It is a requirement of this RFP document that Bidder's submitting proposals for evaluation complete the Pricing Spreadsheet including the ODS_Functionality tab and format their bid submission according to Section 2.4 *Proposal Format Instructions*. NEPA reserves the right to reject any incomplete bids (as per Section 2.6 *Complete Bid*).

NOTE: Where functionality (within the ODS_Functionality tab of the Pricing Spreadsheet) has been misrepresented, NEPA reserves the right to disqualify the Bidder from further evaluation of the RFP.

2.9 Post Bid Meeting

NEPA members reserve the right to invite any or all Bidders to make an in-person presentation regarding the proposed ODS solution. NEPA may request Bidder's assistance in arranging visits to other installations where Bidder has deployed the solution.

2.10 Withdrawal of Proposal

Bidders will be permitted to withdraw their proposal unopened after it has been submitted if such a request is received by the designee of NEPA in writing, prior to the Closing Time.

2.11 Bid Inconsistencies

Any provisions in Bidder's proposal that is inconsistent with the provisions of this Request for Proposals, unless expressly described in the proposal as being exceptions, are deemed waived by the Bidder. In the event the order is awarded to Bidder, any claim of inconsistency between the proposal and this RFP will be resolved in favour of this RFP unless otherwise agreed to in writing by NEPA.

2.12 Bidder's Statement of Understanding

By submitting a response to this RFP, Bidders acknowledge the following:

1) The Bidder acknowledges that it has carefully examined, understands and accepts the proposal documents, has carefully examined the requirements contained in the proposal documents and hereby submits an offer according to the requirements set forth in this proposal.
2) It is understood that this proposal, if it has not been withdrawn in accordance with Section 2, subsection 2.10 *Withdrawal of Proposal*, is irrevocable and shall remain open for acceptance by NEPA for a period of ninety (90) working days following the opening of the proposals.
3) It is further understood by the Bidder that if NEPA accepts its proposal, then the Bidder is bound by the Contract and agrees to provide the goods and/or services upon the terms and conditions of the Contract
4) The Bidder acknowledges and agrees that all quantities shown in the proposal documents are approximate only. Quantities may be subject to increase, decrease, or total deletion in the event that NEPA determines in its absolute discretion that such change is required.
5) While NEPA has used considerable efforts to ensure an accurate representation of information in this Request for Proposal, the information contained in this Request for Proposal is supplied solely as a guideline for Bidders. The information is not guaranteed or warranted to be accurate by NEPA, nor is it necessarily comprehensive or exhaustive. Nothing in this Request for Proposal is intended to relieve Bidders from forming their own opinions and conclusions with respect to the matters addressed in this Request for Proposal.

2.13 Proposal Evaluation

1) All proposals shall be opened after the Closing Time in the presence of NEPA's Representative or another individual designated to open the proposals by NEPA. The opening will not be public.
2) In determining the contract award, the lowest priced proposal will not necessarily be accepted, and NEPA reserves the right to accept or reject any or all proposals in its absolute discretion. Further, proposals may be accepted or rejected in total or in part. Section 2.17 *Proposal Evaluation Criteria* provides further detail regarding the evaluation process which will be utilized by the NEPA group.
3) The Evaluation Committee will review proposals and will then carry out interviews with selected Bidders for clarification as required.
4) It is anticipated that a written contract will be negotiated immediately after the successful Bidder has been notified. If a contract cannot be negotiated within thirty (30) days of notification, NEPA may, at its sole discretion at any time thereafter, terminate negotiations with that Bidder and either negotiate a contract with the next qualified Bidder or choose to terminate the Request for Proposal process and not enter into a contract with any of the Bidders.

2.14 Award of Contract

1) The Bidder acknowledges that NEPA reserves the right, privilege, entitlement and absolute discretion, and for any reason whatsoever to:
   a) Cancel this Request for Proposals at any time, either before or after the Closing Time;
   b) Accept a proposal which is not the highest scoring proposal submission, or reject a proposal that is the highest scoring proposal even if it is the only proposal received;
   c) Accept the proposal deemed most favourable to the interests of NEPA or that may provide the greatest value advantage and benefit to NEPA based upon but not limited to price, ability, quality of work, service, past experience, past performance and qualification;
   d) Accept or reject any and all proposals, whether in whole or in part;
   e) Award any part of any proposal; or
   f) Accept or reject any unbalanced, irregular, or informal proposals.
2) The Bidder acknowledges that NEPA will evaluate proposals using an internal scoring method as referenced in

section 2.13 *Proposal Evaluation* and other criteria which NEPA deems relevant, even though such criteria may not have been disclosed to the Bidder. By submitting a proposal, the Bidder acknowledges NEPA's rights under this section and absolutely waives any right, or cause of action against NEPA and its consultants, by reason of NEPA's failure to accept the proposal submitted by the Bidder, whether such right or cause of action arises in contract, negligence, or otherwise.

3) Contract award, if any, will be communicated by written notification from NEPA to the successful Bidder. The successful Bidder, if any, in the presence of the designate, must sign the Contract Agreement in triplicate (3), within seven (7) Working Days of written notification of acceptance.
4) Bidders whose proposals have been rejected by NEPA will be notified within thirty (30) days of the award date.
5) The successful Bidder shall provide NEPA with a designated inside customer service representative. Any disputes and/or queries with respect to the Contract will be directed to the NEPA representative, whose decisions with respect to any matter under dispute shall be final and binding.

2.15 Freedom of Information

Proposals submitted to NEPA become the property of NEPA and, as such, are subject to the *Freedom of Information and Protection of Privacy Act*, R.S.O. 1990, c. F.31, as amended.

2.16 Ownership of Data

NEPA shall own all data collected by the AMI system, and subsequently stored by the ODS. Data collected and stored by the system shall not be used for any purpose without the approval of NEPA.

2.17 Proposal Evaluation Criteria

NEPA will evaluate proposals using an internal scoring method that weights various parameters to give the NEPA Smart Meter Team insight into the strengths of each proposal relative to NEPA's needs. NEPA's internal scoring method values the following proposal attributes (order of presentation does not reflect priority):

Figure 1 Proposal Evaluation Criteria

Proposal Evaluation Criteria	Section	% Total Points
Project Overview	**3**	
Bidder Information	**4**	
ODS Functionality	**5**	
General Data Management Requirements		
Performance Service Levels		
System Integration		
Meter Event Manager		
System Disaster Recovery Planning		
ODS System Reporting		
Scalability		
ODS System Security		
Perspectives expressed by reference utilities		
Section 3 through 5 inclusive:		**60%**
Pricing Weighting:		**40%**
Total		**100%**

Along with the Bidder's company information, and statements of understanding regarding the project, the answers to sections 3 through 5 will represent 60% of the total weighting of the RFP. Pricing submitted will represent 40% of the total weighting of the RFP. Bidders will be selected for further discussion based on the Team's judgment, developed using the scoring method.

2.18 Payment

When the Vendor has completed all work in accordance with the terms of the contract documents, the Vendor shall submit to NEPA a request for final payment. The request for final payment shall constitute a waiver of all claims by the Vendor except for claims specifically listed in the request. NEPA will make payment within forty-five (45) days of receipt of a request for payment.

Vendor's submission of its request for final payment shall constitute its warrant that the Vendor has to the best of its knowledge fully completed all work included in the Contract and has fully paid for labour, materials, equipment, services, taxes and all other costs and expenses resulting from this Contract.

2.19 Proposal Forms

Within this section, there are two forms required for submission. The first form is found in Section 2.19.1 *Intention to Bid Form*; the intention of this form is to allow the vendor to provide a standard email Response to NEPA designee to notify NEPA of the Bidder's intent to respond to the RFP.

2.19.1 Intention to Bid Form

The procedure to be utilized for this form is to copy and paste the following content into an email, and send the email to:

nepa@util-assist.com

according to the time line as established by Section 1.6 *Key Dates*.

INTENTION TO BID NOTIFICATION FORM

PROPOSAL NO. 2008-0711

Intention to Bid:
Please allow this email to represent "__Insert Company Name Here__" intention to respond to RFP 2008-0711.

Contact for communication regarding bid: ______________________________
Contact phone number: ______________________________
Contact email address: ______________________________

We acknowledge the requirement for our ODS solution to, at minimum, audit the performance of the installed AMI to assist NEPA in making certain the AMI meets the Ministry of Energy's minimum functional requirements as outlined in the document *Functional Specification For An Advanced Metering Infrastructure Version 2* (dated July 5, 2007). Our proposal will include the required compliance statements and documents to properly express our ability to meet these requirements. We also acknowledge the Submission Deadline is 3:00 PM Eastern Time on December 5th, 2008.

2.19.2 RFP Submission Form

The procedure to be utilized for this form is to print the following pages to be included with the RFP submission, which should be addressed to:

Mr. Jim Huntingdon
Niagara-on-the-Lake Hydro Inc.
8 Henegan Road, PO Box 460
Virgil, ON
L0S 1T0

according to the time line as established by Section 1.6 *Key Dates*.

Niagara Erie Power Alliance

Proposal Number: **RFP 2008-0711**

FOR: OPERATIONAL DATA STORAGE SYSTEM & SERVICES

THIS PROPOSAL IS SUBMITTED BY:____________________

ADDRESS:

TELEPHONE: FAX NO.:

BIDDER G.S.T. No.:

PERSON(S) SIGNING ON BEHALF:____________________________(print)

POSITION(S) OF THE PERSON(S):__________________________________(print)

To NEPA, Hereafter called "Owner":

I/WE ____________________________________ the undersigned declare:

1. THAT no Person(s), Firm or Corporation other than the one whose signature(s) of whose proper officers and the seal is or are attached below has any interest in this proposal or in the contract proposed to be taken.

2. THAT this proposal is made without any connections, knowledge, comparison of figures or arrangements with any other company, firm or person making a proposal for the same work and is in all respects fair and without collusion or fraud.

   THE Bidder insures that no owner and or employee of Owner, is, or has become interested, directly or indirectly, as a contracting party, partner, stockholder, surety or otherwise howsoever in or on the performance of the said contract, or in the supplies, work or business in connection with the said contract, or in any portion of the profits thereof, or of any supplies to be used therein, or in any monies to be derived there-from.

3. THAT the several matters stated in the said proposal are in all respects true.

4. THAT I/WE have carefully examined the requirement(s), as well as all the Instructions to Bidders, Project Overview, ODS Technology – Technical Requirements, Proposal Forms, and Appendices relating thereto, prepared, submitted and rendered available by the Owner and hereby acknowledge the same to be part and parcel of any contract to be let for the work therein described or defined.

5. THAT I/WE do hereby propose and offer to enter into a contract to deliver all work as described or implied therein including in every case freight, duty, exchange, G.S.T. and P.S.T. in effect on the date of the acceptance of proposal, and all other charges on the provisions therein set forth and to accept in full payment therefore, the sums calculated in accordance with the actual measured quantities and unit prices set forth in the proposal herein.

6. THAT Addendum/Addenda No. ___ to ___ inclusive relate to the said contract and Bidder hereby accepts and agrees to the same as forming part and parcel of the said contract.

7. THAT additions or alterations to or deductions from the said contract, if any, shall be made in accordance with the prices stated in the Schedule of Items of Unit Prices in strict conformity with the requirements of the Contract.

8. THAT this offer is irrevocable and open to acceptance until the formal contract is executed by the awarded Bidder for the said requirement(s) or Sixty (60) working days, and unit prices for as long as stated elsewhere in the document, whichever event first occurs and that the owner may at any time within that period without notice, accept this proposal whether any other proposal has been previously accepted or not.

9. THAT the awarding of the contract, by the owner is based on this submission which shall be an acceptance of this proposal.

10. THAT I/WE also understand that the owner reserves the right to accept or reject all or part of this proposal or any other and also reserves the right to accept other than the lowest proposal.

The undersigned affirms that he/she is duly authorized to execute this proposal.

BIDDER'S SIGNATURE AND SEAL:

NAME: ______________________________ ______________________________
(Please Print) (Signature)

POSITION: ______________________________

WITNESS
NAME: ______________________________ ______________________________
(Please Print) (Signature)

POSITION: ______________________________

(If Corporate Seal is not available, documentation should be witnessed)

DATED AT THE ____ THIS ________
(City/Town) (Day)

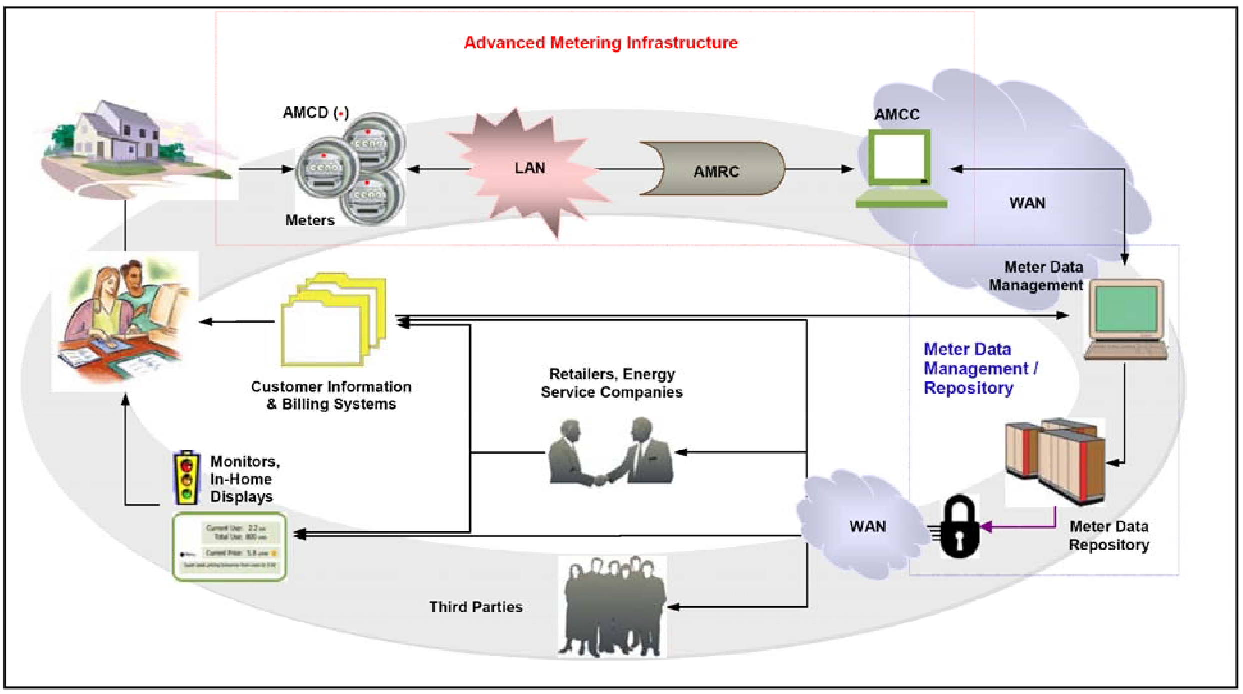
DAY OF ______________________________ 2008.
(Month)

Section 3: Project Overview

3.1 Smart Metering Infrastructure – AMI Landscape

The Advanced Metering Infrastructure (AMI) which NEPA is installing is meant to satisfy the requirements of the provincial Smart Meter Initiative (SMI), which is hoped to contribute to the creation of a conservation culture in Ontario. The metering and associated infrastructure (i.e. AMCDs, AMRCs, and AMCC) will be owned and operated by NEPA, and the centralized Meter Data Management/Repository (MDM/R) will be owned and operated by the Independent Electricity System Operator (IESO). There are performance requirements detailing success rates for data collection from the AMI infrastructure, and time requirements within which the data must be provided to the centralized MDM/R. Following is a diagram depicting the data flow for the Ontario Smart Meter landscape.

Figure 2: Ontario Smart Metering System Data Flow



Performance requirements for the AMI have been specified within the Ministry of Energy document entitled *Functional Specification for an Advanced Metering Infrastructure Version 2* (dated July 5, 2007), which has been provided for reference as Appendix "A". As discussed within this document the AMI system includes the Advanced Metering Communication Devices (AMCD), the Local Area Network (LAN), Advanced Metering Regional Collector (AMRC), the AMI Wide Area Network (AMI WAN) and an Advanced Metering Control Computer (AMCC). The system will provide the infrastructure within which date and time stamped hourly meter reads are remotely collected and transmitted daily to NEPA's AMCC, and which will eventually be sent to the centralized Meter Data Repository (MDM/R) through the MDM/R Wide Area Network (MDM/R WAN).

The MDM/R functions include collecting and storing data, processing it for TOU and CPP billing, and making it accessible to consumers and to LDCs in accordance with their billing cycles. The data will also be made available to retailers, energy service companies and other interested parties in a manner that protects the privacy of consumers.

As discussed in Section 1.3 *NEPA's Approach to Smart Metering*, NEPA members are currently engaged in a project to install Smart Metering in all residential and small commercial (<50 kW) locations by December 2010. Presently NEPA has a total of over 180,000 residential and commercial customers, with smart meter installation commencing March of 2009.

Planning for the Commercial and Industrial component of the smart meter initiative is currently being developed and is not part of the current deployment. However, Bidders are welcome to provide comments on their ODS offering for Commercial/Industrial data, and budgetary pricing may be provided separately should the Bidder decide to do so. Desirable Commercial and Industrial analytical tools have been described in Section 5.4 *Commercial and Industrial Data,* and the Bidder's information regarding these functionality components can be provided as per the Section format instructions included in Section 2.4 *Proposal Format Instructions*, however Bidders are to understand that the immediate requirements of NEPA are for a residential ODS solution to audit the performance of the AMI. The intent of the ODS is NOT to replicate any functions currently in place within the centralized MDM/R. NEPA looks to the ODS to facilitate the implementation of operational efficiencies (currently the centralized MDM/R does not accept operational metering data).

3.2 NEPA's Operational Data Storage Requirements

Section 3.1 *Smart Metering Infrastructure – AMI Landscape* outlines the requirements placed on NEPA in order to meet the provincial mandate.

The Operational Data Storage requirements being procured through this RFP document are considered (at this time) to be exclusive of the requirements being placed upon the IESO centralized MDM/R. The solution that is of interest to NEPA through this process will be utilized to audit the performance of the AMI infrastructure currently being installed, and to store operational data that may be of future use to NEPA. It is NEPA's understanding that these functionality components are standard to ODS solutions, and may not form part of the MDM/R functionality. NEPA would like to clearly express that their intention is NOT to duplicate infrastructure being implemented by provincial entities, but rather to ensure that the AMI infrastructure being deployed by NEPA will satisfy the needs of the Ontario Energy Board (i.e. the Regulator).

3.3 NEPA's Smart Metering Initiative: Current Environment

3.3.1 Description of Environment

For reference, we have included the following information pertaining NEPA member's back office systems.

UTILITY	CIS:	Meters	Projected AMI Install:
Brant County Power Inc.	Daffron	9,000	May 17, 2010
Brantford Power Inc.	Daffron	35,000	August 10, 2009
Canadian Niagara Power Inc.	SAP	28,000	July 13, 2009
Grimsby Power Incorporated	SAP	9,500	March 29, 2010
Haldimand County Hydro Inc.	Harris Northstar	20,500	July 6, 2009
Niagara-on-the-Lake Hydro Inc.	COS	7,500	January 4, 2010
Niagara Peninsula Energy Inc.	Harris Northstar	48,000	April 13, 2009
Norfolk Power Distribution Inc.	Daffron	18,000	May 4, 2009
Welland Hydro Electric System Corp.	APPX 4.2.9	21,000	March 2, 2009

3.3.2 AMI Systems Deployed

The Sensus Metering System's (SMS) Network is a tower based point-to-point radio system, with meters transmitting data directly to the tower. The SMS system uses a licensed frequency (tuneable between 896 – 941 MHz) to transmit directly to the tower, or depending on distance and terrain, they may transmit to another meter before the transmission is sent to the tower (buddy mode). There exists no physical restriction to the number of meters managed by the collector, rather a channel capacity limitation. Meeting Ontario's requirement of hourly interval data and 10wh granularity generally leads to an optimal loading of approximately 30,000 endpoints per AMRC.

The frequency of transmission is periodic and variably independent. Typical transmission rates in a daily read environment would be every four hours, but can increase or decrease in frequency as required (configurable to as often as every 15 minutes). The meters (that are currently Measurement Canada approved) store 30 days of Hourly Interval data, with the most recent 12 hours of data being transmitted with each transmission. To ensure performance requirements are met (98% daily); a Ping function can be set up in the system. In this case the system will check what meters have not successfully communicated their data at a specified time, and the system will ping these meters to initiate a transmission with the Tower Gateway Basestation (TGB). In most cases within Ontario, the Ping function is set for 2:30am, allowing the system to acquire all data and produce an export file between 4:00 A.M. and 5:00 A.M.

Sensus's iCon meter is available in several forms, and allows for (among other things) voltage recording, bi-directional metering, last gasp functionality, firmware upgradeability,72 hours of memory within the meter, as well as 30 days of redundancy through the TGB (if no communications, otherwise it is emptied continuously), and 60 days of backup (on dual drives) through the AMCC. The network handles water meter data collection without electric meter dependence; the system is ready for use with Gas and Water meters, although they are 1-way communication, while the electric meters allow 2-way communication to the Tower.

The FlexNet system utilizes a programmed "Push" from the meters to the tower. Meters push all stored meter read data every ~1.5 hours (programmable). For the Ontario market requiring a granularity of 10Wh, it has been determined 1.5 hours should provide optimal stats and system performance. All meter data is recorded as register readings and transmitted as such.

It is expected that initially the ODS will receive data from the AMI network in a batch mode scenario, with the expected data file to be, on average, 75 MB (based on an example of a daily CMEP file transfer of hourly interval data for a system of 120K endpoints (assume a linear relationship between endpoint # and file size). It is expected that this data files will be transmitted from the AMCC on a daily basis at approximately 4:30 am.

3.3.3 AMI Service Level Agreement

The AMI network has been deployed in such a manner as to accommodate the following performance levels:

i. Percent of hourly (interval) readings captured: 98% in 24 hours
ii. Percent of daily (register) readings captured: 98% in 24 hours

iii. In addition to the above requirements, 99% of all readings (99% of register, and 99% of interval) are required in 72 hours (rolling statistic), and 99.5% of all readings (99.5% of register, and 99.5% of interval) are required in 30 days (calendar statistic). These requirements will demonstrate the Bidder's ability to acquire the readings that were missed in 24 hours, over the subsequent time periods (i.e. continued commitment to acquire as many readings as possible).

iv. Percent of meters communicated within 24 hours: 99.9% (while it is conceded that some meters may be difficult to communicate with, and therefore acquire 100% of the readings 100% of the time, the aim of this statistic is to show that 99.9% of meters can be reached on a daily basis).

This information has been provided as one of the critical functions of the ODS will be to audit the performance of the AMI to ensure that these Service Levels are being satisfied.

3.4 Scope of Work

NEPA, through this RFP, is seeking a cooperative and mutually beneficial relationship with a ODS provider which will allow NEPA to successfully fulfill their regulatory requirements for data collection. That is, it is anticipated that the ODS services being procured will enable NEPA to ensure the performance requirements as documented in Section 3.3.3 *AMI Service Level Agreement* are being satisfied. Knowledge of AMI performance statistics will provide NEPA with the knowledge that sufficient AMI infrastructure has been deployed (or not), such that the performance expectations can be met.

Additionally, AMI systems provide data which can enable NEPA to implement operational enhancements for their customer base. Given that the AMI deployment is in its infancy, NEPA is not in a position to make use of all of the data that is acquired through the system at this time. However, it is NEPA's goal to establish the ODS system such that this information can be stored now, and utilized at a later time.

It is NEPA's intention to implement commercial and industrial applications as appropriate in the future. Planning for this application is ongoing, and no timelines for implementation are available at this time. Therefore, this request for proposal for ODS solutions will address NEPA's requirements for smart metering in residential applications only. However, Bidders should be aware that commercial and industrial applications will be installed in the future, and if the Bidder also provides a solution for commercial and industrial applications, the response may also address this solution distinctly segregated from the solution provided for residential application, if possible. If the proposed solution is applicable for commercial and industrial customers with no modifications, the Bidder shall identify such.

As stated within Section 1.3 *NEPA's Approach to Smart Metering*, it is the intent to procure the ODS solution in an ASP model to mitigate the risk associated with purchasing a license for software which may become redundant due to the ongoing development of the centralized MDM/R. NEPA supports the work of the IESO, and the use of the centralized system, and look to use the ODS to facilitate the introduction of Operational Efficiencies during the period in which these functions are unavailable through the centralized system.

NEPA considers the following list of services as required to successfully satisfy the intent of this RFP:

- Project management, system design, commissioning and training
- System security (i.e. detailed security parameters to protect all information collected)
- Service levels and value added services
- Applicable costs, pricing and rates
- Provide the technical expertise required to establish communications between the AMCC and NEPA's back office systems
- Establish an understanding of the demarcation point
- Describe the technology roadmap for the proposed system/technology

Section 4: Bidder Company Information

4.1 Financial / Business Stability

1) What is the current size (number of employees), turnover rates for last three (3) years, and location(s) of the Bidder's company?
2) Number of employees assigned to application development and support.
3) What is the current financial condition of the Bidder's company? Provide supporting documentation and annual reports for the last three years. If the company is privately held, supply sufficient information to document the company's financial status.

4.2 Experience providing same or similar products & services

1) How many years has the Bidder been in business?
2) How long has the Bidder been providing ODS solutions?
3) How long has the proposed solution been deployed and implemented in the field excluding any period of time for which it was in a Beta Test status?
4) Describe the Bidder's primary line of business and the percentage of its business derived from the sale of ODS solutions and associated services.
5) Bidders should identify and describe services they could offer NEPA as part of the Contract that would support environmentally responsible business practices.
6) Bidders are to provide data to support their safety record such as corporate safety statistics, internal safety record, WSIB rating, injury rate or injury severity. In addition, Bidders must provide documentation supporting their commitment to safety within their facilities and design of products.

4.3 Contract Manager

The Bidder is asked to acknowledge the requirement to designate a Contract Manager, who shall have the authority to handle and resolve any technical issues, disputes or contractual issues in a timely manner. The Bidder should describe the Contract Manager's experience with managing projects of a similar size and scope, including timelines, and results if applicable. Response should include the Contract Manager's and any other related team member's Curriculum Vitae (CV).

4.4 Perspectives expressed by references

To ensure long-term viability and maintenance of the system, the selected Bidder must be a proven vendor in the area of application software and therefore the following information is requested:

1) Provide a list of at least three (3) references (contact names and phone numbers) for companies using the Bidder's proposed system to perform the same or similar application(s) as the one(s) described in this RFP for the past three (3) years.

Section 5: ODS Solution Technical Requirements

5.1 General Data Management Requirements (I)

NEPA is seeking an AMI specific ODS that is designed to store meter data and provide isolation of business processes and business systems from the details of metering and meter data collection, in a multi-vendor, multi-technology environment.

Any ODS proposed by the Bidder shall allow for the application of consistent processes and the maintenance of consistent interfaces independent of how, when, or where various meter reading technologies are deployed. This is intended to simplify and significantly reduce the likelihood of errors in business processes that utilize meter data. It should also allow for the most cost-effective AMI meter reading technologies to be deployed, without affecting downstream processes.

Bidder is to propose a fully capable ODS system able to manage the ongoing collection of all cumulative and interval meters for electricity, and potentially water and gas, as required by NEPA's current structure and operational responsibilities.

The ODS shall utilize a relational and fully versioned database that provides for long-term data storage of register, interval, tamper, outage, and meter event data. The system will provide for business process integration, and be accessible by all business and analytical systems, and readable by users of meter data throughout the utility. The ODS should have the ability to collect energy data streams from physical metered channels, endpoints, or modules, or calculate it as needed. The data should be linked together in flexible relationships that are managed over time.

The ODS data model should provide isolation of users from the day-to-day details of meter reading data collection processing. However, the ODS shall still provide access to those details for the systems and users that require it.

The following chart (Figure 3) can be found within the Pricing Spreadsheet, and is to be completed within the Pricing Spreadsheet, which will be provided in conjunction with the Vendor's Submission as per Section 2.3 *Submission Format Instructions.*

Figure 3: ODS Functionality Checklist

ODS Functionality Check List	ODS Bidder: License or ASP?:	Data R US ASP	
Functions	Compliancy	Included in Base Price?	Incremental Costs
The system stores data in the original time increments as provided by the AMI system. (i.e., raw AMI data including missing intervals and bad data).	Fully Compliant	YES	
The ODS stores register and interval data in any time increment (i.e. 1 min, 2 min, 5 min, 15 min, 30 min, 60 min…).	Fully Compliant	YES	
The ODS is energy independent (multi-commodity) and capable of storing and processing readings from all registers of AMI endpoints (endpoints include electric, water, and gas meters, with all available data from each meter).	Fully Compliant	YES	
Interval reads in the ODS retain the precision of the meter (i.e., 10 Watt hours (.01 kWh) per interval or better).	Fully Compliant	YES	
The ODS maintains a minimum of 2 years data on-line.	Fully Compliant	YES	
The ODS is capable of accessing a total of 7 years of archived data.	Fully Compliant	YES	
The system is designed for a minimum of 1,000,000 customers, for ASP applications and 250,000 for a utility stand alone license purchase model; assuming 2 years of online interval data, with the remainder archived.	Fully Compliant	YES	
The system contains an Event and Task Manager providing the ability to schedule daily tasks on a frequency basis.	Fully Compliant	YES	
The system performs date driven Load Calculations on a per customer basis.	Fully Compliant	YES	
The system performs date driven Loss Calculations on a per customer basis.	Fully Compliant	YES	
The system contains enhanced search capabilities; ability to identify customers by demographics.	Fully Compliant	YES	
The system supports "Thin Client" access to meter data to allow for remote user access.	Fully Compliant	YES	
The system tracks all versioning of data.	Fully Compliant	YES	
The system makes the most recent version of data accessible to all upstream business and analytical processes. All other versions are available.	Fully Compliant	YES	
AMI System Interfaces			
The system supports both batch and real-time interfaces to AMI system Advanced Metering Control Computers (AMCCs) for real time interfaces such as outage events, voltages, and tamper/theft flags.	Fully Compliant	YES	
The system accommodates "Request and Response" Brokering To/From Multiple AMI systems.	Fully Compliant	YES	
AMI data insertion into the ODS is dynamic.	Fully Compliant	YES	
Elster EnergyAxis			
Request Response Brokering - On Demand Reads (kWh, Voltage)	Fully Compliant	YES	
Request Response Brokering - Pinging for Outage Restoration Messages	Fully Compliant	YES	
Daily IESO Reading Output File - XML	Fully Compliant	YES	
Daily Operational Output File - XML	Fully Compliant	YES	
Instantaneous Alarm Messages (Theft, Outages, High/Low Voltage Alarms)	Fully Compliant	YES	
Sensus Flex Net			
Request Response Brokering - On Demand Reads (kWh, Voltage)	Fully Compliant	YES	
Request Response Brokering - Pinging for Outage Restoration Messages	Fully Compliant	YES	
Daily IESO Reading Output File - CMEP	Fully Compliant	YES	
Daily Operational Output File - CMEP	Fully Compliant	YES	
Instantaneous Alarm Messages (Theft, Outages, High/Low Voltage Alarms)	Fully Compliant	YES	
Trilliant			
Request Response Brokering - On Demand Reads (kWh, Voltage)	Fully Compliant	YES	
Request Response Brokering - Pinging for Outage Restoration Messages	Fully Compliant	YES	
Daily IESO Reading Output File - CMEP	Fully Compliant	YES	
Daily Operational Output File - CMEP	Fully Compliant	YES	
Instantaneous Alarm Messages (Theft, Outages, High/Low Voltage Alarms)	Fully Compliant	YES	
Smart Synch			
Request Response Brokering - On Demand Reads (kWh, Voltage)	Fully Compliant	YES	
Request Response Brokering - Pinging for Outage Restoration Messages	Fully Compliant	YES	
Daily IESO Reading Output File	Fully Compliant	YES	
Daily Operational Output File	Fully Compliant	YES	
Instantaneous Alarm Messages (Theft, Outages, High/Low Voltage Alarms)	Fully Compliant	YES	
SilverSpring Networks			
Request Response Brokering - On Demand Reads (kWh, Voltage)	Fully Compliant	YES	
Request Response Brokering - Pinging for Outage Restoration Messages	Fully Compliant	YES	
Daily IESO Reading Output File - CMEP	Fully Compliant	YES	
Daily Operational Output File - CMEP	Fully Compliant	YES	
Instantaneous Alarm Messages (Theft, Outages, High/Low Voltage Alarms)	Fully Compliant	YES	
Tantalus			
Request Response Brokering - On Demand Reads (kWh, Voltage)	Fully Compliant	YES	
Request Response Brokering - Pinging for Outage Restoration Messages	Fully Compliant	YES	
Daily IESO Reading Output File - CMEP	Fully Compliant	YES	
Daily Operational Output File - CMEP	Fully Compliant	YES	
Instantaneous Alarm Messages (Theft, Outages, High/Low Voltage Alarms)	Fully Compliant	YES	

Reporting Tools			
The system provides manually dispatched reports.	Fully Compliant	YES	
The system provides automatically dispatched reports.	Fully Compliant	YES	
The system provides custom reports utilizing report writers (i.e., Crystal Reports, COGNOS, etc.).	Fully Compliant	YES	
AMI Management			
Service Level Agreement Management	Fully Compliant	YES	
Synchronization Status Reports (Meters Reporting not linked to an account, Meter Not Reporting linked to an account)	Fully Compliant	YES	
Meters not reporting performance for the past month/quarter/Year	Partially Compliant	NO	$X.XX
Billing			
Status of Cycles to be billed	Fully Compliant	YES	
Status of all billing cycles	Fully Compliant	YES	
Audit Report Billing output from IESO MDM/R to data in ODS	Not Compliant	NO	$X.XX
Operations			
AMI Voltage Alarm Reporting (Hi/Low Voltage alarms with the voltage reading from the other meters of the same transformer)	Partially Compliant	YES	
AMI Outage Alarm Reports filtered based on volume (i.e. report as an individual outage, transformer outage, feeder outage, substation outage) and the ability to distinguish between momentary and sustained outages	Partially Compliant	NO	$X.XX
SAIDI / CAIDI / SAIFI Reporting	Not Compliant	NO	$X.XX
AMI Tamper report (tamper and number of times reported at this service point)	Partially Compliant	NO	$X.XX
CIS Functionality			
The system accommodates "Request and Response" Brokering To/From CIS.	Fully Compliant	YES	
Current CIS Interfaces			
Cayenta	Fully Compliant	YES	
Harris North Star	Fully Compliant	YES	
Daffron	Not Compliant	NO	$X.XX
Sunguard (H T E)	Not Compliant	NO	$X.XX
SPL	Fully Compliant	YES	
SAP	Fully Compliant	YES	
T&W	Not Compliant	NO	$X.XX
The ODS supports multiple TOU rate schedules and provide “what if” analysis on customers or groups of customers to verify system impact of rate changes (shadow bill analysis)	Partially Compliant	NO	$X.XX
The system is able to track 'equipment type' information (in order to tell the difference between meters collectors, info. meters.).	Fully Compliant	YES	
The system receives and stores meter install and removal information, from CIS. In this way, the system tracks whether a meter is installed or not, and what the physical location (Site ID (Utility Service Delivery Point) and XY coordinate) is at any time while installed.	Fully Compliant	YES	
The system is able to receive a disconnect or reconnect request from CIS, pass it on to the appropriate AMI system, then return a success or failure message to CIS, all in real time.	Not Compliant	NO	$X.XX
The system is able to distinguish between zero consumption due to a meter being removed, zero consumption due to a disconnect, and zero consumption due to an outage.	Fully Compliant	YES	
Time references in data presented to billing or customer via 3rd party web tools is based on the local time zone and use Daylight Savings Time.	Fully Compliant	YES	
Any data that is presented to the customer that is not validated is clearly marked as such. Validated data is available to the customer within 3 days. If the WEB tool is not dynamic, it will display when the data was last downloaded from the ODS.	Fully Compliant	YES	
If information is required from the ODS that is not available (Missing Reads), the ODS automatically creates on-demand read requests to collect and provide the required data. (This will be based on parameters provided),	Not Compliant	NO	$X.XX
The ODS is able to receive alarms messages from AMI system (Tampers, Outages…) and receive Service orders from CIS (Disconnect for Non Payment, Planned Outages...) and filter the alarms to create a list of true messages to be investigated. The ODS will create service order requests and send them to the CIS (Work Order System) to automatically be generated.	Not Compliant	NO	$X.XX
The system is capable of importing and maintaining hourly time series weather data with multiple variables from third party sources and is able to generate weather normalized data.	Fully Compliant	NO	$X.XX

5.2 System Integration (I)

Systems of interest with regards to system integration include CIS systems, Outage Management Systems (OMS), and AMI and other meter reading data collection systems. Bidders are asked to provide a listing of these systems which can currently integrate with the proposed solution. While these systems are of immediate interest, it is expected that NEPA members will investigate the integration of GIS, WFM systems, WEB presentment OMS and other utility data systems in the future. Bidders are invited to provide any information they deem relevant to these interests.

