EB-2010-0131

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 Horizon Utilities Corporation to the Ontario Energy Board for an Order or Orders approving of fixing just and reasonable rates and other service charges for the distribution of Electricity as of January 1, 2011.

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES") RESPONSES TO BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 1

Reference: Responses to Letters of Comment

Following publication of the Notice of Application, did Horizon receive any letters of comment? If so, please confirm whether a reply was sent from the applicant to the author of the letter. If confirmed, please file that reply with the Board. If not confirmed, please explain why a response was not sent and confirm if Horizon intends to respond.

Response:

There are currently three letters of comment in the Ontario Energy Board's ("OEB" or "Board") web drawer under EB-2010-0131. Horizon Utilities wishes to advise that a fourth letter, a letter filed by Customer "Robinson", relating to Horizon Utilities' 2011EDR, was incorrectly filed in the web drawer under EB-2010-0292, the file number related to Horizon Utilities' Smart Meter Funding Adder Application, currently before the

OEB.

Of the letters of comment filed with the OEB, only one of these letters, correspondence from Customer "Trudgian" was sent to Horizon Utilities. Horizon Utilities' Director of Corporate Communications spoke directly with Customer Trudgian on September 30th, 2010. During that conversation, Customer "Trudgian" expressed her frustration with the government of Ontario and Horizon Utilities' potential rate increase. Horizon Utilities' Director of Corporate Communications provided the customer with an explanation of the reasons that Horizon Utilities is seeking the rate increase, including Horizon Utilities need for asset and infrastructure investment and renewal, the need to invest in staff development to address the growing number of retiring skilled trades people, and the need to invest in technology and systems to enhance customer service and control operating costs through process efficiency.

Of the remaining three letters, Horizon Utilities did not reply to these letters of comment that were filed by customers in respect of Horizon Utilities' 2011 Electricity Distribution Rate Application. As noted above, such letters were not sent to Horizon Utilities directly and Horizon Utilities has no contact details for the customers, based on the limited information (of name alone) that is available in web drawer.

Further, while each of the three remaining letters noted are filed in response to Horizon Utilities' 2011 Electricity Distribution Rate Cost of Service Application, in fact on examination of the letters, the customers directed their comments predominantly to opposition of the broader policy agenda of the Ontario government.

The comments oppose: i) the government's policy decision to implement Time of Use pricing, ii) the difficulty of some consumers living on fixed or low incomes, iii) the hours of the day associated with the on-peak, mid-peak and off-peak pricing periods under the TOU rate structure, and iv) Ms. Clitheroe's administration of Hydro One. The letters go on to voice opposition to the introduction of the Harmonized Sales Tax ("HST").

As noted above, the aforementioned letters were sent directly to the Board and Horizon Utilities therefore did not have customer specific contact information in order to be able to reply.

EB-2010-0131

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 2

Reference: E1/T1/13 – Corporate Structure

Horizon Holdings Inc., the parent to Horizon Utilities Corp., wholly owns both Horizon Utilities Corporation and Horizon Solar Corporation. Horizon Solar Corporation is a holding company with 0.1% interest in Solar Sunbelt General Partnership ("SSGP"), with Horizon Utilities owning about 99.9% interest in SSGP.

a) When was Horizon Solar Corporation and SSGP established?

b) Please provide further explanation on why this corporate structure was established? What are the benefits of this arrangement for Horizon Utilities Corporation, particularly with respect to its financial viability and providing distribution services to its ratepayers?

Response:

a) Horizon Solar Corp. was established on June 21, 2010. SSGP was established on July 1, 2010.

b) This corporate structure was established to enable a new solar photovoltaic generation business ("Solar/PV") within the Horizon Group of Companies. The Solar/PV business will be undertaken in SSGP such that SSGP will enter into Feed-in-Tariff ("FIT") contracts with the Ontario Power Authority and develop Solar/PV generation assets. This particular structure was chosen to maximize the economic benefits of Solar/PV, while minimizing related business risks including, to the extent practicable, segregating the risks and benefits from ratepayers. On the latter point, these are the principal benefits of the structure to ratepayers; that they will remain indifferent to the addition of the Solar/PV business.

Horizon Holdings Inc. is financing its investment in SSGP through Horizon Solar Corp. and Horizon Utilities.

The investments, revenues, and expenses for Solar/PV will be segregated from the rate regulated electricity distribution activities in accordance with the OEB's requirements in G-2009-0300 (Regulatory and Accounting Treatments for Distributor Owned Generation Facilities). No investments, revenues and expenses associated with Solar/PV are included in this Application.

The Horizon Utilities regulated electricity distribution operations ("EDO") and its ratepayers are indifferent to this arrangement.

There is no anticipated impact to the financial viability of the Horizon Utilities EDO as a result of this arrangement. This arrangement has been reviewed by Standard and Poor's ("S&P"), the credit rating agency to Horizon Holdings Inc. A copy of such S&P report was included in the pre-filed evidence in EB-2010-0131 at Exhibit 1, Tab 3, Schedule 4, Appendix 1-14. The credit rating on Horizon Holdings Inc. was not affected by this arrangement.

**HORIZON UTILITIES CORPORATION (“HORIZON UTILITIES”)
RESPONSES TO
BOARD STAFF INTERROGATORIES**

DELIVERED: January 24th, 2011

Question 3

Reference: E1/T3/S1/Appendix 1-10 Audited Financial Statements

Please provide a copy of Horizon Utilities Audited Financial Statements for the year ending December 31, 2008.

Response:

Below is a copy of Horizon Utilities Audited Financial Statements for the year ending December 31, 2008.

Horizon Utilities Corporation
Auditors' Report to the Shareholders
and Financial Statements
Year Ended December 31, 2008 and
December 31, 2007

KPMG LLP
Chartered Accountants
Box 976
21 King Street West Suite 700
Hamilton ON L8N 3R1

Telephone (905) 523-8200
Fax (905) 523-2222
Internet www.kpmg.ca

AUDITORS' REPORT TO THE SHAREHOLDER

We have audited the balance sheet of Horizon Utilities Corporation as at December 31, 2008 and the statements of income and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. 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 plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Hamilton, Canada
February 6, 2009

Balance Sheet

(in thousands)

As at December 31, 2008

		2008		2007
ASSETS				
Current assets				
Cash and cash equivalents	**$**	**4,301**	$	14,406
Accounts receivable		**88,541**		81,402
Inventory *[note 3]*		**5,928**		6,378
Other assets *[note 4]*		**1,637**		1,798
		100,407		103,984
Fixed assets *[note 5]*		**307,700**		290,435
Future payments in lieu of taxes		**5,180**		4,750
Goodwill		**18,923**		18,923
Total assets	**$**	**432,210**	$	418,092
LIABILITIES AND SHAREHOLDER'S EQUITY				
Current liabilities				
Accounts payable and accruals	**$**	**59,676**	$	53,586
Accounts payable to corporations under common control		**11,377**		17,120
Credit support for service delivery *[note7]*		**24,792**		23,848
		95,845		94,554
Long-term liabilities				
Long-term borrowings *[note 8]*		**116,000**		116,000
Employee future benefits *[note9]*		**16,294**		15,964
Net regulatory liabilities *[note 10]*		**28,629**		22,501
		160,923		154,465
Total liabilities		**256,768**		249,019
Shareholder's equity				
Share capital *[note 11]*		**123,593**		123,593
Contributed surplus		**15,218**		15,218
Retained earnings		**36,631**		30,262
Total shareholder's equity		**175,442**		169,073
Total liabilities and shareholder's equity	**$**	**432,210**	$	418,092

Commitments and contingencies *[note 13]*

On behalf of the Board:

Director

Director

Statement of Income and Retained Earnings

(in thousands)

For the year ended December 31, 2008

		2008		2007
Electricity distribution service charges *[note 14]*	**$**	**88,335**	$	84,797
Other income from operations *[note 15]*		**9,723**		9,792
		98,058		94,589
Expenses:				
Operating expenses *[note 17]*		**43,920**		41,650
Depreciation and amortization *[note 5]*		**23,365**		21,174
		67,285		62,824
Income from operating activities		**30,773**		31,765
Net gain on sale of assets		**265**		384
Interest income		**312**		642
Interest expense *[notes 8]*		**(9,517)**		(9,584)
Income before payments in lieu of taxes		**21,833**		23,207
Payments in lieu of income and large corporations taxes *[note 6]*		**(6,617)**		(8,438)
Net income		**15,216**		14,769
Retained earnings, beginning of year		**30,262**		25,944
Dividends paid		**(8,847)**		(10,451)
Retained earnings, end of year	**$**	**36,631**	$	30,262

Statement of Cash Flows

(in thousands)

For the year ended December 31, 2008

		2008		2007
OPERATING ACTIVITIES				
Net income for the year	**$**	**15,216**	$	14,769
Add (deduct) non-cash items:				
Depreciation and amortization		**24,738**		22,209
Future payments in lieu of taxes		**(430)**		(542)
Net change in employee future benefits		**330**		362
Net gain on sale of assets		**(265)**		(384)
Net change in other assets and liabilities		**(53)**		4,277
Cash provided by operating activities		**39,536**		40,691
INVESTING ACTIVITIES				
Additions to fixed assets		**(41,784)**		(38,638)
Proceeds received on sale of fixed assets		**46**		432
Cash used in investing activities		**(41,738)**		(38,206)
FINANCING ACTIVITIES				
Net change in credit support for service delivery		**944**		2,756
Dividends paid in the year		**(8,847)**		(10,451)
Cash used in financing activities		**(7,903)**		(7,695)
Net decrease in cash and cash equivalents during the year		**(10,105)**		(5,210)
Cash and cash equivalents, beginning of year		**14,406**		19,616
Cash and cash equivalents, end of year	**$**	**4,301**	$	14,406
Supplemental disclosure of cash flow information				
Interest received	**$**	372	$	654
Interest paid		(9,020)		(8,997)
Taxes paid		(9,628)		(10,163)

Notes to the Financial Statements

December 31, 2008 ($ in thousands)

1) BUSINESS OF CORPORATION

Horizon Utilities Corporation (the “Corporation”) is one of Ontario’s largest municipally owned electricity distribution companies in Ontario, delivering electricity and related utility services to more than 232,000 residential and commercial customers in Hamilton and St. Catharines.

On December 31, 2007, all of the common shareholdings of the Corporation, represented by Class 1 and Class A common shares, were transferred to a corporation incorporated in 2006, Horizon Holdings Inc. (“Horizon Holdings”). In consideration for the transfer, the former shareholder of the Class 1 common shares of the Corporation received the same number of Class 1 common shares of Horizon Holdings. Similarly, the former shareholder of the Class A common shares of the Corporation received the same number of Class A common shares of Horizon Holdings. The share transfer and issuance preserved the continuity of interests in the Corporation through Horizon Holdings. Horizon Holdings is 78.9 per cent owned by Hamilton Utilities Corporation (“HUC”), the holder of its Class A common shares, and 21.1 per cent owned by St. Catharines Hydro Inc. (“SCHI”), the holder of its Class 1 common shares.

2) SIGNIFICANT ACCOUNTING POLICIES

The financial statements have been prepared in accordance with generally accepted accounting principles in Canada consistently applied. The more significant accounting policies are summarized below:

a) Regulation

The Ontario Energy Board Act, 1998 (Ontario) (“OEBA”) conferred on the Ontario Energy Board (“OEB”) increased powers and responsibilities to regulate the electricity industry in Ontario. These powers and responsibilities include approving or fixing rates for the transmission and distribution of electricity, providing continued rate protection for rural and remote electricity consumers, and ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to electricity distributors which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

Rate Setting

The distribution rates of the Corporation are based on a revenue requirement that provides a regulated Maximum Allowable Return on Equity (“MARE”) on the amount of shareholder’s equity supporting the business of electricity distribution, which is also determined by regulation.

On April 12, 2006, the OEB approved distribution rates for the Corporation, effective May 1, 2006 to April 30, 2007. Such distribution rates provided for a revised MARE of 9.0% on the amount of shareholder’s equity supporting the business of electricity distribution as at December 31, 2004. In prior years, such MARE was 9.88%.

Notes to the Financial Statements

December 31, 2008 ($ in thousands)

2) SIGNIFICANT ACCOUNTING POLICIES (Continued)

a) Regulation (Continued)

On April 12, 2007, the OEB approved distribution rates for the Corporation, effective May 1, 2007. Such distribution rates were effectively adjusted upwards from 2006 levels by 1.92%, representing the Gross Domestic Product Inflationary Price Index for Final Domestic Demand ("GDP IPI-FDD") net of an industry productivity expectation of 1%; for a net increase of 0.92%.

On October 22, 2007, the Corporation filed an application for electricity distribution rates to be effective May 1, 2008 ("2008EDR Application"). Such application based distribution rates on a 2008 forecast of the amount of operating and capital expenses, debt, and shareholder's equity required to support the business of electricity distribution. The distribution rates applied for further included provision for the cost of debt capital, payments in lieu of corporate taxes, and the MARE.

On March 7, 2008, and in accordance with its report on Cost of Capital and 2nd Generation Incentive Regulation for Electricity Distributors, the OEB revised the MARE from 9.00% to 8.57% and deemed short-term debt rate from 4.77% to 4.47%. This change was effective May 1, 2008.

On October 3, 2008, the OEB issued its decision regarding the 2008EDR Application. Such decision provided for 2008 base distribution revenue requirement and rate base of $86,662 and $346,420, respectively. Such amounts do not include provision for the investment by the Corporation in the Smart Meter Initiative, further elaborated below. This decision did, however, provide for the Corporation to file a separate application for a rate adder to recover its ongoing investment in Smart Meters and related expenses including financing charges and MARE, which are recorded in a deferral account and will be subject to a future prudency review of the OEB. This decision also provided for the recovery of $868 of lost revenue and shared provincial savings related to certain conservation and demand management ("CDM") programs of the Corporation delivered in 2005 and 2006.

On November 17, 2008, the Corporation submitted its 2009 electricity distribution rate application ("2009EDR Application") to adjust its electricity distribution rates based on the 3rd Generation Incentive Rate Mechanism ("3G-IRM") of the OEB, applicable to all Ontario electricity distributors. Such adjustments are to be effective May 1, 2009. The 3G-IRM provides for a formulaic adjustment to electricity distribution rates. Such adjustment includes, among other components, an increase in distribution rates for the annual change in the GDP IPI-FDD net of a productivity factor of 1% and a "Stretch Factor" determined by the relative efficiency of an electricity distributor. The Stretch Factor applicable to the Corporation as of the effective date of the 2009EDR Application was 0.4%

2) SIGNIFICANT ACCOUNTING POLICIES (Continued)

a) Regulation (Continued)

Regulatory Accounting

In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Corporation's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. The Corporation's regulatory liabilities represent costs with respect to non-distribution market related charges and variances in recoveries that are expected to be settled in future periods.

Specific regulatory assets and liabilities are disclosed in Note 10.

The Electricity Restructuring Act (Ontario), 2004 (the "ERA")

On December 9, 2004, the Province enacted the ERA, which provides for a restructuring of Ontario's electricity sector to promote the expansion of electricity supply and capacity, alternative and renewable energy sources, and conservation and demand management. Under the ERA, the commodity cost of electricity for certain customer classes will be determined by the OEB on an annual basis and based on a combination of regulated, contract and competitive market prices for electricity. There are few provisions in the ERA that apply to electricity distributors.

Smart Meter Initiative

The Province of Ontario has committed to have "Smart Meter" electricity meters installed in 800,000 homes and small businesses throughout Ontario by the end of 2010. Smart Meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals.

The Corporation has installed approximately 140,000 Smart Meters as of the end of 2008 and anticipates having installed a total of 236,000 Smart Meters upon completion of its mass deployment.

b) Financial instruments

Under CICA Handbook Section 3855, Financial Instruments – Recognition and Measurement and Section 3861, Financial Instruments - Disclosure and Presentation all financial assets are classified as held-for-trading, held-to-maturity, loans and receivables or available-for-sale and all financial liabilities must be classified as held-for-trading or other financial liabilities.

Notes to the Financial Statements

December 31, 2008 ($ in thousands)

2) SIGNIFICANT ACCOUNTING POLICIES (Continued)

b) Financial instruments (continued)

All financial instruments are carried on the balance sheet at fair value except for loans and receivables, held-to-maturity investments and other liabilities, which are measured at amortized cost.

The Corporation has classified its financial instruments as follows:

Cash and cash equivalents	Held-for-trading
Accounts receivable	Loans and receivables
Accounts payable and accruals	Other liabilities
Credit support for service delivery	Other liabilities
Long-term borrowings	Other liabilities

Effective January 1, 2008, the Corporation adopted CICA Handbook Sections 3862 Financial Instruments Disclosures; 3863 Financial Instruments Presentation. The adoption of the new standard requires the disclosure of qualitative and quantitative information about the Corporation's risks associated with recognized and unrecognized financial instruments. The adoption of the new standard on presentation carried forward unchanged the presentation requirements from Section 3861, Financial Instruments Disclosure and Presentation, and therefore did not have any impact on the Financial Statements.

c) Measurement uncertainty

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and note disclosures related thereto. Due to the inherent uncertainty in making estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future regulatory decisions.

Accounts receivable and regulatory assets are stated after evaluation of amounts expected to be collected and an appropriate allowance for doubtful accounts. Inventory is recorded net of provisions for obsolescence. Amounts recorded for depreciation and amortization of equipment are based on estimates of useful service life. Employee future benefits are based on certain assumptions, including interest (discount) rate, salary escalation, the average retirement age of employees, employee turnover and expected health and dental care costs.

d) Cash and cash equivalents

Cash equivalents comprise overnight deposits in an investment account with a Schedule A bank. Investments are carried at cost, which approximates fair value.

December 31, 2008 ($ in thousands)

2) SIGNIFICANT ACCOUNTING POLICIES (Continued)

e) Inventory

Effective January 1, 2008, the Corporation adopted Canadian Institute of Chartered Accountant's (CICA) Handbook Section 3031, Inventories. Under the new standard, inventories are required to be measured at the lower of cost and net realizable value and any items considered to be major future components of property, plant and equipment are to be transferred to fixed assets. This new standard also provides updated guidance on the appropriate methods of determining cost and the impact of any write-downs to net realizable value. The implementation of this standard did not have any impact on the Corporations' results of operations.

f) Fixed assets and depreciation

Fixed assets are recorded at cost, including the cost of work in process, and are removed from the accounts at the end of their estimated service lives, except in those instances where specific identification allows their removal at retirement or disposition. For specifically identifiable assets, gains or losses at retirement or on disposition are credited or charged to other income, otherwise, no gain or loss is recognized unless a sale has occurred.

Depreciation is calculated on a straight-line basis over the estimated service life of fixed assets as follows:

Land rights	50 years
Buildings	25-30 years
Distribution stations	30 years
Distribution lines – overhead and underground	25 years
Distribution transformers	25 years
Distribution meters	25 years
Other fixed assets	3-15 years

Work in process reflects the cost of construction materials and applied labour and overheads consumed in partially completed capital projects and is not depreciated.

g) Goodwill

Goodwill represents the amount by which the purchase price of an acquired business exceeds the fair value of the net identifiable assets purchased.

Goodwill is not amortized and is evaluated for impairment on an annual basis, or more frequently if circumstances require, with any write-down of the carrying value of goodwill being charged against the results of operations. Goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill.

2) SIGNIFICANT ACCOUNTING POLICIES (Continued)

h) Credit support for service delivery

Credit support for service delivery represents cash deposits from electricity distribution customers and retailers, as well as construction deposits.

Deposits from electricity distribution customers are applied against any unpaid portion of individual customer accounts. Customer deposits in excess of unpaid account balances are refundable to individual customers upon termination of their electricity distribution service.

Customer deposits are also refundable to residential electricity distribution customers demonstrating an acceptable level of credit risk, as determined by the Corporation.

Pursuant to the Ontario Energy Board retail settlement code, the Corporation is entitled to security from retailers to guarantee the payment of the difference between the market price for electricity and the retailer's average contract price.