5.2.1 Interaction with AMI (CI)

The ODS solution shall provide the following functionality with regards to the handling of data as provided by the AMI infrastructure described in Section 3.3.2 *AMI System Deployed*:

i. AMI data insertion into the ODS will be dynamic.
ii. The system will store data in the original time increments as provided by the AMI system (ie. RAW AMI data including missing intervals and bad data).
iii. The system will store validated register and interval data in any time increment (ie. Intervals of 1 minute, 2 minute, 5 minute, 15 minute, etc.).
iv. Data storage will be energy independent and the ODS will be capable of storing and processing readings from all registers of all AMI endpoints (endpoints can include electric, water, and gas meters, with all available data from each meter).
v. Hourly reads in the system must retain the precision of the meter, to a minimum precision of 10 Watt hours (.01 kWh) for each residential electric data register (interval or otherwise). Bidder is requested to also provide detail regarding the precision of data storage for Commercial/Industrial metering (i.e. It is expected that the ODS would retain the precision of the meter regardless of the number of decimal points.)
vi. The system will accommodate "Request and Response" brokering to/from multiple AMI systems.

Bidders are required, as per Section 2.8 *Grounds for Disqualification* to provide written acknowledgement of the requirement for the proposed solution to be currently capable of these functions for the Sensus AMI system.

5.2.2 Other Meter Reading Data Collection Systems (I)

In addition to the acquisition of Data from the AMI, the ODS shall handle meter data from multiple sources, such as handheld, mobile, fixed network, etc. The ODS will allow the integration of multiple advanced meter reading technologies from multiple suppliers. NEPA will require the ability to seamlessly deploy multiple technologies in conjunction with traditional meter reading methods, and the ability to merge modern and traditional meter reading methods and technologies without impacting or modifying downstream billing processes. This ability is considered of value given that NEPA continues to manually collect meter read data while they deploy their AMI network.

The ODS solution shall have the functionality to emulate and manage schedules, cycles, and routes of manual meter reading operations to allow transition of legacy meter reading tasks, including the functionality to:

i. Process cycle/route-based meter reading systems, such as handheld (i.e. Itron MV-RS) or automated meter reading technology (i.e. Itron ERT enabled electromechanical meters),
ii. Process non-cycle/route-based meter reading systems, such as two-way remote reading technologies (i.e. MV-90 interval data collection from POTS enabled communication modules),
iii. Manage schedules such that the ODS will request all of the meter reading required for a given billing (readings may actually be obtained from multiple systems and/or technologies),
iv. Maintain information about which system is used to obtain readings for each meter so that a given request can be broken into individual requests for each meter reading system,
v. Functionality to create partial or full routes when returning readings to the billing system and combine multiple commodities, i.e. water and gas, into a single meter reading route for field collection and return data to the ODS system.
vi. The ODS should maintain performance statistics for each meter reading system and for the system as a whole.

Given that the ODS can perform the functions listed above, in an effort to retain consistency in the presentation of data, NEPA requires that: time references in data presented must be based on the local time zone and use Daylight Savings Time. Any data that is presented that is not validated should be clearly indicated as such. For further validation requirements, see Section 5.3 *Validation, Editing and Estimation (VEE)*.

5.2.3 Customer Information System (CI)

The system should accommodate "Request and Response" Brokering To/From Multiple Customer Information Systems (CIS). Some of the CIS systems commonly utilized in the Ontario market include:

- APPX/COS
- Cayenta
- Daffron
- Harris NorthStar
- Harris 5.2.19.x
- Sungard HTE
- Peoplesoft
- SAP
- SPL

Bidders are requested to specify the CIS systems for which an interface currently exists, and whether there is a cost to implementing the interface that will be required for NEPA member's CIS systems. In the event that the ODS cannot interface with the CIS systems being used by NEPA (reference Section 3.3.1 *Description of Environment*), the Bidder is asked to provide a high level overview of their system's ease of customization.

As part of the synchronization that is required between ODS and CIS, it is expected that the proposed solution will allow for new or changed customer, account, site ID, and service point information, and that this information will be imported from the external Customer Information System (CIS) en masse or upon completion of service orders.

NEPA anticipates using the ODS to test the IESO Billing Request file format that will be utilized by the centralized MDM/R. If Bidders have experience in this regard, documentation should be included in the response.

5.2.3.1 Wholesale Settlement Calculations (I)

NEPA is interested in whether the system is capable of performing Wholesale Settlement Calculations with billing output files for CIS. If this option is not currently available, please detail the development path.

5.2.3.2 Export Capabilities (I)

In addition to the interface required to directly integrate CIS data, NEPA is interested in the proposed solution's ability to export data in XML format, and the Itron MVRS handheld format. Bidders are requested to provide information explaining their current functionality in this regard, as well as any associated costs to accommodate these requirements if they are not currently available. If incremental costs are not stated, it is NEPA's assumption that costs for this functionality is included in the system pricing (i.e. functionality is considered standard).

5.2.4 Outage Management System (CI)

It is expected that the proposed solution will allow for receipt and display of outage related events from the AMI. NEPA is interested in having these capabilities performed by the ODS system, thereby allowing improved restoration and other outage related services. With the information available from AMI it is expected that the dispatching process for field service crews will be streamlined.

Bidders are requested to provide a listing of interfaces available to integrate the proposed ODS with NEPA's OMS (reference Section 3.3.1 *Description of Environment*). If an interface is not currently available, Bidders should specify the estimated costs associated with the creation of the required interface. In addition to a list of interfaces, Bidders are asked to provide some details regarding past implementations and a list of references with regards to the integration of OMS.

5.2.5 Work Force Management (WFM) (I)

NEPA expects that initially all data will be imported from CIS. However, as the deployment of AMI continues, NEPA will require that the system allow new or changed data to be imported from the workforce management system at the completion of meter-related service orders. The system will allow configuration data to be synchronized on a daily basis using batch files, and should allow real-time transactions to be performed with web-based APIs. The ODS system should also have the ability to interface to the WFM system and automatically create service orders in events where a field visit is required.

5.2.6 3rd Party Interfaces (I)

The ODS must provide a robust, industry standard means for extracting data so that the data can be presented to other 3rd party applications. In addition to CIS, OMS, WFM, other 3rd party applications might include GIS, WEB products, Theft Analysis tools, Load Forecasting/Profiling tools, etc. Bidders are requested to provide detailed information regarding their experience integrating to 3rd party applications.

The system should contain Application Program Interfaces (APIs) for third party applications. The system should not have a load limitation to API's (multi-threaded). If there is a load limitation to API's, please indicate what the limitation is.

The ODS solution should contain the flexibility and functionality to load, change, correct, and view configuration data through use of the following tools:

i. Service Oriented Architecture (SOA) Bus;
ii. XML configurable import APIs (batch or real time);
iii. XML configurable export APIs (batch or real time);
iv. comma delimited file (CSV) exports (batch)
v. configuration attributes reports.

5.3 Validation, Editing and Estimation (VEE) (CI)

All meter data received by the ODS will be subjected to VEE processes. At this time, NEPA requires an ODS solution to process residential AMI data, and the VEE rules for this class of customer have been published by the IESO (*Meter Data Management and Repository (MDM/R) VEE Standard for the Ontario Smart Metering System Issue 1.0*; Attached as Appendix "B").

Bidders are expected to follow this validation process, and as part of this RFP are expected to provide a statement of compliancy that this process will be the standard implemented.

NOTE: As stated in Section 1.2 *Provincial Context for Project* it is NOT NEPA's intention to duplicate infrastructure. NEPA fully supports the intended integration with the centralized MDM/R; VEE according to the IESO rules is required so that validated data is available for NEPA's operational data requirements (i.e. load studies, etc.).

5.3.1 Data Aggregation and Analysis (CI)

The ODS will contain utility analytical tools to enable the aggregation of interval data units into billing determinant format/buckets as required by the NEPA members CIS systems. This will include TOU buckets as provided by the OEB Regulated Price Plan (RPP), Critical Peak Pricing (CPP), and aggregated monthly consumption files for Market Participants.

In addition to data aggregation the ODS calculation engine shall also support advanced calculation capabilities including (but not limited to) the netting of bi-directional meters (enabling net-billing of bi-directional meters), auditable change tracking, the calculation of the maximum demand for any requested customers; when data is requested the proposed ODS solution will calculate (rather than utilize stored values) and calculations will be fully versioned. In addition, the ODS will fully version all formula definitions for calculated channels and registers, and track changes over time as well as corrections. If formulas change over time, the ODS will use the appropriate formula in calculations for each time period.

5.3.2 Ancillary Meter Functions

The ODS application will include the facility to trigger on-demand reads and provide the capacity for revenue protection (theft prevention). To aid in analytical capabilities, we want to ensure that the ODS has the ability to perform comparison scenarios with meter data (i.e. analyze the metering load at a transformer by creating a virtual meter with the load at the homes to perform a comparison and determine losses that exceed a certain prescribed level). The Bidder is to describe how their solution will provide these services.

5.4 Commercial and Industrial Data (I)

As per Section 3.1 *Smart Metering Infrastructure – AMI Landscape* and Section 3.4 *Scope of Work*, NEPA requires a residential ODS solution, however it is a future expectation that Commercial and Industrial data will be aggregated and analyzed within the proposed system.

Bidders are requested to provide details regarding any functionality specific to Commercial and Industrial Metering that have not been explained through responses to other sections within Section 5: *ODS Solution Technical Requirements* of this document.

5.5 ODS System Reporting (I)

To accommodate the provincial requirements for data management NEPA requires that reads missing from the previous 24-hour reporting period ending at midnight must be logged and reported through the system by 6:00 am the following morning. NEPA requires that the ODS make the following reports available according to the same timeline:

- Error,
- Process,
- Event,
- Administration,
- Interactive Graphic and Load Data,
- Statistical,
- Register,

- Manually Edited data, and
- Custom reports utilizing report writers (Crystal, COGNOS, etc).

Bidders are asked to provide description and examples of the above listed reports, and identify whether the information is provided through manually dispatched reports, or automatically dispatched reports.

It is NEPA's preference that the ODS, where possible, accommodate reporting requirements through Exception Reporting. Certain DASHBOARD functions have been identified herein which NEPA has determined would be of particular value in assisting staff with the management of the ODS functions, with the ongoing operational maintenance of AMI, and with the schedule maintenance associated with billing functions.

5.5.1 DASHBOARD: AMI SLA (AMI Performance Levels) (CI)

The ODS, by way of data validation, should be capable of determining the performance levels of the AMI network. We have included the required AMI performance levels in Section 3.3.3 *AMI Service Level Agreement* for reference. As per Section 2.8 *Grounds for Disqualification*, Bidders are required to complete compliancy statements regarding their capacity to perform the necessary audit functions.

It is NEPA's preference that the results of said audits can be displayed graphically, within one screen, or a portion of an Operations screen, demonstrating (at a glance) that the AMI is performing to the required levels and that the ODS functionality allow for the ability to generate emails on exception to advise users when the SLA has not been met. In the event that the AMI is encountering problems, the user should be able to click on the interactive DASHBOARD function and be provided with additional information to explain the problems being encountered (i.e. list of meters not reporting, etc).

If the Bidder does not have a DASHBOARD function to provide this information this should be clearly stated. In this case the Bidder should provide information regarding the level of exception reporting that is inherent to the system, and which might be utilized to determine the level of performance of the installed AMI.

5.5.2 DASHBOARD: Operational Data/Indicators/Events (CI)

It is NEPA's preference that the events produced by the AMI system (outage notification, restoration notification, tamper information, hi/lo voltage indicators, etc) can be displayed graphically, within one screen, or a portion of an Operations screen. In the event that the AMI is encountering problems, the user should be able to click on the interactive DASHBOARD function and be provided with additional information to explain the problems being encountered (i.e. list of meters experiencing power outage, events received to indicate tamper, etc)

If the Bidder does not have a DASHBOARD function to provide this information this should be clearly stated. In this case the Bidder should provide information regarding the level of exception reporting that is inherent to the system, and which might be utilized to efficiently capture events being produced by the AMI.

5.5.3 DASHBOARD: Billing Schedule Maintenance (CI)

It is NEPA's preference that ODS will be able to graphically display, within one screen, or a portion of a billing screen, the current status of the billing schedule. Required information would include cycles billed, cycles pending billing, cycles which have completed validation within the ODS, and cycles being read, as well as the scheduled dates associated with these processes.

If the Bidder does not have a DASHBOARD function to provide this information this should be clearly stated. In this case the Bidder should provide information regarding the level of exception reporting that in inherent to the system, and which might be utilized to efficiently capture events being produced by the AMI.

5.5.4 Reporting: Multiple Systems (I)

It is expected that the operational and performance reporting requirements described through Section 5.5 *ODS System Reporting* will be possible across all meter reading technologies that have been integrated within the ODS, and the ODS will track which meters are to be read by each meter reading technology and the progress of these systems as they deliver data. The ODS will be able to report on the quantity, quality, and timeliness of collected data.

5.5.5 Reporting: Graphing (I)

It is expected that the ODS will provide the ability to produce data graphs and reports for all metered and calculated channels. The system will be flexible, including such functionality as the ability to perform calculations at the time of producing graphs and reports (i.e. the graph or report will calculate and display the result). All graphs and reports shall be viewed within the ODS application user interface, as well as contain the functionality to enable data export to spreadsheets, or be transportable to other electronic file format, and saved as images for use in external reports, etc. Reports will be required to be run in either online or batch mode.

5.5.6 Reporting: Custom Queries (C)

The ODS will be capable of executing custom queries to accommodate any areas where standard reports are not available. The successful Bidder will be required to provide full database documentation (i.e. Data Model Diagrams, Table Relationships, Field Definitions).

As part of their submission, the Bidder should provide a description of how the service is managed in terms of assisting the End-User to understand the data base structures and relationships, the creation/promotion of optimal data queries, and the prevention of machine degradation due to the use of unoptimized queries.

5.5.7 ODS Access

The utilities require that the system be configured in a "Thin Client" so that utility users can access and view data, and as a means to download data in spreadsheet format for ad hoc analysis. Bidder should provide detailed information pertaining to the flexibility and functionality of the proposed solution in this regard, and clearly define the software components residing on the server side and any software components residing on the client side.

5.6 Meter Event Manager (I)

The Bidder should describe their solution’s event management capabilities with regards to receiving, storing, filtering, normalizing, and transferring event data received from any/all meter reading systems. Event data can include power loss, power restore, tamper, tilt, low battery alarms, sags/swells, etc. Event messages from different meters and/or reading systems will be standardized by the ODS solution so that a downstream outage management system can receive the same message for “power off” or “power on” regardless of which meter reading data collection system returned said event. All events received will be stored in the ODS database.

The ODS shall also provide power outage event filtering, such that the downstream outage management system receives only relevant event types, such as power off and power on that are more current than some predefined time period. Event reporting for a given meter shall also be filtered temporarily by the ODS during meter installation and/or scheduled maintenance such that false outages are not transferred to outage management.

5.7 ODS System Disaster Recovery Planning (CI)

The ODS system must reside in Canada, have adequate system redundancy, and the ODS service provider will have recovery planning such that hardware failure at any level of the ODS system will not result in any system downtime lasting more than 2 hours, with no loss in data.

More severe disasters, resulting from more than simple hardware failure (eg. building fire or telecommunications interruption), will be recovered from within 24 hours, with no loss in data. The recovery plan may include having access to a backup ODS server located at a geographically separated site (at least 50 km) and means to publish data on the back-up server. The ODS system provider's disaster recovery plan will include a worst-case provision to ensure that no data is lost.

The Bidder's response should include details regarding the disaster recovery planning that will accommodate both levels of disaster recovery (i.e. 2 hour and 24 hour recovery).

5.8 ODS Performance Service Levels (CI)

AMI Vendors deploying systems in NEPA's service area are expected to perform to the following service levels:

- Percent of hourly (interval) readings captured: 98% in 24 hours
- Percent of daily (register) readings captured: 98% in 24 hours
- In addition to the above requirements, 99% of all readings (99% of register, and 99% of interval) are required in 72 hours (rolling statistic), and 99.5% of all readings (99.5% of register, and 99.5% of interval) are required in 30 days (calendar statistic). These requirements will demonstrate the Vendor's ability to acquire the readings that were missed in 24 hours, over the subsequent time periods (i.e. continued commitment to acquire as many readings as possible).
- Percent of meters communicated within 24 hours: 99.9% (while it is conceded that some meters may be difficult to communicate with, and therefore acquire 100% of the readings 100% of the time, the aim of this statistic is to show that 99.9% of meters can be reached on a daily basis).

It is NEPA's expectation that the ODS system will be able to definitively determine whether the AMI network is satisfying these requirements. The ODS system provider should provide sufficient details to explain how their solution will be able to corroborate the AMI's performance to these service level expectations.

In addition to substantiating the AMI service levels, it is expected that the ODS will provide:

- 99.7% uptime (i.e. 2 hours per month downtime)
- Validated data files within 12 hours (interval data)
- Meter events files within 24 hours
- Alarm notification files immediately (given that the AMI can provide this data, the ODS is expected to filter/scrub alarms against known service orders from CIS)

5.9 Scalability (CI)

The Bidder must describe its proposed ODS data model demonstrating the model's flexibility and scalability to deliver cumulative and interval metering over the next ten years. The system should be designed for a minimum of 250,000 customers, assuming 2 years of online interval data and 7 years off-line data storage. Please specify the methodology for data storage and retrieval.

5.9.1 Ongoing Resource Requirements

Bidders should indicate to NEPA the expected level of resources that is expected to be required for ongoing operation of the proposed ODS solution. NEPA expects that the ODS solution will be managing their entire electric meter population by mid 2010. Assuming a meter population growth resulting for the implementation of gas and/or water AMI, the Bidder should explain how the required resources would be expected to change (or not), beyond 2010.

5.10 ODS System Security (CI)

It is essential that the ODS system have, as a minimum, end-to-end protection against cyber attack and unauthorized intrusions. The Bidder should describe how its ODS ensures against loss or tampering of data. Security requirements are needed to manage the level of access users have, and the Bidder's ODS solution should meet the following minimum standards:

i. The system will contain System Administration and Security Management functions
ii. The system shall support tiered user access levels, to ensure separation of access according to the user's roles and responsibilities.
iii. The system will allow access (with appropriate permissions) to Raw AMI data, VEE formatted data, and Manually Edited data.
iv. Read-only access shall be provided for accessing data by customer, by Site-ID account, or by meter for users for whom those are the reference points, including the ability to reference and search by historical IDs or names and effective dates after changes have been made.
v. All corrections of errors with these entities should also be maintained within the ODS. Functionality should exist to allow comparisons between versions, and also allow previous versions to be restored. For all changes and correction made, information about who (or what system) made the change, when the change was made, and why the change was made shall be maintained and made available through the use of audit logs.
vi. The ODS should be able to integrate to an LDAP directory service for user authentication. This provides the user credentials required for controlling access to the LDC system resources (eg. networks and servers for both external and internal users).

Section 6: Price Submission Requirements

Please note that all documentation must reflect current capabilities. Any future capabilities must be stated as such, and a development schedule outlined.

Describe in detail the pricing for the systems proposed. Detail any assumptions made in the proposed solution and pricing. All of this information should be included within the Pricing and Functionality Spreadsheet. **As per Section 2.4 *Proposal Format Instructions*, any hard copies of the pricing submission should be submitted in a separate envelope, marked "PRICE OFFER".**

In addition to the minimum functionality required by the Ministry of Energy, NEPA is interested in the ability to support load control devices, and multi-utility meters, as this capability is in line with both the intent of the Ministry of Energy, and the service goals of NEPA members. Therefore, in addition to the current data collection requirements outlined in Section 3.3.3 *AMI Service Level Agreement*, NEPA expects to increase non-scheduled data communications to the network. These anticipated communications would in all likelihood include only specific areas, and affect low volumes of meters during any one communication.

6.1 Pricing and Functionality Submission

The Pricing Spreadsheet allows for the Bidder to provide two options for the proposed ODS Infrastructure:

1) Within the tab labelled "Pricing_Option1_ASP" Bidders are required to submit pricing (Capital and 15 year Operating costs) for the proposed ODS Solution, as per the requirements of this RFP document (i.e. ASP model, with capability to accept Sensus AMI network data, perform AMI audit, etc.).
2) Within the tab labelled "Pricing_Option2" Bidders have the option to provide pricing alternative to that provided through Option 1. **NOTE: Pricing Option 1 is required, Pricing Option 2 is optional.** Currently the tab is structured for a license bid price submission, however the Option 2 tab has been provided in the event that Bidders feel that Pricing outside of an ASP model can better represent their model, and will allow Bidders to be creative in demonstrating the value of their solution (i.e. Bidders are free to modify the tab to demonstrate such options as higher upfront capital to allow decreased O&M costs, etc.).

6.2 Incremental Costs

In addition to the Pricing Options described in Section 6.1 *Pricing and Functionality Submission*, Bidder's are required to submit the incremental cost for any functionality that is discussed in their proposal which does not come standard with their product. If an incremental cost is not provided, it is NEPA's understanding that the functionality comes standard with the product being proposed.

Section 7: Contract Terms and Conditions

7.1 Commencement of Contract Time

The successful Vendor shall be notified by NEPA of acceptance of the Vendor's Submission by NEPA sending a Purchase Order. The Vendor shall acknowledge receipt within ten days of the date of sending of the Purchase Order.

The Contract Time shall commence to run on the effective date indicated in the Purchase Order. Vendor shall start to perform the work on the date when the Contract Time commences.

7.2 Vendor Claims

All claims of the Vendor and all questions relating to the interpretation of the Contract, including all questions as to the acceptable fulfillment of the Contract on the part of the Vendor and all questions as to compensation, shall be submitted in writing to the NEPA Project Manager for determination.

All such determinations and other instructions of NEPA will be final unless the Bidder shall file with NEPA a written protest, stating clearly, and in detail the basis thereof, within fifteen (15) calendar days after NEPA notifies the Bidder of any such determination or instruction. NEPA will issue a decision upon each such protest within fifteen (15) calendar days and its decision will be final. Work will not be undertaken until a written final decision is rendered.

7.3 Changes in the Work

NEPA, without invalidating the Contract, may direct the Vendor to perform extra work or make changes in the work, provided that all changes or additions form an inseparable part of the work contracted for. Vendor shall make such changes or additions only after receipt of written instructions to do so from NEPA. If such changes or additions cause an increase or decrease in the cost of the Contract, or in the time required to complete the Contract, the adjustment to the contract price or time frames shall be as set out in the Change Order and the Contract shall be modified accordingly.

When a change is ordered, a change order shall be executed by NEPA and the Vendor before any change order work is performed. Any increase or decrease in the contract price and the time required for the completion of the contract work due to a change order shall be specifically set out in the change order. All terms and conditions contained in the Contract documents shall be applicable to change order work. The amount of any increase or decrease shall be added to or subtracted from the contract price as appropriate.

7.4 Delays & Extension of Time

If the Vendor is delayed at any time in the progress of the work by any act or neglect of NEPA, or any cause beyond the Vendor's reasonable control, he shall file with NEPA a notification that an extension of the Contract period is required.

The NEPA Project Manager shall review said notice and to the extent that the Vendor can reasonably demonstrate to NEPA Project Manager that it shall be delayed in its fulfillment of these terms and conditions and other obligations of this transaction due to a cause beyond its control, a reasonable extension period shall be granted.

7.5 Termination of Right to Proceed

NEPA may, in writing, terminate this Contract in whole or in part at any time, either for NEPA's convenience or for the default of the Vendor. Upon such termination, all data, plans, specifications, reports, estimates, summaries, completed work and work in process, and such other information and materials as may have been accumulated by the Vendor in performing this Contract shall, in the manner and to the extent determined by NEPA, become the property of NEPA. If the termination is for the convenience of NEPA and without default by the Vendor, an equitable adjustment for the Vendor's direct costs and profit for work actually performed shall be made by mutual agreement between the Vendor and NEPA. No amount shall be allowed for anticipated profit on unperformed services. Any expense incurred because of cost of completion by NEPA is chargeable to and shall be paid by the Vendor. The total liability to the Vendor shall be limited to the Contract value less the value of any equipment, material or completed services retained by NEPA member utilities.

Default occurs if the Vendor (1) abandons the work called for hereunder, (2) files a voluntary petition in bankruptcy or fails to obtain dismissal of an involuntary petition in bankruptcy within sixty (60) days after the filing thereof or has a Receiver/Trustee appointed, (3) becomes insolvent, (4) assigns this Contract or sublets any part of the work hereunder without prior written permission of NEPA, (5) repudiates the Contract, (6) allows liens to be filed against property of NEPA, (7) fails to meet or perform its obligations hereunder after five days notice or continues in chronic default of its obligations, (8) disregards laws, ordinances, rules and regulations related to the Contract and the work or disregards instructions of NEPA, (9) fails to complete the work in accordance with the Contract.

7.6 Right to Operate Unsatisfactory Equipment

If the operation or use of the materials or equipment after delivery and/or installation does not comply with the technical requirements set out in the Contract Documents to NEPA, NEPA shall have the right to operate and use such materials or equipment until such deficiency can be reasonably corrected provided that the period of such operation or use pending correction shall not impede or delay the ability of the Vendor to perform corrections. Such operation and use shall not constitute an acceptance of any part of the work, nor shall it relieve Vendor of any requirements of the Contract, nor shall it act as a waiver by NEPA of any requirement of the Contract.

7.7 Casualty Insurance

Before commencing work under this contract the Vendor at his own expense shall submit Certificates of Insurance, providing evidence acceptable to NEPA indicating that the Vendor has obtained and will maintain insurance for the duration of the contract. The following requirements apply to all Certificates of Insurance:

1) The insurance shall be written by an insurer acceptable to NEPA,
2) The insurance shall be primary to any coverage carried by NEPA.
3) The Vendor further agrees to provide NEPA with an executed Certificate of Insurance before commencement of work, and with written copies of the insurance policies at any time upon the written request of NEPA.
4) The Certificate of Insurance shall be an original copy signed by an authorized representative of the insurance carrier(s). (Note – faxed copies may be accepted initially to be followed up by originals in a reasonable length of time.)
5) The Certificate of Insurance shall provide that no less than 30 days advance notice will be given in writing to NEPA prior to cancellation, termination or alteration of the insurance coverage. NEPA shall be named as an additional insured on each General Liability Insurance Policy and any Excess Liability Policy or Umbrella Policy used to meet the required general liability limits.

The types of coverage and minimum limits are as follows:
1) GENERAL LIABILITY*
    a) $4,000,000 each occurrence

b) $6,000,000 general aggregate

2) AUTOMOBILE LIABILITY*
   a) Bodily injury $1,000,000 per person
   b) $1,000,000 per accident
   c) Property damage $500,000 or
   d) Combined Single Limit $1,000,000

** A blanket, umbrella, and/or excess liability policy(s) may be utilized to increase limits to the desired level(s).*

7.8 Subcontractors

NEPA reserves the right to refuse to permit any person or organization (subcontractor) to participate in the work covered by this Contract, such refusal shall not be unreasonably imposed. No subcontract shall relieve the Vendor of any liabilities or obligations under the Contract, and the Vendor agrees that Vendor is fully responsible to NEPA for the acts and omissions of Vendor's subcontractors and of persons employed by them. Vendor shall require every subcontractor to comply with the provisions of the Contract.

7.9 Payment

Payment shall be made based upon completion of the performance milestones itemized below.
Vendor shall submit to NEPA a request for payment for each milestone that has been met. Payment for each milestone shall also be contingent on successful completion of the preceding milestones.

1) Fifteen percent (15%) of the contract price will be paid after the successful Acceptance Test, which requires delivery and integration of the system head-end.
2) Twenty five percent (25%) of the contract price will be paid after delivery of 35% of the communication infrastructure and 35% of the new meters and other customer premises equipment.
3) Twenty percent (20%) of the contract price will be paid upon successful installation, operation and route Acceptance of the equipment described in (2) above and delivery of an additional 30% all equipment on NEPA's system.
4) Twenty percent (20%) of the contract price will be paid upon successful installation, operation and route Acceptance of the equipment described in (3) above and delivery of all remaining system elements.
5) Twenty percent (20%) upon completion of system installation, Acceptance of all routes, and delivery of all documentation, judged by NEPA to be acceptable, in any event not longer than 90 days after complete installation.

NEPA will make payment within thirty (30) days of receipt of a request for payment, if above conditions are met.

When the Vendor has completed all work in accordance with the terms of the Contract Documents, the Vendor shall submit to NEPA a request for final payment. The request for final payment shall constitute a waiver of all claims by the Vendor except for claims specifically listed in the request.

Vendor's submission of its request for final payment shall constitute its warrant that the Vendor has to the best of its knowledge fully completed all work included in the Contract and has fully paid for labour, materials, equipment, services, taxes and all other costs and expenses resulting from this Contract.

7.10 Acceptance

These terms and conditions becoming binding when the Vendor's Submission chosen for acceptance by NEPA is given written notice of acceptance of the submission.

No modification hereof and no condition stated by Vendor in accepting or acknowledging this order, which is in conflict or inconsistent with, or in addition to the terms and conditions set forth herein, shall be binding upon NEPA unless accepted in writing by NEPA.

7.11 Shipments

Vendor shall mail Bill of Lading and Shipping Memo to destination, and NEPA's Project Manager.

Vendor shall notify the NEPA Project Manager promptly if unable to make shipment. Shipments shall be made to multiple destinations in NEPA's service territories for logistical convenience. Such shipment instructions will be stated in the purchase contract that will be developed between the selected Vendor and NEPA.

7.12 Prices

Vendor agrees that prices are firm unless otherwise noted, and Vendor warrants that said prices do not exceed the prices allowed by any applicable Federal, Provincial or Local regulation.

7.13 Compliance with Laws

Vendor warrants that in performing work under this order Vendor will comply with all applicable laws, rules and regulations of governmental authorities and agrees to indemnify and save NEPA harmless from and against any and all liabilities, claims, costs, losses, expenses, and judgments arising from or based on any actual or asserted violation by the Vendor of any such applicable laws, rules and regulations.

7.14 Patents

Vendor agrees to protect and save harmless NEPA from all costs, expenses or damages, arising out of any infringement of claim or infringement or Patents in NEPA's use of material or equipment furnished pursuant to this order.

7.15 Assignment

Vendor agrees that neither this order nor any interest herein shall be assigned or transferred by Vendor except with the prior written approval of NEPA.

7.16 Substitution

No substitution will be permitted under this order except on specific written authority of NEPA's Project Manager.

Appendix A

Ministry of Energy (MoE) Functionality Specification for an Advanced Metering Infrastructure Version 2 (Dated July 5, 2007)

FUNCTIONAL SPECIFICATION

FOR AN

ADVANCED METERING INFRASTRUCTURE

VERSION 2

July 5, 2007

FUNCTIONAL SPECIFICATION

FOR AN ADVANCED METERING INFRASTRUCTURE

Table of Contents

FUNCTIONAL SPECIFICATION

FOR AN ADVANCED METERING INFRASTRUCTURE

1.0 APPLICATION OF SPECIFICATION

This Specification sets the required minimum level of functionality for AMI in the Province of Ontario for residential and small general service consumers where the metering of demand is not required. This Specification is not intended to apply to net metering applications.

2.0 FUNCTIONAL SPECIFICATION

2.1 Deployment

This Specification shall be met regardless of the size or scope of the AMI deployment by a distributor.

2.2 Minimum Functionality

2.2.1 As a minimum:

2.2.1.1 AMI shall collect Meter Reads on an hourly basis from all AMCDs deployed by a distributor and transmit these same Meter Reads to the AMCC and MDM/R, as required, in accordance with these Specifications; and

2.2.1.2 A Meter Read shall be collected, dated and time stamped at the end of each hour (i.e. midnight as represented by 24:00).

2.2.2 The date and time stamping of Meter Reads shall be recorded as year, month, day, hour, minute (i.e. YYYY-MM-DD hh:mm).

2.2.3 All meters shall have a meter multiplier of one (1).

2.2.4 Distributors shall provide the MDM/R with the service multiplier for transformer-type meters.

2.3 Performance Requirements

2.3.1 Collection and Transmission of Meter Reads:

2.3.1.1 AMI shall successfully collect and transmit to the AMCC and MDM/R at least 98.0% of the Meter Reads from all AMCDs deployed by a distributor in any Daily Read Period.

2.3.1.2 Meter Reads unsuccessfully collected or transmitted shall not be due to the same AMI component (including, without limitation, any AMCD) during any three (3) month consecutive time period.

2.3.1.3 AMI shall be able to collect and transmit Meter Reads during its operating life without requiring a field visit.

2.3.2 Transmission Accuracy: Over the Daily Read Period, 99.9% of the Meter Reads received by the AMCC shall contain the same information as that collected by all AMCDs deployed by the distributor.

2.3.3 AMI shall be capable of providing Meter Reads with a precision of at least 10 Watt-hours (0.01 kWh).

2.4 Technical Requirements

2.4.1 When an AMI includes AMRCs, the AMRCs shall have the ability to store meter data to accommodate the performance requirements in section 2.3.1.

2.4.2 Time Synchronization:

2.4.2.1 AMI shall be operated and synchronized to Official Time, as set by the National Research Council of Canada.

2.4.2.2 AMI shall have the capability of adjusting for changes due to local daylight savings time.

2.4.2.3 AMI installed within a distributor’s service area shall have the capability of accommodating more than one (1) time zone.

2.4.2.4 Time synchronization shall be maintained in the AMI to the specified accuracy parameters set out in section 2.4.3.1 following a loss of power.

2.4.2.5 All Meter Reads shall adhere to accurate time synchronization processes to ensure an accurate accounting of electricity consumption at each meter.

2.4.3 Time Accuracy:

2.4.3.1 At all times, time accuracy in the AMI shall not exceed a ±1.5 minute variance from the time established in section 2.4.2.1.

2.4.3.2 AMI shall be able to prove that time accuracy does not exceed the permitted time variance identified in section 2.4.3.1.

2.4.4 Loss and Restoration of Power:

2.4.4.1 AMI shall detect and identify the interval in which a loss of power occurred during a Daily Read Period.

2.4.4.2 AMI shall detect and identify the interval in which power was restored following a loss of power.

2.4.5 Environmental Tolerances: All AMI components (except the AMCC) shall operate and meet the requirements in these Specifications within a temperature range of minus thirty degrees Celsius (–30° C) to positive sixty-five degrees Celsius (+65° C), and within a humidity range of zero percent (0%) to ninety-five percent (95%) non-condensing.

2.5 Advanced Metering Communication Device (AMCD)

2.5.1 Installation Within the Meter:

2.5.1.1 The AMCD shall not impair the ability of the meter to be visually read.

2.5.1.2 Meters in which an AMCD is installed shall be able to be installed in existing meter sockets or enclosures.

2.5.1.3 AMCD shall meet or exceed ANSI standards to withstand electrical surges and transients.

2.5.2 Labelling:

2.5.2.1 The AMCD shall be permanently labelled with:

(1) Legally required labelling;

(2) Manufacturer’s name;

(3) Model number;

(4) AMCD identification number;

(5) Input/output connections;

(6) Date of manufacture; and

(7) Bar code for tracking and inventory management.

2.5.3 When installed at a consumer’s location, the meter shall visibly display, as a minimum, the AMCD identification number, meter serial number and LDC badge number for the meter.

2.5.4 The AMCD shall be able to be initialized or programmed during, or prior to, field installation.

2.6 Transmission of Meter Reads

2.6.1 All Meter Reads collected during the Daily Read Period shall be received by the AMCC and transferred to the MDM/R no later than 5:00 a.m. local time following the Daily Read Period.

2.6.2 Meter Reads are not required to be transmitted in a single transmission and may be transmitted as frequently as necessary in order to meet the requirements in section 2.6.1.

2.6.3 AMCC shall transfer the information identified in section 2.6.1 using an approved protocol and file structure.

2.7 Advanced Metering Regional Collectors (AMRC)

2.7.1 LAN Communication Infrastructure:

2.7.1.1 The spectrum allocation and wattage of the radio signal used by an AMI shall not impede neighbouring frequencies.

2.7.2 When an AMI includes AMRCs:

2.7.2.1 The AMI shall provide for the continuous powering of AMRCs regardless of their location and placement.

2.7.2.2 All AMCDs shall be able to collect and transmit Meter Reads when one or more AMRC has a loss of power.

2.7.2.3 Memory and software parameters shall be maintained at all AMRC during a loss of power, whether by the provision of backup/alternate power or other solution.

2.8 Advanced Metering Control Computer (AMCC)

2.8.1 Each AMCC shall have the ability to store a rolling sixty (60) days of Meter Reads.

2.8.2 A distributor shall not aggregate Meter Reads into rate periods or calculate consumption data from the Meter Reads collected through its AMI either in its AMCC or any other component.

2.8.3 The AMCC shall be able to perform basic operational verification of Meter Reads received before transmitting these Meter Reads to the MDM/R.

2.9 Customer Account Information

2.9.1 Distributors shall provide initial information associated with customer accounts to the MDM/R on a date to be determined.

2.9.2 On an ongoing basis, distributors shall provide information associated with any change to the initial information identified in section 2.9.1 to the MDM/R at a frequency to be determined.

2.9.3 Information to be provided to the MDM//R pursuant to sections 2.9.1 and 2.9.2 is to be determined.

2.10 Monitoring & Reporting Capability

2.10.1 The AMI shall have non-critical reporting functionality and critical reporting functionality as required in this section 2.10. Information generated from this reporting functionality shall be available to the MDM/R.

2.10.2 Non-critical reporting:

2.10.2.1 At the completion of every Daily Read Period and following a transmission of Meter Reads, the AMCC shall generate a status report that includes information regarding anomalies and issues affecting the integrity of the AMI or any component of the AMI including information related to any foreseeable impact that such anomalies or issues might have on the AMI's ability to collect and transmit Meter Reads.

2.10.2.2 In addition to section 2.10.2.1, the AMCC shall generate reports:

(1) Confirming successful initialization of the AMCD's installed in the field;

(2) Confirming data linkages among an AMCD identification number, LDC badge number, serial number and customer account;

(3) Confirming that the MDM/R has successfully received notification of any changes to customer account information;

(4) Confirming that the AMCC has successfully made changes to customer account information following receipt of same from the MDM/R;

(5) Confirming the successful collection and transmission of Meter Reads or logging all unsuccessful attempts to collect and transmit Meter Reads, identifying the cause, and indicating the status of the unsuccessful attempt(s) pursuant to section 2.3.1;

(6) Confirming the accuracy of the Meter Reads received by the AMCC pursuant to section 2.3.2;

(7) Confirming that all Meter Reads have a precision of at least 10 Watt-hours (0.01 kWh) pursuant to section 2.3.3;

(8) Confirming whether the Meter Reads acquired within the Daily Read Period are in compliance with the time accuracy levels identified in section 2.4.3;

(9) Confirming whether time synchronization within the AMI or any components of the AMI has been reset within the Daily Read Period;

(10) Identifying the intervals in which a loss of power occurred and at which power was restored, following a loss of power;

(11) Addressing the functionality of the AMCD communication link, including status indicators related to the AMCD and AMRC;

(12) Identifying suspected instances of tampering, interference and theft;

(13) Flagging potential network, meter and AMCD issues; and

(14) Identifying any other instances that impact or could potentially impact the AMI's ability to collect and transmit Meter Reads to the AMCC and/or MDM/R on a daily basis.

2.10.2.3 Following a transmission of Meter Reads or at the completion of every Daily Read Period, the information in section 2.10.2.2 (5) shall be stored and used by the AMCC to assess compliance with the requirement specified in section 2.3.1.2.

2.10.2.4 The reports generated in sections 2.10.2.1 and 2.10.2.2 shall be made available to the MDM/R with a frequency to be determined.

2.10.3 Critical reporting:

Critical events are defined to include any AMI operational issue that could adversely impact the collection and transmission of Meter Reads during any Daily Read Period.

2.10.3.1 The AMI shall identify and report the following to the distributor:

(1) AMCD failures;

(2) AMRC failures;

(3) Issues related to the storage capacity of any component of the AMI;

(4) Communication links failures;

(5) Network failures; and

(6) Loss of power and restoration of power.

2.10.3.2 The reports generated in section 2.10.3.1 shall be made available to the MDM/R.

2.11 Security and Authentication:

2.11.1 The AMI shall have security features to prevent unauthorized access to the AMI and meter data and to ensure authentication to all AMI elements.

2.12 Proven Technology

2.12.1 The AMI shall be a technology that has been proven to reliably comply with these Specifications.

2.13 Regulatory Requirements

2.13.1 The AMI shall meet all applicable federal, provincial and municipal laws, codes, rules, directions, guidelines, regulations and statutes (including any requirements of any applicable regulatory authority, agency, board, or department including Industry Canada, the Canadian Standards Association, the Ontario Energy Board and the Electrical Safety

Authority) (collectively, "**Laws**"). For greater certainty, the AMI shall meet all applicable Laws that are necessary for the measurement of data and/or the transmission of data to and from the consumers within the Province of Ontario, including Laws applicable to metering, safety and telecommunications.

2.14 Water or Natural Gas Meter Reads

2.14.1 The AMI should be capable of supporting an increased number of Meter Reads associated with the reading and transmission of water and/or natural gas meters through additional ports on the AMCD, through optionally available multi-port AMCDs, or through additional AMCD/AMRC devices that are compatible with operating on the AMI. When procuring AMI, distributors shall obtain an indication of the capabilities of the proposed AMI to read water and natural gas meters, indicating the makes and models of such meters that can be read, and any requirements for retrofitting them.

3.0 DEFINITIONS

Within this Specification the following words and phrases have the following meanings:

"AMCC" is an advanced metering control computer that is used to retrieve or receive and temporarily store Meter Reads before or as they are being transmitted to the MDM/R. The information stored in the AMCC is available to log maintenance and transmission faults and issue reports on the overall health of the AMI to the distributor.

"AMCD" is an advanced metering communication device that is housed either under the meter's glass or outside the meter. It transmits Meter Reads from the meter directly or indirectly to the AMCC.

"AMI" means an advanced metering infrastructure. It includes the meter, AMCD, LAN, AMRC, AMCC, WAN and related hardware, software and connectivity required for a fully functioning system that complies with this Specification. With some technologies, an AMI does not include AMRCs. An AMI does not include the MDM/R.

"AMRC" is an advanced metering regional collector that collects Meter Reads over the LAN from the AMCD and transmits these Meter Reads to the AMCC.

"consumer" or "customer" means a person who uses, for the person's own consumption, electricity that the person did not generate.

"distributor" has the meaning provided in the *Ontario Energy Board Act, 1998*.

"Daily Read Period" means the 24-hour period for collecting Meter Reads, subject to the two periods annually during which changes to and from daylight savings time take place. The Daily Read Period ends at 12:00 midnight of each day.

"LAN" means a local area network, the communication network that transmits Meter Reads from the AMCD to the AMRC.

“meter multiplier” is the factor by which the register reading must be multiplied to obtain the registration in the stated units.

“Meter Read” is a number generated by a meter that reflects cumulative electricity consumption at a specific point in time.

“MDM/R” means the meter data management and meter data repository functions within which Meter Reads are processed to produce rate-ready data and are stored for future use.

“Specification” means these functional specifications.

“transformer-type meter” means a meter designed to be used with instrument transformers.

“WAN” means a wide area network, the communication network that transmits Meter Reads from the AMRC to the AMCC or, in some systems from the AMCD directly to the AMCC, and from the AMCC to the MDM/R.

Appendix B

Meter Data Management
and Repository (MDM/R)
VEE Standard for the
Ontario Smart Metering System
Issue 1.0

STANDARD

Meter Data Management and Repository (MDM/R)

VEE Standard for the Ontario Smart Metering System

Issue 1.0

This document provides the Standards for Validation, Estimation, and Editing of Meter Read Data performed by the MDM/R for the Ontario Smart Metering System

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Status of this Standard

This document was placed under formal change control on March 20, 2008 with the posting of Issue 1.0. However, as of this date, portions of Sections 3, 4, 5, 6 and 7 pertaining to Commercial & Industrial metering are still under review and may be subject to revision. These sections have been highlighted in "yellow".

Document ID	IESO_STD_0078
Document Name	Meter Data Management and Repository (MDM/R) - VEE Standard for the Ontario Smart Metering System
Issue	Issue 1.0
Reason for Issue	VEE Standard issued under formal change control.
Effective Date	March 20, 2008

Document Change History

Issue	Reason for Issue	Date
0.1	Draft VEE Standard for discussion with SMSIP Working Group	January 3, 2007
0.2	Updated and presented to the SMSIP Working Group Sub-committee	January 8, 2007
0.3	Updated and presented to the SMSIP Working Group Sub-committee	January 12, 2007
0.4	Updated with SMSIP Working Group Sub-committee	January 14, 2007
0.5	Updated with Input from Sub-committee members	January 25, 2007
0.6	Updated with Information from the MDM/R Detail Design Document Version 1.9	March 15, 2007
0.7	Updated to incorporate changes per the review of the VEE Sub-Committee	March 19, 2007
0.8	Update of Table 7-5 Default VEE Services Configuration	March 22, 2007
0.9	General revision to reflect additional detail provided in Version 2.0 of the Detailed Design	March 7, 2008
1.0	Document placed under formal change incorporating input of the SMSIP Working Group VEE Sub-Committee	March 20, 2008

Related Documents

Document ID	Document Title	Issue
Ontario Regulation 440/07	*Functional Specification for an Advanced Metering Infrastructure – Version 2*	July 5, 2007
Ontario Energy Board	*Distribution System Code*	Last Revised on June 27, 2007
MDM/R Detailed Design	*Meter Data Management and Repository MDM/R V1.0 Detailed Design Version 2.0*	March xx, 2008
IESO_SPEC_9027	*MDM/R V1.0 Technical Interface Specifications Version 2.3*	30 November 2007
SME_SPEC_0001	*MDM/R V1.0 Reports Technical Specifications Version 2.6*	14 February 2008
Ontario Energy Board Smart Meter Implementation Plan	*Draft Report of the Board For Comment*	November 9, 2004
SOR/86-131	*Electricity and Gas Inspection Regulations*	January 28, 2008

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Table of Changes

The following is a summary of changes to this document from Issue 0.8 dated March 22, 2007.

Reference (Section and Page)	Description of Change
Title Page	• Revised document title
Related Documents	• Updated reference to AMI Function Specification • Updated reference to Distribution System Code • Updated reference to MDM/R Detailed Design Document • Added references to MDM/R Technical Interface Specifications and MDM/R Reports Technical Specifications • Added reference to the Electricity and Gas Inspection Regulations
Section 1, pages 1-3	• Updated role of the OEB as described in the Introduction • Added assumptions regarding net metering and metering for all classification of generators • Updated description of Section 2
Section 2, pages 7-14	• Expanded description of AMI Quality and Completeness tests and Data Quality flags • Relocated and updated new Section 2.3.1 from Section 3 • Relocated and updated new Section 2.3.2 from Section 4 • Added new Section 2.3.3 providing descriptions of Data Collection and VEE Reports
Section 3, pages 15-22	• General re-organization of this section for clarity (changes not tracked) • Update throughout to describe ‘message’ validation services • Update of descriptions of all validation checks to provide greater specificity • Added initial draft of validation services for C&I metering
Section 4, pages 23-29	• General re-organization of this section for clarity (changes not tracked) • Update throughout to describe ‘message’ estimation routines • Update of descriptions of all estimation routines to provide greater specificity • Added initial draft of estimation services for C&I metering
Section 5, page 33	• Added initial draft of editing support for C&I metering
Section 6, pages 35-37	• Update of descriptions of Billing Validation Sum Check to provide greater specificity • Added initial draft of estimation services for C&I metering

Section 7, pages 39-52	• General re-organization of this section for clarity (changes not tracked) • Update throughout to describe 'message' validation and estimation routines • Update of descriptions of all validation and estimation parameters to provide greater specificity • Update of descriptions of Billing Validation Sum Check parameters to provide greater specificity • Additions to VEE Services tabulation to reflect additional parameters • Added placeholder for C&I metering VEE Services
Section 7.2, Table 7-5, pages 50-51	Updates to validation parameters for default VEE Services based on review and input by the SMSIP Working Group VEE Sub-Committee • Confirmed application of the Maximum Demand Check to VEE Services 02, 03, 04, 05, 06, and 07 by setting 'Maximum Demand Check' check service parameter to "Y" • Confirmed application of the Consecutive Zeros Check to VEE Services 02, 03, 04, 05, 06, and 07 by setting 'Consecutive Zeros Check' check service parameter to "Y" Updates to estimation parameters for default VEE Services based on review and input by the SMSIP Working Group VEE Sub-Committee • Disabled Linear Interpolation for VEE Services 03, 04, 05, 06, and 07 setting 'Max Interpolation Minutes' to zero • Confirmed use of Register Read Scaling for VEE Services 03, 04, 05, 06, and 07 setting 'Register Read Allocation' parameter to "Y" • Confirmed use of Newest Like Day for VEE Services 03, 04, 05, 06, and 07 setting 'Newest Like Day Method' parameter to "Newest Like Day" and 'Newest Like Day Limit' parameter to "1" day • Confirmed use of Class Load Profile estimation only for VEE Service 07 – Seasonal establishing the following parameter settings: o 'Use Class Load Profiles' = "Y" o 'Class Profile ADU Min Days' = 5 days o 'Class Profile ADU Oldest Day' = 30 days o 'Class Profile ADU Newest Day' = 1 day Established initial Billing Validation Sum Check parameter settings based on review and input by the SMSIP Working Group VEE Sub-Committee • For VEE Services 01 and 02 o 'BillingSumCheck' = "N" • For VEE Services 03, 04, 05, 06, and 07: o 'BillingSumCheck' = "Y" o 'BillingSumCheckFail Action' = "Value" o 'MaxRegisterRange' = "1" hour o 'NoRegRead Action' = "Fail" o 'ThresholdType' = "Ratio" o For 03, 04, 07 'ThresholdValue' = "0.010" (i.e. 1%) o For 05 and 06 'ThresholdValue' = "0.005" (i.e. ½ %)

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1. Introduction

This document has been prepared in consultation with the sub-committee members of the SMSIP Joint Working Groups as a draft Validation, Estimation and Editing (VEE) Standard for further consideration by the Joint Working Group.

The OEB does not envision approving the VEE rules developed by the IESO SMSIP Working Group. The Board does expect that, at a minimum, the rules would comply with 5.3.2 and 5.3.3 of the *Distribution System Code*.

1.1 Purpose

The purpose of this document is to establish a province wide validation, estimation standard and editing guideline for Meter Read data collected for electricity smart meters in the province of Ontario.

1.2 Scope

The scope of this document is the validation and estimation and editing standards for smart metering used for the following:

- Residential or small general service consumers where the metering of demand is not required for single phase and three phase installations either self-contained or transformer type meters.

- Commercial and Industrial consumers where the metering of demand is required for single phase and three phase installations either self-contained or transformer type meters involving multiple channel and multiple data type metering.

1.3 Who Should Use This Document

This document should be used by Local Distribution Companies, Advance Metering Infrastructure Operators, and the Smart Metering Entity for use in applying the VEE services described herein.

1.4 Assumptions and Limitations

- Wholesale metering installations registered with the IESO are not subject to the VEE services described in this document.

- Net metering and the metering for all classifications of generators are outside the current scope of the MDM/R and the VEE Services described in this document.

- Missing meter read data that requires estimation or editing will not be reported by the MDM/R for customer presentation.

- The sub-committee members of the SMSIP Joint Working Groups preference would be that weather normalization factors be applied to estimated Meter Reads. This MDM/R functionality is not being anticipated in the initial implementation of the MDM/R unless directed by the Ontario Energy Board. Future stages of MDM/R implementation may support this functionality.

- VEE Services provided by the MDM/R shall apply only to Smart Meters that conform to the criteria described in the *Functional Specification for an Advance Metering Infrastructure*.

- The VEE Services described in this document shall only be applied to physical Service Delivery Points.

1.5 Conventions

The standard conventions followed for this document are as follows:

- The word “shall” denotes a mandatory requirement,
- Title case is used to highlight process or component names; and
- *Italics* are used to highlight publication, titles of procedures, letters and forms

1.6 Roles and Responsibilities

Role of the Smart Metering Entity

The role of the Smart Metering Entity will be the configuration and maintenance of VEE Services to be applied to Meter Read data transmitted to the MDM/R by LDCs across the province of Ontario. VEE Services beyond a set of default VEE Services may be configured by the MDM/R Administrator to support additional LDC needs. Any such additional VEE Services will be available to all LDCs.

Role of Local Distribution Companies

The role of the local distribution company shall be to apply the available VEE Services appropriately to all Service Delivery Points within their service territory.

LDC’s will be responsible to validate all Meter Read data that has been identified by the MDM/R as “Needs Validation or Editing” (NVE).

1.7 How This Document Is Organized

This document is organized as follows:

- **Section 2** of this document provides an overview of the Application of the Validation, Estimation, and Editing Standards; the AMI to MDM/R Interface, and MDM/R Data Collection and Reporting Services.

- **Section 3** of this document provides a description of Validation Standards for residential or small general service consumers where the metering of demand is not required and commercial and industrial consumers where the metering of demand is required including meters involving multiple channels and multiple data type metering installations.

- **Section 4** of this document provides a description of Estimation Standards for residential or small general service consumers where the metering of demand is not required and commercial and industrial consumers where the metering of demand is required including meters involving multiple channels and multiple data type metering installations.

- **Section 5** of this document provides a description of Editing Guidelines for residential or small general service consumers where the metering of demand is not required and commercial and industrial consumers where the metering of demand is required including meters involving multiple channels and multiple data type metering installations.

- **Section 6** of this document provides a description of the Billing Quantity Validation Services for residential or small general service consumers where the metering of demand is not required and commercial and industrial consumers where the metering of demand is required including meters involving multiple channels and multiple data type metering installations.

- **Section 7** of this document provides a description of the Validation, Estimation and Editing services for residential and small commercial consumers, commercial and industrial consumers where the metering of demand is required including meters involving multiple channels and multiple data type metering installations.

1.7.1 Definition of Terms used in this Document

Within this document the following words and phrases have the following meanings:

"**AMCC**" means the Advanced Metering Control Computer that is used to retrieve or receive and temporarily store Meter Reads before or as they are being transmitted to the MDM/R. The information stored in the AMCC is available to log maintenance and transmission faults and issue reports on the overall health of the AMI to the LDC.

"**AMI**" means the Advanced Metering Infrastructure, it includes the 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. An AMI does not include the MDM/R.

"AMCD" is an Advanced Metering Communication Device that is housed either under the meter's glass or outside of the meter. It transmits Meter Reads from the meter directly or indirectly to the AMCC.

"AMRC" is an Advanced Metering Regional Collector that collects Meter Reads over the local area network from the AMCD and transmits these Meter Reads to the AMCC.

"**Billing Quantity**" refers to consumption data that has been through VEE and is ready for use in billing.

"**Billing Multiplier**" is a factor that shall be applied to Meter Reads from metering installations where instrument transformers including current transformers (CT) and potential transformers (PT) are installed. For transformer type metering installations this factor shall be the product of the current transformer ratio, the potential transformer ratio and the meter multiplier. All conforming Smart Meters shall have a meter multiplier of one (1) in accordance with the Functional Specification for an Advanced Metering Infrastructure. Transformer loss factors for primary installations shall not be included in the determination of this factor.

Where no external instrument transformers are installed such as for self-contained meters this factor shall be one (1) in accordance with the *Functional Specification for an Advanced Metering Infrastructure*.

"Commercial and Industrial customers" refers to commercial and industrial consumers where the metering of demand for billing purposes is required.

"**Consumer**" or "**customer**" refers to residential or small general service consumers where the metering of demand is not required.

"**Daily Read Period**" means the 24-hour period for collecting Meter Reads, subject to the two periods during which changes to and from Daylight Savings Time take place. The Daily Read Period commences at 12:00 midnight of each day.

"**kWh**" means kilowatt-hour.

"**LDC**" means a Local Distribution Company, which is a LDC, as defined in the Ontario Energy Board Act, 1998.

"**Meter Read**" is a number generated by a meter that reflects cumulative electricity consumption at a specific point in time. (The Meter Read and related data will be reported to the MDM/R at a specific Service Delivery Point).

"**Meter Read Block**" is used by the MDM/R for validation and estimation purposes. All validation and estimation functions are based on acting upon a set of contiguous intervals bounded by a start register read and a stop register read. In some instances a Meter Read Block the data will span two or more Meter Transfer Blocks. For a Meter Transfer Block consisting of interval consumption data with a register reading at the end of a set of interval consumption data, the start register read for the Meter Read Block will be the immediately preceding (contiguous) stop register read.

"Meter Transfer Block" is a set of data transferred from an AMCC (or other system) to the MDM/R relating to meter reads for a specific Universal SDP ID. A Meter Transfer Block is a set of interval consumption data with a register reading at the end of the set of interval data, or a set of interval register reads for a number of contiguous intervals.

"**MDM/R**" means the meter data management and meter data repository functions within which Meter Reads are processed to produce Billing Quantity data and the storage of data for future use.

"**SDP**" means the Service Delivery Point at which delivery is metered or calculated. The SDP is the point at which billing occurs based on input from one or more smart meters.

"**VEE**" means validation, estimating and editing of Meter Reads to identify and account for missed and inaccurate reads used to derive billing data.

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2. Application of the VEE Standards

The Validation, Estimation and Editing Standards offer a series of checks that can be performed against a Meter Transfer Block. Several of the Validation and Estimation checks have variable configurable parameters. These parameters allow for the configuration of the actions taken should the Meter Transfer Block fail the various validation and/or estimation checks.

This section provides a description of the application of these standards by the Smart Meter Entity in establishing default VEE Services or specific VEE Services necessary to support additional LDC needs.

This section also provides a description of the AMI to MDM/R Interface including the quality and completeness tests that are expected to be performed by the Advance Metering Infrastructure prior to the transmission of meter read data to the MDM/R, and MDM/R Data Collection and Reporting Services.

2.1 Application of Standards

The diversity of consumer types, load usage patterns, geographic location, and other variables within Ontario necessitate the creation of a number of VEE Services. Multiple VEE Services will provide the ability to modify the validation and estimation parameters to better meet the VEE needs of a consumer group.

Default VEE Services offered to LDCs will be administered by the Smart Metering Entity and will be available for use throughout the province via the MDM/R.

Creation, maintenance and administration of any additional LDC specific VEE Services once created by the Smart Meter Entity shall be made globally available to all LDCs via the MDM/R.

2.2 AMI – MDM/R Interface

2.2.1 Quality and Completeness Tests Performed by the AMI

It is expected that certain quality and completion tests are performed by the AMI systems prior to the Meter Read data being sent to the MDM/R. Test results are in the form of interval data flags associated with the Meter Reads, in a particular Meter Transfer Block being sent to the MDM/R. These types of tests are listed below:

- Pulse Over Flow Check;
- Test Mode Check;
- Meter Diagnostic Check;

- Reverse Energy Check;
- Time Change Check; and
- Loss and Restoration of Power

Pulse Overflow Check

Pulse Overflow conditions are normally a result of improper scaling factors within the meter, improper instrument transformer sizing or a meter hardware failure. A meter sets a Pulse Overflow flag when the energy consumption in an interval exceeds the range of the interval. This flag generally indicates a serious problem with the meter installation or the meter itself. These metering conditions must be physically investigated and corrected by the LDC.

The AMI System must be capable to analyse and identify the intervals for this condition and flag them with a “PulseOverflow” flag prior to providing the Meter Read Data to the MDM/R. The MDM/R inspects Meter Read Blocks received with this condition and validates the data, estimates the data or flags it for verification or editing by the LDC based on the VEE Service parameter.

Test Mode Check

The Test Mode condition is normally performed at the metering installation by a metering technician. This test requires the meter to be placed in a test mode and possibly have a simulated load condition applied to the meter to verify the meter’s accuracy. The AMI System identifies the interval(s) where the usage is recorded by the meter in a Test Mode and provides this information to the MDM/R. Intervals received and flagged with a “test mode” indicator will be validated, estimated or flagged for verification or editing by the LDC based on the VEE Service parameter.

Meter Diagnostic Check

The AMI System may be capable to identify intervals for various meter diagnostic problem existing prior to providing the Meter Read data to the MDM/R. The Meter Read Blocks provided to the MDM/R with such conditions may be validated, estimated or flagged for verification or editing by the LDC based on the VEE Service parameter.

Reverse Energy Check

The AMI System may be capable to identify intervals for reverse energy condition exists prior to providing the Meter Read Data to the MDM/R. The Meter Read Blocks provided to the MDM/R with such conditions may be validated, estimated or flagged for verification or editing by the LDC based on the VEE Service parameter.