Construction deposits represent cash prepayments for the estimated cost of capital projects recoverable from customers and developers. Upon completion of the capital project, these deposits are transferred to capital contributions in aid of construction.

i) Employee future benefits

The Corporation pays certain health, dental and life insurance benefits, under unfunded defined benefit plans, on behalf of its retired employees.

Employee future benefits are recorded on an accrual basis. The accrued benefit obligations and current service cost are calculated using the projected benefit method pro rated on service and reflect management's best estimate of certain underlying assumptions. The current service cost for a period is equal to the actuarial present value of benefits attributed to that period in which employees rendered their services. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of the amendment. The excess of actuarial gains (losses) over 10% of the accrued benefit obligation is amortized into expense on a straight-line basis over the expected average remaining service life of active employees.

j) Pension plan

The Corporation provides a pension plan for its employees though the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund"), and provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The fund is a contributory defined benefit pension plan. The Corporation records the required contributions as an expense in the period they accrue.

2) SIGNIFICANT ACCOUNTING POLICIES (Continued)

k) Related party transactions

Transactions with related parties represent the culmination of the earnings process and are measured at the exchange amount.

l) Payments in Lieu of Taxes ("PILs")

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) ("ITA") and the Ontario Corporations Tax Act ("OCTA").

Commencing October 1, 2001 and pursuant to the *Energy Competition Act* ("ECA"), the Corporation is required to compute taxes under the ITA and OCTA and remit such amounts thereunder to the Ontario Electricity Financial Corporation ("OEFC"). These amounts, referred to as PILs under the ECA, are applied to reduce certain debt obligations of the former Ontario Hydro continuing in OEFC.

The Corporation provides for PILs using the asset and liability method. Under this method, future tax assets and liabilities are recognized, to the extent such are determined likely to be realized, for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date of enactment or substantive enactment.

m) Capital contributions in aid of construction

Capital contributions arise from development charges which are provided and paid by developers and used to finance additions to fixed assets. Capital contributions received are treated as a "credit" contra account and are included in fixed assets. These amounts are subsequently amortized by a charge to accumulated amortization and a credit to amortization expense at an equivalent rate to that used for the depreciation of the related fixed asset.

n) Revenue recognition

Electricity distribution services charges comprise charges to customers for use of the Corporation's electricity distribution system. These charges are recorded when the related services are performed.

Notes to the Financial Statements

December 31, 2008 ($ in thousands)

3) INVENTORY

Inventory, which consists of parts and supplies acquired for internal construction, consumption or recoverable work, is valued at the lower of cost and replacement cost. Cost is determined on a weighted average basis. Net realizable value is determined by replacement cost.

The amount of inventories consumed by the Corporation and recognized as an expense during 2008 was $840 (2007 - $838).

4) OTHER ASSETS

Other assets comprise:

	2008	2007
Prepaid expenses	1,637	1,612
Other	-	186
Total other assets	1,637	1,798

5) FIXED ASSETS

Fixed assets comprise:

	2008			2007		
	Original Cost	**Accumulated Depreciation**	**Net Book Value**	**Original Cost**	**Accumulated Depreciation**	**Net Book Value**
Land	**1,483**	**-**	**1,483**	1,483	-	1,483
Land rights	**146**	**(49)**	**97**	142	(45)	97
Buildings	**26,988**	**(15,980)**	**11,008**	26,426	(14,725)	11,701
Distribution stations	**9,724**	**(7,102)**	**2,622**	9,706	(6784)	2,922
Distribution lines – overhead and underground	**332,416**	**(148,412)**	**184,004**	319,813	(136,963)	182,850
Distribution transformers	**81,772**	**(37,565)**	**44,207**	79,002	(35,618)	43,384
Distribution meters	**52,992**	**(14,527)**	**38,465**	37,170	(12,498)	24,672
Other fixed assets	**51,953**	**(31,511)**	**20,442**	42,998	(28,297)	14,701
Work in process	**5,372**	**-**	**5,372**	8,625	-	8,625
	562,846	**(255,146)**	**307,700**	525,365	(234,930)	290,435

During the year, the Corporation received $6,198 (2007 - $3,402) of capital contributions in aid of construction.

Total depreciation expense for the year is $24,738 (2007- $22,209) of which $1,373 (2007- $1,035) has been allocated to operating expenses and capital.

Notes to the Financial Statements

December 31, 2008 ($ in thousands)

6) PAYMENTS IN LIEU OF TAXES

The provision for PILs varies from amounts which would be computed by applying the Corporation's combined statutory income tax rate as follows:

	2008	2007
Basic rate applied to income before PILs	33.50%	36.12%
Increase (decrease) in PILs resulting from:		
Tax basis of depreciable capital assets and goodwill in excess of accounting basis	(3.97%)	(2.64%)
Revaluation of Future Tax Liability at 2012 statutory rate of 29.0%	0.31%	3.00%
Items not deductible for tax purposes and other	0.47%	(0.12%)
Effective rate applied to income before PILs	**30.31%**	36.36%

At December 31, 2008, based on substantively enacted income tax rates, future income tax assets of $14,255 (2007 - $14,782) have not been recorded. Such future income tax assets relate to tax bases of depreciable capital assets and employee future benefits in excess of amounts recorded for accounting purposes. Such future tax assets have not been recorded in the accounts as there is uncertainty as to whether the Corporation will realize the benefits related to these assets which would be realized as relatively modest reductions of future tax liability over many future years.

7) CREDIT SUPPORT FOR SERVICE DELIVERY

Credit support for service delivery comprises:

	2008	2007
Customer deposits	15,303	15,112
Construction deposits	9,489	8,736
Total credit support for service delivery	24,792	23,848

Notes to the Financial Statements

December 31, 2008 ($ in thousands)

8) LONG-TERM BORROWINGS

Long-term borrowings comprise:

	2008	2007
Promissory Note Payable to Horizon Holdings	**116,000**	116,000
Total long-term borrowings	**116,000**	116,000

Long-term borrowings comprise a $116,000 Promissory Note Payable to Horizon Holdings (2007 - $116,000) bearing interest at 7.0% per annum (2007 – 7.0%), and payable semi-annually on January 30 and July 30. Such promissory note is unsecured and matures on July 30, 2012.

The Corporation incurred interest expense in respect of the promissory note payable to Horizon Holdings of $8,120 (2007 - $8,120).

9) EMPLOYEE FUTURE BENEFITS

The Corporation pays certain health, dental and life insurance benefits on behalf of its retired employees. The Corporation accrues the cost of these employee future benefits over the periods in which the employees earn the benefits. The cost of employee future benefits earned by employees is actuarially determined applying the projected benefit method pro rated on length of service. Significant assumptions underlying the valuation include management's best estimate of the interest (discount) rate, salary escalation, the average retirement age of employees, employee turnover and expected health and dental care costs.

Information about the Corporation's defined benefit plan is as follows:

	2008	2007
Accrued benefit liability, beginning of year	15,964	15,602
Net benefit expense:		
Current service cost	335	374
Interest cost	1,010	969
Amortization of net actuarial loss	99	138
Net benefit expense for the year	1,444	1,481
Benefits paid for the year	(1,114)	(1,119)
Accrued benefit liability, end of year	16,294	15,964

An actuarial valuation of the plan obligations was completed as at December 31, 2008 resulting in an unamortized net actuarial loss of $1,467. The Corporation has adopted the corridor method of accounting for the actuarially determined experience gains (losses). The excess of actuarial gains (losses) over 10% of the accrued benefit obligation is amortized into expense on a straight-line basis over the expected average remaining service life of active employees.

December 31, 2008 ($ in thousands)

9) EMPLOYEE FUTURE BENEFITS (Continued)

The main actuarial assumptions underlying the valuation are as follows:

a) General inflation

The health care cost trend for prescription drugs is estimated to increase at a declining rate from 8% to 4% over four years. Other medical and dental expenses are assumed to increase at 4% per year.

The approximate effect on the accrued benefit obligation and the estimated net benefit expense if the health care trend rate assumption was increased or decreased by 1% is as follows:

	Accrued Benefit Obligation	**Periodic Benefit Cost**
1% increase in health care trend rate	1,364	163
1% decrease in health care trend rate	(1,114)	(156)

b) Interest (discount) rate

The obligations at the period end and the present value of future liabilities were determined using a discount rate of 7.3% representing an estimate of the yield on high quality corporate bonds as at the valuation date.

(c) Salary levels

Future general salary and wage levels were assumed to increase at 4% per year.

10) NET REGULATORY LIABILITIES

Net regulatory liabilities comprise:

	2008	**2007**
Settlement variances	19,457	18,803
Smart Meter deferral account	1,998	1,699
Regulatory assets recovery account	6,901	1,024
Other	273	975
Total net regulatory liabilities	28,629	22,501

Net regulatory assets (liabilities) represent costs incurred by the Corporation and settlement variances with other participants in the electricity market, less recoveries, for the purpose of supporting the deregulation of the electricity industry in Ontario. These amounts have been accumulated pursuant to regulation underlying the *Electricity Act, 1998 (Ontario)* and deferred in anticipation of their future recovery in electricity distribution service charges.

December 31, 2008 ($ in thousands)

10) NET REGULATORY LIABILITIES (Continued)

Settlement variances - represent amounts that have accumulated since January 1, 2007 and have not yet been approved in rates by the OEB and comprise:

i) variances between amounts charged by the Independent Electricity System Operator ("IESO") for the operation of the wholesale electricity market and grid, various wholesale market settlement charges and transmission charges, and the amounts billed to customers by the Corporation based on the OEB approved wholesale market service rate; and,

ii) variances between the amounts charged by the IESO to allow for purchases of imported electricity and the amounts billed to customers by the Corporation based on OEB approved rates.

Smart Meter deferral account – represents the deferral of operating expenditures, capital expenditures and revenues related to Smart Meters in accordance with the direction set out by the OEB.

Regulatory asset recovery account – represents approved regulatory asset balances as at January 1, 2005, consisting of settlement variances and associated interest, less amounts recovered up to December 31, 2006. The recent OEB decision on the 2008EDR Application provided for the disposition of $7,373 of the Corporation's net regulatory liabilities over a twenty-nine month period ending April 30, 2011.

11) SHARE CAPITAL

	2008	**2007**
Authorized:		
Unlimited Class 1 Common shares		
Unlimited Class A Common shares		
Issued:		
7,890 Class 1 Common shares	91,133	91,133
2,110 Class A Common shares	32,460	32,460
	123,593	123,593

12) PENSION PLAN

The Corporation participates in the Ontario Municipal Employees Retirement Fund (OMERS), a multi-employer plan, on behalf of its employees. The plan is a contributory defined benefit pension plan. Contributions during the year were 6.5% for employee earnings below the year's maximum pensionable earnings and 9.6% thereafter. Contributions are expected to remain the same in 2008. During 2008, the Corporation expensed contributions totaling $1,802 (2007 - $1,809) made to OMERS in respect of the employer's required contributions to the plan.

December 31, 2008 ($ in thousands)

13) COMMITMENTS AND CONTINGENCIES

Commitments

Contractual Obligations

Pursuant to the terms of a Connection and Cost Recovery Agreement dated December 10, 2008, the Corporation has committed to upgrade the capacity of one of its transformer stations. The total commitment over a three year period is approximately $7,278 and the remaining commitment at year-end is approximately $4,876.

Leases

The Corporation has entered into operating leases for certain computer equipment. Minimum annual lease payments required are as follows:

2009	206
Total	**206**

Contingencies

General

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Company's financial position, results of operations or its ability to carry on any of its business activities.

Class Action

A class action claiming $500,000 in restitutionary payments plus interest was served on the former Toronto Hydro-Electric Commission, continuing as Toronto Hydro Corporation, on November 18, 1998. The action was initiated against the former Toronto Hydro-Electric Commission as the representative of the Defendant Class consisting of all municipal electric utilities ("MEU") in Ontario, of which the Corporation is a successor MEU, which have charged Late Payment charges on overdue utility bills at any time after April 1, 1981.

The claim is that late payment penalties result in municipal electric utilities receiving interest at effective rates in excess of 60% per year, which is illegal under Section 347(1)(b) of the Criminal Code. This action is at a preliminary stage. Pleadings have closed but examinations for discovery have not been conducted and the classes have not been certified. The Electricity Distributors Association is undertaking the defense of this class action on behalf of the Defendant Class. It is anticipated that the action will now proceed for determination in light of the reasons of the Supreme Court in the Enbridge class action.

Notes to the Financial Statements

December 31, 2008 ($ in thousands)

13) COMMITMENTS AND CONTINGENCIES (Continued)

Contingencies (continued)

Class Action (continued)

On April 22, 2004, in a decision in a class action commenced against The Consumers' Gas Company Limited (now Enbridge Gas Distribution Inc.), the Supreme Court of Canada ruled that Consumers' Gas was required to repay that portion of certain late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. Although the claim related to charges collected by Consumers' Gas after the enactment of section 347 of the Criminal Code in 1981, the Supreme Court limited recovery to charges collected after the action was initiated in 1994. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. The parties have reached a settlement of this class action and the settlement has been approved by the Ontario Superior Court of Justice.

On February 4, 2008, the OEB, in response to an application filed by Enbridge, ruled that all of Enbridge's costs related to settlements of the class action lawsuits, including legal costs, settlement cost and interest, are recoverable from ratepayers. The OEB's decision allows Enbridge to recover all amounts over a five year period commencing in 2008.

In May 2008, the representative plaintiff in the class action made a petition to the Lieutenant Governor in Council of Ontario (LGiC) in which he asked the LGiC to require the OEB to reconsider it's decision of February 4, 2008 and potentially re-hear the matter. Interested parties have made their submission to the LGiC. It is not clear when the LGiC will make its decision regarding the petition.

The Corporation is not a party to the Consumers' Gas class action, however, it is anticipated that the above noted class action will now proceed for determination in light of the reasons of the Supreme Court in the Consumers' Gas class action.

The Defendant Class may have defences available to it in this action that were not disposed of by the Supreme Court in the Consumers' Gas class action. Also, the determination of whether the late payment charges collected by the Corporation from its customers were in excess of the interest limit stipulated in section 347 of the Criminal Code is fact specific in each circumstance.

At this time, given the preliminary status of this action, it is not possible to quantify the effect, if any, on the financial statements of the Corporation. Consequently, no provision has been made in these financial statements with respect to any possible losses that may arise as a result of this matter.

Notes to the Financial Statements

December 31, 2008 ($ in thousands)

14) BILLINGS TO ELECTRICITY DISTRIBUTION CUSTOMERS

The Corporation is licensed by the OEB to distribute electricity. As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers. The Corporation may file to recover uncollected debt retirement charges from OEFC once each year. Otherwise, the Corporation is unable to recover uncollected amounts formerly remitted to these third parties. The Corporation retains only its electricity distribution services charge that is regulated by the OEB.

Electricity distribution services charges comprise:

	2008	2007
Gross customer billings	508,963	523,360
Less: Pass through charges billed by the Corporation		
Electricity charges paid through to generators	(295,462)	(307,041)
Transmission and miscellaneous charges	(57,066)	(59,849)
Market service charges	(32,895)	(34,408)
Debt retirement charges	(35,205)	(37,265)
Total electricity distribution service charges	88,335	84,797

15) OTHER INCOME FROM OPERATIONS

Other income from operations comprises:

	2008	2007
Water and waste water billing and customer care charges	3,262	3,076
Collection and other service charges	1,917	2,382
Pole and other rental income	1,325	1,358
Late payment charges	1,134	1,023
Management and other support services	604	859
Scrap sales	569	571
Miscellaneous	912	523
Total other income from operations	9,723	9,792

16) CAPITAL DISCLOSURES

The main objectives of the Corporation when managing capital are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

Notes to the Financial Statements

December 31, 2008 ($ in thousands)

16) CAPITAL DISCLOSURES (Continued)

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2008, shareholder's equity amounts to $36,449 (2007 – $30,262) and long-term debt amounts to $116,000 (2007 - $116,000).

The OEB regulates the amount of interest on debt and MARE that may be recovered by the Corporation, through its electricity distribution rates, in respect of its regulated electricity distribution business. The OEB permits such recoveries on the basis of a deemed capital structure represented by 60% debt and 40% equity. The actual capital structure for the Corporation may differ from the OEB deemed structure.

The Corporation has customary covenants typically associated with long-term debt. The Corporation is in compliance with all credit agreement covenants and limitations associated with its long-term debt.

17) RELATED PARTY TRANSACTIONS

Shareholder loans

Pursuant to an Amended Credit Agreement dated January 20, 2006, HUC has made available a revolving line of credit up to $55,000 to finance general corporate requirements, working capital requirements and prudential obligations. The Amended Credit Agreement matures on January 19, 2010. Interest rates payable on the Amended Credit Agreement are based on a margin above HUC's borrowing rate, as determined by reference to HUC's debt rating.

Revenue

The Corporation provides certain water and wastewater billing and customer care services to the sole shareholder of its ultimate parent company, the City of Hamilton. Other income includes $3,262 (2007 - $3,076) earned with respect to this agreement. As at the end of the year, accounts payable and accruals include $9,443 (2007 - $10,214) owing to the City of Hamilton for amounts collected on behalf of the City of Hamilton pursuant to this agreement.

The Corporation provides certain management and administrative services to Hamilton Hydro Services Inc. and Horizon Energy Solutions Inc., corporations under common control. Other income includes $432 (2007- $353) earned with respect to these agreements.

On December 31, 2007, pursuant to an intercompany loan agreement, Horizon Energy Solutions Inc., a corporation under common control, borrowed an amount of $650 from the Corporation. The loan, included in accounts receivable, is payable on demand and bears interest at the rate of 0.5% above the prime rate as determined and posted, from time to time, by the Canadian Imperial Bank of Commerce.

On July 31, 2008, pursuant to an "Asset Purchase Agreement", the Corporation sold assets relating to the meter service provider business to Horizon Energy Solutions Inc. in exchange for a Promissory Note Payable ("Promissory Note") to the Corporation in the amount of $220. The Promissory Note bears interest at 6.1% per annum on the principal sum, payable semi-annually on the last day of January and July. Such promissory note is unsecured and due on demand by the Corporation.

17) RELATED PARTY TRANSACTIONS (Continued)

Revenue (continued)

Interest income includes $35 (2007 - $nil) earned with respect to the loan agreement and the promissory note.

Operating expenses

Operating expenses include $ nil (2007 - $329) paid to Hamilton Utilities Corporation for certain management and administrative services and $nil (2007 - $753) paid to Hamilton Hydro Services Inc. for the provision of certain computer maintenance, telephone services, network and internet services.

Accounts payable

As at the end of the year, accounts payable and accruals include $ nil (2007 - $5,749) due to Hamilton Utilities Corporation and $ nil (2007 - $1,366) due to St. Catharines Hydro Inc.

18) FINANCIAL INSTRUMENTS

The carrying values of cash and cash equivalents, accounts receivable, credit support for service delivery and accounts payable and accruals approximate fair values because of the short maturity of these instruments.

It is not practicable to determine the fair value of the long-term borrowings from Horizon Holdings due to the limited amount of comparable market information available.

Risk Factors

The Corporation's activities provide for a variety of financial risks, particularly credit risk, market risk and liquidity risk.

i) Credit risk

Financial Assets carry credit risk that a counter-party will fail to discharge and obligation which would result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the City of Hamilton and the City of St. Catharines. One customer, the City of Hamilton, accounts for 3% (2007 – 3%) of revenue. No other single customer in either year would account for revenue in excess of 1% of the respective reported balances.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the income statement. Subsequent recoveries of receivables previously provisioned are credited to the income statement. The balance of the allowance for doubtful accounts at December 31, 2008 is $1,000. No single customer accounts for more than 1% of accounts receivable at year-end.

18) FINANCIAL INSTRUMENTS (Continued)

Risk factors (continued)

i) Credit risk (continued)

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2008, approximately $709 is considered 60 days past due. Horizon Utilities has approximately 290,000 customers, the majority of which are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2008, Horizon Utilities holds security deposits in the amount of $24,793 (2007 - $23,848).

ii) Market Risk

Market risks primarily refer to the risk of loss that results from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have commodity or foreign exchange risk. Horizon Utilities is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

iii) Liquidity risk

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest expense. The Corporation has access to a line of credit and monitors cash balances to ensure that sufficient levels of liquidity are on hand to meet financial commitments ad they come due.

19) EMERGING ACCOUNTING CHANGES

Rate Regulated Entities

In August 2007, the Canadian Accounting Standards Board (AcSB) issued a decision, effective January 1, 2009, to withdraw the temporary exemption in CICA Handbook Section 1100, Generally Accepted Accounting Principles, which permits the recognition and measurement of assets and liabilities arising from rate regulation. Further, CICA Handbook Section 3465, *Income Taxes,* was amended to require the recognition of future income tax liabilities and assets for regulated enterprises that were previously not subject these provisions. Consequently, the Company will be required to reflect on its Consolidated Balance Sheet, the effect of applying the liability method when accounting for payments in lieu of corporate income taxes and a corresponding regulatory asset. The Company is currently assessing the impact of the AcSB's decision on its Consolidated Balance Sheet.

Notes to the Financial Statements

December 31, 2008 ($ in thousands)

19) EMERGING ACCOUNTING CHANGES (Continued)

Goodwill and Intangible Assets and Other Standards

In January 2008, the CICA issued Handbook Section 3064, Goodwill and Intangible Assets, and amended Handbook Section 1000, Financial Statement Concepts, and Accounting Guideline 11 Enterprises in the Development Stage and withdrew Handbook Section 3450, Research and Development Costs. Handbook Section 3064 clarifies that costs may only be deferred when they relate to an item that meets the definition of an asset. The concept of matching revenues and expenses remains appropriate for allocating the cost of an asset that is consumed in general revenue over multiple reporting periods. Handbook Sections 3064 replaces Handbook Section 3062 and provides extensive guidance on when expenditures qualify for recognition as intangible assets. These changes are effective for fiscal years beginning on or after October 1, 2008. The Corporation is currently in the process of evaluating the potential impact of these standards on its financial statements.

International Financial Reporting Standards ["IFRS"]

On February 13, 2008, the AcSB announced that publicly accountable enterprises will be required to change over to IFRS effective January 1, 2011. Some of the converged standards will be implemented in Canada during the transition period with the remaining standards adopted at the change over date. The Corporation has launched an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements.

20) COMPARATIVE FIGURES

Certain comparative data have been reclassified to conform with the presentation of the current year.

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 4

Reference: E1/T4/S1/Appendix 1-15 Conditions of Service

Horizon has included a copy of its current Conditions of Service in the referenced schedule

a) Please identify any rates and charges that are included in Horizon's Conditions of Service, and provide an explanation for the nature of the costs being recovered.

b) Please provide a schedule outlining the revenues recovered from these rates and charges from 2006 to 2009 and the revenue forecasted for the 2010 bridge and 2011 test years.

c) Please explain whether, in Horizon's view, these rates and charges should be included on Horizon's Board-approved Tariff of Rates and Charges.

d) Are any changes to Horizon's Conditions of Service contemplated to align with this application for 2011 distribution rates for Horizon, if the application is approved as proposed? If so, please identify the possible changes and the reasons for them.

Response:

a) Please see the attached table for a list of all charges in the Conditions of Service as filed in Exhibit 1, Tab 4, Schedule 1, Appendix 1-15 along with an explanation of the nature of the costs being recovered.

Page	Reference	Charge	Explanation for the Nature of the Costs being Recovered	Basis of Charge
Pg 10	1.4	Amendments and Changes	Hard copy of Conditions of Service provided to customer	Recovery of Cost
Pg12	1.7.3	Safety of Equipment	Disconnect the supply of electricity and or remove or relocate the obstruction or encroachment	Recovery of Cost
Pg13	1.7.4	Damaged Electrical Equipment	Required to pay cost of repair or replacement through wilful misconduct or negligence of Customer (required to pay prior to reconnection)	Recovery of Cost
Pg13	1.7.4	Damaged Electrical Equipment	Third party not under contract to customer, damages equipment, third party will be responsible for the damages caused	Recovery of Cost
Pg 13	1.7.5	Defective Customer Electrical Equipment	Customer will repair or replace any equipment owned by the Customer that may affect integrity or reliability of Horizon Utilities' distribution system	Recovery of Cost
Pg13	1.7.6	Operating Control	Customer will be required to pay the cost of repairs or replacement of Horizon Utilities' equipment that has been damaged, destroyed or lost by the direct or indirect act or omission of the Customer or the Customer's agents	Recovery of Cost
Pg16	2.1.2	Expansions/Offer to Connect	Developer is required to pay 100 percent of the actual construction costs of the expansion if in an area not previously serviced and the load and customer requirements are unknown	Recovery of Cost
Pg 16	2.1.2.1	Expansions	The amount Horizon Utilities charges a customer for the expansion will include the calculated difference in present value between the projected capital and ongoing operating expenses and the projected revenue for distribution services due to the expansion along with other expenses permitted under the DSC Appendix B.	Recovery of Cost
Pg17	2.1.2.2	Offer to Connect	If the Customer subsequently submits revised plans, Horizon Utilities' may provide, at the Customer's expense, a new offer based on the revised plans	Recovery of Cost
Pg17	2.1.2.3	Alternative Bid Option	Customer required to pay Horizon Utilities to inspect all aspects of the constructed assets as part of the system commissioning and prior to connecting the constructed facilities to the existing distribution system	Recovery of Cost
Pg18	2.1.2.4	Capital Contributions	Horizon Utilities will collect the estimated capital contributions as calculated in the economic evaluation model at the time specified in the CCRA	Recovery of Cost
Pg18	2.1.2.5	Expansion Deposit	Expansion deposits will be collected accordingly	Recovery of Cost
Pg20	2.1.5	Relocation of Plant	Customer will pay Horizon Utilities the costs incurred for relocation of plant unless the equipment was improperly located or due to be replaced	Recovery of Cost
Pg22	2.2	Disconnection/Reconnection Processes and Charges	If a customer asks for disconnection more than once in a calendar year, the customer will pay to Horizon Utilities the actual costs for disconnecting and reconnecting its connection assets	
Pg 22	2.2.1	Unauthorized Energy Usage	The customer will pay Horizon Utilities for all costs incurred by Horizon Utilities including but not limited to, investigation and administration, repairs to damaged equipment, disconnect/reconnect, and estimated lost energy as calculated by Horizon Utilities	Recovery of Cost
Pg23	2.3.2	Power Quality	If a Customer identifies a power quality concerns, the Corporation may at its discretion require reimbursement from the Customer for the costs of investigating the complaint	Recovery of Cost
Pg24	2.3.2	Power Quality	The Customer may also be required to pay the cost of any additional connection assets that may be required as a condition of continuing the connection to that Customer, failing which Horizon Utilities may disconnect the Customer from its distribution system	Recovery of Cost
Pg24	2.3.3	Electrical Disturbances	Horizon Utilities may require the Customer to install, at the Customer's expense, additional facilities to nullify the undesirable effects	Recovery of Cost
Pg26	2.3.6.3	Interval Metering	Customers who require or request an interval meter are required to compensate Horizon Utilities for all incremental costs associated with the interval meter installation installs, maintains, and pays the cost of a communication system that satisfies the requirements of Horizon Utilities and provides an ongoing communication line or communication link with the Customer's meter interval meter installation	Recovery of Cost
Pg 26	2.3.6.4	Metering for Embedded Generation Facilities	Any customer with an Embedded Generation Facility shall be responsible for all costs for Horizon Utilities to install the metering, and the costs to have a communication line installed and maintained unless other arrangements have been made which are suitable to Horizon Utilities	Recovery of Cost

Pg29	2.3.6.8	Faulty Registration of Meters	Where a billing error, from any causes, has resulted in a Customer or Retailer being under-billed, Horizon Utilities will charge the Customer or Retailer the amount that not previously billed	Recovery of Cost
Pg29	2.3.6.9	Meter Dispute Testing	Where the Customer initiates the dispute, Horizon Utilities will charge the Customer a meter dispute fee if the meter is found to be accurate by Measurement Canada	Recovery of Cost
Pg29	2.4.1	Service Connection Rates and Charges	The Customer commences paying from the date of connection to Horizon Utilities' distribution system	Recovery of Cost
Pg33	2.5.3	Provision of Current Usage Data to Customers	The Customer will pay the costs of any software, hardware, or other services required in order for him to obtain direct access to meter information	Recovery of Cost
Pg35	2.6.2	Services over Swimming Pools	Horizon Utilities will provide up to thirty meters of overhead service conductors at no charge, any other costs such as pole relocation (labour only) or underground servicing will be at the pool owner's expense	Recovery of Cost
Pg38	3.1.5	Metering	The Customer will be required to pay if the repair or replacement requires an upgrade in the size of the meter socket	Recovery of Cost
Pg38	3.1.5.2	Metering for Condominium Townhouses	Any cost incurred by Horizon Utilities due to incorrect or incomplete making will be borne by the property owner and/or developer	Recovery of Cost
Pg38	3.1.5.3	Metering for New Mutli-Unit Residential Rental Buildings and Condominiums	Any incremental costs of installations (compared to the cost of the conventional metering method) will be payed by the building owner and developer	Recovery of Cost
Pg40	3.1.6	Overhead Secondary Service	If the replacement wire exceeds thirty meters, the Customer is required to pay for the portion beyond thirty meters, and the charge will be noted on the Service Application Form	Recovery of Cost
Pg41	3.1.7	Underground Secondary Service	If a Customer requests an underground road crossing, the Customer will pay the actual costs	Recovery of Cost
Pg41	3.1.7	Underground Secondary Service	The Customer will be charged for the actual costs arising from the installation of underground cable that is more than the basic thirty meters	Recovery of Cost
Pg41	3.1.7	Underground Secondary Service	The Customer is responsible for all costs incurred by Horizon Utilities associated with the installation of the upgraded service beyond the basic connection	Recovery of Cost
Pg41	3.1.7	Underground Secondary Service	Customer-requested relocation of underground service will be done at the Customer's expense	Recovery of Cost
Pg41	3.2.1	Application	Failure to request and obtain a Service Layout may result in the ownership demarcation point and or the point of entry being relocated at the Customer's expense	Recovery of Cost
Pg42	3.2.2	Connection	The Customer is responsible for any costs associated with providing necessary access to the Corporation's equipment by employees or authorized agents of the Corporation for the purpose of maintenance or replacement	Recovery of Cost
Pg42	3.2.2	Connection	Economic evaluation projects conducted for expansions related to Large User Class customers shall include the following capital costs: (connection costs, cost of dedicated feeders, cost of dedicated Transformer Station)	Recovery of Cost
Pg42	3.2.2	Connection	Where Horizon Utilities provides backup supply, Horizon Utilities will charge the Customer a Standby Charge	Recovery of Cost
Pg44	3.2.3	Service Removals and New Installations - General Service	If a service has been removed and a new service is to be installed, the Customer will pay for the upgrade or new connection	Recovery of Cost
Pg45	3.2.5	Supply	The Customer is responsible for providing at the Customer's own expense adequate protective equipment for any electrical apparatus, such equipment as may be required for the prompt disconnection of any of the Customer's apparatus, a coordination study for protection review	Recovery of Cost
Pg46	3.2.7	Overhead Secondary Service	Horizon Utilities will install, at the Customer's expense an overhead secondary service from its circuits to the ownership demarcation point provided that the ownership demarcation point is located no more than thirty meters from the point of entry	Recovery of Cost
Pg47	3.2.8	Underground Secondary Service	Horizon Utilities will supply and install underground cable inside the Customer-installed conduit, at the Customer's expense	Recovery of Cost
Pg47	3.2.8	Underground Secondary Service	If a Customer requests an underground road crossing, the Customer will pay the actual costs of the underground road crossing	Recovery of Cost
Pg47	3.2.8	Underground Secondary Service	Customer-requested relocation of underground service will be done at the Customer's expense	Recovery of Cost
Pg47	3.2.8	Underground Secondary Service	At its discretion, Horizon Utilities may provide a 400-AMP, 120/240 Volt service at the Customer's expense	Recovery of Cost
Pg49	3.3.5	Location of Transformers	Customer is responsible for providing unobstructed access to the transformer, any damages to Horizon Utilities vehicles resulting due to inadequate roadway will be paid by the Customer	Recovery of Cost
Pg49	3.4.1.1	Underground Primary Construction to Pad-Mounted Transformers	The Customer will pay for the cost of supplying, installing, and maintaining a concrete-encased duct bank located on the Customer's property	Recovery of Cost

Pg49	3.4.1.1	Underground Primary Construction to Pad-Mounted Transformers	Horizon Utilities will supply and install primary cable from the point of supply to the ownership demarcation point at the Customer's expense	Recovery of Cost
Pg50	3.4.1.1	Underground Primary Construction to Pad-Mounted Transformers	Customer is responsible for providing unobstructed access to the transformer, any damages to Horizon Utilities vehicles resulting due to inadequate roadway will be paid by the Customer	Recovery of Cost
Pg50	3.4.1.1	Underground Primary Construction to Pad-Mounted Transformers	The Customer, at his own expense, will supply and install two-hole compression style secondary lug connectors compatible with the Canadian Standards Association (CSA)	Recovery of Cost
Pg50	3.4.2	Customer-owned Transformer or Substation	Customers will pay for the cost of supplying and installing primary cable from the point of supply to the ownership demarcation point	Recovery of Cost
Pg51	3.4.2.2	Plans and Specifications for Transformers or Substations	Costs of any additional review will be charged to the Customer (Horizon will review and approve original proposal once free of charge)	Recovery of Cost
Pg52	3.4.2.4	Operation of Primary Disconnect Devices on Substations	The Customer will be charged for any subsequent disconnection requests during that same calendar year	Recovery of Cost
Pg53	3.5.2	Connection	If no transformation or secondary service exists on the public road allowance, Horizon Utilities will supply and install and, later, remove these facilities at the Customer's expense	Recovery of Cost
Pg53	3.5.2	Connection	The Customer is required to pay a deposit in the amount of the estimated variable costs prior to the installation of the service by Horizon Utilities	Recovery of Cost
Pg54	3.9.1	Unmetered Connections - Application	The Customer is responsible for the cost of connection and service conductors from the point of the supply of the load	Recovery of Cost

b) No rates and charges that are identified in the Conditions of Service are included in Horizon Utilities' revenues for the years 2006 to 2009 and no such revenues are included in the revenue forecasted for the 2010 bridge and 2011 test years. All such rates and charges mentioned in the Conditions of Service are recovery of costs and are not revenue.

c) In Horizon Utilities' view none of these rates and charges should be included on Horizon Utilities' Board-approved Tariff of Rates and Charges at this time, because they are all recovery of cost based and vary depending on the circumstances and Horizon Utilities is unaware as to whether there is consistent practice across utilities for such. However, Horizon Utilities would be supportive of the Board initiating a generic review of common charges including whether such should be included on the Board-approved Tariff of Rates and Charges.

d) There is one change in Horizon Utilities' Conditions of Service contemplated to align with this application for 2011 distribution rates. The change appears in section 3.2.2 of the Conditions of Service. In this section, Horizon Utilities indicates that, where Horizon Utilities provides backup power supply, Horizon Utilities will charge the Customer a Standby Charge. Please refer to Horizon Utilities' response to Board Staff interrogatory #16 for further details on Standby Power charges.

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 5

Reference: E1/T2/S1/pp. 6-10, E2/T1/S1 and E2/T1/S2 Rate Base

Horizon notes in E1/T2/S1 that it deferred some operating and capital programmes and projects, starting in 2009, in light of reduced revenues resulting from reduced load, primarily from larger commercial and industrial customers. It quotes from the record in its Z-factor application considered under Board File No. EB-2009-0332.

The Rate Base variance table 2-1 in E2/T1/S1 and the rate base variance analysis discussed in E2/T1/S2 shows that Horizon has increased its net fixed assets in every year since 2007. The following table, prepared by Board staff, shows the annual growth rates, and the geometric mean annual growth rate from 2007 to 2011. The annual growth rate ranges from 2.8% to 4.2%, averaging 3.8% over the period. Growth in net fixed assets is highest from 2009 to 2011.

2008 OEB		2008 OEB					
	2007 Actual	Approved	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year	
Average Fixed Assets	$271,377,722	$280,832,772	$279,033,671	$290,779,112	$302,301,149	$315,023,558	
Working Capital Allowance	$64,730,069	$65,587,452	$62,278,977	$60,393,662	$66,863,422	$61,866,468	
Total Rate Base	$336,107,791	$346,420,224	$341,312,648	$351,172,774	$369,164,571	$376,890,026	
Annual % Change			2008 vs. 2007	2009 vs. 2008	2010 vs. 2009	2011 vs. 2010	2011 vs. 2007
Average Fixed Assets			2.82%	4.21%	3.96%	4.21%	3.80%
Working Capital Allowance			-3.79%	-3.03%	10.71%	-7.47%	-1.12%
Total Rate Base			1.55%	2.89%	5.12%	2.09%	2.90%

a) Please explain the strong growth in net fixed assets from 2009 to 2011 in light of Horizon's evidence that it began deferring projects.

b) Please quantify, in terms of dollars and % of capex, what capital projects deferred in 2008 or 2009, have been included in 2010 and 2011 capital projects and capital additions.

Response:

a) As noted in Exhibit 1, Tab 2, Schedule 1, Page 9 of the Application, Horizon Utilities has increased its distribution system capital expenditures from $23MM in 2008 to over $30MM in 2010.

As also noted in Exhibit 1, Tab 2, Schedule 1, Page 8, Horizon Utilities is not unlike many other large utilities servicing older communities with low growth, and has had "material increases in capital related costs in order to renew and enhance its distribution system".

Throughout 2008 to 2010, despite the material decline in distribution revenue, Horizon Utilities continued to make investments in its distribution system. Project deferrals in 2008 and 2009 represented deferrals of necessary expenditures in support of sustainable electricity distribution infrastructure, but such deferrals did not pose an immediate significant risk for Horizon Utilities (Exhibit 1, Tab 2, Schedule 1, Page 8).

The following table provides a breakdown of the average net fixed assets by fiscal year, by USofA account, and shows the change in the average net fixed assets from 2009 to 2011. As highlighted in yellow, the most significant growth areas from 2009 to 2011 are concentrated in distribution plant assets. This growth in distribution plant assets is consistent with the investment requirements arising from Horizon Utilities' Asset Management Plan (Appendix 2-1 in Exhibit 2, Tab 3, Schedule 2) and are explained in Exhibit 2 of the Application (Exhibit 2, Tab 2, Schedule 4) as well as the variance analyses for the rate base (Exhibit 2, Tab 2, Schedule 4 and Tab 3, Schedule 1).