Time Change Check

Time change checks are performed within the AMI system to verify that the components used for data collection are within the acceptable time thresholds as described in the, “*Functional Specification for an Advanced Metering Infrastructure*.” The Time Change Flag indicates that the meter time was adjusted during the interval and the interval may be either shorter or longer than the specified interval at which the data is to be collected. Meter Read Blocks provided to the MDM/R with time change flags may be validated, estimated or flagged for verification or editing by the LDC based on the VEE Service parameter.

Loss and Restoration of Power

Loss of power is a condition where the supply of electricity to the AMCD and/or AMRC has occurred. This failure could be as a result of a LDC distribution supply failure or the operation of an electricity disconnect prior to the AMCD and/or AMRC device.

Restoration of power is a condition where the supply of electricity to the AMCD and/or AMRC has been re-established.

The AMI system shall detect and identify the interval(s) in which a loss of power occurred and identify the interval(s) in which the restoration of power occurred. These interval flags made available to the MDM/R are required to assure accurate validation and estimation of data for each SDP.

2.2.2 Data Quality Flags Provided by the AMI

AMI systems may provide additional data quality flags that will be recognized by the MDM/R and recorded as part of the meter data record.

Data quality flags do not represent validation tests but simply set data quality flags and failure codes in the MDM/R Meter Data Database. Data quality flags are applied as part of the meter data collection process. The data quality flags that are transferred vary by AMCC type and may set corresponding MDM/R flags. In addition to the quality and completeness test flags used for validation, the MDM/R will store the following data quality flags.

Partial Data

The MDM/R inspects each interval for a partial data flag. The ‘PARTIAL_INTERVAL’ flag is set in the Meter Data Database of each interval for which the AMCC reports a partial data condition.

Short Interval

The MDM/R inspects each interval for a short interval flag. The ‘SHORT_INTERVAL’ flag is set in the Meter Data Database of each interval for which the AMCC reports the interval to be shorter than the specified interval at which the data is to be collected.

Long Interval

The MDM/R inspects each interval for a long interval flag. The ‘LONG_INTERVAL’ flag is set in the Meter Data Database of each interval for which the AMCC reports the interval to be longer than the specified interval at which the data is to be collected.

Data Collection Estimation

The MDM/R inspects each interval for a data collection estimation flag. The ‘DC_DATA_ESTIMATION’ flag is set in the Meter Data Database for each interval for which the AMCC reports the interval has been estimated outside the MDM/R as part of the data collection process. This flag sets the Validation Status to EST (estimated) and sets the Change Method to EXT (external – indicating estimation performed external to the MDM/R). Other Validation checks work normally and can re-set the Validation Status; failure codes, and estimation Change Method on failure of such tests.

2.3 MDM/R Data Collection and Reporting Services

2.3.1 Meter Read Data Validation During Loading

These services are performed immediately upon receipt of the Meter Transfer Block from either an AMCC, manual input or other system(s). The AMCC generates the Meter Transfer Block file that is transferred to the MDM/R. The MDM/R will process the files through a series of processes as outlined in the table below.

Type	Description	Pass	Fail
Syntactic Check	The structure of the file is validated against the appropriate file format for the specific AMCC.	• Acknowledgement back to LDC or AMI Operator. • Continue Processing Data.	• The LDC or AMI Operator is notified of rejected data records flagged as invalid.
Semantic Check	The content of the file is checked for validity and to determine whether a power outage, power restoration, or meter rollover has occurred.	• Continue Processing Data • Power outage, restoration, and meter rollovers are flagged	• The LDC or AMI Operator is notified of rejected data records flagged as invalid
Other Meter Read Data Loading Services			
Application of CT/PT Multiplier	Interval consumption data is multiplied by the CT/PT Multiplier set for each SDP through the synchronization process. Register reads are stored "as received" and no multiplier is applied		
Calculation of Interval Consumption from Register Reads	In the event that the AMCC only delivers register reads, the MDM/R calculates the corresponding interval consumption data prior to loading data into the Meter Data Database. Interval consumption data is stored at the same granularity of the Meter Read data as received from the AMCC (e.g. Meter Read data received at 5-minute intervals will be stored as 12 values). The register reads are also stored. The CT/PT Multiplier is applied when creating the associated interval consumption data. Register reads are stored "as received" and no multiplier is applied.		
Treatment of Missing Reads and Zero Reads	Zero reads are stored as an actual Meter Read of zero. Missing reads are detected by the MDM/R, stored as zero and flagged as 'No-Data' but may be estimated during VEE.		

Table 2-1 Pre-VEE Processes

2.3.2 Meter Read Data Transmission

The following sections describe the sets of data that may be transmitted from the various AMCC technologies to the MDM/R. These data sets are defined as Meter Transfer Blocks. Also described is the application of message validation and estimation services to the Meter Read Block as used by the MDM/R for validation and estimation.

"**Meter Transfer Block**" is a set of data transferred from an AMCC (or other system) to the MDM/R relating to Meter Read data for a specific SDP. A Meter Transfer Block is a set of interval consumption data with a register reading at the end of the set of interval data (see Figure 2-1), or a set of interval register reads for a number of contiguous intervals (see Figure 2-2).

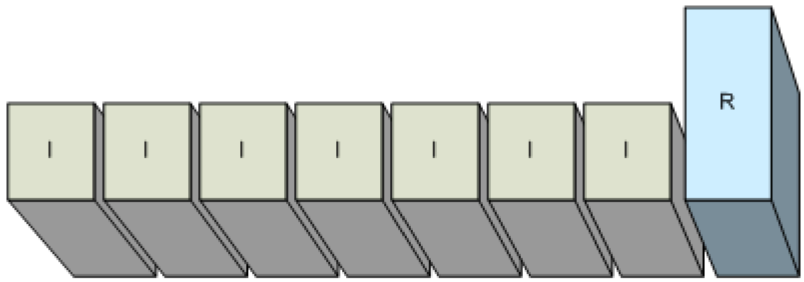

Figure 2-1 Cumulative Interval Consumption with a Stop Register Read

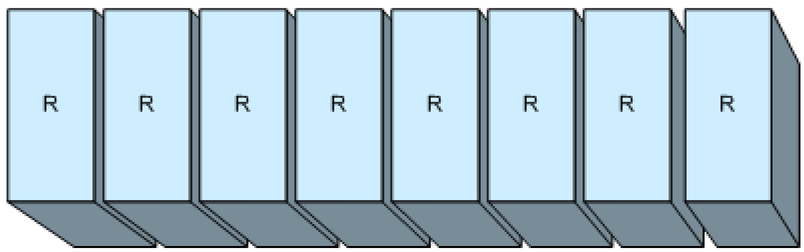

Figure 2-2 Register Reads For Each Interval

"**Meter Read Block**" is used by the MDM/R for validation and estimation purposes. Certain validation and estimation functions are based on acting upon a set of contiguous intervals bounded by a start register read and a stop register read. In some instances a Meter Read Block (see Figure 2-3) may span two Meter Transfer Blocks. For a Meter Transfer Block consisting of interval consumption data with a register reading at the end of a set of interval consumption data, the start register read for the Meter Read Block will be the immediately preceding (contiguous) stop register read.

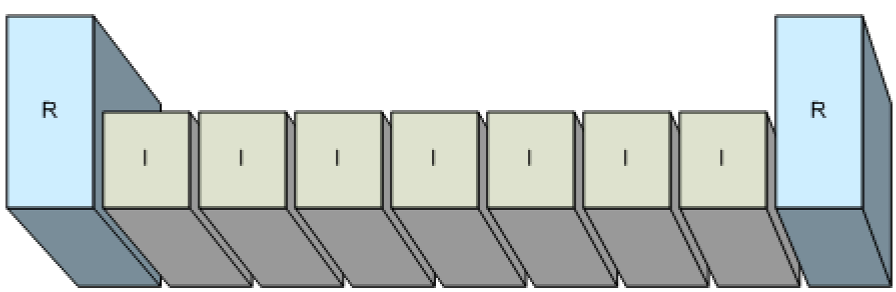

Figure 2-3 Interval Consumption with Start and Stop Register Reads

A Meter Transfer Block may be transmitted comprised of a stop register read only, with no associated interval consumption (see Figure 2-4). Such register read transmissions will be stored in the Meter

Data Database but will not trigger any validation algorithm or estimation algorithm for the estimation of the missing intervals.

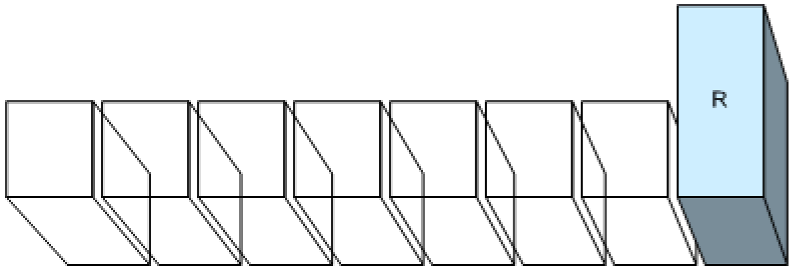

Figure 2-4 Stop Register Read Only, with No Interval Consumption

In Figure 2-5 the start register read (on the left) and subsequent interval consumption (below in grey) are stored in the MDM/R. Interval flags check; Maximum Demand Check, and Spike Check will be performed and if estimation is called for by the VEE Service, estimation will be attempted. The Sum Check will not be performed on the initial Meter Transfer Block. The new Meter Transfer Block contains a stop register read (on the right) but no interval consumption data. As with Figure 2-4 this register read transmission will be stored in the Meter Data Database but will not trigger any validation algorithm or estimation algorithm for the estimation of the missing intervals.

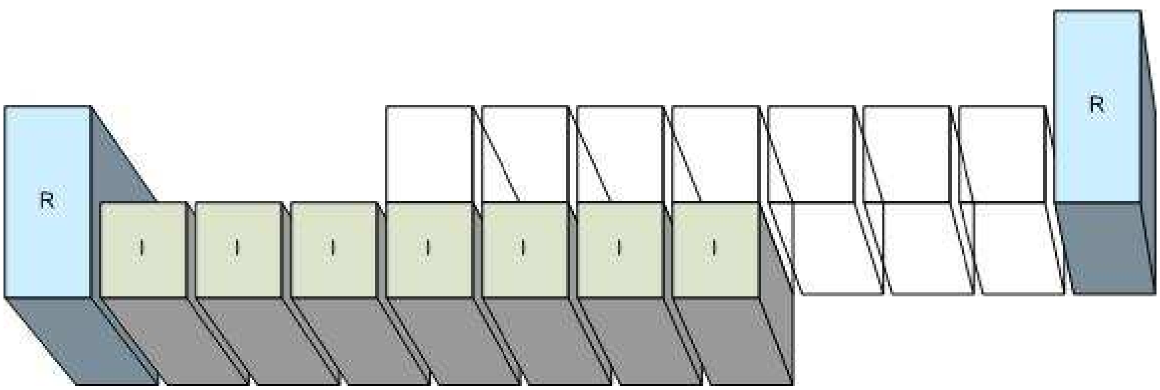

Figure 2-5 Meter Change with Incomplete Intervals

A Meter Transfer Block may be transmitted comprised of interval consumption only, with no associated stop register read (see Figure 2-6). Interval flags check; Maximum Demand Check, and Spike Check will be performed and if estimation is called for by the VEE Service, estimation will be attempted. The Sum Check will not be performed.

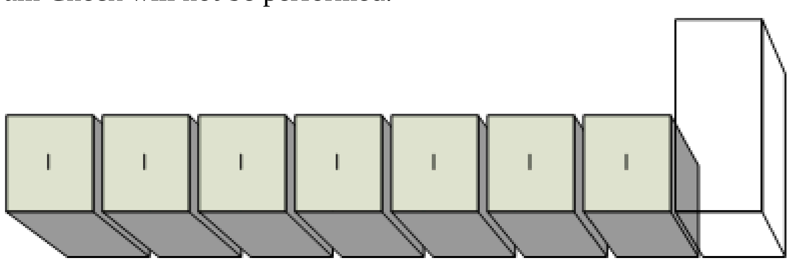

Figure 2-6 Interval Consumption with no Stop Register Read

In Figure 2-7 the stop and start register reads already exist in the MDM/R but with either no interval consumption data or perhaps estimated consumption data in between. The new Meter Transfer Block (below, grey) may provide, for example, edits to replace missing values or actual reads to replace estimated reads. This provides the LDC with the ability to send in edited meter reads or actual meter reads to fill in the gap between two register reads.

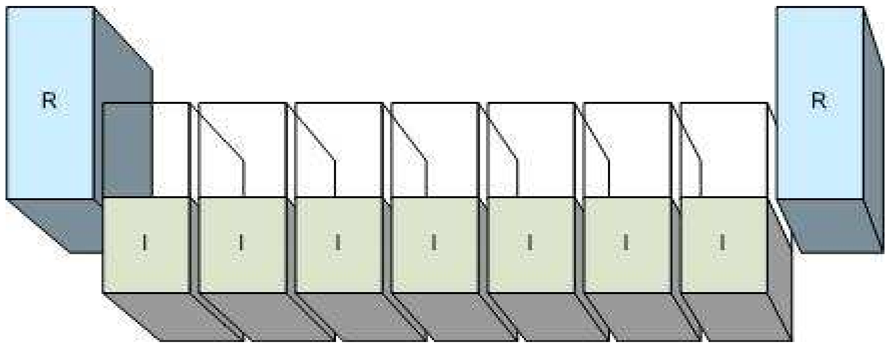

Figure 2-7 Edits Performed between Register Reads

2.3.3 Data Collection and VEE Reporting

The MDM/R provides daily reporting of the data collection processes and generates operational reports that detail the results. Complete specifications for these reports can be found in the MDM/R V1.0 Reports Technical Specifications. The data collection reports are as follows:

- DC01: Daily Read Status Report – providing a total count of meters for which data was received in the prior day segmented by AMCC type.
- DC02: Excessive Missing Reads Report – identifying meters that have failed to transmit register data for more than five days in a 10-day window.
- DC03: Interim Read Validation Failure Report – identifying *Meter Read* data files that have failed the incoming validation process for *Meter Read* data delivered to the MDM/R between midnight and the daily morning deadline for receipt of data for the prior *Daily Read Period* 'N'.
- DC13: Final Read Validation Failure Report – identifying *Meter Read* data files that have failed the incoming validation process for *Meter Read* data delivered to the MDM/R during the entire previous day 'N+1'.
- DC04: Missing Reads Detail Report – providing a listing of those meters for which data was not received for the most recent *Daily Read Period* 'N'.
- DC05: Daily Data Collection Report – providing a total count of meters for which data was received in the prior day segmented by AMCC type and read age.

- DC06: Interim AMCC Data Collection Summary Exception Report – providing a summary of all exceptions encountered during the processing of *Meter Read* data files delivered to the MDM/R between midnight and the daily morning deadline for receipt of data for the prior *Daily Read Period* 'N'.

- DC16: Final AMCC Data Collection Summary Exception Report – providing a summary of all exceptions encountered during the processing of *Meter Read* data files delivered to the MDM/R during the entire previous day 'N+1'.

- DC07: Interim AMCC Data Collection Detailed Exception Report – providing a listing of all exceptions encountered during the processing of *Meter Read* data files delivered to the MDM/R between midnight and the daily morning deadline for receipt of data for the prior *Daily Read Period* 'N'.

- DC17: Final AMCC Data Collection Detailed Exception Report – providing a listing of all exceptions encountered during the processing of *Meter Read* data files delivered to the MDM/R during the entire previous day 'N+1'.

The MDM/R also provides daily reporting of the validation and estimation processes and generates operational reports that detail the results. Complete specifications for these reports can be found in the MDM/R V1.0 Reports Technical Specifications. The VEE reports are as follows:

- VE01: Interim Validation Failure Detail Report – providing a listing of all meters where Meter Transfer Block data has failed one or more of the validation checks for Meter Read data files delivered to the MDM/R between midnight and the daily morning deadline for receipt of data for the prior Daily Read Period 'N'.
- VE11: Final Validation Failure Detail Report – providing a listing of all meters where Meter Transfer Block data has failed one or more of the validation checks for Meter Read data files delivered to the MDM/R during the entire previous day 'N+1'.
- VE02: Interim Estimation Failure Detail Report – providing a listing of all meters where Meter Transfer Block data could not be estimated and the reason why for Meter Read data files delivered to the MDM/R between midnight and the daily morning deadline for receipt of data for the prior Daily Read Period 'N'.
- VE12: Final Estimation Failure Detail Report providing a listing of all meters where Meter Transfer Block data could not be estimated and the reason why for Meter Read data files delivered to the MDM/R during the entire previous day 'N+1'.
- VE03: Missing Interval Aging Report – providing a listing of those meters for which data was not received within the previous 3 calendar days.
- VE04: VEE Summary Report – providing summary number counts for the results of the validation; estimation; and verification/editing processes.

– End of Section –

3. Validation Standards

Validation is applied by the MDM/R in two ways: 1) data validation performed during loading of Meter Read data and 2) by the application of Daily Validation Services. Meter Read data validation during loading is applied to Meter Transfer Blocks received from all Smart Metering installations. The Daily Validation Services are applied in accordance with VEE Services defined for the type of consumer and metering installation. Daily Validation Services are configured to identify Meter Reads that fall outside of acceptable tolerance(s) and anomalies recorded by the meter.

The following sections describe the Meter Read data validation during loading, and the missing read checks.

- Validation Services for Residential or Small General Service Consumers, and
- Validation Services for Commercial and Industrial Consumers with the metering of demand with multiple channel metering.

3.1 Residential or Small General Service Consumers

Validation must be based on the characteristics of the data on hand. The list of checks and criteria itemized in the following sections shall be applied during validation of data collected by the AMI and transmitted to the MDM/R for consumers where the metering of demand is not required.

Validation will be performed for each Meter Transfer Block received from the AMI as part of Message Validation Services for residential or small general service consumers.

3.1.1 Message Validation Services

Validation Services are performed immediately upon completion of the Meter Read data load validation services for each applicable Meter Transfer Block. These services are performed on Meter Transfer Blocks received from the AMI or other systems. The validation checks performed on each Meter Transfer Block are referred to as message validation services.

Message validation service checks must be performed at the appropriate point in the data processing cycle of the MDM/R. Without strict adherence to the processing cycle, the validation service may fail resulting in invalid data. Some of these quality and completion checks must be performed by the AMCC and are described in section 2.2 of this document. Other validation checks within the MDM/R can be performed any time after data collection and before Billing Quantity generation. Billing Validation processes act upon the output from the Billing Quantity generation process and are described in Billing Validation Services section 6 of this document.

3.1.2 Overall Control

This parameter determines whether or not any validation and estimation is undertaken. If set to 'N' (No) then none of the following tests are undertaken. If the parameter is set to 'Y" (Yes), then all of the following tests that are enabled are undertaken.

Validation Check Sequence – Validation checks are performed in the following order:

1. Missing Intervals Check
2. Interval Flags Check
    a. Test Mode Check
    b. Pulse Overflow Check
    c. Time Change Check
    d. Meter Diagnostic Check
    e. Reverse Energy Check
3. Maximum Demand Check
4. Spike Check
5. Sum Check
6. Consecutive Zeros Check

3.1.3 Missing Intervals Check

The validation process identifies any gaps in interval consumption data within a Meter Transfer Block or between Meter Transfer Blocks and flags these gaps for Estimation or for verification/editing by the LDC based on the VEE Service parameter. Intervals for which a power outage is detected are not flagged as missing.

Power Outage Detection Within a Meter Transfer Block – This power outage detection algorithm identifies sections of missing intervals (i.e. 'NO_DATA' intervals) within a Meter Transfer Block that are part of a power outage. This algorithm for power outage detection is:

1. Within the Meter Transfer Block contiguous 'NO_DATA' intervals on either side of an "Outage" interval are flagged as 'POWER_OFF' and the 'NO_DATA' flag is cleared in these intervals.

2. An "Outage" interval is defined as:

    a. An interval with the 'POWER_OFF' flag set,
    OR

    b. An interval with the 'POWER_ON' flag set.

The "Outage" interval definition addresses data collection systems that may not set a power outage flag for an interval that contains a power restore event. A power restore event ('POWER_ON') in an interval implies that a power outage state ('POWER_OFF') was true at some point in the interval.

Power Outage Detection Between Meter Transfer Blocks – This power outage detection algorithm identifies sections of missing intervals between Meter Transfer Blocks that are part of a power outage. This algorithm for power outage detection is:

1. If the first interval of the of the current Meter Transfer block has a ‘POWER_ON’ flag set, get the interval record from the Meter Data Database for the last interval received prior to the start of the current Meter Transfer block
    a. If the last prior interval from the Meter Data Database has a ‘POWER-OFF’ flag set to ‘Y’, the section of missing intervals between Meter Transfer Blocks is part of a power outage. In this case set the ‘POWER_OFF’ flag to ‘Y’ and the interval value to ‘0’ for every missing interval between the last prior interval and the start of the current Meter Transfer Block.
    b. If the ‘POWER_OFF’ flag is not set for the last prior interval from the Meter Data Database, the section of missing intervals between Meter Transfer Blocks is NOT part of a power outage. In this case set the ‘NO_DATA’ flag to ‘Y’ for every missing interval between the last prior interval and the start of the current Meter Transfer Block.

3.1.4 Interval Flags Check

The Interval Flags Check handles all single-interval checks – checks that can be done without comparing intervals to other intervals. This includes the Missing Intervals Check described above as well as the validation checks described below.

Test Mode Check

The MDM/R inspects each interval for a Test Mode Flag. An interval with the Test Mode flag set fails validation only if the interval consumption is non-zero. If zero usage is recorded for the intervals in which the meter was in test mode, (i.e. meter was bypassed during testing) this data is considered valid.

Many meters will register 0 interval consumption while in test mode, thus if the meter records usage in test mode, the data does not represent actual Customer consumption.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

Pulse Overflow Check

The MDM/R inspects each interval for a Pulse Overflow Flag. A meter sets a Pulse Overflow flag when the energy consumption in an interval exceeds the range of the interval. This flag generally indicates a serious problem with the meter installation or the meter itself.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

Time Change Check

The MDM/R inspects each interval for a Time Change flag. The Time Change Flag indicates that the meter time was adjusted during the interval and the interval may be either shorter or longer than the specified interval at which the data is to be collected. The Time Change flag is maintained since intervals with Time Change are not used in Demand computations.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

Meter Diagnostic Check

The MDM/R inspects each interval for a Meter Reset Flag. The meter read interface adaptor maps the meter diagnostic flags from each individual type of device to the Meter Reset Flag a part of the Data Collection process. (Reference MDM/R Technical Interface Specifications, Meter Read Interface – for each AMI technology.)

Meter diagnostic error flags generally indicate a serious meter problem but may not necessarily indicate that the interval data is erroneous.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

Reverse Energy Check

The MDM/R inspects each interval for a Reverse Rotation Flag.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

3.1.5 Maximum Demand Check

The Maximum Demand Check is a conditional test enabled or disabled for each specific VEE Service by a “check” product parameter.

The MDM/R compares each interval consumption value against the Maximum Demand Value specified in the VEE Service parameter. Interval values represent fully scaled kWh quantities including the CT/PT Multiplier. The Maximum Demand Value is in fully scaled kW.

The Maximum Demand Value (in kW) is divided by the number of intervals per hour (intervals/hr) providing an energy equivalent Maximum Interval Value (in kWh per interval). Each interval consumption value (in kWh) is then compared to the Maximum Interval Value. Interval consumption values greater than the Maximum Interval Value will fail the Maximum Demand Check and the ‘Maximum Demand Action’ will be performed.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

3.1.6 Spike Check

The Spike Check is a conditional test enabled or disabled for each specific VEE Service by a "check" product parameter.

The MDM/R may perform a spike check on each Meter Transfer Block to identify intervals with high consumption relative to the surrounding intervals. The spike check validation is performed as follows:

- Identify the highest and Nth highest interval values where N is a VEE Service parameter. The default value for N is 3.
- If the highest interval has already failed a prior validation check, then spike check is not performed.
- If the highest interval is less than or equal to the configurable Spike Check threshold, skip the spike check. The Spike Check Threshold value is specified in kWh units. The Spike Check Threshold is set in the VEE Service parameters.
- If the Nth highest interval is less than or equal to the configurable Spike Check threshold, skip the spike check. Otherwise, subtract the Nth highest interval from the highest interval and divide by the Nth highest interval. The algorithm is as follows:
  (highest interval - Nth highest interval)/Nth highest interval)
- The MDM/R will apply the following pass/fail criteria to the data set:
  - If ((highest interval - Nth highest interval)/Nth highest interval) <= threshold (a configurable value) the interval passes the spike check.
  - If ((highest interval - Nth highest interval)/Nth highest interval) > threshold (a configurable value), the interval fails the spike check and the 'Spike Check Action will be performed.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

3.1.7 Sum Check

The Sum Check is a conditional test enabled or disabled for each specific VEE Service by a "check" product parameter.

The Sum Check is performed after other validation checks and will only be performed if the Meter Transfer Block passes the Missing Intervals Check and all intervals have passed the previous validation tests flagged as validated (including "soft fail" intervals).

The MDM/R performs a sum check on the Meter Read Block. Should the absolute value of the Sum Check difference exceed the threshold this validation fails, and all interval records in the Meter Transfer Block will be flagged with the failure.

- The Meter Transfer Block must include at least one Register Read with a timestamp that is between the earliest and the latest interval timestamps in the Transfer block, i.e. the register read occurred during one of the intervals in the block. The Register Read with a timestamp at the end of a Meter Transfer Block is defined as the End Read. For the purposes of this

Sum Check the timestamp for the End Read is defined to be the reading at the end of the interval in which the reading was taken.

- Intermediate Register Read Conversion to End Read – A by-product of validation is that the Validator calculates the End Read from the Intermediate Register Read (IRR) value if all of the intervals between the two are valid. An Intermediate Register Read is defined as a Register Read with a timestamp that is between the earliest and the latest interval timestamps in the Transfer block. IRR conversion is performed using the following logic:
  IF:
  End Read is null AND Intermediate Register Read is null, do not perform Sum Check
  IF:
  End Read is null AND Intermediate Register Read is NOT null, calculate End Read from Intermediate Read and the sum of the valid intervals between the Intermediate register Read and the end of the Meter Transfer Block
  IF:
  End Read is not null, use End Read supplied as part of the Meter Transfer Block
- The Sum Check test will retrieve the most recent register reading and interval data from the Meter Data Database. This register read is defined as the Start Read and for the purposes of the Sum Check its timestamp is defined as the end of the interval in which if occurred.
- The Sum Check will subtract the Start Read from the End Read and compute the difference. If the value is negative the meter register has "rolled over" and 1 x 10^N will be added to the negative difference value where N is 4, 5 or 6 whichever will results in a positive value. The N reflects the number of meter register digits. For example add 100,000 to the negative difference value for a 5 dial meter.
- Sum Check failure is determined as follows. The sum of the interval consumption for intervals between the Start Read and End Read is divided by the CT/PT Multiplier and compared to the un-scaled register read difference. If the absolute value of the difference is greater than the Msg Sum Check Threshold, the 'Msg Sum Check Action' will be performed.

  |(∑ Interval values / CTPT Multiplier) **-** *(RR_Difference)| > Msg Sum Check Threshold*

  Note: When used with different CT/PT Multipliers, this algorithm tests that the tolerance is within the unscaled register readings. For example, if the CT/PT Multiplier was 80.0 and the Msg Sum Check Threshold was also 1.0, the Sum Check would test that the dial reading was within 1, meaning that the kWh was within 80.
- Meter Change and CT/PT Multiplier Change Detection – Because of the logic leading up to a Sum Check, it is not expected that a meter change event or CT/PT Multiplier change event would be the cause of a Sum Check failure. Nevertheless, if a sum check fails, the Validator does check for a meter change and/or CT/PT Multiplier value change event before reporting a sum check failure.
  A Sum Check failure is disregarded if a meter change or CT/PT Multiplier relationship change occurred anywhere in the time span delimited by a Start Read time and End Read time relative to the dataset being evaluated.

This test can be configured to validate with the failure flagged (i.e. soft failure), or require verification/editing. The 'estimate' action is not available for the Sum Check.

3.1.8 Extra-Message Checks

The Consecutive Zeros Check acts on data beyond the Meter Read data contained in a Meter Transfer Block.

Consecutive Zeroes Check

The Consecutive Zeros Check is a conditional test enabled or disabled for each specific VEE Service by a "check" product parameter.

A "Zero Interval" is defined as an interval where:

- Interval Value = 0
- NO_DATA is false (i.e. the 0 value is not the result of Missing Intervals)
- POWER_OFF is false
- POWER_ON is false

The MDM/R checks the Meter Transfer Block for consecutive zero values. The Consecutive Zeros Check is performed as follows:

IF there is at least one contiguous section of Zero Intervals in the dataset equal to or longer than 'Consecutive Zeros Threshold' THEN:

- Set 'ZER' bit in each Zero Interval FAIL_CODE
- Take action specified by 'Consecutive Zeros Action'

IF the dataset contains one or more trailing Zero Intervals, query Meter Data Database for count of adjacent later Zero Intervals. If the count of adjacent later Zero Intervals + count of leading Zero Intervals is longer than 'Consecutive Zeros Threshold' (hours) THEN:

- Set 'ZER' bit in each leading Zero Interval FAIL_CODE
- Take action specified by 'Consecutive Zeros Action'

IF the dataset contains one or more trailing Zero Intervals, query Meter Data Database for count of adjacent later Zero Intervals. If the count of adjacent later Zero Intervals + count of leading Zero Intervals is longer than 'Consecutive Zeros Threshold' (hours) THEN:

- Set 'ZER' bit in each trailing Zero Interval FAIL_CODE
- Take action specified by 'Consecutive Zeros Action'

A Consecutive Zeros Check does not flag prior or later intervals that are discovered in the Meter Data Database to be part of a consecutive zeros failure.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimated, or require verification/editing.

3.2 Commercial and Industrial Consumers with metering of Demand (Multiple channel metering)

Data collection for Commercial & Industrial metering is expected to provide measurement data beyond the kWh data and associated register readings provided by metering used for Residential and Small General Service Customers where metering of demand is not required.

The MDM/R adaptors used for C&I Customers must be able to support kWh, kW, kVA, kVAh, kVAR, and kVARh along with associated registers.

3.2.1 Message Validation Services available to C&I Metering

Message validation services used for Residential and Small General Service Customers will also be available for use for C&I Customers.

3.2.2 Additions to Validation Services to Support C&I

The following validation check specific to C&I meters will be supported by the MDM/R.

kVARh Check

The kVARh check is performed to identify intervals where reactive load (kVARh) is present and active load (kWh) is not, indicating a suspicious usage pattern and possible meter malfunction. This check is only required when both kWh and kVARh are used for billing. If kVARh data is available but not used for billing, the check is optional. This check may be done on either consumption or pulse data, provided the data scaling is consistent throughout the period

– End of Section –

4. Estimation Standards

The MDM/R Estimation Standards applies a method that is operationally manageable and maintainable and is fair to Residential and Small General Service Customers where the metering of demand is not required, and Commercial and Industrial customers with the metering of demand is required.

The MDM/R Estimation Standard is consistent with the standard described in the "Ontario Energy Board, *Distribution System Code*, Last revised on June 27, 2007 (Originally Issued on July 14, 2000)" Section 5.3.2, specifically:

> "A distributor shall establish a VEE process according to local practice that is fair and reasonable and provides assurance that correct data is submitted to the settlement process."

This section provides a description of the application of the MDM/R Estimation Standards to:

- Residential or small general service consumers where the metering of demand is not required for single phase and three phase installations either self-contained or transformer type meters.

- Commercial and Industrial consumers where the metering of demand is required for single phase and three phase installations either self-contained or transformer type meters involving multiple channel and multiple data type metering.

4.1 Residential or Small General Service Customers

Estimation standards described in this section of the document refer to residential or small general service consumers where the metering of demand is not required. While other methods may arguably provide more accurate estimates the solution chosen uses historical data from a SDP to provide estimates that are representative of historical consumption at that SDP while providing computationally manageable overhead for 4.5 million meters or more.

4.1.1 Message Estimation Routines

Gaps or errors in interval data may be estimated by the MDM/R as they are identified in the validation process. Estimation for filling gaps between Meter Transfer Blocks is limited by the 'Max Estimation Days' parameter and gaps that exceed this value are not estimated. These estimations are performed on interval records marked as 'data requires estimation' by the validation processing.

Message estimation does not extend beyond the most recent Meter Transfer Block received. The Billing Validation process will call exception handling processes that will attempt use estimation to complete interval data that is missing at the end of a Billing Period. This includes extrapolation[1] of

[1] Billing Validation Extrapolation is a deferred delivery component – reference Component 27, MDM/R Change Request MCR No. 003.

interval data and associated reframing to generate complete Billing Quantities to the required End Date.