Analysis of Growth in Fixed Assets between 2009 - 2011

OEB	OEB Description	2009 Average Fixed Assets	2010 Average Fixed Assets	$ Change	2011 Average Fixed Assets	$ Change
1805	Land - Substations	414,741	414,741	0	414,741	0
1808	Buildings - Substations	644,221	565,571	(78,650)	489,775	(75,795)
1810	Leasehold Improvements	0	0	0	0	0
1820	Substation Equipment	2,639,543	2,519,917	(119,626)	2,242,908	(277,009)
1830	Poles, Towers & Fixtures	41,420,399	46,652,938	5,232,540	52,756,706	6,103,768
1835	OH Conductors & Devices	39,599,680	41,017,921	1,418,241	43,303,218	2,285,298
1840	UG Conduit	51,740,474	52,643,960	903,486	53,450,141	806,180
1845	UG Conductors & Devices	58,145,653	61,839,769	3,694,117	64,396,161	2,556,392
1850	Line Transformers	47,143,324	50,655,789	3,512,465	52,774,077	2,118,289
1855	Services (OH & UG)	15,103,766	15,224,581	120,815	14,794,746	(429,835)
1860	Meters	21,290,306	21,342,444	52,138	21,276,766	(65,678)
1860	Smart Meters	(0)	(0)	0	(0)	0
1905	Land	1,067,629	1,067,629	0	1,067,629	0
1906	Land Rights	95,554	92,156	(3,398)	88,818	(3,338)
1908	Buildings & Fixtures	11,258,235	10,568,898	(689,337)	10,310,204	(258,695)
1910	Leasehold Improvements	0	0	0	0	0
1915	Office Furniture & Equipment	1,191,751	1,479,938	288,187	1,644,335	164,397
1920	Computer - Hardware	35,164	(378,579)	(413,742)	(1,297,961)	(919,382)
1920	Computer - Hardware post Mar 22/04	1,912,737	2,673,263	760,527	4,059,130	1,385,866
1925	Computer - Software	5,178,416	4,860,155	(318,261)	4,526,876	(333,279)
1930	Transportation Equipment	6,087,523	6,047,756	(39,767)	6,053,026	5,270
1935	Stores Equipment	347,293	360,534	13,241	314,228	(46,305)
1940	Tools, Shop & Garage Equipment	1,578,016	1,685,665	107,649	1,880,463	194,798
1945	Measurement & Testing Equipment	519,409	509,083	(10,326)	557,997	48,914
1950	Power operated Equipment	52,515	41,078	(11,436)	29,642	(11,436)
1955	Communications Equipment	878,388	905,915	27,527	1,419,429	513,514
1960	Load Management controls	389,637	338,105	(51,533)	286,572	(51,533)
1980	System Supervisory Equipment	560,092	710,986	150,894	849,821	138,835
1995	Hydro One S/S Contribution	5,991,179	6,914,834	923,655	6,591,558	(323,276)
1995	Contributions & Grants	(24,506,533)	(28,453,900)	(3,947,368)	(29,257,450)	(803,549)
Total		**290,779,111.62**	**302,301,148.65**	**11,522,037.03**	**315,023,557.61**	**12,722,408.96**

1

b) The following table identifies those capital projects that were deferred in 2008 or 2009, and that were previously identified as part of the $3.6MM in capital expenditure deferrals as part of the Z-Factor Application (Exhibit 1, Tab 2, Schedule1, Page 8).

Horizon Utilities Capital Projects - Deferred in 2008 & 2009						
Description	**Budgeted Project Value ($)**	**Type**	**Deferred from Year**	**Reschedule Year**	**Project Amount Deferred ($)**	**% of CAPEX**
Capital - As stated in the Z Factor Application						
Computer hardware/software upgrades	$62,500	General Plant Capital	2009	2010	$62,500	0.15%
Computer hardware/software upgrades	$63,000	General Plant Capital	2009	2011	$63,000	0.15%
Computer hardware/software upgrades	$47,500	General Plant Capital	2009	2011	$47,500	0.11%
Facilities - Parking Lot Upgrade - Stoney Creek	$80,000	General Plant Capital	2009	2010 - 2011	$80,000	0.19%
Facilities - Parking Lot Upgrade - Vansickle Road	$80,000	General Plant Capital	2009	2010 - 2011	$80,000	0.19%
Elevator Machine Room Fencing Retrofit	$25,000	General Plant Capital	2009	2010	$17,000	0.04%
Other miscellaneous capital	$318,000	General Plant Capital	2009	2010	$318,000	0.75%
Smart Meter - Commercial Customers - Deferred pending approval of Smart Meter Adder	$2,900,000	Distribution Capital	2009	2010 - 2015	$2,900,000	6.80%
TOTAL CAPITAL	**$3,576,000**				**$3,568,000**	**8.36%**

In addition to the above, Horizon Utilities also deferred the following capital expenditures in 2009.

Other Capital - Not included in the Z Factor Application						
Description	**Budgeted Project Value ($)**	**Type**	**Deferred from Year**	**Reschedule Year**	**Project Amount Deferred ($)**	**% of CAPEX**
2009 Pole Residual	$1,044,065	Distribution Capital	2009	2010	$635,866	1.49%
St. Catharines Downtown Network	$716,412	Distribution Capital	2009	2010	$130,758	0.31%
Webster Conversion Phase 2	$536,011	Distribution Capital	2009	2010	$268,586	0.63%
TOTAL OTHER CAPITAL	**$2,296,488**				**$1,035,210**	**2.43%**

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HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES") RESPONSES TO BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 6

Reference: E2/T3/S1 – Capital Expenditures 2007 to 2013 Forecast

Board staff has prepared the table on the following page that summarizes Horizon's capital expenditures from 2007 Actual to 2013 Forecast as documented in Tables 2-16, 2-17, 2-20, 2-21, 2-22, 2-23, 2-27, 2-32 and 2-33.

a) Please confirm or correct the numbers documented in the table.

b) Please provide, for 2010:

i. Year-to-Date actuals, and indicate the end-date used

ii. Expected Y-E results to December 31, 2010, based on YTD Actuals.

iii. Please explain the drivers for the significant variances between 2010 Budget and 2010 Y-E Expected Capex

Response:

a) Horizon Utilities has revised the table created by Board Staff, which is included in response to part b).

b) With respect to 2010, please note that YTD actuals are not currently available. The 2010 year-end expected figures ("YE Expected") are based on the 2010 forecast prepared as of September 30, 2010.

	2007			2008			2009			2010			2011 Test	2012 Forecast	2013 Forecast
	Budget	Actual	Variance	Budget	Actual	Variance	Budget	Actual	Variance	Budget	Actual YTD	YE Expected	Budget	Budget	Budget
Customer Demand	$ 8,770,000.00	$ 10,424,877.00	$ 1,654,877.00	$ 8,239,423.00	$ 7,642,977.00	$ (596,446.00)	$ 13,950,000.00	$ 11,786,928.85	$ (2,163,071.15)	$ 12,962,595.69		$ 15,362,595.69	$ 7,406,467.00	$ 7,637,022.00	$ 8,195,066.00
Renewal	$ 8,353,000.00	$ 8,137,381.00	$ (215,619.00)	$ 8,795,000.00	$ 8,452,500.00	$ (342,500.00)	$ 12,010,000.00	$ 22,298,894.00	$ 10,288,894.00	$ 12,016,915.35		$ 12,016,915.35	$ 19,734,731.00	$ 20,163,983.00	$ 22,342,007.00
Capacity	$ 1,142,000.00	$ 522,162.00	$ (619,838.00)	$ 2,270,000.00	$ 364,928.00	$ (1,905,072.00)	$ 3,150,000.00	$ 165,372.15	$ (2,984,627.85)	$ 4,289,197.60		$ 1,889,197.60	$ 613,628.00	$ 2,049,627.00	$ 2,315,338.00
Security	$ 3,887,000.00	$ 1,830,779.00	$ (2,056,221.00)	$ 4,912,000.00	$ 4,436,447.00	$ (475,553.00)	$ 1,460,000.00	$ 1,419,969.00	$ (40,031.00)	$ 2,300,449.15		$ 2,300,449.15	$ 2,005,237.00	$ 4,333,937.00	$ 2,253,783.00
Reliability	$ 966,000.00	$ 1,489,771.00	$ 523,771.00	$ 385,000.00	$ 178,356.00	$ (206,644.00)	$ 890,000.00	$ 44,601.42	$ (845,398.58)	$ 58,893.85		$ 58,893.85	$ 437,235.00	$ 823,583.00	$ 536,082.00
Substation	$ 277,000.00	$ 277,000.00	$ -	$ 202,000.00	$ 191,213.00	$ (10,787.00)	$ 750,000.00	$ 1,357,816.00	$ 607,816.00	$ 198,098.29		$ 198,098.00	$ 3,019,177.00	$ 521,000.00	$ 600,000.00
Safety	$ -	$ -	$ -	$ -	$ -	$ -				$ 504,417.41		$ 504,417.41	$ 537,830.00	$ 547,480.00	$ 566,617.00
Regulatory	$ -	$ -	$ -	$ 278,000.00	$ 483,590.00	$ 205,590.00				$ -			$ 947,653.66	$ -	$ -
Distribution System Technology Enablers	$ -												$ 1,000,000.00	$ 1,135,000.00	$ 1,100,000.00
Gross Expenditure	$ 23,395,000.00	$ 22,681,970.00	$ (713,030.00)	$ 25,081,423.00	$ 21,750,011.00	$ (3,331,412.00)	$ 32,210,000.00	$ 37,073,581.42	$ 4,863,581.42	$ 32,330,567.33		$ 32,330,567.04	$ 35,701,958.66	$ 37,211,632.00	$ 37,908,893.00
Capital Contribution	$ (2,854,992.00)	$ (3,401,684.00)	$ (546,692.00)	$ (3,329,423.00)	$ (3,908,587.00)	$ (579,164.00)	$ (5,076,766.00)	$ (5,675,309.05)	$ (598,543.05)	$ (2,262,647.00)		$ (2,262,647.00)	$ (2,044,172.00)	$ (2,092,706.00)	$ (2,242,513.00)
Net Expenditure	$ 20,540,008.00	$ 19,280,286.00	$ (1,259,722.00)	$ 21,752,000.00	$ 17,841,424.00	$ (3,910,576.00)	$ 27,133,234.00	$ 31,398,272.37	$ 4,265,038.37	$ 30,067,920.33		$ 30,067,920.04	$ 33,657,786.66	$ 35,118,926.00	$ 35,666,380.00
Capex over $500,000		$ 7,441,236.00			$ 10,794,243.00			$ 13,062,706.00		$ 23,349,954.00			$ 25,411,187.00		
Significant CAPEX/CAPEX		38.6%			60.5%			416%		77.7%			75.5%		

Notes:

1) The 2009 actual amount for Capacity and Customer Demand have been restated to reflect the reclassification of amounts related to capital contribution payments to Hydro One. The reclassification was required in order to provide consistency for the periods 2008, 2009 and 2010.

2) Other corrections include an adjustment to the 2010 Renewal Budget from $12,353,791 to $12,016,915. Table 2-32 on page 45 of Exhibit 2, Tab 3, Schedule 1 has also been revised below to reflect this change. The 2011 Budget for Regulatory was revised to $947,655 from $250,000 to reflect costs related to the wholesale meter exchange program, which were originally omitted from this table.

E2/T3/S1 Page 45 of 96 Table 2-32 - Distribution Plant Capital 2010-2013 Total by Type				
	2010 Budget	**2011- Forecasted**	**2012- Forecasted**	**2013- Forecasted**
Customer Demand	$ 12,962,596	$ 7,406,467	$ 7,637,022	$ 8,195,066
Renewal	$ 12,016,915	$ 19,734,731	$ 20,163,983	$ 22,342,007
Capacity	$ 4,289,198	$ 613,628	$ 2,049,627	$ 2,315,338
Security	$ 2,300,449	$ 2,005,237	$ 4,333,937	$ 2,253,783
Reliability	$ 58,894	$ 437,235	$ 823,583	$ 536,082
Substation	$ 198,098	$ 3,019,177	$ 521,000	$ 600,000
Safety	$ 504,417	$ 537,830	$ 547,480	$ 566,617
Regulatory	$ -	$ 947,654	$ -	$ -
Distribution System Technology Enablers		$ 1,000,000	$ 1,135,000	$ 1,100,000
Gross Expenditure	$ 32,330,567	$ 35,701,959	$ 37,211,632	$ 37,908,893
Capital Contribution	$ (2,262,647)	$ (2,044,172)	$ (2,092,706)	$ (2,242,513)
Net Expenditure	$ 30,067,920	$ 33,657,787	$ 35,118,926	$ 35,666,380

b iii) The following is an explanation of the drivers for the significant variances between 2010 Budget and 2010 Year End Expected for the categories of Customer Demand, Capacity and Contributions below:

<u>Customer Demand</u>:

The budgeted expenditure for customer demand connection projects is based on historical levels of connection, prior year project carry-over and project inquiries. The year-end expected expenditure is forecasted to be $2MM over budget based on more customer demand connections than budgeted.

Capacity

There is a forecasted decrease in capital expenditures with respect to Capacity, based on the Vansickle TS contribution payment of $2.4MM to Hydro One. This amount was budgeted as Capacity spending but will be recorded as a capital contribution to Hydro One.

Contributions

There is a forecasted decrease in Contributions based on the Vansickle TS payment of $2.4MM to Hydro One, as described above. In addition, capital contributions from customers are expected to be higher than originally budgeted as a result of an increase in customer demand connection projects, as noted above.

HORIZON UTILITIES CORPORATION (“HORIZON UTILITIES”)
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 7

Reference: E2/T3/S1, Board staff IR # 6

With reference to the summary table of capital expenditures referenced in Board staff IR # 6 above, capital projects exceeding the $500,000 threshold account for 38.6% of 2007 actual capex, 60.5% of 2008 actual capex, and 41.9% of 2009 actual capex. This leaves a large portion of annual capital expenditures unexplained.

For each of 2007, 2008 and 2009, please provide further documentation on capital expenditures incurred for projects under the $500,000 materiality threshold. Such documentation should identify the nature and drivers and benefits for projects, albeit at a higher level than the explanations for significant projects already provided in Horizon’s application and that exceed the materiality threshold.

Response:

The table below outlines the capital expenditures that exceed $100,000 but are under the $500,000 materiality threshold for 2007, 2008 and 2009.

Year	Project Number	Project Description	Actual Costs	Driver	Benefit
2007	7084	Barton Street East - Woodward to Nash - Road Relocation	$266,327	Customer Demand	Roadway Reconstruction
2007	7242	Ferguson Ave. S. - Main to Grange	$179,652	Customer Demand	Roadway Reconstruction
2007	7355	Henderson Hospital Co-gen	$238,236	Customer Demand	Embedded Generation
2007	7356	General Hospital	$222,736	Customer Demand	Embedded Generation
2007	7360	Kenilworth Avenue N - 600 NSC	$188,098	Customer Demand	New or Upgraded Service
2007	7496	Old Guelph Road/Mountain Brow Double CCT Extension	$217,105	Capacity	Load Growth
2007	7681	King William St. E. of Hughson St. (ST LTG Supplies)	$110,981	Customer Demand	New or Upgraded Service
2007	7687	Baldwin Feeder Conversion	$427,289	Renewal	Replace near end of life Assets
2007	7758	Hamilton Transformer Upgrades	$336,912	Renewal	Replace near end of life Assets
2007	7764	Hamilton - Various Locations (TX's 70+)	$217,308	Renewal	Replace near end of life Assets
2007	7909	Benedict Place (off Lorenzo Dr.) - Hamilton	$126,779	Customer Demand	New Subdivision
2007	7933	Lawfield Heights (Court off Lawson Street)	$169,273	Customer Demand	New Subdivision
2007	7957	King Street East - Dundas Canal Relocation	$192,095	Customer Demand	Roadway Reconstruction
2007	7976	Thornbrae Estates Subdivision	$289,288	Customer Demand	New Subdivision
2007	7986	Parkway Manor - Phase 2 (Fortissimo Drive)	$103,454	Customer Demand	New Subdivision
2007	7996	Mountain Park #174 @ Summit Ave. (Pole removal Request)	$107,587	Customer Demand	Other Customer Request
2007	8024	Ferguson Ave. - Barton to Simcoe	$126,476	Customer Demand	Roadway Reconstruction
2007	8166	Mohawk Drive Rebuild	$175,068	Customer Demand	Roadway Reconstruction
2007	8237	Aberdeen Ave. F/O #436 (Building Conflict)	$106,789	Renewal	Convert to Current Standards
2007	8267	Summit Ave. Conversion to 8kV	$115,117	Renewal	Replace near end of life Assets
2007	8301	St. Catharines full Tension Sleeve Replacements	$120,643	Renewal	Replace near end of life Assets
2007	8418	Barton Street East @ Woodward Avenue	$111,350	Capacity	Load Growth
2007	8432	Cannon Street West Primary 3ph Extension	$113,574	Capacity	Load Growth
2007	8474	McNeilly Road - South of the CN Tracks	$164,174	Customer Demand	New or Upgraded Service
2007	9000071	#6 Primary Renewal	$338,736	Renewal	Replace near end of life Assets
2007	n/a	Telephone IVR Hardware and Software Upgrade	$250,032	Renewal	Replace near end of life Assets

2007	n/a	Passenger Elevator Upgrade John Street Head Office	$255,500	Renewal	Replace near end of life Assets
		2007 Total:	$5,270,579		
2008	7179	Flam PC South Side hwy 5 & 6	$132,726	Customer Demand	New or Upgraded Service
2008	7892	St.Catharines Downtown Network	$191,055	Security	Provide back-up capabilities
2008	7943	Conservation Run - PH 3	$168,901	Customer Demand	New Subdivision
2008	8028	St.Catharines O/H overloaded Tx	$244,159	Renewal	Replace near end of life Assets
2008	8034	Lakeshore Road - Broadway to Read Rd	$124,201	Customer Demand	Roadway Reconstruction
2008	8082	Welland F1 - Feeder Conversion	$361,450	Security	Provide back-up capabilities
2008	8184	Osler Drive - Main St. W 27kV U/G Supply	$123,303	Capacity	Load Growth
2008	8263	Wilson St East U/G rebuild	$357,287	Security	Provide back-up capabilities
2008	8357	St.Catharines Wood Pole Residual	$238,406	Renewal	Replace near end of life Assets
2008	8374	St.Catharines Wood Pole Residual	$302,011	Renewal	Replace near end of life Assets
2008	8486	Hamilton Pole Residual	$416,770	Renewal	Replace near end of life Assets
2008	8586	Hamilton O/H TX Replacements	$272,626	Renewal	Replace near end of life Assets
2008	8717	Martindale Road & QEW - widening	$437,212	Customer Demand	Roadway Reconstruction
2008	8730	Rymal Road - STC - Extend 3-PH Primary - PH 1	$100,808	Regulatory	Eliminate Long Term Load Transfers
2008	8764	Mohawk 10 Feeder Conversion	$205,779	Renewal	Replace near end of life Assets
2008	8808	St.Catharines Downtown Network	$292,700	Security	Provide back-up capabilities
2008	8825	Rymal Road - STC - Extend 3-PH Primary - PH 2	$252,416	Regulatory	Eliminate Long Term Load Transfers
2008	8887	Green Mountain Road East	$113,625	Renewal	Replace near end of life Assets
2008	8950	Wilson Street Deficiencies	$131,729	Renewal	Replace near end of life Assets
2008	9007	Lottridge Street 3-PH Expansion/13kV Expansion	$178,664	Capacity	Load Growth
2008	9085	Vine F1 Cable Fault	$111,158	Renewal	Replace near end of life Assets
2008	n/a	Roof Repairs Vansickle Rd Location	$225,000	Renewal	Replacement of membrane
		2008 Total:	$4,981,986		
2009	7683	Spadina Feeder SP7 Conversion - Phase 2	$330,067	Renewal	Replace near end of life Assets
2009	7684	Webster SS Conversion - WB-1 & WB-2 - Phase 1	$404,326	Renewal	Network Enhancement
2009	8176	Centre Mall Redevelopment Project	$365,630	Customer Demand	New or Upgraded Service
2009	8213	Wellend F1 Conversion Phase 2	$385,081	Security	Provide back-up capabilities

2009	8535	DiCenzo Gardens - Subdivision Development	$293,824	Customer Demand	New Subdivision
2009	8615	Heritage Greene Power Centre - Phase 1	$122,855	Customer Demand	New or Upgraded Service
2009	8630	Horning TS M50	$404,884	Capacity	Load Growth
2009	8632	Rosehill Gardens Sub-Division Development	$308,474	Customer Demand	New Subdivision
2009	8778	Halson Decommissioning - 28kV Conversion - Phase 1	$289,840	Renewal	Replace near end of life Assets
2009	8778	Halson Decommissioning - 28kV Conversion - Phase 2	$282,546	Renewal	Replace near end of life Assets
2009	8780	Upper Wellington #500	$128,678	Customer Demand	New or Upgraded Service
2009	8807	Paramount and Winterberry Expansion	$265,820	Customer Demand	New or Upgraded Service
2009	8857	Mattamy On The Lake - Fifty Rd - Subdivision Development	$371,671	Customer Demand	New Subdivision
2009	8939	2009 Pole Residual Replacement - St. Catharines	$250,545	Renewal	Replace near end of life Assets
2009	8977	Kerns Road Expansion	$214,961	Renewal	Network Enhancement
2009	9041	Bartonville Spare Power Transformer Connection to Network	$189,654	Security	Provide back-up capabilities
2009	9048	Heritage Greene Power Centre - Phase 2	$133,121	Customer Demand	New or Upgraded Service
2009	10024	Eastchester and Buckland - Corner Re-Design	$160,547	Renewal	Replace near end of life Assets
2009	10029	Concrete Pole Replacement - Bond Street - Hamilton	$100,811	Renewal	Replace near end of life Assets
2009	10072	Spadina Feeder SP7 Conversion - Phase 1	$117,749	Renewal	Replace near end of life Assets
2009	10079	Concrete Pole Replacement Phase 1 - St. Catharines	$125,712	Renewal	Replace near end of life Assets
2009	10083	Wood Pole Replacement Phase 2 - St. Catharines	$102,111	Renewal	Replace near end of life Assets
2009	10092	Upper Paradise - New Duct structure	$353,136	Renewal	Replace near end of life Assets
2009	10098	Hester Conversion	$138,656	Renewal	Replace near end of life Assets
2009	10157	Caroline CA8 Conversion	$306,060	Renewal	Replace near end of life Assets
2009	10184	King St. E. - Nash to Centennial Roadway Reconstruction	$148,520	Customer Demand	Roadway Reconstruction
2009	10186	Taylor Conversion - Phase 1	$189,099	Renewal	Replace near end of life Assets
2009	10210	2009 Pole Residual Replacement - Hamilton	$301,839	Renewal	Replace near end of life Assets
2009	10358	Install A/B Padmount Transformers - Various Locations	$319,548	Renewal	Replace near end of life Assets
2009	10502	OPG - Property Plant Relocations	$228,553	Customer Demand	Other Customer Request
2009	n/a	Upgrade SCADA System	$461,604	Renewal	Hardware/Software Upgrade
2009	n/a	National Steel Car customer expansion	$200,000	Customer Demand	New or Upgraded Service
2009	n/a	Retaining Wall Nebo Service Centre	$102,000	New Construction	Erosion control

2009	n/a	Repairing Exterior Building John Street Head Office	$115,050	Renewal	Limestone façade replacement
2009	n/a	Building of the Disaster Recovery Data Centre in St. Catharines	$215,929	Security	Business Continuity
2009	n/a	Implementation of IT Service Desk Software	$106,326	New Software	Helpdesk Tracking
		2009 Total:	$8,535,227		

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HORIZON UTILITIES CORPORATION (“HORIZON UTILITIES”)
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 8

Reference: E2/T2/S1 Tables 2-32 and 2-33, Board staff IR # 6

In E2/T3/S1/Table 2-32, Horizon documents 2011 forecasted Distribution Plant capital expenditures of $32,960,133. In Table 2-33, Horizon documents 2011 capital projects exceeding $100,000 as being $37,383,695.

a) Please provide a reconciliation between Tables 2-32 and 2-33.

b) If the tables shown in E2/T3/S1 and summarized in the table provided in Board staff IR #6 do not correspond to all of Horizon’s capital expenditures from 2007 to 2013 forecast, please provide a table using the format shown in Board staff IR # 6 for all capital expenditures (budget and actual, as applicable).