4.1.2 Linear Interpolation

If a section of data needing estimation is less than ‘Max Interpolation Minutes’ in length (e.g. 60 minutes) then this estimation uses linear interpolation to compute the interval values. If the ‘Max Interpolation Minutes’ is set to zero this method is not used.

Use point-to point linear interpolation to estimate the data using before and after endpoints, where:

1. Endpoints must be intervals with a validation status of ‘validated’ (VAL) including “soft fail” intervals. Intervals containing a power failure cannot be used as end points for linear interpolation.
2. If the section occurs in the middle of the Meter Transfer Block, the “first point” is the last valid interval before the section, and the “second point” is the first valid interval after the section.
3. If the section occurs at the beginning of the Meter Transfer Block, use the last interval from the historical data as the first point if the historical data is available and valid.

If before and after endpoints are not available, the interval(s) requiring linear interpolation will be flagged as PTS (i.e. no endpoints) with a validation status of ‘needs verification or editing’ (NVE).

4.1.3 Historic Estimation

If the section of data needing estimation is more than the ‘Max Interpolation Minutes’ and less than the ‘Max Estimation Days’ then estimation will be performed by averaging intervals from like day types to create a Daily Profile for the period to be estimated. A Daily Profile is a ranked list of valid reference days and the interval consumption value for each interval in the Daily Profile is simply the average of the interval values for the reference days.

If the section of data to be estimated exceeds ‘Max Estimation Days’ the intervals will be flagged as ‘GAP’ with a validation status of ‘needs verification or editing’ (NVE).

Use the average of selected reference days to estimate interval consumption data as follows:

- Only “validated” intervals can be used. Valid intervals are defined as those that have a validation status of VAL (including “soft fail” intervals and intervals that have been “verified” i.e. change method code ‘VER’). Estimated intervals with a validation status of (EST) cannot be used.
- Data from days with a power failure cannot be used. Power failures can cause irregular usage patterns, resulting in data that is not typical for the Customer.
- The earliest possible reference date is calculated as the ‘Oldest Like Day’ before the section of data needing estimation.
- The latest possible reference date is calculated as either:

    a. The ‘Newest Like Day’ past the last day in the section of data needing estimation, or

b. The last day of the same billing cycle as the last day in the section of data needing estimation.

- Reference days are chosen to be of the like day type that are closest chronologically to the data needing estimation, regardless of seasonal crossover. Currently, like days can include days behind an account change.[2] This may include days after the day requiring estimation. When two potential like days are equidistant from the day requiring estimation the ‘before’ day is selected over the ‘after’ day.

There are two steps to the historic estimation process and these are described below:

1) Develop an average Daily Profile for each period to be estimated:

   a) Find the ‘Number Like Days’ (e.g. five) “same day of the week” reference days with valid data closest in time to each section of data needing estimation based on the rules listed in the previous section. If the section needing estimation is a holiday, the “same day of the week” is the closest Sunday. Calculate the average Daily Profile for each day type to be allocated using the selected reference days. If ‘Number Like Days’ same day of the week are not available, calculate the average Daily Profile using fewer reference days. For example if the section of data to be estimated is on a Tuesday and the ‘Number Like Days’ is five, select the five closest Tuesdays. If five Tuesdays are not available select four, if not then three, then two, then one.

   b) If no “same days of the week” reference days are available, look for the ‘Number Like Days’ “like” days that are closest chronologically to the section of data needing estimation. For example, if the intervals needing estimation are on Tuesday, use Monday, Wednesday, and Thursday. Only use weekdays with weekdays; only use weekends with weekends; use only Sundays or holidays with holidays. Calculate the average Daily Profile using up to ‘Number Like Days’ reference days (e.g. from one to five as available).

   c) If there is no valid ”same day of the week” or “like” reference days and ‘Use Class Load Profile” is set to “N”, the data may not be estimated and is flagged as NLK (NO_LIKE_DAYS) with a validation status of ‘needs verification or editing (NVE).

2) Use the average Daily Profile to estimate the usage data:

   The estimated value for each interval is simply the average interval value from the calculated Daily Profile. The average interval value from the Daily Profile is considered “raw estimated data” and is subject to Register Read scaling if the ‘Register Allocation’ parameter is set to ‘Y’ for the VEE Service.

The MDM/R will normalize the representative profile so that the consumption for the Daily Read Period is the same as for the daily read profile to be estimated. The profile could at some future point also be normalized for weather factors but weather factors will not be supported unless directed by the Ontario Energy Board.

Note that this method does not assume that the historical days are a good match for the profile of the Meter Read Block being estimated and implicitly assumes that no large changes in consumption behavior have occurred. The technique generates estimates that are typical of recent behavior as opposed to trying to match historical usage to the profile of the Meter Read Block being estimated.

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[2] Account Specific Historical Information Algorithm is a deferred delivery component – reference Component 35, MDM/R Change Request MCR No. 013.

4.1.4 Class Load Profile

The MDM/R supports estimation using a single specified Class Profile for each VEE Service. These Class Profiles may be applied optionally to each VEE Service. The MDM/R Administrator loads the Class Load Profiles into the appropriate interval channels in the MDM/R. One Class Load Profile channel for each VEE Service is defined.

Setting the ‘Use Class Profile’ parameter to “Y” enables Class Load Profile estimation. It can then be used in two situations:

- The most common intended use case of Class Load Profile estimation is as a fallback estimation option for intervals that cannot be historically estimated because of NO_LIKE_DAYS. The historical estimation algorithm will set a flag on a dataset if an interval has a NO_LIKE_DAYS failure. After the dataset has been fully processed by the historical estimation algorithm, the flag is checked, and if it is set, the ClassLoadProfiler is called to estimate all intervals in the dataset that have NO_LIKE_DAYS failures.

- Alternatively, Class Load Profile can be configured to be used instead of historical estimation, by setting the ‘Number Like Days’ parameter to ‘0’. In this case, all sections of NE (needs estimation) intervals in a dataset that are NOT linear interpolation are estimated using Class Load Profile.

Class Load Profile estimation consists of two steps described below.

1. Initialization. At the level of the section of data needing estimation, a Class Profile is initialized using the channel reference specified by the ‘Class Profile Channel’ parameter for the VEE Service associated with interval data being estimated; and the Start Time and End Time of the section of data needing estimation.

    a. The Class Profile is loaded for a given time period. Class Profiles are always loaded in 24-hour midnight-to-midnight time chunks (to set up for subsequent Average Daily Usage scaling). A section of data needing estimation that contains less than a full day of data will trigger a full day of Class Profile data that covers the dataset time period. A section of data needing estimation that contains intervals that span more than one day will trigger multiple days of Class Profile data to be loaded to cover all the days represented in the dataset.

    b. If the Class Profile is successfully loaded (all expected Class Profile intervals are found in the database), an attempt is made to scale the Class Profile interval values using the **Average Daily Usage** of the interval channel. The scaler sums up the interval data values in the class profile and divides by the number of days in the class profile to obtain the Average Profile Daily Usage in kWh per day. The Average Daily Usage is then obtained for the interval channel (see algorithm description below). The scaling factor is then calculated as:

       scalingFactor = Average Daily Usage / Average Profile Daily Usage

    c. If a scaling factor is successfully calculated, each interval of the “raw class profile interval data” is scaled as:

       scaledIntervalValue = rawIntervalValue * scalingFactor

2. For each interval in the section of data needing estimation obtain the estimated interval from the ClassLoadProfiler, and set the change method code based on whether the Class Profile has been scaled:

   If scaled, change method set to 'Class Load Profile, scaled with ADU' (ESE)

   If not scaled, change method set to 'Class Load Profile, unscaled' (ESD)

The **Average Daily Usage** (ADU) for the interval channel is obtained by querying the Meter Data Database for register reads, and calculating the Average Daily Usage using the first two register reads that meet the criteria for use as endpoints in the ADU calculation.

Register reads are queried over the time period delimited by the "Class Profile ADU Newest Read" (# of days) after the End Time of the section of data needing estimation, and going backwards through the "Class Profile ADU Oldest Read" (# of days) prior to the Start Time of the section of data needing estimation.

Beginning with the most recent register read and working backwards in time, the list is searched for the first pair of register read values (designated as RR1 at RR1Time; RR2 at RR2Time) that meet the following criteria:

- The register reads must be separated by at least "Class Profile ADU Min Days" full days, and
- Both register reads must have been obtained from the same meter with the same active CT/PT Multiplier value, and
- Neither of the register reads can be estimated (ESTIMATED_METHOD must be NULL).[3]

If there is a Meter or CT/PT Multiplier change between RR1Time and RR2Time, the earlier register read of the pair is re-designated as RR2 and a search is performed for an earlier register read (RR1) that meets the criteria above within time period delimited by the "Class Profile ADU Newest Read" and the "Class Profile ADU Oldest Read".

If a valid register read pair is NOT obtained by this search, the Average Daily Usage cannot be calculated and the Class Profile is not scaled.

If a valid register read pair is obtained, they are first run through the Dial Rollover algorithm to adjust for possible dial rollover between the readings, and the Average Daily Usage (ADU) in kWh per day is calculated as follows:

ADU = (((RR2 – RR1)*CTPT Multiplier) * (seconds-per-day)) / (RR2Time-RR1Time)

Loading Class Profile Data – The MDM/R Administrator loads the Class Profile data into the appropriate interval channels in the MDM/R. One Class Profile channel for each VEE Service is defined. The Class Profile data is maintained in an Interval Data channel. The standard class profile is a 60 Minute Interval Data, kWh channel. Class Profile interval data must be provided in advance of any period that is to be estimated by the Class Load Profile estimation process. This means that

[3] Estimation of Register Reads is not performed by the MDM/R.

the interval data must be provided for several weeks or months into the future. Generally a Class Profile is available for a full year.

4.1.5 Register Read Scaling

Register Read Scaling is applied to sections of intervals after they have been populated with raw estimated data using either the historical or class load profile estimation methods. Before scaling, each section of estimated intervals is first checked to determine if a meter change has occurred during the section. If so, the section is divided into meter-specific sections and each meter-specific section is scaled separately. If a meter change is detected, the algorithm checks for CT/PT Multiplier changes within the dataset time period, and the sections belonging to the different meters are scaled separately using appropriate CT/PT Multiplier values. If there is a gap between the two meter relationships, the estimated intervals in that gap are left unscaled.

Historic estimation and Class Load Profile estimation will operate with and without register reads. The VEE Service parameter "Register Allocation" determines if the register reads will be used to scale the "raw estimated data" from historical estimation or the "raw class profile interval data" from Class Load Profile estimation. When register reads are available before and after the gap being estimated and 'Register Allocation' is set to "Y", the estimated interval values will be adjusted so that the sum of the intervals (actual and estimated) between the register reads is equal to the difference in register reads.

Intervals estimated using historical estimation with register read scaling are recorded in the Meter Data Database with a validation status of 'estimated' (EST) and a change method code ESC.

Intervals estimated using Class Load Profile estimation with register read scaling are recorded in the Meter Data Database with a validation status of 'estimated' (EST) and a change method code ESF.

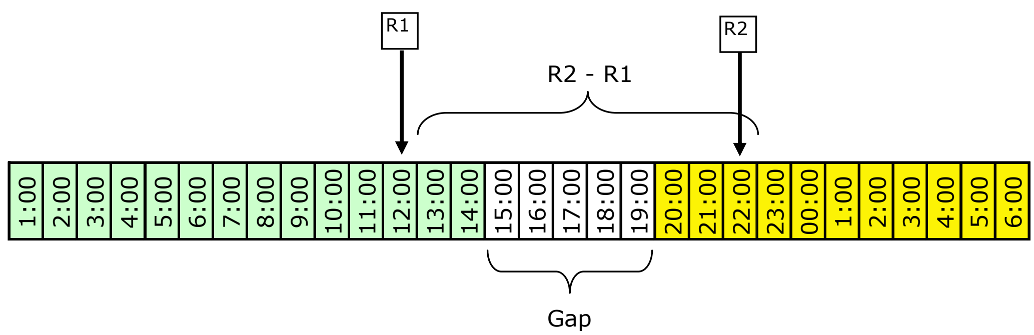

Figure 4-1 Estimation with Register Reads

As shown in Figure 4-1 register reads used in estimations are deemed to have occurred at the end of the interval in which they occurred. This assumption allows register reads to be used regardless of their alignment to the Meter Transfer Block or an interval boundary.

Although the AMCC interface requires that interval data is always accompanied by a register read, should register reads not be available on both sides of the gap being estimated or if ‘Register Allocation’ is set to “N” the ”raw estimated data” are not adjusted and are used as the estimate.

Intervals estimated using historical estimation without register read scaling are recorded in the Meter Data Database with a validation status of ‘estimated’ (EST) and a change method code ESB.

Intervals estimated using Class Load Profile estimation without register read scaling are recorded in the Meter Data Database with a validation status of ‘estimated’ (EST) and a change method code ESD.

4.2 Commercial and Industrial Consumers with metering of Demand (Multiple channel metering)

4.2.1 Message Estimation Services available to C&I Metering

The estimation algorithms used for C&I metering must require that all channels be present for estimation. In the event that one of more channels, but not all channels, are present for the same time interval, the estimation should fail. In effect, all non-register channels must be estimated simultaneously and in concert of each other. The absence of a single channel implies a serious meter failure and must be able to be configured for manual verification.

Message estimation services used for Residential and Small General Service Customers will also be available and applied to all channels for C&I metering and will include:

- Linear Interpolation, and
- Historic Estimation

Class Load Profile estimation is not proposed or expected to be required as the profiles for individual installations will vary drastically from location to location.

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5. Editing Guidelines

The MDM/R provides a Graphical User Interface (GUI) for performing manual verification and editing on Meter Read data. Upon notification of Meter Read data that Needs Verification/ Editing, the LDC will use the GUI to perform such verification or editing.

The OEB has provided some guidance for editing as described in the November 9, 2004 *Ontario Energy Board Smart Meter Implementation Plan, Draft Report of the Board For Comment*. Specifically:

> "When meter data is adjusted during the estimating process, there is always some risk that the estimated value will differ from actual consumption. Every effort must be made to ensure each estimate reflects accrual consumption to the extent possible. And to the extent possible, the risk of error should be born by the distributor."

The above principle may be applied by each LDC when editing meter read data.

5.1 Residential or Small General Service Customers

5.1.1 Manual Editing and Verification

Where actual interval consumption data is not available and automated estimation processes have not been successful, the LDC may be required to manually inspect and approve interval consumption data or to manually edit the values. The flowchart in Figure 5-1 describes this process.

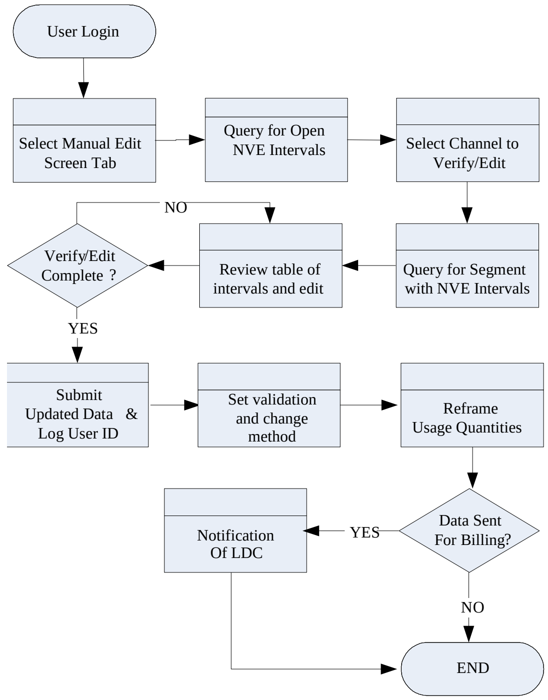

Figure 5-1 Manual Verification and Editing Flow

Locating Channels for Manual Editing

When validation checks result in interval consumption data being marked as data Needs Verification/Editing (NVE) the process automatically creates a record which contains the start and end times of the intervals that need manual verification and/or editing. An LDC user with appropriate permissions may generate a list of all such records and navigate to the interval channels that require attention.

Verifying or Editing Intervals

The LDC user may change interval consumption values in the GUI. When completed, the user submits the updated interval consumption data set. If the interval consumption data value is not changed the records are simply marked with validation status of Validated (VAL) and change method of Verified. If the interval consumption data values were changed (edited) they are marked with Validation Status set to Estimated (EST) and change method set to Edited (EDT). Intervals that are verified or edited in this process are updated in the Meter Data Database. The previous interval consumption data records are moved to the Prior Version table to maintain interval history.

Updating Billing Quantities After Editing

Channels that have been manually verified or edited in this process will be automatically reframed in order to update or complete the values in the Meter Data Database Usage table. Reframing is triggered as the interval consumption data version is updated. The LDC is notified where Billing Quantities have already been sent to the LDC based on prior interval consumption data versions.

5.2 Commercial and Industrial Consumers with Metering of Demand (Multiple channel metering)

5.2.1 Editing Support for C&I Metering

The editing functionality for meter data received from C&I metering must support the editing of all channel data (e.g.: kW, kVA, kVAR, kVAh and kVARh) simultaneously on the same screen.

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6. Billing Validation Services

Billing Validation takes place as Billing Quantities are assembled for delivery to the LDC or its agent as defined by the Data Delivery Service. Billing Validation is configured as part of the overall configuration of a Data Delivery Service including association with each VEE Service.

Billing Validations are performed on the data prior to producing Billing Quantity data. The Billing Validation process includes performing a sum check on the Billing Quantities over the period for which Billing Quantities are being provided.

The Billing Validation process will call exception handling processes that will attempt to use estimation to complete interval data that is missing during the Billing Period. This includes extrapolation[4] of interval data and associated reframing to generate complete billing quantities to the required End Date of the billing period. The extrapolation capability will be implemented consistent with the recommendation of the members of the SMSIP Joint Working Groups.

The Check Sum validation on Billing Quantity data will be performed by the MDM/R. SDPs identified as having this flag will be reported to the LDC to investigate and resolve.

6.1 Residential or Small General Service Customers

6.1.1 Billing Validation Sum Check

Prior to delivery of Billing Quantities for each SDP, the MDM/R performs the billing period validations. The Billing Validation Sum Check is configured as part of the Data Delivery Service parameters including association with a VEE Service. The MDM/R will perform the following billing validation tests once per billing request, as the Billing Quantities are prepared for export.

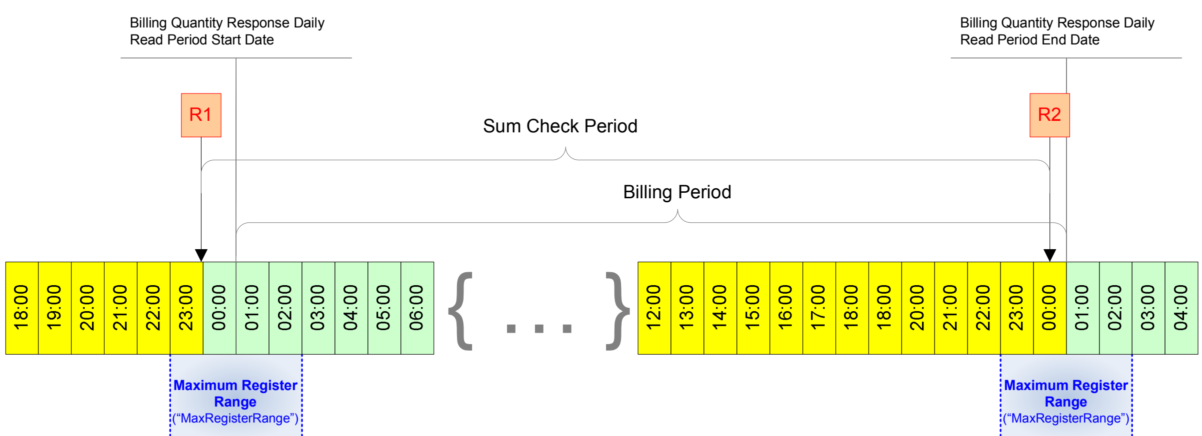

Figure 6-1 Billing Validation Sum Check on Billing Period

[4] Ibid Footnote No. 1.

The Billing Validation Sum Check is performed by comparing the total consumption of the Billing Quantity Response with the difference between the register read values nearest to the start and end points of the billing period as shown in Figure 6-1. Discrepancies may be the result of inaccuracies in manual meter data verification or editing activities.

The Billing Validation Sum Check accounts for the meter multiplier and applicable CT and VT ratios assigned to the SDP through synchronization (CT/PT Multiplier attribute) and meter register rollover and meter changes (using the First and Last Meter register readings taken at the time of the meter change and communicated through the synchronization process). The Billing Validation Sum Check requires two register readings. The first must be within 'MaxRegisterRange' hours of the Start of the billing period, the second within 'MaxRegisterRange' hours of the End of the billing period. If these register values are not available the Billing Validation Sum Check may be marked as a Billing Validation Sum Check failure or Billing Validation Sum Check skipped.

If the difference calculated above is greater than the 'ThresholdValue' for the VEE Service the Billing Validation Sum Check has failed.

The Billing Validation Sum Check 'ThresholdValue' is set specifically for the Data Delivery Service associated with each VEE Service. The threshold value above which the Billing Validation Sum Check fails may be expressed for each Data Delivery Service as one of:

1. 'Ratio' – the Sum Check is determined by comparing the absolute value of the total Billing Quantity consumption subtracted from the register reads difference divided by the register read difference to an allowable ratio i.e. the 'ThresholdValue', or
2. 'Value' – the Sum Check is determined by comparing the absolute value of the total Billing Quantity consumption subtracted from the register reads difference to a maximum kWh value i.e. the 'ThresholdValue'.

The register read difference (RR2 – RR1) is determined by RR2Time within the 'MaxRegisterRange of the Billing Quantity Response End Date and RR1Time within the 'MaxRegisterRange' of the Billing Quantity Response Start Date.

The threshold value when using the threshold type 'Ratio' is expected to be set at or below the error permitted under the dispute provisions of the Electricity and Gas Inspection Regulations. When using the threshold type 'Value' the threshold value is expected to be the maximum value of one interval period in kWh.

The Billing Validation Sum Check process accounts for CT/PT Multiplier when comparing the difference between the register read values and the total consumption of the Billing Quantity Response.

Billing Quantities for SDPs that fail the Billing Validation Sum Check may still be reported but the record will be flagged with the Billing Validation Sum Check failure code, alternatively the Billing Quantities may be nullified and the record(s) reported with the Billing Validation Sum Check failure code. The Billing Validation Sum Check is performed as soon as the billing process acquires complete data for the billing period in order to provide the LDC the opportunity to address sum check failures prior to the close of the billing window as defined by the 'LatestReportDays' parameter of the Billing Quantity process.

6.2 Commercial and Industrial Consumers with Metering of Demand (Multiple channel metering)

Billing validation services used for Residential and Small General Service Customers will also be available for use for C&I Customers.

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7. VEE Services

7.1 Overview of Message Validation and Estimation

Figure 7-1 illustrates the high-level flow of the message validation and message estimation processes. The initial step in the process is to determine the VEE Service that is to be used for the Meter Transfer Block. The process flow is then as follows:

1) Message Validation Checks - Interval consumption data in the Meter Transfer Block is checked against the criteria defined in the VEE Service parameters. Each interval within the Meter Transfer Block is assigned an outcome. The four outcomes supported are:
   a) Validated – the consumption in the interval passed all tests and is acceptable for billing and recorded with a validation status of ‘validated’ (VAL) in the Meter Data Database.
   b) Validate/Flag – the consumption in the interval has failed some validations but is acceptable for billing – these are soft validation failures. This data is flagged as having failed validations and recorded with a validation status of ‘validated’ (VAL) in the Meter Data Database. Soft validation failures are recorded as flag and failure codes on each interval record.
   c) Estimate – the consumption in the interval is incomplete or has failed validation, this data is passed on for automated estimation. This information will be recorded with a validation status of ‘needs estimation’ (NE) in the Meter Data Database but will not be made available for billing purposes until estimation is completed. These are hard validation failures.
   d) Verify/Edit – the consumption in the interval that is incomplete or has failed validation checks configured for manual verification or editing, this data is recorded with a validation ststus of ‘needs verification or edit’ (NVE) in the Meter Data Database pending manual processing. This information will not be made available for billing purposes until verification and editing is completed. These are hard validation failures.
2) Message Estimation Routines – Interval consumption data that has failed validation as incomplete (e.g. missing intervals) or having failed validation tests configured for estimation may be estimated according to processes defined by the VEE Service parameters. Register reads are not estimated. Estimated interval consumption data is then recorded with a validation status of ‘estimated’ (EST) in the Meter Data Database and flagged with a Change Method code indicating the type of estimation performed. Estimated interval consumption data is available for framing and the production of Billing Quantities.
3) Manual Verification or Edit – Consumption values for intervals that requires manual intervention is recorded with a validation status of ‘needs verification or edit’ (NVE) in the Meter Data Database. This data remains in this state and is not usable for billing until manual verifications or edits have been completed.
4) Interval consumption data for which the VEE Service is “No Validation” is recorded with a validation status of ‘not validated’ (NV) in the Meter Data Database and made available for billing.
5) Validated data; validated/flagged data; estimated data; verified or edited data, and ‘not validated’ data is available for daily Framing and the production of Billing Quantities.

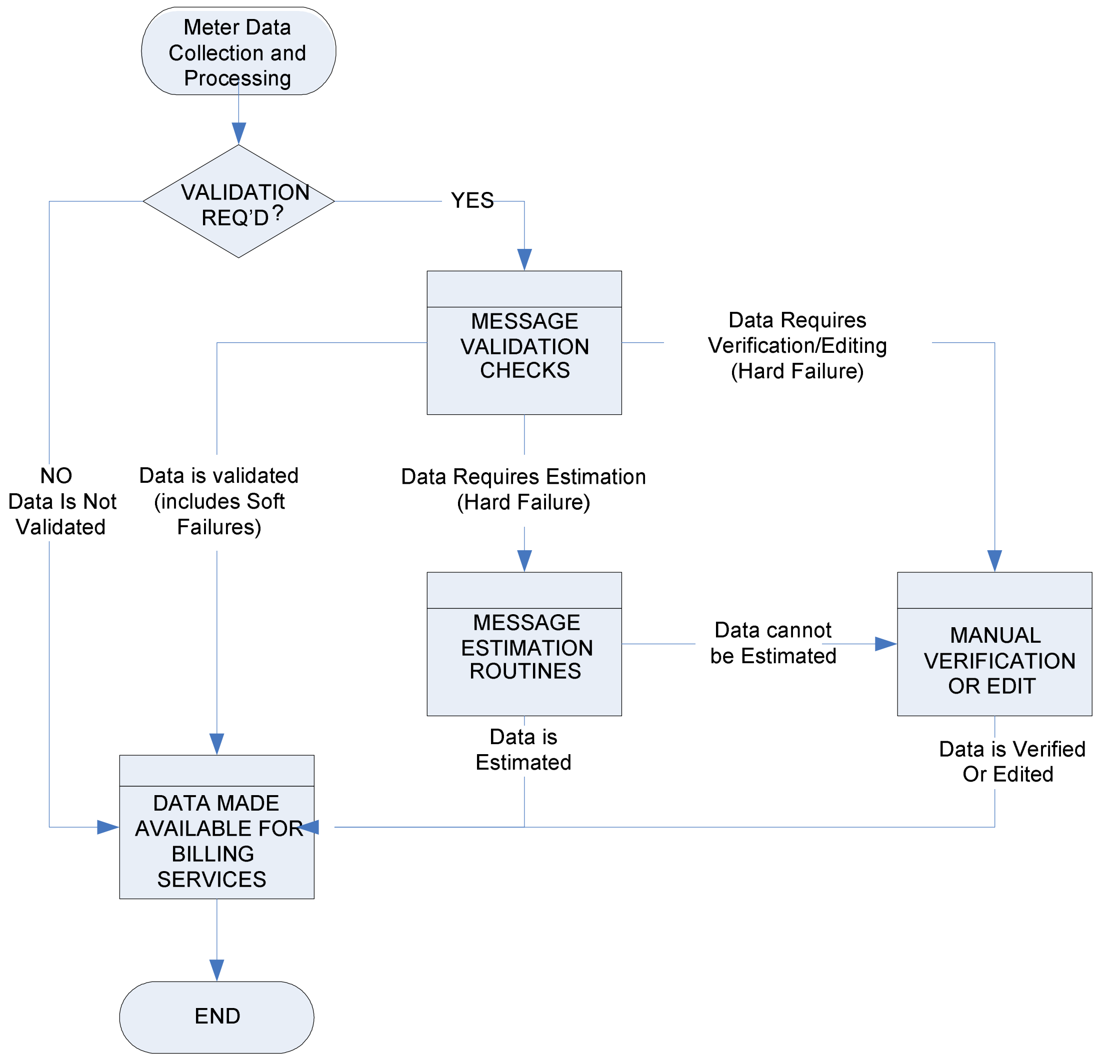

Figure 7-1 VEE Sequence as Meter Transfer Block is Received

7.1.1 Message Validation Checks

Table 7-1 below provides the parameters and descriptions for the message validation checks that are undertaken against each Meter Transfer Block. The columns in the table have the following meanings:

- **Validation Checks –** the nature of the validation test or check
- **Parameter –** the parameter that is set when the VEE Service is configured
- **Valid Value** – the allowable values of the parameter. For parameters labeled as 'Action' these are the values available for configuration to set the action when the validation check is deemed to have failed.

- **Description** – description of the parameter.

For each of the validation checks where an action is taken (as noted in the Parameter column in Table 7-1) one possible outcome is available based upon the configuration value chosen. Up to three configurable values may be available:

- **Validate/Flag –** Upon validation test failure interval consumption data is acceptable for billing. This data is flagged as having failed validations and stored in the Meter Data Database. These soft validation failures are recorded and reported to the LDC.
- **Estimate –** Upon validation test failure interval consumption data will not be made available for billing. This data is passed on for automated Estimation. These failures are recorded and reported to the LDC.
- **Verify/Edit –** Upon validation test failure interval consumption data will not be made available for billing. This data requires manual verification or editing and is saved in the Meter Data Database for manual processing. These failures are recorded and reported to the LDC.

All validation checks are undertaken for each interval, i.e. the process does not stop on encountering the first failure.

Validation Checks	Parameter	Valid Value	Description
Overall Control	Validation Enabled	Y/N	Indicates whether any validation or estimating is to be performed. If ‘Y’ validation is enabled If ‘N’ validation is disabled
Interval Flags Check			
Missing Intervals	Missing Intervals Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken for missing intervals. Flagged in the Meter Data Database as ‘NO_DATA’ and displayed in the GUI as ‘Y’ in the ‘NoData’ field.
Test Mode	Test Mode Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on reporting of a test mode condition by the AMCC. Flagged in the Meter Data Database as ‘TEST_MODE’ and displayed in the GUI as ‘Y’ in the ‘TestMode’ field.
Pulse Overflow	Pulse Overflow Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on reporting of a pulse overflow condition by the AMCC. Flagged in the Meter Data Database as ‘PULSE_OVERFLOW’ and displayed in the GUI as ‘Y’ in the ‘Overflow’ field.

Validation Checks	Parameter	Valid Value	Description
Time Change	Time Change Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on reporting of a time change by the AMCC. Flagged in the Meter Data Database as 'TIME_CHANGE' and displayed in the GUI as 'Y' in the 'TimeChg' field.
Meter Diagnostic	Meter Reset Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on reporting of a diagnostic error by the AMCC. Flagged in the Meter Data Database as 'METER_RESET' and displayed in the GUI as 'Y' in the 'MtrDiagError' field.
Reverse Energy	Reverse Rotation Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on reporting of reverse rotation by the AMCC. Flagged in the Meter Data Database as 'REVERSE_ROTATION' and displayed in the GUI as 'Y' in the 'RevEnergy' field
Calculation Based Checks			
Maximum Demand	Maximum Demand Check	Y/N	Indicates whether to perform the maximum demand check on each interval. If 'Y' maximum demand is enabled If 'N' maximum demand is disabled
	Maximum Demand Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken if maximum demand check fails. Upon failure stored in the Meter Data Database as a bit sum 'FAIL_CODE' decimal value = 64 and displayed in the GUI as a decimal sum under 'FailCode'.
	Maximum Demand Value	Min: 0 Max: n/a Units: kW	Maximum demand value in kW for an interval
Spike Check	Spike Check	Y/N	Indicates whether to perform a spike check on the Meter Transfer Block. If 'Y' spike check is enabled If 'N' spike check is disabled
	Spike Check Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken if a spike check fails. Upon failure stored in the Meter Data Database as a bit sum 'FAIL_CODE' decimal value = 1 and displayed in the GUI as a decimal sum under 'FailCode'.

Validation Checks	Parameter	Valid Value	Description
	Spike Check Threshold	Min: 0 Max: n/a Units: kWh	Minimum value in kWh of highest interval required to perform spike check
	Spike Check Ratio	Min: 0.0 Max: n/a	Maximum ratio of highest to Nth highest interval value to pass spike check.
	Second Peak Rank	Min: 2 Max: n/a	2,3,4, … 'n' the order of the interval value to use in the spike check ratio test – e.g. 2nd highest value, 3rd, 4th, etc.
Sum Check	Msg Sum Check	Y/N	Indicates whether to perform a sum check on the Meter Transfer Block. If 'Y' sum check is enabled If 'N' sum check is disabled
	Msg Sum Check Action	Validate/Flag Verify/Edit	Indicates action to be taken on failure of sum check in a Meter Transfer Block. Upon failure stored in the Meter Data Database as a bit sum 'FAIL_CODE' decimal value = 2 and displayed in the GUI as a decimal sum under 'FailCode'.
	Msg Sum Check Threshold	Min: 0 Max: n/a Units: kWh	The threshold value for a Meter Transfer Block in kWh for which the Sum Check test will fail. This is a value in kWh before the CT/PT Multiplier.
Extra-Message Checks			
Consecutive Zeros	Consecutive Zeros Check	Y/N	Indicates if the consecutive zeros check is to be performed If 'Y' consecutive zeros is enabled If 'N' consecutive zeros is disabled
	Consecutive Zeros Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on failure of consecutive zeros check. Upon failure flagged as 'ZER' on Reports VE01 and VE11.
	Consecutive Zeros Threshold	Number of intervals	Number of consecutive intervals with zeros allowed. NOTE: The specification of the threshold value as a number of intervals requires that a different VEE Service be defined for meters of different interval length.

Table 7-1 Message Validation Check Parameters and Descriptions

7.1.2 Message Estimation Routines

Gaps or errors in interval consumption data may be estimated by the MDM/R as they are identified in the validation process. Estimation for filling gaps between Meter Transfer Blocks is limited by the 'Max Estimation Days' parameter and gaps that exceed this value are not estimated.

Estimation does not extend beyond the most recent Meter Transfer Block received. The LDC is responsible for manually editing any Meter Read data where the Meter Transfer Blocks are not complete to the end of the billing period.

These estimations are performed on intervals recorded by the validation process with a validation status of 'NE' in the Meter Data Database.

Table 7-2 provides the parameters and descriptions for the message estimation that will be undertaken for intervals in each Meter Transfer Block that have been recorded as needing estimation. The columns in the table have the following meanings:

- **Estimation –** the nature of the estimation routine
- **Parameter –** the parameter that is set when the VEE Service is configured
- **Valid Value –** the allowable values of the parameter
- **Description –** description of the parameter.

Estimation Routine	Parameter	Valid Value	Description
Linear Interpolation	Max Interpolation Minutes	Min: 0 Max: n/a Units: minutes	Maximum number minutes that may be estimated using linear interpolation. Set to zero if linear interpolation is not allowed.
Overall Control	Max Estimation Days	Min: 0 Max: n/a Units: days	Maximum number of consecutive days that may be estimated either using Historic (Like Days) or Class Load Profile estimation.
	Register Allocation	Y/N	Determines if Historic estimations and/or Class Load Profile estimations are scaled using Register Reads at the start and end of the Meter Transfer Block.
Historic Estimation	Oldest Like Day	Min: 0 Max: n/a Units: days	Specifies the oldest day of historical data that may be used in historic estimation. The date established by this parameter is calculated in 24-hour increments relative to the Start Time of the first interval of a Meter Transfer Block needing estimation.

Estimation Routine	Parameter	Valid Value	Description
	Number Like Days	Min: 0 Max: n/a Units: days	Specifies the preferred (and maximum) number of reference days to use in calculating an historical estimation. Note: Setting this value to '0' effectively switches Historical estimation off. A '0' value is used when only Class Load Profile estimation is to be used for a particular VEE Service.
	Newest Like Day Method	'Newest Like Day' or 'Billing Cycle'	Provides for days after the day being estimated used as reference days. 'Newest Like Day' – use newer like days up to a 'Newest Like Day Limit' 'Billing Cycle' – use newer like days within a billing cycle.
	Newest Like Day Limit	Min: 0 Max: n/a Units: days	Used when 'Newest Like Day Method' is set to 'Newest Like Day'. Specifies the latest day of data that may be used in historical estimation. The date established by this parameter is calculated in 24-hour increments relative to the End Time of the last interval of a Meter Transfer Block needing estimation.
Class Load Profile	Use Class Profile	Y/N	Indicates if Class Load Profile estimation is to be performed. If 'Y' Class Load Profile is enabled If 'N' Class Load Profile is disabled
	Class Profile ADU Min Days	Min: 0 Max: n/a Units: days	Specifies the minimum separation between Register Reads used in calculating Average Daily Usage for Class Profile scaling
	Class Profile ADU Oldest Read	Min: 0 Max: n/a Units: days	Specifies the oldest day of Register Read data that may be used when calculating Average Daily Usage for Class Profile scaling
	Class Profile ADU Newest Read	Min: 0 Max: n/a Units: days	Specifies the latest day of Register Read data that may be used when calculating Average Daily Usage for Class Profile scaling
	Class Profile Channel	Channel Reference	If 'Use Class Profile' is set to "Y" this parameter must reference a valid channel containing reference interval data

Table 7-2 Message Estimation Routine Parameters and Descriptions

7.1.3 Validation and Estimation Outcomes

The MDM/R VEE Services generate meta-data relating to each specific interval consumption value and this meta-data is stored against interval records in the Meter Data Database. Table 7-3, Daily VEE Outcomes, lists the four validation statuses used to identify the state of an interval. Each state is further defined by the method used to modify an interval value and the validation test that failed. All Change Method Codes are recorded for each interval consumption value. Validation Failure Codes are set for all the VEE checks that fail for each interval.

Interval Validation Status	Change Method Codes	Validation Failure Code
NO VALIDATION (NV): No validation performed, data may be used as permitted.	**NULL**: Interval value not changed.	Not applicable
VALIDATED (VAL): Interval has been validated and is available for billing and other uses.	**NULL**: Interval value not changed. **VER**: Interval has been manually reviewed and verified for submission to billing.	Failure code(s) from validation failures as indicated in Table 7-1 NOTE: Failure code on validated interval is a Warning or Soft error
ESTIMATED (EST): Interval was estimated and is available for billing and other uses.	**ESA:** Interval value estimated using linear interpolation **ESB**: Interval value estimated using Historic estimation without Register Read scaling **ESC**: Interval value estimated using Historic estimation with Register Read scaling **ESD**: Interval value estimated using Class Load Profile estimation without scaling **ESE**: Interval value estimated using Class Load Profile estimation scaled using Average Daily Usage from register reads **ESF**: Interval value estimated using Class Load Profile estimation with Register Read scaling **ESG**: Interval value estimated using extrapolation **EDT:** Interval value has been manually edited. **EXT:** Interval value was estimated by an external system	Failure code(s) from validation failures as indicated in Table 7-1

NEEDS VERIFICATION/EDITING (NVE): Interval requires manual verification or editing and is not available for billing or other uses.	**NULL:** Null pending manual edit or verification then Validation Status changed to VAL or EST.	Failure code(s) from validation failures as indicated in Table 7-1

Table 7-3 VEE Outcomes

7.1.4 Billing Validation Sum Check

Table 7-4 provides the parameters and descriptions for the Billing Validation Sum Check that will be undertaken against each Billing Quantity Response. The columns in the table have the following meanings:

- **Validation Check** – the nature of the validation check
- **Parameter** – the parameter that is set when the VEE Service is configured
- **Valid Value** – the allowable values of the parameter
- **Description** – description of the parameter

Validation Check	Parameter	Valid Value	Description
Billing Validation Sum Check	BillingSumCheck	Y/N	Indicates whether to perform the Billing Validation Sum Check on the computed Billing Quantity. If 'Y' sum check is enabled If 'N' sum check is disabled
	BillingSumCheckFail Action	'Value' OR 'null'	Upon Billing Validation Sum Check failure: If set to 'Value' will provide Billing Quantity Response with computed values and error code If 'null' will provide Billing Quantity Response with 'null' values and error code
	MaxRegisterRange	Min: 0 Max: n/a Units: hours	Maximum period in hours to search for the register reads nearest the: Billing Quantity Response Daily Read Period Start Date and Billing Quantity Response Daily Read Period End Date

Validation Check	Parameter	Valid Value	Description
	NoRegRead Action	'Skip' OR 'Fail'	Action to take if register readings are not available. If 'Skip' Billing Validation Sum Check is not performed If 'Fail' Billing Validation Sum Check fails upon failure to find register reads
	Sync Mapping Code	Char (2) Specific usage: 01, 02, 03 … 30	The VEE Service to which the Data Delivery Service is to be associated.
	ThresholdType	'Ratio' OR 'Value'	The type of Billing Sum Check: If set to 'Ratio', a percentage based sum check is performed. If set to 'Value', a threshold based sum check is performed.
	ThresholdValue	Min: 0 Max: n/a Value of form: Number (1,3)	Threshold at which sum check passes or fails. If 'ThresholdType' is set to: 'Ratio' – then a percentage allowed for the sum check difference expressed as a ratio of the register read difference and the total Billing Quantity, e.g. 1% is 0.010 'Value' – then a value in kWh allowed for the actual sum check difference

Table 7-4 Billing Validation Sum Check Parameters and Description

7.2 VEE Services for Residential or Small General Service Customers

A VEE Service refers to a specific validation configuration in combination with a specific set(s) of estimation algorithms. A set of default VEE Services will be created that will enable Ontario LDCs to choose the VEE Services that are most appropriate for their consumers yet still provide a level of standardization across the province. The default VEE Services will be:

VEE Service, No Validation

This VEE Service does not perform any validation checks. This could be used when new SDPs are established in the MDM/R and the quality of data has not yet stabilized. This will allow for the collection of interval data in the MDM/R to be used for future estimation processes but will not create unnecessary notifications to the LDC until the data quality has stabilized. The SDPs using this VEE

Service will typically not be set to send Billing Quantities to the LDCs CIS system as the Meter Read data has not been validated.

VEE Service, No Estimation

This VEE Service could be used for any SDP where no automatic estimation is required. Any missing Meter Read data for a SDP using this VEE Service will require manual estimation or editing.

VEE Service, Residential

This VEE Service shall be used for the majority of residential consumers.

VEE Service, Residential – Electric Heat

This VEE Service can be used for residential electric heat consumers. These consumers typically display very unbalanced usage patterns between seasons.

VEE Service, Transformer Type

This VEE Service can be used for transformer type SDPs. These SDPs generally have a higher level of usage and the presence of Voltage and/or Current Transformers with a CT/PT Multiplier greater than 1 (one) require the need to have unique thresholds on some of the validation checks.

VEE Service, Small General Service

This VEE Service can be used for high usage consumers. This VEE Service has higher threshold values in the maximum demand validation check.

VEE Service, Seasonal

This VEE Service can be use for consumers that have no usage for extended periods of time.

Table 7-5 provides the configuration parameters applied for each of the default VEE Services described above. The configuration parameters for each default VEE Service are considered initial values. The efficacy of the configuration for each VEE Service will be demonstrated during testing and initial integrated operation of the MDM/R and AMI systems. The configuration for each VEE Service may be updated as the result of ongoing testing and operation of the Ontario Smart Metering System.

Parameter	No Validation	No Estimation	Residential	Residential – Electric Heat	Transformer Type	Small General Service	Seasonal
Sync Mapping Code	01	02	03	04	05	06	07
MESSAGE VALIDATION CHECKS							
Validation Enabled	N	Y	Y	Y	Y	Y	Y
Interval Flags Check							
Missing Intervals Action	N/A	Verify/Edit	Estimate	Estimate	Estimate	Estimate	Estimate
Test Mode Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Pulse Overflow Action	N/A	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit
Time Change Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Meter Reset Action	N/A	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit
Reverse Rotation Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Maximum Demand Check							
Maximum Demand Check	N/A	Y	Y	Y	Y	Y	Y
Maximum Demand Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Maximum Demand Value	N/A	50 kW	15 kW	25 kW	35 kW	50 kW	25 kW
Spike Check							
Spike Check	N/A	N	Y	Y	Y	Y	Y
Spike Check Action	N/A	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Spike Check Threshold	N/A	N/A	7.5 kWh	15 kWh	20 kWh	25 kWh	7.5 kWh
Spike Check Ratio	N/A	N/A	50	50	50	50	50
Second Peak Rank	N/A	N/A	3	3	3	3	3
Sum Check							
Msg Sum Check	N/A	Y	Y	Y	Y	Y	Y
Msg Sum Check Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Msg Sum Check Threshold	N/A	0.25 kWh	0.25 kWh	0.25 kWh	0.25 kWh	0.25 kWh	0.25 kWh
Consecutive Zeros Check							
Consecutive Zeros Check	N/A	Y	Y	Y	Y	Y	Y
Consecutive Zeros Threshold	N/A	336[5]	336	336	336	336	4380[6]
Consecutive Zeros Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag

[5] Based on a one (1) hour interval meter and 14 days

[6] Based on a one (1) hour interval meter and 6 months

Parameter	No Validation	No Estimation	Residential	Residential – Electric Heat	Transformer Type	Small General Service	Seasonal
Sync Mapping Code	01	02	03	04	05	06	07
MESSAGE ESTIMATION ROUTINES							
Max Interpolation Minutes	N/A	0	0	0	0	0	0
Overall Control – Historic Estimation and Class Load Profile Estimation							
Max Estimation Days	N/A	0	15	15	15	15	45
Register Allocation	N/A	N	Y	Y	Y	Y	Y
Historic Estimation							
Oldest Like Day	N/A	0	30	30	30	30	0
Number Like Days	N/A	0	5	5	5	5	0
Newest Like Day Method	N/A	Newest Like Day	Newest Like Day	Newest Like Day	Newest Like Day	Newest Like Day	Newest Like Day
Newest Like Day Limit	N/A	0	1	1	1	1	1
Class Load Profile Estimation							
Use Class Load Profiles	N	N	N	N	N	N	Y
Class Profile ADU Min Days	N/A	N/A	N/A	N/A	N/A	N/A	5
Class Profile ADU Oldest Day	N/A	N/A	N/A	N/A	N/A	N/A	30
Class Profile ADU Newest Day	N/A	N/A	N/A	N/A	N/A	N/A	1
Class Profile Channel	N/A	N/A	N/A	N/A	N/A	N/A	Internal Siebel Ref
BILLING VALIDATION SUM CHECK							
BillingSumCheck	N	N	Y	Y	Y	Y	Y
BillingSumCheckFail Action	N/A	N/A	Value	Value	Value	Value	Value
MaxRegisterRange	N/A	N/A	1	1	1	1	1
NoRegRead Action	N/A	N/A	Fail	Fail	Fail	Fail	Fail
Sync Mapping Code	01	02	03	04	05	06	07
ThresholdType	N/A	N/A	Ratio	Ratio	Ratio	Ratio	Ratio
ThresholdValue	N/A	N/A	0.010	0.010	0.005	0.005	0.010

Table 7-5 Default VEE Services Configuration

7.3 VEE Services for Commercial and Industrial Consumers with metering of Demand (Multiple channel metering)

VEE Services for C&I customers will be configured based on existing and additional validation, estimation and editing functionality developed for the MDM/R and after consultation with the SMSIP Working Group VEE Sub-Committee.

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APPENDIX K

Smart Meter Network Security Audit Services for Sensus AMI

Request for Proposal
RFP#: 2105S
May 21, 2010

Smart Meter Network Security Audit Services For Sensus AMI Request for Proposal

RFP# 2105S

Facilitated by util-assist

Contents

Section 1: Introduction

1.1 Introduction

1.1.1 Background

With the mass deployment of AMI systems currently under way, security of the AMI network is critical to prevent utilities from becoming susceptible to new levels of potential security breaches and to ensure customer privacy and acceptance of the network. Now that network infrastructure is being installed in the field, there is a requirement for additional security measures to ensure that utility data and equipment are kept secure from manipulation or other forms of control.

Some of the privacy and network security infrastructure concerns that have been raised include:

- Monitoring a consumer's usage;
- Modifying one's own, or another consumer's usage;
- Interrupting the power of one or more consumers; and
- Tampering with demand side management tools which can be controlled through smart meters.

Since early 2009, Ontario utilities have been working with their smart meter providers in understanding the security features of the networks, best practices for their deployment and new features that are being developed for future implementation within the smart meter networks. In November of 2009 the Information and Privacy Commissioner of Ontario released the report Smart Privacy for the Smart Grid which identified areas of concern to be addressed in the area of smart meter and smart grid devices. For reference to this report, please access the following link: http://www.ipc.on.ca/images/Resources/pbd-smartpriv-smartgrid.pdf.

As part of the planned implementation of annual security audits for the smart meter networks, in December of 2009, Util-Assist hosted a security audit discovery session in which Ontario Local Distribution Company (LDCs) and security firms discussed possible approaches to AMI network security audits. In particular the LDCs were interested in the possibility of working collaboratively to maximize the cost effectiveness of the security audit process. An opportunity was identified to work together as an industry to complete this critical step in the due diligence required to ensure that utility AMI networks are secure. A common approach to the audit will allow the AMI vendors to allocate resources to focus specifically on the Ontario LDCs' audit firm efforts and their needs.

The following Request for Proposal (RFP) is being released by a Consortium of Ontario LDCs (the "Consortium") who are working together to maximize cost and time effectiveness. The utilities participating in the Consortium are listed below.

Sensus Utility	
Algoma Power Inc.	Newmarket Tay Power Distribution Ltd
Bluewater Power Distribution Corporation	Niagara Peninsula Energy Inc.
Brant County Power Inc.	Niagara-on-the-Lake Hydro Inc.
Brantford Power Inc.	Norfolk Power Distribution Inc.
Cambridge and North Dumfries Hydro Inc.	North Bay Hydro Distribution Ltd.
Canadian Niagara Power Inc.	Northern Ontario Wires Inc. - Cochrane
Chapleau Public Utilities Corporation	Oakville Hydro Electricity Distribution Inc.
COLLUS Power Corp.	Orangeville Hydro Limited / Grand Valley Energy Inc.
Espanola Regional Hydro Distribution Corp.	Orillia Power Distribution Corporation
Greater Sudbury Hydro Inc.	PowerStream Inc. / Barrie Hydro Distribution Inc.
Grimsby Power Incorporated	PUC Distribution Inc. (Sault Ste. Marie)
Haldimand County Hydro Inc.	Wasaga Distribution Inc.
Hearst Power Distribution Co. Ltd.	Waterloo North Hydro Inc.
Innisfil Hydro Distribution Systems Ltd.	Welland Hydro Electric System Corp.
Kitchener-Wilmot Hydro Inc.	Whitby Hydro Electric Corp.
Lakefront Utilities Inc.	

The attached documentation sets out the procedural and technical requirements for the submission of Proposals to the Consortium, outlines the audit requirements as well as provides the substantive contractual terms that will govern the relationship between parties upon award of the contract

1.1.2 Terminology

For the purposes of this procurement process:

1. ***Bidder*** shall refer to the vendor proposing a solution to this RFP document by submission of a Proposal.
2. ***Vendor*** shall refer to the successful Bidder. The term Vendor will be used when stating future requirements, to be performed only by the successful Bidder.
3. ***Proposal*** shall mean the Bidder's written response provided to the Consortium in accordance with this RFP. The Proposal shall include all written material submitted by Bidder as of the date set forth in the Key Dates (Section 1.2 *Key Dates*)

1.2 Key Dates

Below is the expected timeline that the Consortium will be following during the evaluation of security audit solutions. The Consortium reserves the right to adjust these dates as needed. All Bidders will be notified if any of the following dates are altered. As can be seen, it is the intention of the Consortium to make its decision by **August 13, 2010**.

Security Audit Services RFP released by the Consortium:	**May 21, 2010**
Intention to bid:	**May 31, 2010**
Final Questions Due:	**June 7, 2010**
Answers to Questions:	**June 14, 2010**
Closing Time (Proposals Due):	**June 28, 2010 @ 3:00PM**
Vendor Presentations:	**TBD (if required)**
Proposal Decision:	**August 13, 2010**

Section 2: Instructions to Bidders

2.1 Bid Documents

This RFP establishes the services that the Consortium wishes to acquire. This bid document is the basis upon which the Consortium seeks firm Proposals from selected Bidders and upon which Proposals will be evaluated. The documents are:

- This RFP (a .pdf document), including Appendices that are integral to it.
- Sensus_SecurityAudit_Pricing_May2010.xls, a Microsoft Excel workbook. This file allows for entry of pricing information and will heretofore be referred to as the Pricing Spreadsheet.

2.2 Intention to Bid

Recipients of this RFP are asked to inform the Consortium of their intention to bid by completing the template form found in Section 2.19 *Proposal Forms*, and by submitting this form by the date shown in Section 1.2 *Key Dates*. Recipients that express intention to bid will be included in all correspondence (if any) during the bidding process. Please provide full contact information and expression of intention via the provided form to the Consortium contact as per instruction in Section 2.19.1 *Intention to Bid Form*

2.3 Submission Requirements

1) A complete Proposal will consist of an original and eight (8) copies of each of
   a) The Proposal forms,
   b) The Bidder's response document (including all associated attachments),
   c) Accompanying the Bidder's response document should be the Proposal forms provided in Section 2.19 *Proposal Forms*,
   d) The required format of the Bidder's response document is outlined in Section 2.4 *Proposal Format Instructions*,
   e) A soft copy of all of the above forms and documents should also be provided on one CD.

2) The original hard copy shall be clearly identified as "ORIGINAL"; the remainder (i.e. eight copies) shall be marked as "COPY". In the event of discrepancy between the copies of the Response, the one marked "ORIGINAL" shall prevail. Each Bidder's Response shall consist of the required documents with the required number of copies of all commercial information, including pricing, terms and conditions and exceptions (if applicable). Faxed or late Proposals will not be accepted. Proposals must be sealed and marked clearly quoting the RFP number referred to on the cover sheet of the Request for Proposal documents. The use of any means of delivery of a Proposal shall be at the risk of the Bidder.

3) Any Bidder wishing to provide additional information other than what is requested in the RFP documents must place such additional information in a separate section marked Supplementary Information, as per Section 2.4 *Proposal Format Instructions*. Any Additional Information or any unsolicited value-added alternatives may, in the Consortium's absolute discretion, be given due consideration, or not.

4) The Consortium shall not be liable for, nor shall it reimburse any Bidder for costs incurred in the preparation of Proposals, or any other services or samples that may be requested as part of the evaluation process.

5) The Proposal Forms shall be signed under the Corporate Seal of the Bidder, by the duly authorized signing officer(s). All submitted pages shall be initialled by such officer(s).

2.4 Proposal Format Instructions

Where information has been requested through this RFP, the Bidder's Proposal should clearly indicate the RFP section number that the response pertains to. The Bidder's Proposal should be organized according to the following sections:

1) Section 1 of the Proposal will contain the Bidder's Executive Summary, no more than two pages in length that introduces the Bidder and highlights key features of the Proposal.
2) Section 2 of the Proposal **should be provided in a separate envelope which has been clearly marked "PRICE OFFER".** This section will contain the summary pages pertaining to the Price Offer, contained within the Pricing Spreadsheet. The Bidder's detailed itemized pricing information for all services is to be contained within the Pricing Spreadsheet which is to be included with the Proposal in its entirety as well as within this section. Any alternative pricing offers may also be included within the Pricing Spreadsheet, by adding tabs as needed. All pricing shall be expressed in Canadian currency, exclusive of taxes. If your originating currency is not Canadian, the currency exchange that was used to calculate the price in Canadian currency is to be provided.
3) Section 3 of the Proposal will contain all requested information from Section 3 of this RFP in the order presented in this document, with the numbering used in this document.
4) Section 4 of the Proposal will contain all requested information regarding the Bidder (Section 4: *Bidder Company Information*) in the order presented in this document, with the numbering used in this document.
5) Section 6 of the Bidder's Proposal will contain any additional documentation that the Vendor decides to provide regarding their offering.

2.5 Adjustments / Substitutions

1) A Proposal may be altered by a Bidder only by submitting another Proposal at any time up to the Closing Time. Adjustments by telephone, facsimile, telegram or letter to a Proposal already submitted will not be considered. The last Proposal received by the Consortium's designee shall supersede and invalidate all Proposals previously submitted by the Bidder for this RFP.

2) During the period prior to the Closing Time, changes made by the Consortium to the RFP documents will be issued by the Consortium to the Bidders as written addenda. The Bidder shall list in its Proposal all addenda that were considered in the preparation of its Proposal.

No substitutions or deviation from the Specifications, Proposal Form or General Conditions of Contract will be permitted without the Consortium's approval in writing.

2.6 Complete Bid

Bidders are requested to submit bids that are complete and unambiguous without the need for additional explanation or information. The Consortium reserves the right to make a final determination as to whether a bid is acceptable or unacceptable solely on the basis of the bid as submitted, and proceed with bid evaluation (or not) without requesting further information from any Bidder. If the Consortium deems it desirable and in its best interest, the Consortium may, in its sole discretion, request from any Bidder or Bidders, additional information clarifying or supplementing any submitted bid.

2.7 Clarifications

Upon the issuance of this RFP to Bidders, and continuing through the submission date, all questions or other communications with the Consortium shall be by email only, with the Consortium's authorized representative:

Email: security-sensus@util-assist.com

The Consortium will respond to the question in writing, with both the question and response provided to each Bidder that has declared intention to bid. No response will be made to questions submitted after June 7, 2010.

2.8 Grounds for Disqualification

It is a requirement of this RFP document that Bidder's submitting Proposals for evaluation complete the Pricing Spreadsheet and format their bid submission according to Section 2.4 *Proposal Format Instructions*. The Consortium reserves the right to reject any incomplete bids (as per Section 2.6 *Complete Bid*).

2.9 Post Bid Meeting

The Consortium reserves the right to invite any or all Bidders to make an in-person presentation regarding the proposed security audit solution. The Consortium may request Bidder's assistance in arranging visits or meetings with customers who have completed a security audit with the assistance of the Bidder.

2.10 Withdrawal of Proposal

Bidders will be permitted to withdraw their Proposal unopened after it has been submitted if such a request is received by the designee of the Consortium in writing, prior to the Closing Time.

2.11 Bid Inconsistencies

Any provisions in Bidder's Proposal that is inconsistent with the provisions of this Request for Proposals, unless expressly described in the Proposal as being exceptions, are deemed waived by the Bidder. In the event the order is awarded to Bidder, any claim of inconsistency between the Proposal and this RFP will be resolved in favour of this RFP unless otherwise agreed to in writing by the Consortium.

2.12 Bidder's Statement of Understanding

By submitting a response to this RFP, Bidders acknowledge the following:

1) The Bidder acknowledges that it has carefully examined, understands and accepts the RFP documents, has carefully examined the requirements contained in the RFP documents and hereby submits an offer according to the requirements set forth in this RFP.

2) It is understood that this Proposal, if it has not been withdrawn in accordance with Section 2, subsection 2.10 *Withdrawal of Proposal*, is irrevocable and shall remain open for acceptance by the Consortium for a period of ninety (90) working days following the opening of the Proposals.

3) It is further understood by the Bidder that if the Consortium accepts its Proposal, then the Bidder is bound by the Contract and agrees to provide the goods and/or services upon the terms and conditions of the Contract.

4) While the Consortium has used considerable efforts to ensure an accurate representation of information in this Request for Proposal, the information contained in this Request for Proposal is supplied solely as a guideline for Bidders. The information is not guaranteed or warranted to be accurate by the Consortium, nor is it necessarily comprehensive or exhaustive. Nothing in this Request for Proposal is intended to relieve Bidders from forming their own opinions and conclusions with respect to the matters addressed in this Request for Proposal.

2.13 Proposal Evaluation

1) All Proposals shall be opened after the Closing Time in the presence of a Representative of the Consortium or another individual designated by the Consortium to open the Proposals. The opening will not be public.

2) In determining the contract award, the lowest Proposal will not necessarily be accepted, and the Consortium reserves the right to accept or reject any or all Proposals in its absolute discretion. Further, Proposals may be accepted or rejected in total or in part.

3) An Evaluation Committee will be selected by the Consortium and will review Proposals and will then carry out interviews with selected Bidders for clarification as required.

It is anticipated that a written contract will be negotiated immediately after the successful Bidder has been notified. If a contract cannot be negotiated within sixty (60) days of notification, the Consortium may, at its sole discretion at any time thereafter, terminate negotiations with that Bidder and either negotiate a contract with the next qualified Bidder or choose to terminate the Request for Proposal process and not enter into a contract with any of the Bidders.

2.14 Award of Contract

1) The Bidder acknowledges that the Consortium reserves the right, privilege, entitlement and absolute discretion, and for any reason whatsoever to:

   a) Cancel this Request for Proposals at any time, either before or after the Closing Time;
   b) Accept a Proposal which is not the highest scoring Proposal submission, or reject a Proposal that is the highest scoring Proposal even if it is the only Proposal received;
   c) Accept the Proposal deemed most favourable to the interests of the Consortium or that may provide the greatest value advantage and benefit to the Consortium based upon but not limited to price, ability, quality of work, service, past experience, past performance and qualification;
   d) Accept or reject any and all Proposals, whether in whole or in part;
   e) Award any part of any Proposal; or
   f) Accept or reject any unbalanced, irregular, or informal Proposals.

2) The Bidder acknowledges that the Consortium will evaluate Proposals using an internal scoring method as referenced in Section 2.17 *Proposal Evaluation Criteria* and other criteria which the Consortium deems relevant, even though such criteria may not have been disclosed to the Bidder. By submitting a Proposal, the Bidder acknowledges the Consortium's rights under this section and absolutely waives any right, or cause of action against the Consortium and its consultants, by reason of the Consortium's failure to accept the Proposal submitted by the Bidder, whether such right or cause of action arises in contract, negligence, or otherwise.

3) Contract award, if any, will be communicated by written notification from the Consortium to the successful Bidder.

4) Bidders whose Proposals have been rejected by the Consortium will be notified within thirty (30) days of the award date.

5) The successful Bidder shall provide the Consortium with a designated inside customer service representative. Any disputes and/or queries with respect to the Contract will be directed to the Consortium representative, whose decisions with respect to any matter under dispute shall be final and binding.

2.15 Freedom of Information

Proposals submitted to the Consortium become the property of the Consortium and, as such, are subject to the *Freedom of Information and Protection of Privacy Act*, R.S.O. 1990, c. F.31, as amended.

2.16 Ownership of Data

The Consortium shall own all information collected and reported on by the Vendor during the security audit process. Information collected and reported by the Vendor shall not be used for any purpose without the approval of the Consortium.

2.17 Proposal Evaluation Criteria

The Consortium and the evaluation committee representatives will evaluate Proposals using an internal scoring method that weights various parameters to give the Consortium insight into the strengths of each Proposal relative to the Consortium's needs. The Consortium's internal scoring method values the following Proposal attributes (order of presentation does not reflect priority):

Proposal Evaluation Criteria	Section	% Total Points
Project Overview	**3**	
Bidder Company Information	**4**	
Section 3 and 4 inclusive:		**65%**
Pricing Weighting:		**35%**
Total		**100%**

Along with the Bidder's company information, and statements of understanding regarding the project, the answers to Sections 3 and 4 will represent 65% of the total weighting of the RFP. Pricing submitted will represent 35% of the total weighting of the RFP. Bidders will be selected for further discussion based on the Team's judgment, determined using the scoring method.

2.18 Payment

When the Vendor has completed all work in accordance with the phases of the contract documents, the Vendor shall submit to the Consortium a request for payment. The request for payment shall constitute a waiver of all claims by the Vendor except for claims specifically listed in the request. The Consortium will make payment within sixty (60) days of receipt of a request for payment at the completion of each project phase.

Vendor's submission of its request for final payment shall constitute its warrant that the Vendor has to the best of its knowledge fully completed all work included in the Contract and has fully paid for labour, materials, equipment, services, taxes and all other costs and expenses resulting from this Contract..

2.19 Proposal Forms

Within this section, there are two forms required for submission. The first form is found in Section 2.19.1 *Intention to Bid Form*; the intention of this form is to allow the Bidder to provide a standard email Response to the Consortium designee to notify the Consortium of the Bidder's intent to respond to the RFP.

2.19.1 Intention to Bid Form

The procedure to be utilized for this form is to copy and paste the following content into an email, and send the email to:

Email: security-sensus@util-assist.com

according to the time line as established by Section 1.2 *Key Dates*.

INTENTION TO BID NOTIFICATION FORM

PROPOSAL NO. – The Consortium RFP-2105S

Intention to Bid:
Please allow this email to represent "   Insert Company Name Here   " intention to respond to the Consortium Proposal No. The Consortium RFP-2105S.