Summary Table of Capital Expenditures – Ref: Board staff IR # 6

Capex	2007			2008			2009			2010			2011 Test	2012 Forecast	2013 Forecast
	Budget	Actual	Variance	Budget	Actual	Variance	Budget	Actual	Variance	Budget	Actual YTD	YE Expected	Budget	Budget	Budget
Customer Demand	$8,770,000	$10,424,877	$1,654,877	$8,239,423	$7,642,977	-$596,446	$13,950,000	$8,852,427	-$5,097,573	$12,962,596			$7,406,467	$7,637,022	$8,195,066
Renewal	$8,353,000	$8,137,381	-$215,619	$8,795,000	$8,452,500	-$342,500	$12,010,000	$22,298,894	$10,288,894	$12,353,791			$19,734,731	$20,163,983	$22,342,007
Capacity	$1,142,000	$522,162	-$619,838	$2,270,000	$364,928	-$1,905,072	$3,150,000	$3,099,874	-$50,126	$4,289,198			$613,628	$2,049,627	$2,315,338
Security	$3,887,000	$1,830,779	-$2,056,221	$4,912,000	$4,436,447	-$475,553	$1,460,000	$1,419,969	-$40,031	$2,300,449			$2,005,237	$4,333,937	$2,253,783
Reliability	$966,000	$1,489,771	$523,771	$385,000	$178,356	-$206,644	$890,000	$44,601	-$845,399	$58,494			$437,235	$823,583	$536,082
Substation	$277,000	$277,000	$0	$202,000	$191,213	-$10,787	$750,000	$1,357,816	$607,816	$198,098			$3,019,177	$521,000	$600,000
Safety	$0	$0	$0	$0	$0	$0			$0	$504,417			$537,830	$547,480	$566,617
Regulatory	$0	$0	$0	$278,000	$483,590	$205,590			$0	$0			$250,000	$0	$0
Distribution System Technology Enablers										$0			$1,000,000	$1,135,000	$1,100,000
Gross Expenditure	$23,395,000	$22,681,970	-$713,030	$25,081,423	$21,750,009	-$3,331,414	$32,210,000	$37,073,581	$4,863,581	$32,667,043			$35,004,305	$37,211,632	$37,908,893
Capital Contribution	-$2,855,000	-$3,401,684	-$546,684	-$3,329,423	-$3,908,587	-$579,164	-$5,080,000	-$5,931,170	-$851,170	-$262,647			-$2,044,172	-$2,092,706	-$2,242,513
Net Expenditure	$20,540,000	$19,280,286	-$1,259,714	$21,752,000	$17,841,422	-$3,910,578	$27,130,000	$31,142,411	$4,012,411	$32,404,396			$32,960,133	$35,118,926	$35,666,380
Capex over $500,000		$7,441,351			$10,794,243			$13,062,706		$23,349,954			$37,383,595		
Significant capex/capex		38.6%			60.5%			41.9%		72.1%			113.4%		

Response:

a) Please refer to the response to Board Staff Interrogatory #6, as well as 8b) below, which provides a reconciliation of total capital expenditures.

Please note that Table 2-32 includes only the budget for the Distribution System Plant capital expenditures (excluding meters). Table 2-33 includes all capital budget expenditures for 2011 that are in excess of $100,000. Capital expenditures in excess of $100,000 include the Distribution System Plant capital expenditures, as well as general plant and other, including meters, buildings, transportation equipment, computer hardware and software.

b) The following table provides the total capital expenditures for the electricity distribution operations (budgets and ctuals, if applicable) for 2007 to 2013 .

	2007			2008			2009			2010			2011 Test	2012	2013
	Budget	Actual	Variance	Budget	Actual	Variance	Budget	Actual	Variance	Budget	Actual YTD	YE Expected	Budget	Forecast	Forecast
Customer Demand	8,770,000	10,424,877	1,654,877	8,239,423	7,642,977	(596,446)	13,950,000	11,786,929	(2,163,071)	12,962,596	-	12,962,596	7,406,467	7,637,022	8,195,066
Renewal	8,353,000	8,137,381	(215,619)	8,795,000	8,452,500	(342,500)	12,010,000	22,298,894	10,288,894	12,016,915	-	12,016,915	19,734,731	20,163,983	22,342,007
Capacity	1,142,000	522,162	(619,838)	2,270,000	364,928	(1,905,072)	3,150,000	165,372	(2,984,628)	4,289,198	-	4,289,198	613,628	2,049,627	2,315,338
Security	3,887,000	1,830,779	(2,056,221)	4,912,000	4,436,447	(475,553)	1,460,000	1,419,969	(40,031)	2,300,449	-	2,300,449	2,005,237	4,333,937	2,253,783
Reliability	966,000	1,489,771	523,771	385,000	178,356	(206,644)	890,000	44,601	(845,399)	58,894	-	58,894	437,235	823,583	536,082
Substation	277,000	277,000	-	202,000	191,213	(10,787)	750,000	1,357,816	607,816	198,098	-	198,098	3,019,177	521,000	600,000
Safety	-	-	-	-	-	-	-	-	-	504,417	-	504,417	537,830	547,480	566,617
Regulatory	-	-	-	278,000	483,590	205,590	-	-	-	-	-	-	947,654	-	-
Distribution System Technology Enablers	-	-	-	-	-	-	-	-	-	-	-	-	1,000,000	1,135,000	1,100,000
Gross Expenditure	**23,395,000**	**22,681,970**	**(713,030)**	**25,081,423**	**21,750,011**	**(3,331,412)**	**32,210,000**	**37,073,581**	**4,863,581**	**32,330,567**	**-**	**32,330,567**	**35,701,959**	**37,211,632**	**37,908,893**
Capital Contribution	(2,854,992)	(3,401,684)	(546,692)	(3,329,423)	(3,908,587)	(579,164)	(5,076,766)	(5,675,309)	(598,543)	(2,262,647)	-	(2,262,647)	(2,044,172)	(2,092,706)	(2,242,513)
Net Expenditure	**20,540,008**	**19,280,286**	**(1,259,722)**	**21,752,000**	**17,841,424**	**(3,910,576)**	**27,133,234**	**31,398,272**	**4,265,038**	**30,067,920**	**-**	**30,067,920**	**33,657,787**	**35,118,926**	**35,666,380**
Substation Equipment	-	81,752	-	-	17,443	-	-	306,707	-	-	-	-	-	-	-
Distribution General Plant	8,391,525	7,773,006	(618,519)	5,386,379	9,722,610	4,336,231	6,008,440	4,574,039	(1,434,401)	5,788,561	-	5,516,561	9,208,878	7,705,378	7,897,778
Meters	2,735,679	1,178,884	(1,556,795)	2,419,914	5,403,196	2,983,282	1,221,806	1,276,556	54,750	1,736,319	-	1,736,319	1,125,434	1,651,938	1,606,938
Buildings and Substation Equipment	-	83,043	83,043	-	9,964	9,964	-	3,740	3,740	-	-	-	-	-	-
General Plant WIP Balances	-	2,425,694	-	-	(1,798,503)	-	-	-	-	-	-	-	-	-	-
Total Capital Expenditures	**31,667,212**	**30,822,665**	**(3,351,993)**	**29,558,293**	**31,196,134**	**3,418,901**	**34,363,480**	**37,559,314**	**2,889,127**	**37,592,800**	**-**	**37,320,800**	**43,992,099**	**44,476,242**	**45,171,096**
Smart Meters (As previously reported)	7,653,905	7,679,949	26,044	10,573,416	10,547,660	(25,756)	8,082,520	6,043,663	(2,038,857)	701,000		701,000	1,578,275	1,850,937	1,827,371
Adjustment to Smart Meter General Plant Capital	-	-	-	-	-	-	-	869,191	869,191	-	-	-	-	-	-
Adjustment for MSP Transitional Assets	-	-	-	-	-	-	-	202,800	202,800	-	-	-	-	-	-
Total Capital Expenditures (including Smart Meters)	**39,321,117**	**38,502,614**		**40,131,709**	**41,743,794**		**42,446,000**	**44,674,968**		**38,293,800**	**-**	**38,021,800**	**45,570,373**	**46,327,179**	**46,998,467**

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES") RESPONSES TO BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 9

Reference: E2/3/S1/page 79

Horizon documents a 2011 capital project titled: Meter Upgrade & Replacement Program, with a forecasted budget of $1,712,784. Horizon documents that:

> "[t]he work includes: the installation of complex and commercial meters at new service locations; the upgrade of metering installations for expanded service requirements; inspection and replacement of defective meters; and the replacement of commercial meters with smart meters as their Measurement Canada seal expires (meter costs included in smart meter adder)."

a) Are the commercial meters for GS<50 kW customers, or for other General Service customers' interval meters?

b) What does Horizon mean in stating that "meter costs [are] included in [the] smart meter adder"?

c) Please explain how this project relates to Horizon's smart meter deployment to residential and small commercial customers as authorized under *O.Reg. 427/06*.

Response:

a) Customers in the GS<50 kW customer class are not interval metered. Historically, interval meters have only been installed for General Service customers over

500kW. Starting in 2009, Horizon Utilities began installing interval meters for all new services over 250 kW.

b) In stating that the "meter costs are included in the smart meter adder", Horizon Utilities clarifies that the capital costs of procurement of the commercial smart meters are included in its Smart Meter Funding Adder Application currently before the Ontario Energy Board (EB-2010-0292). However, the internal labour cost for the meter installation of commercial meters as their Measurement Canada seal date expires is included in the 2011 Electricity Distribution Rate Cost of Service Application. The internal labour component for the replacement of these meters is not considered an incremental cost and has not been included in Horizon Utilities Smart Meter Funding Adder.

c) The Meter Upgrade and Replacement Program represents Horizon Utilities' ongoing meter work which is separate from the smart meter deployment, as authorized under *O. Reg. 427/06*.

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
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Question 10

Reference: E2/T3/S3 – Capitalization Policy

a) With the exception of compensation that is discussed below, please confirm that Horizon's capitalization policy has not changed since its last cost of service application for 2008 distribution rates, and that Horizon is not proposing any changes related to this current application.

b) In the alternative, please provide a detailed explanation of any changes made or proposed, and the reasons for the actual or proposed changes to Horizon's capitalization policy.

Response:

a) Horizon Utilities confirms that its capitalization policy has not changed since its last cost of service application for 2008 distribution rates. Horizon Utilities also confirms that it is not proposing any changes related to its 2011EDR Cost of Service Application.

As noted in the 2011EDR Cost of Service application at Exhibit 4, Tab 2, Schedule 9 (Page 32), the amount of labour costs that are allocated to capital on an annual basis will vary based on the level of planned activities between operations, maintenance, and capital projects.

b) Please refer to the response in a) of this interrogatory

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HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
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Question 11

Reference: E2/T4/S1 Lead/Lag Study

On page 12 of the Lead/Lag Study commissioned by Horizon and conducted by Navigant Consulting Inc. ("Navigant"), it is stated:

> The Ontario government has harmonized the Ontario Provincial Sales Tax with the Federal GST into a harmonized single sales tax effective July 1, 2010. Based on current information, there appears to be no change to the current schedule of both remittances and receipts of the HST compared with what existed under the GST regime. Thus, no changes to the schedule of either remittances or receipts of the HST relative to the schedule that governed the GST have been considered in this study.

Tables 6, 7 and 8 on pages 13 and 14 show Navigant's estimates of cash working capital requirements for 2009, 2010 and 2011, and the GST/HST component for these tables is shown in Table 9 on page 14.

a) Please confirm that, for controllable expenses in 2010, PST, as applicable, is only factored into expenses for the period January 1 to June 30, 2010.

b) Please confirm that PST (or what would have formerly applied as PST) is not included in controllable expenses in 2011.

c) If either a) or b) is in the negative, please explain how the lead/lag methodology avoids a double recovery of the PST and its successor component of the new HST as of July 1, 2010.

d) Board staff observes the following with respect to HST collected by a utility from its rate payers. Effective July 1, 2010, HST is applicable to the ratepayer's total bill, including distribution charges. Because of "value-added" distribution services provided by the utility itself, the HST paid for by the ratepayer and collected by a utility is larger than the HST paid by the utility to its suppliers, including the IESO. There is thus an "incremental HST" collected by the utility for the "value added" by the utility in providing distribution services to its ratepayers. This HST is collected by the utility and is then remitted to Canada Revenue Agency (the "CRA") on a periodic basis. There is a "lead" between when Horizon collects this incremental HST amount from customers and subsequently remits it to the CRA periodically.

i. How frequently does Horizon remit HST payments to the CRA?

ii. Has Horizon and/or Navigant factored the lead time associated with the incremental HST into the lead/lag study? If "yes", please explain. If not, please explain why this has not been considered. Can Horizon provide an estimate of the incremental impact on cash working capital due to the lead on the incremental HST?

Response:

a. Horizon Utilities confirms that it has included PST, as applicable, into expenses for the period January 1 to June 30, 2010.

For the period July 1, 2010 – December 31, 2010, Horizon Utilities' OM&A expenditures were forecasted based on expected expenditures for the balance of the year. The 2010 forecast did not specifically exclude PST as Horizon Utilities was not able to quantify the impact to OM&A expenditures for the balance of the year as a result of the implementation of HST.

b. That is correct. In its calculation of the cash working capital requirements for 2011, Horizon Utilities has not included amounts associated with what may have been previously attributable to the PST.

c. With respect to the response to part a., the following table provides an illustration of the potential range of impact on the working capital computation using an assumption that PST may be included in certain costs for the period July 1 through December 31, 2010, where PST would have previously applied.

Line	Description	Lead (Lag) [1]	Working Capital Factor	Expense Amounts 2010	Working Capital 2010 As Filed $M	Working Capital Adjustment [2] $M	Working Capital Adjustment [3] $M
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Telecommunications	44.32	12.14%	0.195	0.002	(0.0009)	(0.0009)
2	Software	44.85	12.29%	0.780	0.009	(0.0038)	(0.0038)
3	Corporate Credit Card	18.83	5.16%	0.216	0.001	(0.0002)	(0.0004)
4	Miscellaneous OM&A	45.87	12.57%	11.735	0.133	(0.0295)	(0.0590)
5	Total			$ 12.9258	$ 0.1445	$ (0.0345)	$ (0.0642)

Notes To Above Table:

[1] These are lead or lags applicable to items that have traditionally attracted the PST.

[2] This is the amount by which the Working Capital amount as filed – see Col (E) of the Table – would need to be adjusted assuming that 100% of Telecommunications and Software expense amounts and 50% of Corporate Credit Card and Miscellaneous OM&A expense amounts – shown on Col (D) of the Table – would have attracted the PST over the period July 1, 2010 – December 31, 2010. Negative adjustments imply a reduction

[3] This is the amount by which the Working Capital amount as filed – see Col (E) of the Table – would need to be adjusted assuming that 100% of Telecommunications, Software, Corporate Credit Card and Miscellaneous OM&A expense amounts – shown on Col (D) of the Table – would have attracted the PST over the period July 1, 2010 – December 31, 2010. Negative adjustments imply a reduction.

As illustrated, the potential impact to Horizon's working capital allowance, as filed, would be a reduction in the range of $35,000 to $64,000.

Horizon Utilities:

i. Remits HST to the Canada Revenue Agency at the end of each month. The monthly remittance is based on the HST collected and incurred for the previous month, in a manner consistent with statutory requirements.

ii. Yes. Horizon Utilities/Navigant has factored in the lead time associated with the incremental HST with respect to the increase in HST collected on utility billings in excess of the HST paid by the utility to its suppliers, including the IESO.

Provided in the Table below is the work-paper supporting the information shown on Tables 6-9, Pages 13-14 of Navigant's Lead/Lag study filed as Exhibit E2/T4/S1. The working capital amounts associated with the incremental "lead" on GST/HST shown on Line 2 of the Table below are negative indicating a reduction to the otherwise applicable working capital requirement associated with the GST/HST.

	Description	GST or HST Lead (Lag)	Working Capital Factor	Amount 2009 $M	Amount 2010 $M	Amount 2011 $M	GST 2009 $M	GST/HST 2010 $M	GST/HST 2011 $M	Working Capital 2009 $M	Working Capital 2010 $M	Working Capital 2011 $M
	(A)	(B)	(C) = (B)/365	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	GST Rate			5.00%	9.00%	13.00%						
2	Revenues [including COP]	(17.41)	-4.77%	485.8	495.2	502.7	24.29	44.57	65.36	(1.1587)	(2.1262)	(3.1176)
3	Cost of Power	43.25	11.85%	365.3	405.1	394.0	18.27	36.46	51.22	2.1643	4.3203	6.0697
4	C&C Services	44.24	12.12%	2.3	2.1	3.5	0.12	0.19	0.45	0.0141	0.0228	0.0545
5	Freight Postage and Delivery	45.10	12.36%	0.1	0.2	0.1	0.00	0.02	0.02	0.0004	0.0019	0.0020
6	Tree Trimming	43.41	11.89%	1.0	1.3	1.2	0.05	0.12	0.15	0.0058	0.0141	0.0179
7	Telecommunications	44.32	12.14%	0.2	0.2	0.2	0.01	0.02	0.03	0.0011	0.0021	0.0038
8	Software	44.85	12.29%	0.6	0.8	1.1	0.03	0.07	0.15	0.0037	0.0086	0.0180
9	Corporate Credit Card	18.83	5.16%	0.2	0.2	0.2	0.01	0.02	0.03	0.0005	0.0010	0.0015
10	Miscellaneous OM&A	45.87	12.57%	12.0	11.7	14.8	0.60	1.06	1.92	0.0756	0.1327	0.2417
11	**Total**									$1.1068	$2.3773	$ 3.2916

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
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DELIVERED: January 24th, 2011

Question 12

Reference: E3/T2/T2 and E3/T2/S2/Appendix 3-1 Load Forecast

On pages 2-3 of E3/T2/S2, Horizon states that "The actual results of the CDM programs provided to Horizon Utilities' customers since 2005 have been determined and included as a dependent variable in the regression analysis." In Appendix 3-1, Horizon provides the data used in the regression analysis and load forecast.

a) Please provide details on the definition and derivation of the "CDM Savings" exogenous variable.

b) What is the unit of measurement of the CDM Savings exogenous variable?

c) What is the interpretation or implication of the estimated CDM Savings coefficient of 0.37?

d) Please provide a detailed explanation of how Horizon has forecasted the CDM Savings variable for the 2010 Bridge and 2011 Test Years.

Response:

a) The "CDM Activity" variable, as referenced on page 4 of Exhibit 3, Tab 2, Schedule 2, represents an estimate of the year to date savings by month from CDM programs provided to Horizon Utilities' customers since 2005. The following table outlines the actual accumulated year end CDM savings for 2005 to 2009 and the forecasted year end CDM savings for 2010 and 2011.

	CDM Cumulative Results (kWh)
2005	6,873,000
2006	49,194,000
2007	60,548,000
2008	71,888,000
2009	81,888,000
2010 (F)	91,888,000
2011 (F)	167,138,000

For 2005, the monthly CDM Activity values are 6,873,000 (kWhs) divided by 12 and then accumulated in each month. The resulting monthly 2005 CDM Activity values represent an estimate of the year to date savings in the month. For 2006, the difference between the 2006 CDM Cumulative Results of 49,194,000 (kWh) and the 2005 value of 6,873,000 (kWhs) is determined. This difference is divided by 12 and added to the 2005 value of 6,873,000 for January 2006. For all other months in 2006, one twelfth of the difference between 2006 and 2005 CDM Cumulative Results is then added to the previous month to achieve a year to date value for each month. By December 2006 the value is 49,194,000 (kWh)

The same method that was used for 2006 is applied to 2007, 2008, and 2009. For example, in 2008 the difference between the 2008 CDM Cumulative Results of 71,888,000 (kWhs) and the 2007 CDM Cumulative Results of 60,548,000 (kWhs) is determined. This difference is divided by 12 and added to the 2007 value of 60,548,000 (kWhs) for January 2008. For all other months in 2007 one twelfth of the difference between 2008 and 2007 value is then added to the previous month to achieve a year to date value for each month. By December 2008, the value is 71,888,000 (kWhs).

For the 2010 forecast, the same activity in 2009 is assumed to continue in 2010. As a result, one twelfth of the difference between the 2009 and 2008 CDM Cumulative Results is added to the previous month to determine a year to date value for each month.

For the 2011 forecast, the proposed CDM targets to be achieved by Horizon Utilities by 2014, as per the Board's letter on Electricity Conservation and Demand Management Targets (EB-2010-0216) dated June 22, 2010 letter, was 301 (GWh) in energy savings and

60 (MW) in 2014 summer peak demand savings. For the 2011 CDM Activity Variable, 25% of the 301 (GWh) energy saving target (i.e. 75.25 (GWh) was divided by 12 and added to the 2010 value of 91,888,000 (kWhs) for the January 2011 value. For all other months, one twelfth of the 75.25 (GWh) was then added to the previous month to achieve a year to date value for each month.

The 2011 monthly information provided in Exhibit 3, Tab 2, Schedule 2, Appendix 3-1 for CDM Activity and Predicted Purchases was incorrect. The following table provides the corrected numbers which supports the 2011 power purchased forecast in Exhibit 3, Tab 2, Schedule 2.

Month	CDM Activity	Predicted Purchases
Jan-11	98,158,833	379,756,411
Feb-11	104,429,667	345,230,876
Mar-11	110,700,500	351,714,882
Apr-11	116,971,333	319,753,286
May-11	123,242,167	320,375,993
Jun-11	129,513,000	354,121,725
Jul-11	135,783,833	395,948,333
Aug-11	142,054,667	377,627,886
Sep-11	148,325,500	307,877,277
Oct-11	154,596,333	312,868,953
Nov-11	160,867,167	313,108,902
Dec-11	167,138,000	349,235,344

b) The unit of measurement of the CDM Activity variable is year to date kWhs

c) The interpretation or implication of the estimated CDM Activity coefficient of -0.37 is that the regression analysis has estimated a reduction in Horizon Utilities' monthly predicted purchases.

d) See response to 12 a).

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Question 13

Reference: E3/T2/S2 CDM Targets

On page 6 of E3/T2/S2, Horizon states:

> With regard to the forecast of the CDM savings variable, Horizon Utilities has assumed in 2010 that CDM savings will be consistent with the expected results for 2009 (i.e. 10 GWh). Horizon Utilities acknowledges that it is in receipt of the proposed CDM Targets for 2011 as set out in EB-2010-0215, released by the OEB on June 22, 2010. Such targets reflect a four year requirement of approximately 1.1% annual savings in total kWh.

a) Has Horizon reflected the four year CDM target set out in EB-2010-0215 in its forecast for 2011?

i. If yes, please explain in detail how it has incorporated the CDM target into the 2011 load forecast.

ii. If no, please explain.

b) Given that, in 2012 to 2014, Horizon will be expected to adjust rates through the IRM mechanism, has Horizon taken into account further CDM target reductions expected in the 2012 to 2014 period in accordance with EB-2010-0215? Please explain your response in detail.

Response:

a) Horizon Utilities has not reflected the four year CDM target set out in EB-2010-0215 in its forecast for 2011, but has reflected the four year CDM target set out in EB-2010-0216 in its forecast for 2011 in a manner consistent with that outlined in the Board's letter dated June 22, 2010 regarding Electricity Conservation and Demand Management Targets.

The CDM target set out in EB-2010-0215 was not used in the Application since such information was not available until after the Application was filed.

b) Please see response to part a) above and response to Board staff 12 a).

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Question 14

Reference: E3/T2/S2 Customer/Connection Growth

In Table 3-11, Horizon provides annual growth rates and the geometric mean annual growth rate in customers/connections by class. Horizon states that it has applied the geometric mean annual growth rate to 2009 numbers to estimate customers/connections by class, with the exception of the Large Use and Standby customer classes, to estimate 2010 Bridge and 2011 Test year forecasts.

a) In Table 3-11, the annual growth rate in customers for the GS 50-4999 kW class declines annually from 5.7% in 2004 to (0.3%) in 2009.

Horizon has used the geometric mean of 2.4% to increase the number of customers in this class for 2010 and 2011.

i. Given that the growth rate in this class has been declining and shows effectively no growth in 2009, why did Horizon not use a lower growth rate based on the declining growth in recent years?

ii. Please provide the actual number of GS 50-4999 kW customers serviced by Horizon as of June 30, 2010.

iii. If Horizon were to take into account the growth patterns in more recent years, what would be Horizon's estimate of GS 50-4999 kW customers for the 2010 Bridge and 2011 Test Years? Please provide details of the derivation.

b)

i. Given that the growth rate in this class has been increasing over time, and shows growth over 2% per annum in 2008 and 2009, why did Horizon not use a higher growth rate based on actual growth in recent years?

ii. Please provide the actual number of Sentinel Lighting connections serviced by Horizon as of June 30, 2010.

iii. If Horizon were to take into account the growth patterns in more recent years, what would be Horizon's estimate of Sentinel Lighting connections for the 2010 Bridge and 2011 Test Years? Please provide details of the derivation.

Response:

a)

i. Horizon Utilities did not use a lower growth rate based on the declining growth in recent years. The growth rate reflects a consistent period of historical data from 2003 to 2009 for forecasting, energy, load, and customer connections.

ii. The actual number of GS 50-4999 kW customers serviced by Horizon Utilities as of June 30, 2010 is 2,231.

iii. Horizon Utilities has taken into account the growth patterns in more recent years from 2006 to 2009. The geometric mean growth rate over this period for the GS 50-4999 kW rate class is 1.09% which results in a customer forecast for this class of 2,196 for the 2010 Bridge year and 2,220 for the 2011 Test Year.

b) .

i. Please see response 14 a) part i.

ii. The actual number of Sentinel Lighting connections serviced by Horizon Utilities as of June 30, 2010 is 502.

iii. Horizon Utilities has taken into account the growth patterns in more recent years from 2006 to 2009. The geometric mean growth rate over this period for the Sentinel Lighting rate class is 1.05% which results in a connection forecast for this class of 507 for the 2010 Bridge year and 513 for the 2011 Test Year.

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Question 15

Reference: E3/T2/T2/Table 3-23 Large Use Forecast

a) Please provide actual Large Use consumption in GWh for the following periods:

i. January 1 to June 30, 2010; and

ii. January 1 to November 30, 2010.

b) What is Horizon's basis for assuming that Large Use Demand (kW)and Consumption (GWh) is the same for both the 2010 Bridge and 2011 Test Years?

Response:

a)

i. January 1 to June 30, 2010

Large Use Consumption	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10
GWh	64.00	60.44	65.37	62.52	64.55	64.03

ii. January 1 to December 30, 2010

Large Use Consumption	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
GWh	64.00	60.44	65.37	62.52	64.55	64.03	62.63	67.48	60.95	52.80	46.84	43.44

b) In Horizon Utilities' 2008 Electricity Distribution Rate Cost of Service Application (EB-2007-0697), the proposed 2007 bridge year and 2008 test year load forecast for the Large Use class was held constant at the actual 2006 level. The Board approved

Horizon Utilities' proposal for the 2007 and 2008 load forecast for the Large Use class. However, after its 2008 rates were approved, Horizon Utilities experienced material revenue shortfalls, particularly in its larger commercial customer classes and, most notably, its Large Use customer class, due to customer demand and consumption that have been materially below the load forecast in Horizon Utilities' 2008 Cost of Service Application. In its correspondence to the Board dated December 23, 2008, Horizon Utilities advised the Board of the general decline in commercial load, and of the potential need to bring forward a Z-factor Application to address the revenue volatility arising out of the loss of load. In September 2009, Horizon Utilities filed its Z-factor Application (EB-2009-0332) to address the revenue shortfall and volatility in respect of one of its Large Use customers for which consumption and demand had declined dramatically. On March 24, 2010, the Board denied Horizon Utilities' Z-factor Application. In doing so, the Board found, in part:

"…Horizon has not demonstrated that the revenue losses experienced are an event genuinely external to the regulatory regime for which the management of the Applicant could not plan and budget, and thus has failed to establish that a Z-factor event has occurred." (at page 9)

and,

"In making these findings, the Board is mindful of the need to provide guidance to distributors as to the appropriate approach to take when confronted with such revenue losses. The Board notes the importance of assessing the actions taken by a distributor to deal with customer load loss in the context of their overall impact on the utility, including the overall financial impacts on the utility. The Board believes that the most appropriate approach for a distributor to take under such circumstances is to file a cost of service application." (at page 16)

It appears clear from the Z-Factor Decision that it is the Board's expectation that utilities should be planning for revenue volatility and mismatches between anticipated and actual loads and revenues and that managing such risk should be built into their load forecast. As such, load forecasts must reflect more consideration than historical regression and statistical analysis.

This past fall, one of Horizon's Large Use customers, U.S. Steel Canada Inc. ("USSC"), announced the idling of its Hamilton Works blast furnace. An October 1, 2010 article from the Globe and Mail[1] reported USSC's shutdown of its Hamilton steelmaking operations. More recently, USSC's Hamilton employees have been locked out of USSC's facilities. That lockout, which began on November 7, 2010, continues. Recently, Max Aicher North America acquired from USSC the bar and bloom mills that the former Stelco had closed in the months after it came out of bankruptcy protection.[2] Such acquisition represents only a small fraction of USSC's facilities and an even smaller share of Horizon Utilities' lost load. At this time, it is not clear to Horizon Utilities when and at what capacity these facilities will be operating. Moreover, there is no certainty at this point as to whether the additional load will be of any significance for the 2011 Test Year or the extent to which it may be of significance thereafter.

Based on these uncertainties and the insight from the Board in Horizon Utilities' Z-factor Decision, it is Horizon Utilities' view that the load forecast for the Large Use class should be determined with consideration for the significant volume and concentration risk associated with this class. As a result, the 2011 load forecast was held constant at the 2010 forecast level similar to the method approved by the Board in the 2008 Electricity Distribution Rate Cost of Service Application in which the Test Year forecast was the same as the Bridge Year forecast. However, in this Application, the 2010 Bridge Year forecast for the Large Use class has been adjusted upwards over the 2009 actual level to reflect the actual year to date experience in load growth from 2009 to 2010.

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[1] A copy of this article was provided as part of Horizon Utilities' November 8, 2010 response to Board Staff Interrogatory No.4(b) on the Preliminary Issue in the current proceeding.

[2] See page 10 of Horizon Utilities' November 29, 2010 reply submission on the preliminary issue in this proceeding.

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Question 16

Reference: E3/T2/T2/page 14 Standby Power

On lines 7-16, Horizon states:

> Horizon Utilities is proposing a change in the way the standby charge is applied to load displacement generators. Standby does not apply to Feed in Tariff ("FIT") generators as they are parallel connected or gross load billed. Historically, the standby charge was applied to the customer's account as a flat rate based on the generator name plate rating. The proposed change is to apply the standby charge based on the amount of load displaced with the result that the customer is only billed on the reserved capacity to supply its gross load. Such change is proposed as a number of customers have reduced the amount of load displacement generation below the name plate ratings. Consequently, such customers are paying for reserved capacity beyond both their gross load and beyond that which is necessary for the system to supply in the event of a generation shut down.

a) Please provide further explanation of how the charge for a Standby Customer is currently applied and how it would be applied under Horizon's proposal. Please provide an example showing the bill determination under both scenarios.

b) For one or more "typical" Standby customers, please show the bill impacts under current and proposed Standby Charges, using the Bill Impact table format shown in Appendix 8-1.

c) Please provide examples of other utilities in Ontario or elsewhere that Horizon is aware of, where the charge for Standby Power is applied in the manner which Horizon is proposing.

d) Has Horizon discussed this proposal with affected Standby customers? If so, please identify their position on Horizon's proposal.

e) Please explain whether or not Horizon proposes any changes to the interim status of their 2011 stand by charges.

Response:

a) Standby charges for load displacement generations is currently being applied as a flat charge each month based on the name plate rating of the generator. For example, consider a customer with a 4000 kW average load who installs a 2000 kW load displacement generator and in a particular month the customer operates the generator at 1000kW. In this example, the General Service rates would apply to the customer's purchased power paying a 3000 kW demand charge (4000kW load minus 1000kW displaced generation) and the customer would pay the standby charge based on the 2000kW name plate rating for the generator. Using the existing rates, the standby charge would be $4,100.60 (2000 kW x $2.0503).

With the proposed change the standby charge for a load displacement customer's generation would be based on the amount of load displaced rather than the name plate rating of the generator. Again, using the example above, the customer would continue to pay the General Service rates for the purchased power but would pay a standby charge based only on the displaced load reduction of 1000 kW. Using the proposed rates the standby charge would be $2,860.90 (1000 kW x $2.8639).

b) Horizon Utilities has provided the table below to show for one or more "typical" Standby customers, the bill impacts under current and proposed Standby Charges, using the Bill Impact table format shown in Appendix 8-1. The columns under the heading "2011 BILL" represent the proposed charges.

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE	CHARGE	Volume	RATE	CHARGE	Change	Change	% of
Monthly Service Charge			0.00			0.00	0.00	0.00%	0.00%
Distribution (kW)	0	0.0000	0.00	0	0.0000	0.00	0.00	0.00%	0.00%
Low Voltage Rider (kW)	0	0	0.00	0	0.000000	0.00	0.00	0.00%	0.00%
Smart Meter Rider (per			0.00			0.00	0.00	0.00%	0.00%
LRAM & SSM Rider (kW)	0		0.00	0	0.0000	0.00	0.00	0.00%	0.00%
Smart Meter Entity			0.00			0.00	0.00	0.00%	0.00%
Late Payment (kWh)	0	0.0000	0.00	0	0.0000	0.00	0.00	0.00%	0.00%
Standby Charge	2,000	2.0503	4,100.60	1,000	2.8639	2,863.90	($1236.70)	(30.16%)	88.50%
Deferrral & Variance	0	0.0000	0.00	0	0.0000	0.00	0.00	0.00%	0.00%
Distribution Sub-Total			**4,100.60**			**2,863.90**	**($1236.70)**	**(30.16%)**	**88.50%**
Retail Transmisssion	0	0	0.00	1,000	0	0.00	0.00	0.00%	0.00%
Delivery Sub-Total			**4,100.60**			**2,863.90**	**($1236.70)**	**(30.16%)**	**88.50%**
Other Charges (kWh)	0	0.0000	0.00	0	0.0000	0.00	0.00	0.00%	0.00%
Cost of Power	0	0.0000	0.00	0	0.0000	0.00	0.00	0.00%	0.00%
SPC (kWh)	0	0.0000000	0.00	0	0.0000000	0.00	0.00	0.00%	0.00%
Total Bill Before Taxes			**4,100.60**			**2,863.90**	**($1236.70)**	**(30.16%)**	**88.50%**
HST		13.00%	533.08		13.00%	372.31	($160.77)	(30.16%)	11.50%
Total Bill			**4,633.68**			**3,236.21**	**($1397.47)**	**(30.16%)**	**100.00%**

c) Horizon Utilities has not completed a review of how standby charges are being applied across other LDCs whether in Ontario or elsewhere.

d) Horizon Utilities has had discussion with its customers with load displacement generation. Through such discussion, Horizon Utilities has understood from customers their dissatisfaction with how the standby charges are applied, in particular as to how the charge is applied when their generation is either shut down or operating at reduced output. Horizon Utilities communicated to these customers that it would submit a proposal for the change in application of such charges at the time of its next Cost of Service Application. Horizon Utilities based its approach on these charges on the feedback from customers. This proposal, while not presented to customers, is in line with the aforementioned discussions. All accounts with load displacement generation will benefit from the proposed change and it will help to encourage/maintain distributed generation.

e) Horizon Utilities is continuing to apply the standby charge according to its current Board approved rates. This change, contained within Horizon Utilities' Conditions of Service, will be published when the rate is approved.

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Question 17

Reference: E3/T3/S1/Table 3-25 Specific Service Charges

a) Please provide the derivation of Horizon's forecast of $1,545,462 for Account 4235 – Miscellaneous Service Revenues for each of the 2010 Bridge and 2011 Test Years.

b) Please provide a table showing the quantities of specific service charge requests delivered or forecasted to be delivered, by type (e.g. special meter reads, account set-up, temporary disconnection/reconnection, temporary service) and for each of the

2008 actual, 2009 actual, 2010 Bridge and 2011 Test years, corresponding to the Other Operating Revenues shown in Table 3-25.

Response:

a) Please find below the table that provides the derivation of Horizon Utilities' forecast of $1,545,462 for account #4235 – Miscellaneous Service Revenue for each of the 2010 Bridge and 2011 Test Years.