Contact for communication regarding bid: ____________________________________
Contact phone number: ____________________________________
Contact email address: ____________________________________

We acknowledge the Submission Deadline is 3:00 p.m. Eastern Time on June 28, 2010.

2.19.2 RFP Submission Form

The procedure to be utilized for this form is to print the following pages, and include them with the RFP submission, which should be addressed to:

Orangeville Hydro Limited
Attn: Ruth Tyrrell
400 C Line
Orangeville, ON L9W 2Z7

and be submitted according to the timeline as established by Section 1.2 *Key Dates*.

RFP SUBMISSION FORM

The Consortium

Request for Proposal Number: **The Consortium RFP-2105S**

FOR: SECURITY AUDIT SERVICES

THIS PROPOSAL IS SUBMITTED BY:____________________

ADDRESS: ____

____

____

TELEPHONE: ______________________ FAX NO.: ________________________

BIDDER G.S.T. NO.: ____

PERSON(S) SIGNING ON BEHALF:_________________________________(print)

POSITION(S) OF THE PERSON(S):_________________________________(print)

To the Consortium, Hereafter called "Owner":

I/WE ____________________________________ the undersigned declare:

1. THAT no Person(s), Firm or Corporation other than the one whose signature(s) of whose proper officers and the seal is or are attached below has any interest in this Proposal or in the contract proposed to be taken.

2. THAT this Proposal is made without any connections, knowledge, comparison of figures or arrangements with any other company, firm or person making a Proposal for the same work and is in all respects fair and without collusion or fraud.

   THE Bidder insures that no Owner and or employee of the Consortium, is, or has become interested, directly or indirectly, as a Contracting Party, Partner, Stockholder, surety or otherwise howsoever in or on the performance of the said contract, or in the supplies, work or business in connection with the said contract, or in any portion of the profits thereof, or of any supplies to be used therein, or in any monies to be derived there-from.

3. THAT the several matters stated in the said Proposal are in all respects true.

4. THAT I/WE have carefully examined the requirement(s), as well as all sections of the document including Instruction to Bidders, Project Overview, Installation Services, Proposal Forms, and Appendices relating thereto, prepared, submitted and rendered available by the Consortium and hereby acknowledge the same to be part and parcel of any contract to be let for the work therein described or defined.

5. THAT I/WE do hereby Propose and offer to enter into a contract to deliver all work as described or implied therein including in every case freight, duty, exchange, G.S.T. and P.S.T. in effect on the date of the acceptance of Proposal, and all other charges on the provisions therein set forth and to accept in full payment therefore, the sums calculated in accordance with the actual measured quantities and unit prices set forth in the Proposal herein.

6. THAT Addendum/Addenda No. ___ to ___ inclusive relate to the said contract and Bidder hereby accepts and agrees to the same as forming part and parcel of the said contract.

7. THAT additions or alterations to or deductions from the said contract, if any, shall be made in accordance with the prices stated in the Schedule of Items of Unit Prices in strict conformity with the requirements of the Contract.

8. THAT this offer is irrevocable and open to acceptance until the formal contract is executed by the awarded Bidder for the said requirement(s) or Sixty (60) working days, and unit prices for as long as stated elsewhere in the document, whichever event first occurs and that the Consortium may at any time within that period without notice, accept this Proposal whether any other Proposal has been previously accepted or not.

9. THAT the awarding of the contract, by the Consortium is based on this submission which shall be an acceptance of this Proposal.

10. THAT I/WE also understand that the Consortium reserves the right to accept or reject all or part of this Proposal or any other and also reserves the right to accept other than the lowest Proposal.

<u>The undersigned affirms that he/she is duly authorized to execute this Proposal.</u>

BIDDER'S SIGNATURE AND SEAL: ______________________________

NAME: ______________________________
(Please Print)

POSITION: ______________________________

WITNESS SIGNATURE: ______________________________

WITNESS NAME: ______________________________
(Please Print)

POSITION: ______________________________

(If Corporate Seal is not available, documentation should be witnessed)

DATED AT THE ______________________________ THIS ________
(City/Town) (Day)

DAY OF ______________________ 2010.
(Month)

Section 3: Project Overview

3.1 The Current Environment

The chart below includes an overview of the network infrastructure and 3rd party systems in use at each participating utility.

Sensus Utility	Address	# Mtrs	# of Towers	WAN	RNI Location	HAN Devices	Interfaces to the IESO MDMR as well as the following 3rd Party Systems					
							WFM	CIS	GIS	ODS	OMS	AS2
Algoma Power Inc.	Sault Ste. Marie, ON	11,600	8	Bell GPRS and TBD	Q-9 Data Centre	not in use	not in use	H T E	not in use	Harris	not in use	TBD
Bluewater Power Distribution Corporation	Sarnia, ON	35,000	2 plus 2 FNPs	H.S.A.	Q-9 Data Centre	not in use	not in use	SAP	ESRI	TBD	not in use	Cleo VLTrader v4.2
Brant County Power Inc.	Paris, ON	9,300	1	Bell Mobility - VPN	Q-9 Data Centre	Peaksaver	not in use	Daffron	TBD	Harris	not in use	TBD
Brantford Power Inc.	Brantford, ON	34,189	1	H.S.A. Bell	Q-9 Data Centre	Peaksaver & Load Ctrl	Fieldworker	Daffron	Intergraph	Kinetiq	not in use	nSoftware
Cambridge and North Dumfries Hydro Inc.	Cambridge, ON	40,000	3	H.S.A Wireless	Q-9 Data Centre	Peaksaver	not in use	Harris Northstar	not in use	TBD	not in use	TBD
Canadian Niagara Power Inc.	Fort Erie, ON	28,100	3 plus 1 FNP and 2 FRP	H.S.A. Bell	Q-9 Data Centre	not in use	Fieldworker	SAP	not in use	Harris	not in use	TBD
Chapleau Public Utilities Corporation	Chapleau, ON	1,370	1	Bell DSL	Q-9 Data Centre	not in use	not in use	T&W	not in use	Harris	not in use	Cleo
COLLUS Power Corp.	Collingwood, ON	14,717	1 plus 1 FRP	H.S.A. Wireless	Q-9 Data Centre	not in use	Harris mCare	Harris Northstar 6.3.0	not in use	Kinetiq	not in use	Cleo
Espanola Regional Hydro Distribution Corp.	Espanola, ON	3,353	1 plus 1 FNP	Bell Mobility	Q-9 Data Centre	not in use	not in use	Harris	not in use	Harris	not in use	nSoftware
Greater Sudbury Hydro Inc.	Sudbury, ON	43,772	6	Fibre Optic	in-house	not in use	Harris mCare	Harris Northstar	not in use	TBD	not in use	TBD
Grimsby Power Incorporated	Grimsby, ON	9,600	1	Frame Relay	Q-9 Data Centre	not in use	Fieldworker	SAP	not in use	Harris	not in use	TBD
Haldimand County Hydro Inc.	Caledonia, ON	20,551	4	H.S.A. and VPN Bell	Q-9 Data Centre	not in use	not in use	Harris Northstar 6.2.9	ESRI	Harris	not in use	TBD
Hearst Power Distribution Co. Ltd.	Hearst, ON	2,751	1	Bell DSL	Q-9 Data Centre	not in use	not in use	Harris Northstar	not in use	Harris	not in use	TBD
Innisfil Hydro Distribution Systems Ltd.	Innisfil, ON	14,000	2	Bell HS Wireless	Q-9 Data Centre	Peaksaver & Load Ctrl	Harris mCare	Harris Northstar 6.2.9	ASI/Autodesk	Kinetiq	ASI/goOutage	nSoftware
Kitchener-Wilmot Hydro Inc.	Kitchener, ON	85,000	4	H.S.A Wireless	Q-9 Data Centre	Peaksaver	Fieldworker	in-house	Intergraph	inhouse	not in use	Inovis
Lakefront Utilities Inc.	Cobourg, ON	8,238	2	H.S.A. VPN	Q-9 Data Centre	not in use	not in use	Harris Ver 5.34	not in use	Kinetiq	not in use	TBD
Newmarket Tay Power Distribution Ltd	Newmarket, ON	35,000	3 plus 1 FNP	H.S.A. Frame Relay	Q-9 Data Centre	Peaksaver	onService	Harris	not in use	Kinetiq	not in use	Cleo
Niagara Peninsula Energy Inc.	Niagara Falls, ON	48,416	1	Fibre&H.S.A.	Q-9 Data Centre	not in use	not in use	Harris Northstar	not in use	Harris	not in use	TBD
Niagara-on-the-Lake Hydro Inc.	Virgil, ON	7,650	1	VPN	Q-9 Data Centre	Omnistat	not in use	Harris Northstar 6.3.0	not in use	Kinetiq	not in use	TBD
Norfolk Power Distribution Inc.	Simcoe, ON	18,300	2 plus 2 FNP and 1 FRP	VPN Bell	Q-9 Data Centre	not in use	not in use	Daffron	not in use	Harris	not in use	TBD
North Bay Hydro Distribution Ltd.	North Bay, ON	23,268	2	Bell DSL	Q-9 Data Centre	not in use	not in use	H T E	not in use	Harris	not in use	nuBridges
Northern Ontario Wires Inc. - Cochrane	Cochrane, ON	6,370	3	Bell DSL	Q-9 Data Centre	not in use	not in use	Harris	not in use	Harris	not in use	Cleo
Oakville Hydro Electricity Distribution Inc.	Oakville, ON	60,000	3	Fibre Optic H.S.A.	Q-9 Data Centre	Peaksaver	Harris mCare	Harris Northstar 6.3.0	not in use	Kinetiq	not in use	nSoftware
Orangeville Hydro Ltd. / Grand Valley Energy	Orangeville, ON	9,112	1 plus 1 FRP	H.S.A.	Q-9 Data Centre	not in use	not in use	Harris Northstar 6.3.0	not in use	Kinetiq	not in use	Cleo
Orillia Power Distribution Corporation	Orillia, ON	9,694	1	H.S.A.	Q-9 Data Centre	not in use	Harris mCare	Harris Northstar	not in use	Harris	not in use	Cleo
PowerStream Inc. / Barrie Hydro Distribution	Vaughan, ON	350,000	24	Fibre	Q-9 Data Centre	Peaksaver	Fieldworker	T&W	not in use	Kinetiq	ESRI Responder	BizTalk
PUC Distribution Inc. (Sault Ste. Marie)	Sault Ste. Marie, ON	32,300	3	Fibre Bell DSL	Q-9 Data Centre	not in use	not in use	Harris	not in use	Harris	not in use	nSoftware
Wasaga Distribution Inc.	Wasaga Beach, ON	11,800	2	H.S.A.	Q-9 Data Centre	not in use	not in use	Harris Northstar 6.3.0	not in use	Kinetiq	not in use	Cleo
Waterloo North Hydro Inc.	Waterloo, ON	45,000	4	Fibre Optic H.S.A. Wireless	Q-9 Data Centre	Peaksaver	Fieldworker	Daffron	ESRI	inhouse	not in use	VLTrader
Welland Hydro Electric System Corp.	Welland, ON	21,493	1	H.S.A. Bell	Q-9 Data Centre	Peaksaver	Fieldworker	APPX 4.2.9	not in use	Harris	not in use	TBD
Whitby Hydro Electric Corp.	Whitby, ON	36,000	2	H.S.A.	Q-9 Data Centre	not in use	Harris mCare	Northstar ver 6.2.9	not in use	Kinetiq	not in use	TBD

3.2 Project Objectives

The objective of this project is to complete an audit of security of the AMI systems in place at the participating utilities and to produce results with the audit firm to work with the AMI vendor to implement viable countermeasures to address areas of concern from their report.

There are common characteristics / configurations within the AMI networks deployed at the utilities that are part of the Consortium enabling us to benefit from a group audit. What will be important to utilities is that the audit firm completes the necessary tasks to provide confirmation that each utility's system is configured to the tested standard. Custom configurations such as Wide Area Network (WAN) backhauls and unique head end system hosting locations or data access by other systems have been identified to allow the audit firm to describe their approach on common and custom configurations that should be addressed during the audit process.

Utilities that have installed the same AMI network configuration throughout their network will have a common review. It is understood that the custom efforts for unique configurations will be identified by the audit firm and quoted so the individual utilities that this is applicable to have clarity on the costing and audit process proposed by the Bidder.

Specifically, the audit will:

- Identify security vulnerabilities within an entire AMI solution, from both an independent device perspective and for the infrastructure as a whole;
- Perform a threat risk assessment with the vendor to assess viability of existing security countermeasures embedded in AMI solutions and the management of those countermeasures as they pertain to confidentiality, integrity, and availability of the solution; and
- Where required, provide direction on new countermeasures or remedial actions to ensure an adequate level of security exists within the AMI system. It is a requirement that the Vendor participate in meetings with the AMI vendor representatives as part of the remediation process.

3.3 The Audit Process

The audit process described in this RFP is designed to be extensive, efficient and cost-effective for the participating utilities and provides benefits to the AMI vendor and the security audit firms as compared to completing individual reviews.

The Vendor is expected to complete an in-depth security review at one participating utility that has installed the Sensus AMI solution. The audit should utilize the ”bottom up” approach as described in the NIST document entitled ”Smart Grid Cyber Security Strategy and Requirements”; http://csrc.nist.gov/publications/drafts/nistir-7628/draft-nistir-7628_2nd-public-draft.pdf identifying any gaps in the system and working with the vendors and utilities on filling these gaps.

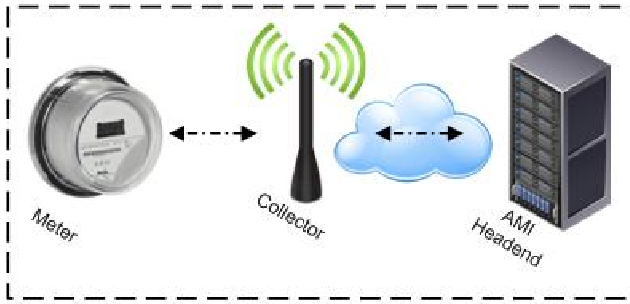
Once this review is complete, the Vendor is expected to review the technology at all participating utilties to confirm that their AMI systems are configured to the same standard as that declared as the standard for the group audit. In cases where the set-up is different, the Vendor must describe any security risks this poses and describe any remedial actions required.

Util-Assist will support all parties during this project with their project management team acting as the liason in the process, coordinating meetings and action items and acting as the main point of contact on behalf of the Consortium with the audit firm..

3.4 Project Scope

The enduring goal is to ensure that the AMI network deployed has secure end to end communication. The following sections address the levels of the network to be audited with the Bidder to provide detailed responses on all the sections listed.

The following list is a summary of the smart meter networks deployed at each Consortium member.



AMI Network

Sensus Utility	
Algoma Power Inc.	Newmarket Tay Power Distribution Ltd
Bluewater Power Distribution Corporation	Niagara Peninsula Energy Inc.
Brant County Power Inc.	Niagara-on-the-Lake Hydro Inc.
Brantford Power Inc.	Norfolk Power Distribution Inc.
Cambridge and North Dumfries Hydro Inc.	North Bay Hydro Distribution Ltd.
Canadian Niagara Power Inc.	Northern Ontario Wires Inc. - Cochrane
Chapleau Public Utilities Corporation	Oakville Hydro Electricity Distribution Inc.
COLLUS Power Corp.	Orangeville Hydro Limited / Grand Valley Energy Inc.
Espanola Regional Hydro Distribution Corp.	Orillia Power Distribution Corporation
Greater Sudbury Hydro Inc.	PowerStream Inc. / Barrie Hydro Distribution Inc.
Grimsby Power Incorporated	PUC Distribution Inc. (Sault Ste. Marie)
Haldimand County Hydro Inc.	Wasaga Distribution Inc.
Hearst Power Distribution Co. Ltd.	Waterloo North Hydro Inc.
Innisfil Hydro Distribution Systems Ltd.	Welland Hydro Electric System Corp.
Kitchener-Wilmot Hydro Inc.	Whitby Hydro Electric Corp.
Lakefront Utilities Inc.	

3.4.1 Meters to Collectors

The communication of the meter to the Collectors is a common characteristic in all AMI networks deployed by the Consortium in this RFP with no unique configuration by any members. There are four type of meters deployed with each type potentially containing a different firmware. A list of the meters types deployed at each Consortium member is listed below.

Meter(s) to Collector(s)

Sensus Utility	Meter Types currently in the field	# Mtrs
Algoma Power Inc.	iConA	11,600
Bluewater Power Distribution Corporation	iConA, A3	35,000
Brant County Power Inc.	iConA	9,300
Brantford Power Inc.	iCon, iConA, A3	34,189
Cambridge and North Dumfries Hydro Inc.	iConA, A3	40,000
Canadian Niagara Power Inc.	iConA	28,100
Chapleau Public Utilities Corporation	iConA	1,370
COLLUS Power Corp.	iConA, iCon1, iCon2, iCon3, iCon 5, A3D/Flex1, A3D/Flex2, A3RL/Flex1, A3RL/Flex2, A3RL/Flex3, A3RL/Flex4, A3TL/Flex1	14,717
Espanola Regional Hydro Distribution Corp.	iConA	3,353
Greater Sudbury Hydro Inc.	iConA	43,772
Grimsby Power Incorporated	iConA	9,600
Haldimand County Hydro Inc.	iConA	20,551
Hearst Power Distribution Co. Ltd.	iConA	2,751
Innisfil Hydro Distribution Systems Ltd.	iConA	14,000
Kitchener-Wilmot Hydro Inc.	iConA	85,000
Lakefront Utilities Inc.	iConA	8,238
Newmarket Tay Power Distribution Ltd	iConF, A3	35,000
Niagara Peninsula Energy Inc.	iConA	48,416
Niagara-on-the-Lake Hydro Inc.	iConA	7,650
Norfolk Power Distribution Inc.	iConA	18,300
North Bay Hydro Distribution Ltd.	iConA	23,268
Northern Ontario Wires Inc. - Cochrane	iConA	6,370
Oakville Hydro Electricity Distribution Inc.	iConA, A3	60,000
Orangeville Hydro Limited / Grand Valley Energy Inc.	iConA	9,112
Orillia Power Distribution Corporation	iConA	9,694
PowerStream Inc. / Barrie Hydro Distribution Inc.	iConA, iConG, iConF, A3	350,000
PUC Distribution Inc. (Sault Ste. Marie)	iConA	32,300
Wasaga Distribution Inc.	iConA	11,800
Waterloo North Hydro Inc.	iConA, iCon	45,000
Welland Hydro Electric System Corp.	iConA	21,493
Whitby Hydro Electric Corp.	iConA	36,000

Components of the Meters to Collectors layer of the AMI system that should be included in the audit are:

- Meter Communication
  - Residential (All Meter Manufacturers)
  - Commercial (All Meter Manufacturers)
  - Remote Disconnect
- Collector Communication Infrastructure and Physical Access to Equipment
  - TGB's
  - FRP (Pole Top)
- Repeater Communication (FNP)
- Field Tools (FMT)
- Vendor Meter Configuration Software

For this Section 3.4.1, the Bidder is to declare their understanding of the components that need to be audited in this section with the Bidder to provide a list of their experience with each of the components to be audited listed above.

Instructions to Bidders for responding to Sections 3.4.1.1 through 3.4.1.7

The Bidder is to provide a written response to the items in Sections 3.4.1.1 to 3.4.1.7 identifying the following for each item;

a) Please provide a listing of what the Bidder's recommendation is in regards to the scope of detail required in each of the categories.

b) Please describe the proposed methodology to complete this scope of work including what role each party is to play in the audit process.

c) Please describe the recommended on-going audit and security processes for both the AMI vendors and participating utilities for this level of the audit.

d) Experience in completing an audit at the level described in an AMI network.

e) Bidder to declare if this portion of the audit would be performed by the Bidder or sub-contracted out. If it is the intent of the Bidder to sub-contract out this work, the Bidder is required to supply details on who the sub-contractor is and provide detail on the sub-contractor's experience.

3.4.1.1 Remote Attestation of Meters

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to the means to determine whether a remote field unit has an expected and approved configuration.

3.4.1.2 Protection of Routing Protocols in AMI Layer

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to protection from route injection, node impersonation, traffic injection, traffic modification.

3.4.1.3 Key Management for Meters

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to analysing meter, collector or other devices to determine if they are subject to a break-once break-everywhere scenario due to one shared secret being used across the entire infrastructure. In relation to encryption, Bidders are to provide their recommendation as to how the sharing and trusting of keys is evaluated.

3.4.1.4 Tamper Evidence

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to analysing that tamper resistance and tamper evidence must be resistant to false positives from both natural and adversarial actions.

3.4.1.5 Authenticating and Authorizing Maintenance Personnel to Meters and Collectors

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to user and role based (read-only, read-write) authentication to meters and collectors.

3.4.1.6 Protection from Eavesdropping, Impersonation, Man-in-the-Middle, and Denial-of-Service

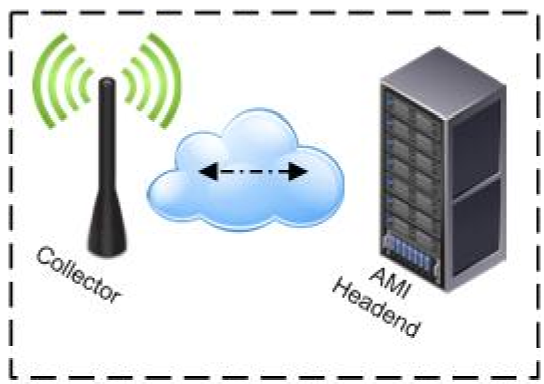
Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to analysing protection from eavesdropping, impersonation, man-in-the-middle and denial-of service threats.

3.4.1.7 Insecure Firmware Updates

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to verifying firmware update mechanisms are not used to install malware.

3.4.2 Collector(s) to AMI Headend

The communication from the Collector(s) to AMI Headend is unique to the WAN availability at the collector location for each AMI network deployed by the Consortium in this RFP. A list of the different WAN configurations in use by Consortium member has been provided below.



Collector(s) to AMI Headend

Sensus Utility	WAN Backhaul in use
Algoma Power Inc.	Bell Mobility GPRS and TBD
Bluewater Power Distribution Corporation	H.S.A.
Brant County Power Inc.	VPN Bell Mobility
Brantford Power Inc.	H.S.A. Bell Canada
Cambridge and North Dumfries Hydro Inc.	H.S.A. and Wireless
Canadian Niagara Power Inc.	H.S.A. and Wireless
Chapleau Public Utilities Corporation	Bell DSL
COLLUS Power Corp.	H.S.A. and Wireless Via Point to Point
Espanola Regional Hydro Distribution Corp.	Bell Mobility
Greater Sudbury Hydro Inc.	Customer Supplied Fibre
Grimsby Power Incorporated	Frame Relay Pagenet
Haldimand County Hydro Inc.	Fibre Optic
Hearst Power Distribution Co. Ltd.	Bell DSL
Innisfil Hydro Distribution Systems Ltd.	Bell HS and Wireless
Kitchener-Wilmot Hydro Inc.	H.S.A and Wireless
Lakefront Utilities Inc.	H.S.A. and VPN
Newmarket Tay Power Distribution Ltd	H.S.A. and Frame Relay
Niagara Peninsula Energy Inc.	Fibre to VPN to H.S.A. Bell Cda
Niagara-on-the-Lake Hydro Inc.	VPN through Pagenet Cda
Norfolk Power Distribution Inc.	VPN Bell Canada; FRP - GPRS Bell Mobility
North Bay Hydro Distribution Ltd.	Bell DSL
Northern Ontario Wires Inc. - Cochrane	Bell DSL
Oakville Hydro Electricity Distribution Inc.	Fibre Optic and H.S.A.
Orangeville Hydro Limited / Grand Valley Energy Inc.	H.S.A.
Orillia Power Distribution Corporation	H.S.A.
PowerStream Inc. / Barrie Hydro Distribution Inc.	Fibre
PUC Distribution Inc. (Sault Ste. Marie)	Customer Supplied Fibre and Bell DSL
Wasaga Distribution Inc.	H.S.A.
Waterloo North Hydro Inc.	Fibre Optic H.S.A. Wireless
Welland Hydro Electric System Corp.	H.S.A. Bell Canada
Whitby Hydro Electric Corp.	H.S.A. Bell Canada

Components of the Meters to Collectors layer of the AMI system that should be included in the audit are:

- Collectors
  - Pole Top
  - Socket Based
  - All WAN Providers listed in Consortium
- AMI Headend WAN Communication Interface

For this Section 3.4.2, the Bidder is to declare their understanding of the components that need to be audited in this section with the Bidder to provide a list of their experience with each of the components to be audited listed above.

Instructions to Bidders for Sections 3.4.2.1 through 3.4.2.3

The Bidder is to provide a written response to the following areas in question identifying the following for each item;

a) Please provide a listing of what the Bidder's recommendation is in regards to the scope of detail required in each of the categories.

b) Please describe the proposed methodology to complete this scope of work including what role each party is to play in the audit process.

c) Please describe the recommended on-going audit and security processes for both the AMI vendors and participating utilities for this level of the audit.

d) Experience in completing an audit at the level described in an AMI network.

e) Bidder to declare if this portion of the audit would be performed by their Bidder or sub-contracted out. If this is the Bidders intent, Bidder is required to supply details on who the sub-contractor is and their experience..

3.4.2.1 Public Versus Private WAN Links

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to verifying the security of the WAN communication, Identifying counter measure systems (e.g. firewalls) in both public and private WAN environments.

3.4.2.2 Physical and Logical Security of Modem and TGB

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to testing the physical and logical security of a modem. At minimum, it is the expectation that the Bidder would analyze:

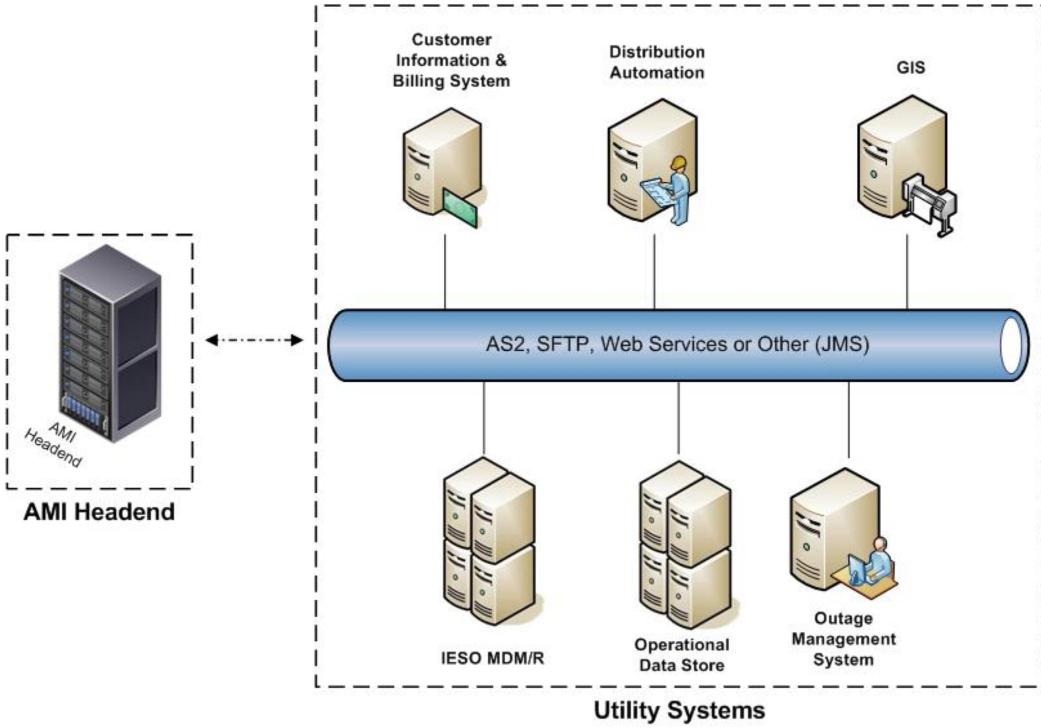
- Physical breach in access to the TGB equipment
- Physical breach of the hardware in use for TGB communication

3.4.2.3 Traffic Analysis / Logging

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to traffic analysis and logging including the identity of the communicating parties, message length, frequency, etc.

3.4.3 AMI Headend to Other Utility Interfaces

The hosting location of the AMI Headend systems is common amongst a large majority of the Consortium members. The communication of the AMI Headend to other utility systems has some common characteristics (i.e. communication from AMI Headend to IESO MDM/R) with the majority being a unique configuration.



A list of the hosting location and third party systems connected to the AMI Headend for each Consortium member is listed below.

Utility	Headend Location	Headend Shared?	WFM	CIS	GIS	ODS	OMS	AS2
Kitchener-Wilmot Hydro Inc.	Q-9 Data Centre	No	Fieldworker	in-house	Intergraph	in-house	Not In Use	Inovis
COLLUS Power Corp.	Q-9 Data Centre	Yes - CHEC	Harris mCare	Harris Northstar 6.3.0	Not In Use	Kinetiq	Not In Use	Cleo
Innisfil Hydro Distribution Systems Ltd.	Q-9 Data Centre	Yes - CHEC	Harris mCare	Harris Northstar 6.2.9	ASI/Autodesk	Kinetiq	ASI/goOutage	nSoftware
Lakefront Utilities Inc.	Q-9 Data Centre	Yes - CHEC	Not In Use	Harris Ver 5.34	Not In Use	Kinetiq	Not In Use	TBD
Orangeville Hydro Limited / Grand Valley Energy Inc.	Q-9 Data Centre	Yes - CHEC	Not In Use	Harris Northstar 6.3.0	Not In Use	Kinetiq	Not In Use	Cleo
Wasaga Distribution Inc.	Q-9 Data Centre	Yes - CHEC	Not In Use	Harris Northstar 6.3.0	Not In Use	Kinetiq	Not In Use	Cleo
Algoma Power Inc.	Q-9 Data Centre	Yes - D9	Not In Use	H T E	Not In Use	Harris	Not In Use	TBD
Chapleau Public Utilities Corporation	Q-9 Data Centre	Yes - D9	Not In Use	T&W	Not In Use	Harris	Not In Use	Cleo
Espanola Regional Hydro Distribution Corp.	Q-9 Data Centre	Yes - D9	Not In Use	Harris	Not In Use	Harris	Not In Use	nSoftware
Hearst Power Distribution Co. Ltd.	Q-9 Data Centre	Yes - D9	Not In Use	Harris Northstar	Not In Use	Harris	Not In Use	TBD
North Bay Hydro Distribution Ltd.	Q-9 Data Centre	Yes - D9	Not In Use	H T E	Not In Use	Harris	Not In Use	nuBridges
Northern Ontario Wires Inc. - Cochrane	Q-9 Data Centre	Yes - D9	Not In Use	Harris	Not In Use	Harris	Not In Use	Cleo
PUC Distribution Inc. (Sault Ste. Marie)	Q-9 Data Centre	Yes - D9	Not In Use	Harris	Not In Use	Harris	Not In Use	nSoftware
Brant County Power Inc.	Q-9 Data Centre	Yes - NEPA	Not In Use	Daffron	TBD	Harris	Not In Use	TBD
Brantford Power Inc.	Q-9 Data Centre	Yes - NEPA	Fieldworker	Daffron	Intergraph	Kinetiq	Not In Use	TBD
Canadian Niagara Power Inc.	Q-9 Data Centre	Yes - NEPA	Fieldworker	SAP	Not In Use	Harris	Not In Use	TBD
Grimsby Power Incorporated	Q-9 Data Centre	Yes - NEPA	Fieldworker	SAP	Not In Use	Harris	Not In Use	TBD
Haldimand County Hydro Inc.	Q-9 Data Centre	Yes - NEPA	Not In Use	Harris Northstar 6.2.9	ESRI	Harris	Not In Use	TBD
Niagara-on-the-Lake Hydro Inc.	Q-9 Data Centre	Yes - NEPA	Not In Use	Harris Northstar 6.3.0	Not In Use	Kinetiq	Not In Use	TBD
Niagara Peninsula Energy Inc.	Q-9 Data Centre	Yes - NEPA	Not In Use	Harris Northstar	Not In Use	Harris	Not In Use	TBD
Norfolk Power Distribution Inc.	Q-9 Data Centre	Yes - NEPA	Not In Use	Daffron	Not In Use	Harris	Not In Use	TBD
Welland Hydro Electric System Corp.	Q-9 Data Centre	Yes - NEPA	Fieldworker	APPX 4.2.9	Not In Use	Harris	Not In Use	TBD
Cambridge and North Dumfries Hydro Inc.	Q-9 Data Centre	No	Not In Use	Harris Northstar	Not In Use	TBD	Not In Use	TBD
Waterloo North Hydro Inc.	Q-9 Data Centre	No	Fieldworker	Daffron	ESRI	in-house	Not In Use	VLTrader
Bluewater Power Distribution Corporation	Q-9 Data Centre	No	Not In Use	SAP	ESRI	TBD	Not In Use	Cleo VLTrader v4.2
Greater Sudbury Hydro Inc.	In-house	No	Harris mCare	Harris Northstar	Not In Use	TBD	Not In Use	TBD
Newmarket Tay Power Distribution Ltd	Q-9 Data Centre	No	OnService	Harris	Not In Use	Kinetiq	Not In Use	Cleo
Oakville Hydro Electricity Distribution Inc.	Q-9 Data Centre	No	Harris mCare	Harris Northstar 6.3.0	Not In Use	Kinetiq	Not In Use	nSoftware
Orillia Power Distribution Corporation	Q-9 Data Centre	Yes - CHEC	Harris mCare	Harris Northstar	Not In Use	Harris	Not In Use	Cleo
PowerStream Inc. / Barrie Hydro Distribution Inc.	Q-9 Data Centre	No	Fieldworker	T&W	Not In Use	Kinetiq	ESRI - Responder	BizTalk
Whitby Hydro Electric Corp.	Q-9 Data Centre	No	Harris mCare	Northstar ver 6.2.9	Not In Use	Kinetiq	Not In Use	TBD

Components of the AMI Headend to other utility interfaces layer of the AMI system that should be included in the audit are;

- AMI Headend

For this Section 3.4.3, Bidder is to declare their understanding of the components that need to be audited in this section with the Bidder to provide a list of their experience with each of the components to be audited listed above.