OTHER CHARGES	2007	2008	2009	3 year av	rate	total	used for COS	
Arrears	1,225	938	1,087	1083.33	$15	$16,250	$11,167	used 3 year average of revenue
Lawyers letters					$15		$35,400	used 3 year average of revenue
Pull post dates	40	40	53	44.33	$15	$665	$665	
Duplicate invoices	45	40	21	35.33	$15	$530	$530	
Credit references	2,059	1,775	1,364	1732.67	$15	$25,990	$25,990	
Returned items	5,387	5,287	5,375	5349.67	$19.50	$104,319	$55,233	used 3 year average of revenue
Set up charges	41,123	39,846	37,524	39497.67	$30	$1,184,930	$1,184,930	
Collection of account charges	1,355	1,324	1,533	1404.00	$30	$42,120	$42,120	
Disconnect at meter - reg hours	2,724	2,366	3,159	2749.67	$65	$178,728	$178,728	
Disconnect at meter - after reg hours	56	17	9	27.33	$185	$5,057	$5,057	
Disconnect at pole - reg hours	28	18	28	24.67	$185	$4,563	$4,563	
Disconnect at pole - after reg hours	1	0	0	0.33	$415	$138	$138	
Meter dispute charges	25	36	33	31.33	$30	$940	$940	
ESTIMATE FOR 2010 BRIDGE YEAR AND 2011 TEST YEAR.							$1,545,461	

In three situation (arrears, lawyers letters and returned items) the quantities of specific service charges is not a true indication of the revenue generated from the charges. The quantities are not always charged to the customer or the quantities are recorded in a manner which is not consistent with the revenue.
In these three situations, the three year average of revenue is used for 2010 and 2011 revenue, and not the three year average of quantities.

b) Please find below a table that shows the quantities of specific service charge requests delivered or forecast to be delivered for each of the 2008 actual, 2009 actual, 2010 Bridge, and 2011 Test years, corresponding to the Other Operating Revenues shown in Table 3 – 25. Actual quantities for 2007 are also shown as these figures are integral in determining the three year average quantities.

OTHER CHARGES	2007	2008	2009	Three year Average	2010	2011
Arrears/Lawyers letters	1,225	938	1,087	1,083	3,104	3,104
Pull post dates	40	40	53	44	44	44
Duplicate invoices	45	40	21	35	35	35
Credit references	2,059	1,775	1,364	1,733	1,733	1,733
Returned items	5,387	5,287	5,375	5,350	2,832	2,832
Set up charges	41,123	39,846	37,524	39,498	39,498	39,498
Collection of account charges	1,355	1,324	1,533	1,404	1,404	1,404
Disconnect at meter - reg hours	2,724	2,366	3,159	2,750	2,750	2,750
Disconnect at meter - after reg hours	56	17	9	27	27	27
Disconnect at pole - reg hours	28	18	28	25	25	25
Disconnect at pole - after reg hours	1	0	0	0	0	0
Meter dispute charges	25	36	33	31	31	31

In three situation (arrears, lawyers letters and returned items) the quantities of specific service charges is not a true indication of the revenue generated from the charges. The quantities are not always charged to the customer or the quantities are recorded in a manner which is not consistent with the revenue.
In these three situations, the three year average of revenue is used for 2010 and 2011 revenue, and not the three year average of quantities.

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Question 18

Reference: Ref: E3/T3/S5/Tables 3-27 and 3-28 Management Fees

In table 3-27, Horizon provides a disaggregation of Account 4390 – Miscellaneous Non-operating Revenue for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Bridge and 2011 Test Years. For Management fees, the 2010 Bridge year forecast is $761,365 and the 2011 Test year forecast is $784,515.

In Table 3-28 – Summary of Management Fee Revenue in Miscellaneous Revenue, Horizon shows a total of $751,976 for the 2010 Bridge year and $772,376 for the 2011 Test year.

Please reconcile, with an explanation, the Management Fee revenues documented in Tables 3-27 and 3-28.

Response:

The Management fees for the 2010 Bridge Year forecast and the 2011 Test Year of $761,365 and $784,515 respectively are correct as shown in Table 3-27.

The Management Fee in Table 3-28 for St. Catharines Hydro Inc. should be $81,365 for the 2010 Bridge Year and $84,115 for the 2011 Test Year. With this correction, the Total Management Fee for 2010 and 2011 reconciles to Table 3-27.

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Question 19

Reference: Ref: E4/T2/S1/Table 4-1 OM&A Costs

On the second page of Table 4-1, the top sub-list of accounts 5305, 5310, 5315, 5320, 5325, 5330, 5335 and 5340 is not labelled. Please confirm whether this is "Billing and Collections". If not, please provide the descriptor for the subcategory that includes these accounts.

Response:

Horizon Utilities confirms that on the second page of Table 4-1, the top sub-list of accounts 5305, 5310, 5315, 5320, 5325, 5330, 5335 and 5340 should be labelled "Billing and Collections".

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Question 20

Reference: Ref: E4/T2/S10/page 11 Appendix 2-K

Horizon is proposing to capitalize approximately 30.6% of its compensation costs for 2011. This is about 5% higher than its 2008 approach.

a) Please explain the change in capitalization from 2008 to 2011.

b) Please confirm that Horizon has not made changes to the company's accounting policies in respect to capitalization of operation expenses and/or has not made any significant changes to accounting estimates used in allocation of costs between operations and capital expenses post fiscal year end 2004. If any accounting policy changes or any significant changes in accounting estimates have been made post 2004 fiscal year end, please provide all supporting documentation and a discussion highlighting the impact of the changes.

Response:

a) The change in the amount of labour capitalization from 2008 to 2011 is generally consistent with the projected increase in capital expenditures over the same period. The amount of labour capitalized in any particular year is a function of: (i) the level of planned activities in a given year between operations, maintenance and capital projects; (ii) the labour intensity of specific projects in each year; and iii) whether there has been an increase in the proportion of trades to total headcount arising from new hires.

b) Horizon Utilities confirms that it has not made changes to the company's accounting policies with respect to the capitalization of operating expenses nor has it not made any significant changes to accounting estimates used in the allocation of costs between operations and capital expenses.

As noted in Exhibit 4, Tab 2, Schedule 9, Page 1, the implementation of the ERP system in the latter part of 2008 resulted in structural changes to the mapping and allocation of costs to certain specific Uniform System of Accounts ("USoA") to better understand process costs on an activity basis. One of the most significant areas affected by this change was the recording of wages and benefit costs between Operations, Maintenance, and General Administration. All employees now record their time electronically by allocating such, on an activity basis, in fractions as small as ¼ hour, to specific OM&A and capital activities using pre-defined projects, work orders, and activities.

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Question 21

Reference: Ref: E4/T2/S6/page 20 Tree Trimming Expenses

Line 14 states that Horizon's tree trimming budget for 2011 is $1,210,000. Table 4-7 indicates that Horizon's tree trimming budget for 2011 is $1,328,186. Please confirm what is Horizon's tree trimming budget for the 2011 Test Year incorporated in its proposed revenue requirement.

Response:

Horizon Utilities' tree trimming budget for the 2011 Test Year incorporated in its proposed revenue requirement is $1,328,186. Horizon Utilities regrets that the amount stated at line 14 was incorrect.

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Question 22

Reference: Ref: E4/T2/S1/page 2 Bad Debt Expense

Please provide the actual bad debt expense (unaudited) for 2010 (i.e. from January 1 to December 31, 2010).

Response:

Horizon Utilities has not completed the preparation of its financial statements for the year ended December 31, 2010 and as such is not able to provide the actual bad debt expense for 2010.

Based on the 2010 year-end forecast prepared as at September 30, 2010, bad debt expense for 2010 is projected to be $1,400,000.

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Question 23

Reference: E4/T2/S7/page 1 One Time Costs

Please identify all one-time costs included in the OM&A forecast for the 2011 Test Year.

Response:

Certain regulatory costs, specifically costs associated with this rebasing proceeding, are one-time costs. Please see response to Board staff Interrogatory 40 with respect to the treatment of regulatory costs within the 2011 Cost of Service Application.

In any given year Horizon Utilities' budget would reflect both ongoing and one-time costs. Many of these one-time costs span multiple fiscal years and have maintenance costs associated with them. In respect of its OM&A forecast for the 2011 Test Year, there are a number of initiatives that will likely cross more than one fiscal period.

Horizon Utilities plans to procure, implement, and maintain certain technology enhancements. Similar to Horizon Utilities' response to Board staff Interrogatory 7, Horizon Utilities provides such projects, based on a threshold of $100,000, as follows:

Description	Reference	$
Planning and Scheduling (ERP)	Ex. 4, T2, S6, Table 4-8	300,000
Budget and Forecast Software	Ex. 4, T2, S6, Table 4-8	100,000
Enterprise Risk Management Framework	Ex. 4, T2, S6, Table 4-8	100,000
Redesign of Corporate Website	Ex. 4, T2, S6, Pg. 32	295,000
E-Mobile	Ex. 4, T2, S6, Table 4-8	226,000

These technology enhancements are multi-year projects and include both OM&A and capital expenditures. While certain of the OM&A costs incorporated within the 2011 Test Year OM&A include upfront costs related to the development and implementation of the particular enhancement, such costs do not include on-going license fees and maintenance costs. Such costs are expected to be incurred in future years.

Horizon Utilities submits that, although certain costs in any year are “one-time” costs, that its 2011 budget is representative of an ongoing funding requirement to address forecast costs through the IRM period; each of which will have some measure of discreet one-time costs related to planned projects in support of ongoing service delivery to its customers.

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Question 24

Reference: Ref: Low Income Energy Assistance Program (LEAP)

Please state whether or not Horizon has included an amount in its 2011 Test year revenue requirement for the emergency financial assistance component of the Low Income Energy Assistance Program.

a) If yes, please identify the amount included for LEAP emergency financial assistance, and identify the percentage of total distribution rates.

b) If no, please provide the following calculation: 0.12% of the total distribution revenue proposed by the applicant for the 2011 Test Year.

c) Please state whether or not Horizon has included an amount in its 2011 Test year revenue requirement for any legacy program(s), such as Winter Warmth. If so, please identify the amount and provide a breakdown identifying the cost of each program along with a description of each program.

Response:

a) No, Horizon Utilities has not included the LEAP Emergency Financial Assistance amount in its 2011 test year revenue requirement.

b) Counsel to Horizon Utilities filed a letter with the Board on January 4, 2011 on matters related to its 2011 Electricity Distribution Rate Cost of Service Application; a copy of that correspondence is attached. In that letter, Counsel to Horizon Utilities indicated that the LEAP Emergency Financial Assistance amount would be approximately $130,450, based on 0.12% of Horizon Utilities' proposed service revenue requirement of $108,707,939. Such amount will be adjusted according to the Board's decision on this Application.

c) Horizon Utilities has included the amount of $55,000 in its 2011 Test Year revenue requirement for Winter Warmth programs in its service territory. Such have been categorized under "Donations" in the pre-filed evidence (please see Horizon Utilities' response to Board staff Interrogatory #26). This expenditure is now anticipated to be allocated to the LEAP program and as such, provided to the United Way of Burlington & Greater Hamilton and the United Way of St. Catharines and District, following the principles specified in the *2011 LEAP Emergency Financial Assistance Program Manual* provided by the Ontario Energy Board in November 2010. Horizon Utilities identified these two agencies as its lead agencies in its correspondence filed with the Board on November 12, 2010. A copy of such correspondence is included with this response. Further, such is acknowledged in the Board's listing of Utility - Social Agency Partnerships for the Delivery of LEAP Emergency Financial Assistance, dated December 21, 2010.

In 2010, Horizon Utilities supported the Winter Warmth program by providing funds directly to the North Hamilton Community Health Centre and Community Care of St. Catharines and Thorold to provide financial assistance to families in need. These two social agencies will now be acting as intake agencies under the LEAP model. With its participation in LEAP, Horizon Utilities does not anticipate providing additional funds to Winter Warmth or other assistance programs in 2011.

horizon UTILITIES Looking beyond...

November 12, 2010

BY RESS AND BY COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge St., Suite 2700
Toronto, ON, M4P 1E4

Dear Ms. Walli:

RE: LEAP Emergency Financial Assistance EB-2008-0150, EB-2007-0722, and EB-2008-0346

The Ontario Energy Board (the "Board") issued a letter (the "Letter") to all licensed Electricity and Natural Gas Distributors and other Interested Parties, dated October 20th, 2010, in respect of the initiative to develop emergency financial assistance for customers associated with the Low Income Energy Assistance Program ("LEAP") program.

In the Letter, the Board requested that all distributors report the name and contact information of the distributor's chosen social agency partner(s) by no later than November 12, 2010. By way of this letter, Horizon Utilities is pleased to provide the following contact information, as such relates to Horizon Utilities' chosen social agency partner(s):

The United Way of Burlington and Greater Hamilton
Contact: Angela Dawe
Director, Community Investment and Agency Relations
Email: adawe@uwaybh.ca
Phone: 905-635-3123
Fax: 905-632-1918
www.uwaybh.ca

United Way of St. Catharines and District
Director, Community Investments and Communications
Email: ndipasquale@stcatharines.unitedway.ca
Phone: 905-688-5050 ext. 104
Fax: 905-688-2997

Should you have further questions or concerns, please do not hesitate to contact me.

Yours Truly,

Original signed by Indy J. Butany-DeSouza

Indy J. Butany-DeSouza, MBA
Vice-President, Regulatory and Government Affairs
Horizon Utilities Corporation
Tel: (905) 317-4765

EB-2010-0131

HORIZON UTILITIES CORPORATION (“HORIZON UTILITIES”)
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 25

Reference: Ref: Assumptions for Increases to OM&A

Please identify the inflation rate used for the 2011 OM&A forecast and the source document for the inflation assumptions.

Response:

For purchased goods and services, the general assumption was inflation of 2%, based on Horizon Utilities’ expectation of the Implicit Price Index for National Gross Domestic Product (GDP-IPI) for Final Domestic Demand.

Horizon Utilities is submitting its inflation assumptions for salaries and benefits as a confidential response, for the reasons set out in pages 9-10 of Exhibit 4 / Tab 2 / Schedule 10.

[redacted]

Benefits:

[redacted]

As noted in response to Board staff Interrogatory 52a), the 2011 OM&A forecast for OMERS reflects the contribution increase announced in July 2010.

EB-2010-0131

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 26

Reference: E4/T2/S1/page 2 Donations

Horizon has identified $60,000 for 2011 in account 6205 – charitable donations. Please comment on whether the amounts are compliant with Section 2.5.2 of the Filing Requirements.

Response:

The $60,000 in charitable donations recorded in account 6205 comprises:

Low-income Energy Assistance Program	$55,000
Other	5,000

The Low-income Energy Assistance Program (LEAP) program is a mandated Ontario Energy Board (OEB) program that directs utilities to provide year-round emergency financial assistance to low-income households. Horizon Utilities will contribute to local agencies to support the Ontario Energy Board's new LEAP program. These funds will provide much needed financial support to customers, allowing them to better manage their bill payments and energy costs while giving them some financial relief.

As per Section 2.5.2 of the Filing Requirements,

> "… the recovery <u>of charitable donations will not be allowed for the purpose of setting rates, except for contributions to programs that provide assistance to the distributor's customers in paying their electricity bills and assistance to low income consumers"</u>. If the applicant wishes to recover such contributions, it must provide detailed information for those claims. The applicant must review the amounts filed to ensure

> that all other non-recoverable contributions are identified, disclosed and removed. [emphasis added].

As Horizon Utilities documented in a letter to the Board on January 4, 2011 (attached), Horizon Utilities' LEAP Emergency Financial Assistance amount for 2011 will be approximately $130,450, based on 0.12% of Horizon Utilities' proposed service revenue requirement. This amount is in excess of the amount currently provided for in the 2011 Cost of Service Application. Horizon Utilities will seek an increase in its revenue requirement to recover the difference between the amount noted in account 6205 and the LEAP calculated amount; this difference is $75,450.

January 4, 2011

Delivered by E-mail and Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4
Dear Ms. Walli:

Re: EB-2010-0131
Horizon Utilities Corporation
Application to the Ontario Energy Board for Electricity Distribution Rates and Charges as of January 1, 2011

We are counsel to Horizon Utilities Corporation ("Horizon Utilities") with respect to the above captioned matter. We are writing to you today with respect to two matters: confidentiality; and a request for inclusion in Horizon Utilities' 2011 Test Year Revenue Requirement and rates an amount related to LEAP Emergency Financial Assistance.

Confidentiality:
Horizon Utilities' Application was filed on August 26, 2010. As discussed in the cover letter to the Application, two pages of the Application contained a small amount of redacted material – specifically, Exhibit 4, Tab 2, Schedule 10, pages 11 and 14 (Tables 4-25 and 4-26). A description of the material, and the grounds for Horizon Utilities' request for confidentiality in respect of the redacted material were set out in detail at pages 8-10 of that Schedule, and unredacted versions of those pages were delivered to the Board on August 27, 2010. In the cover letter and the Schedule, Horizon Utilities indicated that it was prepared to provide copies of the confidential material to parties' counsel and experts or consultants provided that they have executed the OEB's form of Declaration and Undertaking with respect to confidentiality and that they comply with the Practice Direction, subject to Horizon Utilities' right to object to the OEB's acceptance of a Declaration and Undertaking from any person.
In its December 15, 2010 Decision on the preliminary issue of early rebasing and Procedural Order No.4, the Board ordered that Board staff and intervenors may file with the Board and deliver to Horizon Utilities Corporation and other parties any submissions with respect to the claim for confidentiality submitted by Horizon Utilities, and that such submissions were to be filed on or before December 23, 2010. Any reply submission by Horizon Utilities would be due by January 7, 2011. No submissions have been received from Board staff or intervenors in this regard.

Page 2

Last night (January 3, 2011), we received a copy of correspondence from Mr. MacIntosh, a consultant to Energy Probe, advising that he had not received unredacted versions of pages 11 and 14. In reviewing our records, it appears that while unredacted copies of certain material provided in confidence in response to interrogatories on the preliminary issue in this proceeding were provided to persons who had executed the confidentiality undertaking (the Board subsequently determined that that material would be placed on the public record), unredacted versions of pages 11 and 14 may not have been provided to those persons. I apologize for that oversight, which was entirely inadvertent. Copies of the two pages will be provided forthwith to those persons who had executed the confidentiality undertaking. At this time, we have undertakings from Mr. Warren (counsel to CCC); and from Messrs. Aiken and MacIntosh (Energy Probe). We respectfully submit that the nature of the minimal redactions from the Application and the grounds for those redactions have been clear since last August, and that disclosure of the specific redacted numbers in Tables 4-25 and 4-26 is not necessary for submissions on confidentiality, if any.

Accordingly, Horizon Utilities believes that it is not necessary to make any further provision with respect to intervenor submissions and a reply submission on confidentiality, and that the timeline set out in Procedural Order No. 4 should not be altered. If the Board believes that additional time should be given for confidentiality-related submissions, Horizon Utilities submits that the Board should provide only for minimal extensions to the confidentiality-related deadlines. Horizon Utilities trusts that there will be no change to the interrogatory-related deadlines, as the determination of the confidentiality issue is independent of the interrogatories. Horizon Utilities is confident that staff and intervenors will phrase any questions related to the material proposed to be kept in confidence in such a way as to respect the confidentiality request pending the Board's determination of that request.

LEAP Emergency Financial Assistance:

On October 20, 2010, almost two months after the Horizon Utilities Application was filed, the Board issued a letter regarding LEAP Emergency Financial Assistance. The Board determined an appropriate Emergency Financial Assistance funding level is the greater of 0.12% of a distributor's Board-approved distribution revenue requirement, or $2,000. With respect to recovery of that amount through rates, the Board wrote (at page 3):

"With respect to the recovery of LEAP emergency financial assistance funding through distribution rates, each distributor that applies to the Board for new cost of service-based rates for 2011 should include the relevant LEAP amount as part of the distributor's operating, maintenance and administration (OM&A) expenses. For greater clarity, Board-approved total distribution revenue means a distributor's forecasted service revenue requirement as approved by the Board. The relevant LEAP amount proposed would be adjusted in distributors' draft rate orders to account for any changes resulting from the Board's decision on the final service revenue requirement."

In the case of Horizon Utilities, the LEAP Emergency Financial Assistance amount will be approximately $130,450, based on 0.12% of Horizon Utilities' proposed service revenue requirement in accordance with the Board's methodology.

Page 3

Horizon Utilities confirms that it intends to include this amount in its revenue requirement for recovery through its 2011 electricity distribution rates, and acknowledges that the actual LEAP amount will depend on any changes resulting from the Board's decision on Horizon Utilities' final service revenue requirement. At this time, Horizon Utilities can confirm that LEAP-related impacts on rates and bills will be minimal, and Horizon Utilities can provide further information in this regard if requested to do so in staff or intervenor interrogatories.
We thank you for your consideration in these matters. Should you have any questions or require further information, please do not hesitate to contact me.