Instructions to Bidders for Sections 3.4.3.1 through 3.4.3.11

The Bidder is to provide a written response to the following areas in question identifying the following for each item;

a) Please provide a listing of what the Bidder's recommendation is in regards to the scope of detail required in each of the categories.

b) Please describe the proposed methodology to complete this scope of work including what role each party is to play in the audit process.

c) Please describe the recommended on-going audit and security processes for both the AMI vendors and participating utilities for this level of the audit.

d) Experience in completing an audit at the level described in an AMI network.

e) Bidder to declare if this portion of the audit would be performed by their Bidder or sub contracted out. If this is the Bidders intent, Bidder is required to supply details on who the sub contractor is and their experience..

3.4.3.1 Patch Management

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their process to identify the risk and impact of vulnerability in order to prioritize upgrades.

Security infrastructure needs to be in place that can mitigate possible threats with patches until the upgrade can be qualified and deployed so that the reliability of the system can be maintained.

3.4.3.1(a) Change Management Controls

Bidders are to comment on their level of experience in the area of Change Management Controls. Bidders are to also provide information in helping the LDCs to identify what system patches or other changes would actually change the security levels. This should include possible requirements for QA, development and/or testing environments to allow for proper change management and patch testing.

3.4.3.2 Code Quality Vulnerability

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to testing code quality as this leads to unpredictable behaviour providing an opportunity to an attacker to stress the system in unexpected ways.

3.4.3.3 Authorization Vulnerability

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to testing of authorization vulnerabilities.

3.4.3.4 Cryptographic Vulnerability

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to testing for cryptographic vulnerabilities.

3.4.3.5 Interfaces

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to testing configuration and interfaces in place when considering the AMI network and its segregation in relation to the utility's existing corporate network infrastructure. Below are the suggested interfaces that would be a minimum requirement in the analysis:

- AS2
- SFTP
- Web Services / JMS (If Applicable)

3.4.3.6 Logging and Auditing Standards

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to testing logging and auditing vulnerability.

3.4.3.7 Sensitive Data Protection

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to testing for sensitive data protection.

3.4.3.8 Session Management Standards

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to testing for session management.

3.4.3.9 Use of Dangerous Web Services

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to testing for the user of dangerous APIs.

3.4.3.10 System Configuration / Hardening

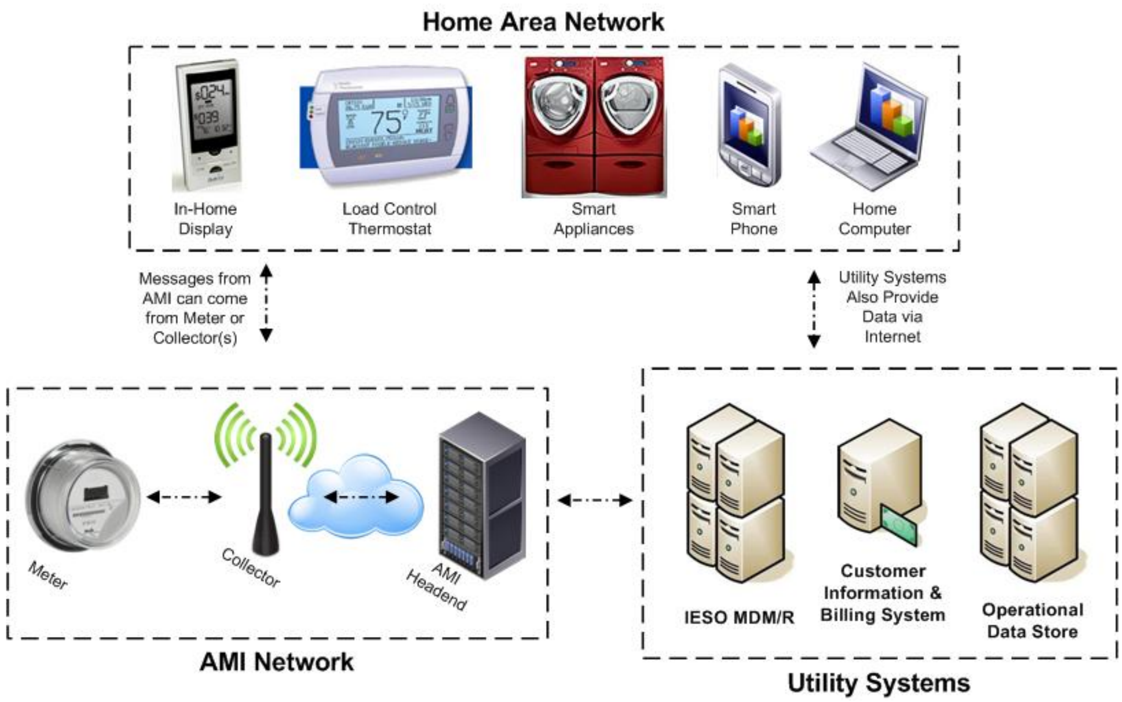
Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to analysing system configuration / hardening.

3.4.3.11 Malware Protection

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to analyzing for protection against malware.

3.4.4 Home Area Network (HAN) Interfaces

Connections between the utility AMI system and the customer's HAN should also be included in the audit. In the case where HAN technology has not been installed at the utility but is commercially available from the vendor, the technology should be tested to ensure it would be secure if installed to the vendor's specifications.



A list of HAN devices deployed for each Consortium member is listed below.

Sensus Utility	HAN Devices in Use
Algoma Power Inc.	not in use
Bluewater Power Distribution Corporation	not in use
Brant County Power Inc.	Peaksaver - stat
Brantford Power Inc.	Peaksaver - stat & Load Control Units
Cambridge and North Dumfries Hydro Inc.	Peaksaver - stat
Canadian Niagara Power Inc.	not in use
Chapleau Public Utilities Corporation	not in use
COLLUS Power Corp.	not in use
Espanola Regional Hydro Distribution Corp.	not in use
Greater Sudbury Hydro Inc.	not in use
Grimsby Power Incorporated	not in use
Haldimand County Hydro Inc.	not in use
Hearst Power Distribution Co. Ltd.	not in use
Innisfil Hydro Distribution Systems Ltd.	Peaksaver - stat & Load Control Units
Kitchener-Wilmot Hydro Inc.	Peaksaver - stat
Lakefront Utilities Inc.	not in use
Newmarket Tay Power Distribution Ltd	Peaksaver - stat
Niagara Peninsula Energy Inc.	not in use
Niagara-on-the-Lake Hydro Inc.	50 HAI Omnistat - stat
Norfolk Power Distribution Inc.	not in use
North Bay Hydro Distribution Ltd.	not in use
Northern Ontario Wires Inc. - Cochrane	not in use
Oakville Hydro Electricity Distribution Inc.	Peaksaver - stat
Orangeville Hydro Ltd / Grand Valley Energy Inc.	not in use
Orillia Power Distribution Corporation	not in use
PowerStream Inc. / Barrie Hydro Distribution Inc.	Peaksaver - stat
PUC Distribution Inc. (Sault Ste. Marie)	not in use
Wasaga Distribution Inc.	not in use
Waterloo North Hydro Inc.	Peaksaver - stat
Welland Hydro Electric System Corp.	Peaksaver - stat
Whitby Hydro Electric Corp.	not in use

Components of the HAN layer of the AMI system that should be included in the audit are;

- In-Home Display
- Load Control Thermostat
- Energy Gateway
- Load Control Devices
- WEB Presentment Tools

For this Section 3.4.4, Bidder is to declare their understanding of the components that need to be audited in this section with the Bidder to provide a list of their experience with each of the components to be audited listed above.

Instructions to Bidders for Sections 3.4.4.1 through 3.4.4.3

The Bidder is to provide a written response to the following areas in question identifying the following for each item;

a) Please provide a listing of what the Bidder's recommendation is in regards to the scope of detail required in each of the categories.

b) Please describe the proposed methodology to complete this scope of work including what role each party is to play in the audit process.

c) Please describe the recommended on-going audit and security processes for both the AMI vendors and participating utilities for this level of the audit.

d) Experience in completing an audit at the level described in an AMI network.

e) Bidder to declare if this portion of the audit would be performed by their Bidder or sub contracted out. If this is the Bidders intent, Bidder is required to supply details on who the sub contractor is and their experience.

3.4.4.1 Authenticating and Authorizing Consumers to Meters

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to analysing the authentication and authorization of consumers to meters.

3.4.4.2 Authenticating HAN Devices to/from HAN Gateways

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to analysing the authentication of HAN devices to and from HAN gateways.

3.4.4.3 Control the Range of History on In-Home Displays

Following the instructions to Bidders above, Bidders are to respond to questions A though E when describing their approach to how they would analyze the controls to determine how private information of previous owners is not shared in consumption history with move-in move outs and new owners..

3.5 Deliverables

The deliverables for this audit are:

- An agreed upon security assessment framework and methodology for
  a) AMI vendors and
  b) utility environments;

- A Security Audit Risk Assessment Report which includes for
  a) each participating AMI vendor and
  b) each participating utility:
    - a listing of existing risks by AMI components and classification by likelihood and consequence;
    - a listing remedial actions or mitigating measures for each risk identified;
    - a description of the ongoing audit processes which should be undertaken by the utility on an annual basis'
    - the applicable vendor assessment blended with the utility's specific environment (within the utility's report).
- A presentation of audit findings to the Consortium and AMI vendor with custom audit components presented to each applicable utility.
- The Bidder is to provide a sample template as to the deliverable report that they will provide (utility agnostic). This report should address the strengths, weaknesses, opportunities and threats found.
- The Bidder shall identify minimum acceptable security practices to allow the Consortium to review and decide what should be adopted so that the proper reporting can be set up to indicate the level being achieved.
- The Bidder is expected to participate in the remediation process with the AMI vendors as outlined further in Section 3.7 *Remediation Process*.

The Bidder shall confirm acceptance of these deliverables.

3.6 Project Timing

The following dates are the proposed timelines for the project:

Item	Start Date	Completion Date
Vendor to conduct audit and testing	August 16th, 2010	October 15th, 2010
Draft report to utilities		November 15th, 2010
Remediation of issues with utilities and vendors		November 15th, 2010 to December 15th, 2010
Final Report		To be determined

a) The Bidder shall confirm acceptance of these dates and indicate any recommended changes to the timeframes based on their experience.
b) The Bidder shall provide a detailed project plan and schedule for completion of the project within the defined timelines.
c) The Bidder shall provide information on their experience working with remediation efforts.

3.7 Remediation Process

The remediation process is deemed as a critical component in the success of this project and it is the expectation that the Bidder is involved in the remediation process with the AMI vendors to include, at minimum, the following:

- Meet with the AMI vendors to discuss the results of the security audit report;
- Provide the AMI vendors with detailed written information on security violations found; and
- Comment on acceptability of the AMI vendor's remedial actions or mitigating measures to the risks identified in the audit.

Section 4: Bidder Company Information

4.1 Bidder Experience

The Bidder must have demonstrated experience in evaluating security, identifying issues and providing direction on remediation within Smart Grid environments in North America.

1. How long has the Bidder been providing security audit services?
2. Describe the Bidder’s primary line of business and the percentage of its business derived from the completion of security audit services.
3. The Bidder must provide documentation of:
    a) Proven experience in performing security and vulnerability testing in the AMI / Smart Grid space, with a specific focus on addressing the entire AMI network (HAN to meter to systems);
    b) Knowledge and experience pertaining to AMI security testing, regulations, and guidelines;
    c) Indicate the standards and methodologies that the Bidder has used in past that are relevant to AMI network security;
4. The Bidder must identify and describe the suggested process for the security assessments and testing to be performed;
5. The Bidder must identify and describe the proposed methodology for security testing along with an explanation on why this methodology should be used;
6. The Bidder must identify and describe the proposed approach for determining the correct depth of testing required for each component of AMI;
7. The Bidder must identify work groups that they are involved and awards that they may have received that are relevant to the Smart Grid;
8. The Bidder must provide a security audit sample report.

4.2 Financial / Business Stability

1. How many years has the Bidder been in business?
2. What is the current size (number of employees), turnover rates for last three (3) years, and location(s) of the Bidder’s company?
3. Number of employees assigned to application audit services.

4.3 Resources

1. The Bidder is asked to acknowledge the requirement to designate a Contract Manager, who shall have the authority to handle and resolve any issues, disputes or contractual issues in a timely manner. The Bidder should describe the Contract Manager’s experience with managing projects of a similar size and scope, including timelines, and results if applicable.
2. The Bidder is to describe how the assigned project manager oversees subcontractor work.
3. The Bidder is asked to provide a listing of the key resources that will be utilized within this project and to provide a description of their related experience.

4. Should the Bidder sub-contract out any of the work described in Section 3, the Bidder is asked to provide a listing of the key resources that will be utilized within this project and to provide a description of their related experience.
5. Response should include the Contract Manager's and any other team member's Curriculum Vitae (CV) that will be assigned to the project. It is the expectation that the resources outlined in the Bidder's response will be the resources allocated to the project and changes to the resources will require the approval of the Consortium.
6. The Bidder is to identify the process used to perform background checks on its employees.
7. The Bidder is to identify the process used to perform background checks on any subcontractors used.

4.4 Perspectives Expressed by References

To ensure the best possible audit results, the selected Bidder must be a proven vendor in the area of security audit services and therefore the following information is requested:

Provide a list of at least three (3) references (contact names and phone numbers) and letters of reference for companies for whom the Bidder has completed security audit services the same or similar to the one(s) described in this RFP for the past three (3) years.

4.5 Bidder Services / Audit Service Contract

Based on the engagement described in Section 3 *Project Overview* the Bidder is to provide a contract for their services for the Consortium to review. This review will allow the Consortium to evaluate the ability of the Consortium to come to commercial terms with the Bidder and mitigate risks with a delay in the start up of the project due to an extended contract negotiations process.

Section 5: Price Submission Requirements

Describe in detail the pricing for the systems proposed. Detail any assumptions made in the proposed solution and pricing. All of this information should be included within the Pricing Spreadsheet. **As per Section 2.4 *Proposal Format Instructions*, any hard copies of the pricing submission should be submitted in a separate envelope, marked "PRICE OFFER".**

5.1 Pricing Submission

A Microsoft Excel workbook has been provided with this pdf document (entitled Sensus_SecurityAudit_Pricing_May2010.xls). The following tabs are included within this Pricing Spreadsheet:

a) Pricing_Option1: This tab requires completion by the Bidder, and represents the pricing for the Bidder to provide security audit services as outlined within this RFP.
b) Pricing_Option2: This tab is optional and allows the Bidder to provide pricing in an alternative format, should they desire to do so, and are of the opinion that their services are better represented with pricing apart from that outlined on the Pricing_Option1 tab.
   Note: Pricing_Option1 is mandatory, Pricing_Option2 is optional.
   Bidders are free to add additional pricing tabs as required should they feel that there are more than one alternative option which may allow for more competitive pricing.

Section 6: Contract Terms and Conditions

6.1 Commencement of Contract Time

The successful Vendor shall be notified by the Consortium of acceptance of the Vendor's Submission by the Consortium sending an Acceptance Letter. The Vendor shall acknowledge receipt, sign a non-disclosure agreement with each Consortium member, the AMI Vendor (as per Appendix "B") and enter contract negotiations within ten days of the date of sending of the Acceptance Letter.

The Contract Time shall commence to run as per the dates indicated in Section 3.6 *Project Timing*. Vendor shall start to perform the work on the date when the Contract Time commences

6.2 Vendor Claims

All claims of the Vendor and all questions relating to the interpretation of the Contract, including all questions as to the acceptable fulfillment of the Contract on the part of the Vendor and all questions as to compensation, shall be submitted in writing to the Util-Assist Project Manager for determination.

All such determinations and other instructions of the Consortium will be final unless the Bidder shall file with the Consortium a written protest, stating clearly, and in detail the basis thereof, within fifteen (15) calendar days after the Consortium notifies the Bidder of any such determination or instruction. The Consortium will issue a decision upon each such protest within fifteen (15) calendar days and its decision will be final. Work will not be undertaken until a written final decision is rendered.

6.3 Changes in the Work

The Consortium, without invalidating the Contract, may direct the Vendor to perform extra work or make changes in the work, provided that all changes or additions form an inseparable part of the work contracted for. Vendor shall make such changes or additions only after receipt of written instructions to do so from the Consortium. If such changes or additions cause an increase or decrease in the cost of the Contract, or in the time required to complete the Contract, the adjustment to the contract price or time frames shall be as set out in the Change Order and the Contract shall be modified accordingly.

When a change is ordered, a change order shall be executed by the Consortium and the Vendor before any change order work is performed. Any increase or decrease in the contract price and the time required for the completion of the contract work due to a change order shall be specifically set out in the change order. All terms and conditions contained in the Contract documents shall be applicable to change order work. The amount of any increase or decrease shall be added to or subtracted from the contract price as appropriate.

6.4 Delays and Extension of Time

If the Vendor is delayed at any time in the progress of the work by any act or neglect of the Consortium, or any cause beyond the Vendor's reasonable control, they shall file with the Consortium a notification that an extension of the Contract period is required.

The Util-Assist Project Manager shall review said notice and to the extent that the Vendor can reasonably demonstrate to the Consortium Project Manager that it shall be delayed in its fulfillment of these terms and conditions and other obligations of this transaction due to a cause beyond its control, a reasonable extension period shall be granted.

6.5 Termination of Right to Proceed

The Consortium may, in writing, terminate this Contract in whole or in part at any time, either for the Consortium's convenience or for the default of the Vendor. Upon such termination, all data, plans, specifications, reports, estimates, summaries, completed work and work in process, and such other information and materials as may have been accumulated by the Vendor in performing this Contract shall, in the manner and to the extent determined by the Consortium, become the property of the Consortium. If the termination is for the convenience of the Consortium and without default by the Vendor, an equitable adjustment for the Vendor's direct costs and profit for work actually performed shall be made by mutual agreement between the Vendor and the Consortium. No amount shall be allowed for anticipated profit on unperformed services. Any expense incurred because of cost of completion by the Consortium is chargeable to and shall be paid by the Vendor. The total liability to the Vendor shall be limited to the Contract value less the value of any equipment, material or completed services retained by the utility.

Default occurs if the Vendor (1) abandons the work called for hereunder, (2) files a voluntary petition in bankruptcy or fails to obtain dismissal of an involuntary petition in bankruptcy within sixty (60) days after the filing thereof or has a Receiver/Trustee appointed, (3) becomes insolvent, (4) assigns this Contract or sublets any part of the work hereunder without prior written permission of the Consortium, (5) repudiates the Contract, (6) allows liens to be filed against property of the Consortium, (7) fails to meet or perform its obligations hereunder after five days notice or continues in chronic default of its obligations, (8) disregards laws, ordinances, rules and regulations related to the Contract and the work or disregards instructions of the Consortium, (9) fails to complete the work in accordance with the Contract.

6.6 Casualty Insurance

Before commencing work under this contract the Vendor at his own expense shall submit Certificates of Insurance, providing evidence acceptable to the Consortium indicating that the Vendor has obtained and will maintain insurance for the duration of the contract. The following requirements apply to all Certificates of Insurance:

1) The insurance shall be written by an insurer acceptable to the Consortium,
2) The insurance shall be primary to any coverage carried by the Consortium.
3) The Vendor further agrees to provide the Consortium with an executed Certificate of Insurance before commencement of work, and with written copies of the insurance policies at any time upon the written request of the Consortium.
4) The Certificate of Insurance shall be an original copy signed by an authorized representative of the insurance carrier(s). (Note – faxed copies may be accepted initially to be followed up by originals in a reasonable length of time.)
5) The Certificate of Insurance shall provide that no less than 30 days advance notice will be given in writing to the Consortium prior to cancellation, termination or alteration of the insurance coverage. The Consortium shall be named as an additional insured on each General Liability Insurance Policy and any Excess Liability Policy or Umbrella Policy used to meet the required general liability limits.

The types of coverage and minimum limits are as follows:

1) COMPREHENSIVE & COMMERCIAL GENERAL LIABILITY*
    a) $2,000,000 each occurrence
    b) $5,000,000 general aggregate

2) AUTOMOBILE LIABILITY*
   a) Bodily injury $1,000,000 per person
   b) $1,000,000 per accident
   c) Property damage $500,000 or
   d) Combined Single Limit $2,500,000
3) PROFESSIONAL LIABILITY*
   a) Policies of insurance in an amount of not less than $500,000 per claim

** A blanket, umbrella, and/or excess liability policy(s) may be utilized to increase limits to the desired level(s).*

6.7 Sub-contractors

The Consortium reserves the right to refuse to permit any person or organization (sub-contractor) to participate in the work covered by this Contract, such refusal shall not be unreasonably imposed. No sub-contract shall relieve the Vendor of any liabilities or obligations under the Contract, and the Vendor agrees that Vendor is fully responsible to the Consortium for the acts and omissions of Vendor's sub-contractors and of persons employed by them. Vendor shall require every sub-contractor to comply with the provisions of the Contract

6.8 Acceptance

These terms and conditions becoming binding when the Vendor's Submission chosen for acceptance by the Consortium is given written notice of acceptance of the submission.

No modification hereof and no condition stated by Vendor in accepting or acknowledging this order, which is in conflict or inconsistent with, or in addition to the terms and conditions set forth herein, shall be binding upon the Consortium unless accepted in writing by the Consortium.

6.9 Shipments

Vendor shall mail Bill of Lading and Shipping Memo to destination, and the Consortium's Project Manager for any hardware / equipment being sent to the Consortium.

Vendor shall notify the Util-Assist Project Manager promptly if unable to make shipment.

6.10 Prices

Vendor agrees that prices are firm unless otherwise noted, and Vendor warrants that said prices do not exceed the prices allowed by any applicable Federal, Provincial or Local regulation.

6.11 Compliance with Laws

Vendor warrants that in performing work under this order Vendor will comply with all applicable laws, rules and regulations of governmental authorities and agrees to indemnify and save the Consortium harmless from and against any and all liabilities, claims, costs, losses, expenses, and judgments arising from or based on any actual or asserted violation by the Vendor of any such applicable laws, rules and regulations.

6.12 Assignment

Vendor agrees that neither this order nor any interest herein shall be assigned or transferred by Vendor except with the prior written approval of the Consortium.

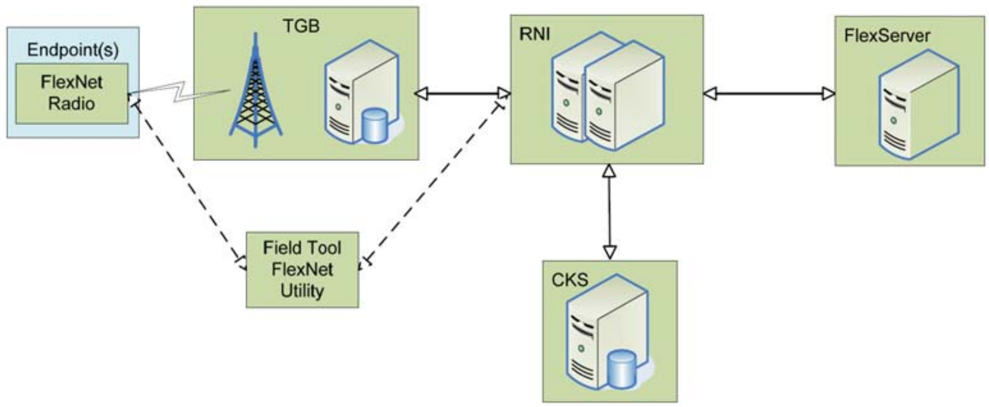
6.13 Substitution

No substitution will be permitted under this order except on specific written authority of the Consortium's Project Manager.

Appendix A

Sensus Network Overview

Certification Environment



Components includes:

- RNI – Three Server Configuration
- Sensus CKS
- TGB
- FlexNet Radio
- Field Tool (FlexNet Utility)
- FlexServer
- Endpoints (includes HAN/LCM)

CONFIDENTIAL

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Appendix B

Sensus NDA Requirements

Sensus
The Measure of the Future

MUTUAL NON-DISCLOSURE AGREEMENT

This Mutual Non-Disclosure Agreement ("Agreement") is made this ____ day of ________, 2010 ("Effective Date"), between Sensus USA Inc., of 8601 Six Forks Road, Suite 700, Raleigh, North Carolina, 27615 ("Sensus") and (insert name of other party) of (insert address of other party) ("Company").

Whereas, the parties wish to hold discussions to share information about customers, markets, and technology between the companies to investigate consumer strategies for the smart grid (collectively, the "Purpose");

Whereas, both parties may disclose Confidential Information, as defined herein, in the course of these discussions;

Whereas, both parties desire to protect the Confidential Information which may be disclosed between them.

IT IS AGREED:

1. **Confidential Information.** "Confidential Information" means any and all non-public information disclosed by either party to the other for the Purpose, including, without limitation, all technical information about either party's products or services, product specifications, pricing, marketing, marketing plans and strategy, information about the Sensus FlexNet system, customer lists, other business or financial information or plans of either party, and all trade secrets of either party. The Confidential Information may be transmitted orally, in writing or electronically. Notwithstanding the foregoing, "Confidential Information" shall not include, (i) any information that is in the public domain other than due to a breach of this Agreement, (ii) any information in the possession of the Recipient prior to disclosure by the Discloser hereunder, or (iii) any information independently developed by the Recipient without reliance on the information disclosed hereunder by the Discloser. "Discloser" means either party that discloses Confidential Information hereunder, and "Recipient" means either party that receives it.

2. **Protection.** For three (3) years after the date of disclosure, the Recipient shall keep all Confidential Information of the Discloser confidential, provided that trade secret information shall be maintained in confidence until the longer of (i) three years from the date of disclosure; or (ii) until the information is no longer a trade secret under applicable law. Except as provided in Section 3, the Recipient shall not, directly or indirectly, disclose the Confidential Information to any third party, and the Recipient shall take reasonable care to protect the Discloser's Confidential Information. The Recipient shall not make any copies of any tangible documentation or materials provided hereunder, except to the extent

necessary for the Purpose. The Recipient shall not use the Confidential Information of the Discloser for any reason other than for the Purpose.

3. **Permitted Disclosures.** The Recipient may only disclose the Confidential Information provided hereunder to its employees, agents, consultants and contractors who are directly involved in the Purpose and whom the Recipient has legally bound to comply with reasonable confidentiality obligations. The Recipient may also disclose Confidential Information to the extent it is obliged to do so under applicable laws, so long as it gives the Discloser reasonable notice to enable the Discloser to take protective steps.

4. **Return.** Upon the written request of the Discloser, the Recipient shall either (i) return all Confidential Information (including all copies) to the Discloser; or (ii) destroy all Confidential Information (including all copies) and provide written certification of their destruction to the Discloser

5. **Term**. This Agreement shall commence on the Effective Date and shall continue for three (3) years after the Effective Date. The provisions of this Agreement that are applicable to circumstances occurring after termination or expiration shall survive such termination or expiration.

6. **Warranty.** Both parties represent and warrant that they have the right to engage in the discussions and to disclose all information disclosed in the discussions. Notwithstanding the above, the Discloser does not make any representation or warranty as to the accuracy or completeness of the Confidential Information.

7. **No Obligations.** Neither party is under any obligation to disclose Confidential Information. Nothing in this Agreement obligates either party (i) to offer for sale any product or service using or incorporating the Confidential Information it discloses; or (ii) to purchase any product or service from the other party.

8. **Ownership.** All rights in the Confidential Information disclosed remain the property of the Discloser. The Recipient does not acquire any intellectual property rights to the Discloser's Confidential Information.

9. **Entire Agreement.** This Agreement constitutes the entire agreement between the parties related to the subject matter hereof, and it supersedes any and all prior agreements, understanding or other communications, whether written or oral, formal or informal, between them. No consent, waiver, alteration, amendment, or modification shall be binding unless in writing and signed by both parties.

10. **Assignment.** Neither party may assign its rights or delegate its duties or obligations under this Agreement without the prior written consent of the other party.

11. **Governing Law and Arbitration.** This Agreement is governed by North Carolina law. Any Cause of Action, as defined below, shall be submitted to binding arbitration in Wake County, North Carolina, under the rules of the American Arbitration Association, provided that; (i) the arbitration shall be

completed within twelve months of commencement; and (ii) the arbitrator shall sign an acknowledgement that (s)he has not awarded any damages which are excluded by Section 13. This arbitration provision is binding and neither party may commence any action inconsistent with it.

12. **Injunctive Relief.** Both parties acknowledge that a breach of this Agreement can cause the Discloser to suffer irreparable harm. IF ANY SUCH BREACH OCCURS OR IS THREATENED, THE DISCLOSER MAY SEEK INJUNCTIVE RELIEF, SPECIFIC PERFORMANCE AND OTHER EQUITABLE REMEDIES (IN ADDITION TO ANY AND ALL OTHER REMEDIES AT LAW) WITHOUT PROOF OF MONETARY DAMAGES OR THE INADEQUACY OF OTHER REMEDIES, AND THE RECIPIENT WAIVES ITS RIGHT TO ALL SUCH DEFENSES.

13. **Limitation of Liability.** Sensus' liability in any cause of action arising under, out of, or in relation to this Agreement, its negotiation, performance, breach or termination (collectively, "Cause of Action") shall be limited to direct damages. Sensus shall not be liable for any indirect, incidental, punitive or consequential damages. This is so whether the Cause(s) of Action are in contract, under statute, in tort, including, without limitation, negligence, or otherwise. The limitations on liability set forth in this Agreement are fundamental inducements to Sensus entering into this Agreement. They apply fundamentally and in all respects. They are to be interpreted broadly so as to give Sensus the maximum protection permitted under law. If Sensus is successful in any Cause of Action, Company shall pay Sensus' legal costs and reasonable attorneys' fees.

14. **Severability.** In the event any provision of this Agreement is held to be void, unlawful or otherwise unenforceable, that provision will be severed from the remainder of the Agreement and replaced automatically by a provision containing terms as nearly like the void, unlawful, or unenforceable provision as possible; and the Agreement, as so modified, will continue to be in full force and effect.

15. **Counterparts.** This Agreement may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. Additionally, this Agreement may be executed by facsimile or electronic copies, all of which shall be considered an original for all purposes.

IN WITNESS WHEREOF, the parties hereto have duly executed this Confidentiality Agreement as of the date first written above.

SENSUS USA INC.	**(name of other party)**
By: ______________________________	By: ______________________________
Name:____________________________	Name:____________________________
Title:_____________________________	Title:_____________________________

APPENDIX L

Confidential Materials Filed Separately with the Board

1. Util-Assist Consulting Services Proposal
2. AMI Sales and Services Agreement – Sensus Metering Systems Inc.
3. NEPA Installation Services Vendor Selection Report
4. AMI Installation Services Agreement – Olameter Inc.
5. NEPA Operational Data Store Vendor Selection Report
6. Software License, Implementation and Support and Maintenance Agreement – N. Harris Computer Corporation
7. Master Services Agreement – Savage Data Systems
8. Smart Meter Network Security Audit Services Statement of Work – Bell Wurldtech
9. Bell Professional Services Schedule Agreement – Bell Wurldtech
10. Utility Checklist for Sensus AMI TRA – Bell Canada
11. Letter to Sensus Metering Systems Inc. – dated August 29, 2011