Yours very truly,

BORDEN LADNER GERVAIS LLP

Original Signed by James C. Sidlofsky

James C. Sidlofsky
JCS/ac
Encl.
cc. Keith Ritchie, Ontario Energy Board
John G. Basilio, Horizon Utilities Corporation
Indy J. Butany-DeSouza, Horizon Utilities Corporation
Intervenors of Record
::ODMA\PCDOCS\TOR01\4535825\1

EB-2010-0131

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 27

Reference: E4/T2/S12/page 1-3 – Purchases from Non-Affiliates

Horizon has provided tables of purchases from non-affiliates for 2007, 2008 and 2009. No information is provided for the 2010 Bridge and 2011 Test Years.

a) Please provide similar tables for each of the 2010 Bridge and 2011 Test Years.

b) Please provide a qualitative explanation for each year-to-year total Variance (2007 – 2011).

Response:

a) The purchasing thresholds from Non- Affiliates spent reported were not consistent between 2007 and 2009, as the defined materiality thresholds were different between Horizon Utilities 2008 Electricity Distribution Rate Application (EB-2007-0697) and the current Application. For 2007 and 2008 a threshold reported was >$500k and for 2009 a threshold reported was >$250k, generating a larger variance between each reporting year. Enclosed are Horizon Utilities purchasing from Non-Affiliates from 2007 to 2010 using the threshold of > $250k. Please note that the 2010 purchases from Non-Affiliates are estimated pending completion of year end.

The name of the Non-Affiliate companies contained in the table below are being filed confidentially.

2007 Purchases from Non-Affiliates >$250K			
Name	**Activity**	**Priced By**	**Total**
[redacted]	Inventory	RFP/RFQ/PO	$3,048,971
[redacted]	Inventory	RFP/RFQ/PO	$1,517,972
[redacted]	Equipment/Maintenance	RFP/RFQ/PO	$1,460,351
[redacted]	Consultant	RFP/RFQ/PO	$1,413,398
[redacted]	Service Provider	Sole Source	$1,124,724
[redacted]	Inventory	RFP/RFQ/PO	$1,074,530
[redacted]	Inventory	RFP/RFQ/PO	$922,141
[redacted]	Contractor	RFP/RFQ/PO	$858,802
[redacted]	Consultant	RFP/RFQ/PO	$855,820
[redacted]	Contractor	RFP/RFQ/PO	$798,678
[redacted]	Computer Equipment	RFP/RFQ/PO	$708,795
[redacted]	Service Provider	RFP/RFQ/PO	$694,559
[redacted]	Fleet Equipment	RFP/RFQ/PO	$651,054
[redacted]	Contractor	RFP/RFQ/PO	$650,078
[redacted]	Service Provider	RFP/RFQ/PO	$560,234
[redacted]	Computer Equipment	RFP/RFQ/PO	$508,430
[redacted]	Contractor	RFP/RFQ/PO	$503,196
[redacted]	Fleet Equipment	RFP/RFQ/PO	$474,299
[redacted]	Fleet Equipment	RFP/RFQ/PO	$461,646
[redacted]	Contractor	RFP/RFQ/PO	$442,043
[redacted]	Inventory/Maintenance	RFP/RFQ/PO	$404,899
[redacted]	Contractor	RFP/RFQ/PO	$391,110
[redacted]	Inventory	RFP/RFQ/PO	$347,383
[redacted]	Inventory	RFP/RFQ/PO	$295,120
[redacted]	Service Provider	RFP/RFQ/PO	$252,227
[redacted]	Furniture/Equipment	RFP/RFQ/PO	$251,313
TOTAL			**$20,671,774**

2008 Purchases from Non-Affiliates >$250K			
Name	**Activity**	**Priced By**	**Total**
[redacted]	Service Provider	Sole Source	$5,174,776
[redacted]	Inventory	RFP/RFQP/PO	$3,158,506
[redacted]	Contractor	RFP/RFQP/PO	$2,614,241
[redacted]	Inventory	RFP/RFQP/PO	$1,933,475
[redacted]	Contractor	RFP/RFQP/PO	$1,221,934
[redacted]	Computer Equipment	RFP/RFQP/PO	$1,128,333
[redacted]	Inventory/Maintenance	RFP/RFQP/PO	$827,424
[redacted]	Inventory	RFP/RFQP/PO	$665,756
[redacted]	Contractor	RFP/RFQP/PO	$636,559
[redacted]	Fleet Equipment	RFP/RFQP/PO	$631,580
[redacted]	Fleet Equipment	RFP/RFQP/PO	$279,352
[redacted]	Contractor	RFP/RFQP/PO	$569,896
[redacted]	Contractor	RFP/RFQP/PO	$559,127
[redacted]	Inventory	RFP/RFQP/PO	$533,090
[redacted]	Contractor	RFP/RFQP/PO	$503,226
[redacted]	Service Provider	RFP/RFQP/PO	$499,634
[redacted]	Fleet Equipment	RFP/RFQP/PO	$485,010
[redacted]	Service Provider	RFP/RFQP/PO	$456,540
[redacted]	Service Provider	RFP/RFQP/PO	$437,314
[redacted]	Consultant	RFP/RFQP/PO	$402,631
[redacted]	Consultant	RFP/RFQP/PO	$354,172
[redacted]	Inventory	RFP/RFQP/PO	$353,448
[redacted]	Computer Equipment	RFP/RFQP/PO	$334,530
[redacted]	Inventory	RFP/RFQP/PO	$319,790
[redacted]	Consultant	RFP/RFQP/PO	$316,784
[redacted]	Inventory	RFP/RFQP/PO	$312,897
[redacted]	Service Provider	RFP/RFQP/PO	$301,884
[redacted]	Contractor	RFP/RFQP/PO	$295,043
[redacted]	Service Provider	RFP/RFQP/PO	$289,110
[redacted]	Fleet Equipment	RFP/RFQP/PO	$280,896
[redacted]	Service Provider	RFP/RFQP/PO	$268,227
[redacted]	Inventory	RFP/RFQP/PO	$266,671
[redacted]	Contractor	RFP/RFQP/PO	$255,217
TOTAL			**$26,667,072**

2009 Purchases from Non-Affiliates >$250K			
Name	**Activity**	**Priced By**	**Total**
[redacted]	Inventory	RFP/RFQ/PO	$5,090,691
[redacted]	Contractor	RFP/RFQ/PO	$1,893,173
[redacted]	Inventory	RFP/RFQ/PO	$903,237
[redacted]	Inventory	RFP/RFQ/PO	$794,788
[redacted]	Maintenance	RFP/RFQ/PO	$742,594
[redacted]	Contractor	RFP/RFQ/PO	$688,080
[redacted]	Computer Equipment	RFP/RFQ/PO	$686,936
[redacted]	Contractor	RFP/RFQ/PO	$595,968
[redacted]	Service Provider	Sole Source	$574,767
[redacted]	Fleet Equipment	RFP/RFQ/PO	$550,105
[redacted]	Consultant	RFP/RFQ/PO	$506,989
[redacted]	Service Provider	RFP/RFQ/PO	$506,818
[redacted]	Inventory	RFP/RFQ/PO	$506,702
[redacted]	Consultant	RFP/RFQ/PO	$494,228
[redacted]	Computer Equipment	RFP/RFQ/PO	$492,853
[redacted]	Service Provider	RFP/RFQ/PO	$443,574
[redacted]	Contractor	RFP/RFQ/PO	$427,178
[redacted]	Inventory	RFP/RFQ/PO	$408,441
[redacted]	Consultant	RFP/RFQ/PO	$390,000
[redacted]	Contractor	RFP/RFQ/PO	$382,515
[redacted]	Contractor	RFP/RFQ/PO	$381,472
[redacted]	Inventory	RFP/RFQ/PO	$380,043
[redacted]	Furniture/Equipment	RFP/RFQ/PO	$357,883
[redacted]	Inventory	RFP/RFQ/PO	$351,748
[redacted]	Service Provider	RFP/RFQ/PO	$348,891
[redacted]	Contractor	RFP/RFQ/PO	$343,845
[redacted]	Inventory	RFP/RFQ/PO	$331,882
[redacted]	Inventory	RFP/RFQ/PO	$314,761
[redacted]	Inventory	RFP/RFQ/PO	$313,487
[redacted]	Inventory	RFP/RFQ/PO	$310,696
[redacted]	Fleet Equipment	RFP/RFQ/PO	$305,002
[redacted]	Service Provider	RFP/RFQ/PO	$282,724
[redacted]	Inventory	RFP/RFQ/PO	$280,528
[redacted]	Inventory	RFP/RFQ/PO	$273,875
[redacted]	Inventory	RFP/RFQ/PO	$254,656
[redacted]	Contractor	RFP/RFQ/PO	$249,335
[redacted]	Service Provider	RFP/RFQ/PO	$247,715
[redacted]	Service Provider	RFP/RFQ/PO	$228,184
TOTAL			**$22,636,365**

2010 Purchases from Non-Affiliates >$250K

Name	Activity	Priced By	Total
[redacted]	Inventory	RFP/RFQ/PO	$3,866,607
[redacted]	Service Provider	Sole Source	$2,608,718
[redacted]	Contractor	RFP/RFQ/PO	$1,273,958
[redacted]	Contractor	RFP/RFQ/PO	$710,629
[redacted]	Inventory	RFP/RFQ/PO	$696,247
[redacted]	Fleet Equipment	RFP/RFQ/PO	$692,130
[redacted]	Computer Hardware	RFP/RFQ/PO	$661,785
[redacted]	Consultant	RFP/RFQ/PO	$658,849
[redacted]	Inventory	RFP/RFQ/PO	$600,070
[redacted]	Inventory	RFP/RFQ/PO	$576,209
[redacted]	Contractor	RFP/RFQ/PO	$573,117
[redacted]	Computer Hardware	RFP/RFQ/PO	$565,211
[redacted]	Contractor	RFP/RFQ/PO	$521,839
[redacted]	Service Provider	RFP/RFQ/PO	$508,696
[redacted]	Contractor	RFP/RFQ/PO	$449,438
[redacted]	Inventory/Maintenance	RFP/RFQ/PO	$448,652
[redacted]	Service Provider	RFP/RFQ/PO	$448,053
[redacted]	Service Provider	RFP/RFQ/PO	$430,889
[redacted]	Contractor	RFP/RFQ/PO	$426,734
[redacted]	Inventory	RFP/RFQ/PO	$401,109
[redacted]	Inventory	RFP/RFQ/PO	$397,854
[redacted]	Fleet Equipment	RFP/RFQ/PO	$372,661
[redacted]	Inventory	RFP/RFQ/PO	$351,115
[redacted]	Fleet Equipment	RFP/RFQ/PO	$317,862
[redacted]	Contractor	RFP/RFQ/PO	$312,584
[redacted]	Contractor	RFP/RFQ/PO	$293,148
[redacted]	Inventory	RFP/RFQ/PO	$290,588
[redacted]	Contractor	RFP/RFQ/PO	$287,568
[redacted]	Inventory	RFP/RFQ/PO	$286,424
[redacted]	Service Provider	RFP/RFQ/PO	$277,590
[redacted]	Inventory	RFP/RFQ/PO	$276,507
[redacted]	Supplies	RFP/RFQ/PO	$275,435
[redacted]	Service Provider	RFP/RFQ/PO	$272,642
[redacted]	Furniture/Equipment	RFP/RFQ/PO	$255,894
[redacted]	Inventory	RFP/RFQ/PO	$251,269
TOTAL			**$21,638,081**

b) The following table summarizes Horizon Utilities purchases from Non- Affiliates of $250,000 or greater from 2007 to 2011:

Horizon Utilities Corporation Purchases Spent from Non- Affiliates of $250k and greater				
2007	**2008**	**2009**	**2010**	**2011**
$20,671,774	$26,667,072	$22,636,365	(*)$21,638,081	Not Applicable

Note: (*) 2010 estimated values pending completion of year end.

Variances in the level of purchases year over year are typically driven by projects from any given year. Purchasing from Non-Affiliates for 2011 is not available at this time, as Horizon Utilities budgets are not developed based on purchasing volume. The table below summarizes the purchasing variance from Non-Affiliates in 2008, 2009 and 2010.

Reporting Year	**Purchasing Variance**	**Variances Explanation**
2008	$5,995,298	$2,401,800 – Hydro One (Vansickle Capital Contribution) $1,254,182 – Toromont (Emergency Generators) $1,907,836 – Outside Contractors (Capital Projects) $419,538 – Able One (Enterprise Resource Planning System Project)
2009	($4,030,707)	$1,932,185 – HD Supply (Transformers Inventory to support demand) $794,788 – Eaton Yale (Replacement Substation Transformer) $494,228 – IFS (Enterprise Resource Planning System Project) ($4,600,009) – Hydro One (Various Station Projects & Capital Contribution) ($1,030,238) – Prysmian Cable (Lead Cable Inventory) ($536,433) – Outside Contractors (Capital Projects) ($441,397) – Able One (Computer Equipment) ($285,713) – Guelph Utility Pole (Pole Inventory) ($254,044) – PVS (Locates Services)
2010	($998,284)	$2,033,951 – Hydro One (Transformation Pool Work Capital Contribution) $164,621 – IFS (Enterprise Resource Planning System Project) ($1,224,084) – HD Supply (Transformer Inventory)

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 28

Reference: E4/T2/S10/page 12 Incentive Plan

Please provide further documentation regarding Horizon's incentive plan (i.e.,what metrics are applied, which class(es) of employees are subject to the incentive plan, etc.)

Response:

Employee eligibility and metrics upon which incentive pay is calculated and paid is detailed in the Horizon Utilities Annual Incentive Plan Document. The document is being provided in confidence for reasons which are outlined in the cover letter accompanying Horizon Utilities interrogatory responses.

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 29

Reference: E4/T2/S9/Tables 4-13, 4-15, 4-17 and 4-18 – Meter Expenses

Horizon documents its meter expenses by year in the referenced tables. Horizon also documents that Account 5695 – OM&A Contra Account is used to reflect Residential and GS < 50 kW Smart Meter costs.

Board staff has prepared the following summary from the referenced tables:

Account	2008 Actual	2009 Actual	2010 Bridge	2011 Test
5065 Meter Expense	$ 2,782,355	$ 3,487,991	$ 4,059,631	$ 4,698,805
5695 OM&A Contra Account	-$ 950,929	-$ 1,240,883	-$ 932,627	-$ 1,680,292
Meter Expense net of Contra	$ 1,831,426	$ 2,247,108	$ 3,127,004	$ 3,018,513

Horizon has increased its meter expense by $1.9M from 2008. Horizon has noted that the increase reflects expenditures related to the roll-out of both the residential and small commercial smart meter program, costs associated with the deployment of Time-of-Use rates and meter staff costs that were previously allocated to general and administration.

Even adjusting for smart meter-related costs reflected in the contra account, there is an increase in meter expenses of about $1.2 million, more than a 50% increase from 2008 actuals.

a) Please confirm or correct the above table.

b) Please explain the increase in meter expense increases net of Smart Meter-related operating expenses.

c) Are these cost increases on-going or one time? Please explain your response.

Response:

a) Horizon Utilities confirms that the table prepared by Board staff (as shown above), is correct.

b) The increase in meter expense, net of Smart Meter-related operating expenses, is principally the result of a change in the allocation of employee costs related to supervisory and management of the meter department to account 5065. As noted in Exhibit 4, Tab 2, Schedule 9, Page 1, the implementation of the ERP system in 2008 resulted in a change in mapping and allocation of certain costs to specific OEB accounts. In particular, one of the most significant areas affected by this change was the recording of wages and benefit costs between Operations, Maintenance, and General Administration. Prior to the ERP implementation, all supervisory and management position costs, including operations and maintenance management personnel were recorded in general and administration OEB accounts (Accounts 5610 and 5615). Subsequent to the ERP implementation, wages and benefits for operations and maintenance personnel are being directed principally to the Operations Supervision and Engineering, other Operations Labour accounts, and Meter expenses based on the key responsibilities and activities that are being performed by the employee.

This explanation was also provided as part of OM&A variance analysis for 2011 Test Year compared to 2008 Actuals at Exhibit 4, Tab 2, Schedule 9, Page 27.

c) The increase in meter costs are a one-time reallocation from General and Administration to Meter Expenses.

EB-2010-0131

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 30

Reference: Ref: E4/T2/S10/Table 4-26 Additional Full Time Employees

Please update Table 4-26 to reflect new hires and vacancies for additional FTEs as of December 31, 2010

Response:

Year	Position	Month/Yr of Hire	Budgeted Salary/Annum
2010	Manager, IT Security	November 15, 2010	[redacted]
2010	Manager, Treasury & Risk	Not yet hired	
2010	Database Analyst	Not yet hired	
2010	Engineering Intern	September 21, 2010	
2010	Line Maintainer/Cable Splicer (7 positions)	5 – October 2010, 2 – November 2010	

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 31

Reference: E4/T2/S6/Appendix 4-3 Basic Green Energy Act Plan

a) Did Horizon incur capital expenditures in 2010 as part of its Green Energy Act ("GEA") Plan for which it seeks recovery?

b) Please clarify whether there are costs related to Expansion and Renewable Enabling Improvement that Horizon has included in the GEA. If so, please provide amounts for these two types of costs in the following table for 2010, 2011, and 2012.

	2010	2011	2012
	(Additions in $000)		
Expansions			
Enabling Improvements			

c) Is Horizon seeking Board approval of all forecasted projects and capacity from 2011 through 2015 in this application?

Response:

a) Horizon Utilities did not incur any capital expenditures in 2010 as part of its Green Energy Act ("GEA") Plan for which it is seeking recovery.

b) In the costs for renewable connections that appear on pages 36 and 37 of Horizon Utilities' GEA Plan, in Exhibit 4, Tab 2, Schedule 6, Appendix 4-3, Horizon Utilities has incorporated costs related to Expansions and Renewable Enabling Improvements for 2012 through 2015. No expenditures related to Expansions or Renewable Enabling Improvements were incurred in 2010, and no expenditures related to Expansions or

Renewable Enabling Improvements are expected in 2011. The costs for Expansions and Renewable Enabling Improvements for 2010 through 2012 are provided in the table below.

	2010	**2011**	**2012**
	(Additions in $000)		
Expansions	0	0	108
Renewable Enabling Improvements	0	0	48

c) On Page 19 of Exhibit 4, Tab 2, Schedule 6, Horizon Utilities states the following:

"Horizon Utilities has submitted a Basic Green Energy Act Plan ("GEAP") that includes capital and operating expenditures for the period of 2011 through 2015. Horizon Utilities is seeking approval for 2011 through 2013 expenditures. Operating expenditures include the costs of full time equivalents, consultant support, and participation in industry groups and events. Horizon Utilities' GEAP requires one incremental full-time equivalent in 2011, and two incremental full time equivalents in 2012. Consultant support will assist Horizon Utilities in: optimizing the connection of renewable generators; engaging various customer groups to understand the value of Smart Grid to customers; investigating cyber-security technologies and advancements; better understanding the impacts of renewable generation, energy storage, and plug-in hybrid/electric vehicles; assessing feeder automation technologies; and, the application of substation automation to aging substations."

Horizon Utilities intends to file an updated GEA Plan in its next EDR Cost of Service application.

In its GEA Plan, Horizon Utilities has included feeder generation capacities. On Page 8 of the GEA Plan, Horizon Utilities has stated:

"These feeder available generation capacities are subject to change as Horizon Utilities continues to study generation capacity on its distribution system. These feeder available generation capacities are also subject to transformer station generation capacity limits established by Hydro One and publicly available on Hydro One's website."

Since the capacities included in the GEA Plan are subject to revision as Horizon Utilities continues to study the issue of capacity constraints, Horizon Utilities is seeking acknowledgement of the capacities it has included in its GEA Plan.

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
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BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 32

Reference: E4/T2/S6/Appendix 4-3/page 5 and *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence*, issued March 25, 2010 [EB-2009-0397]

With respect to Horizon's filed GEA Plan:

a) Has Horizon consulted with its host distributor and/or upstream transmitter when preparing its GEA plan?

b) Has Horizon participated in planning meetings with the OPA?

Response:

a) Consultations with Hydro One have been discussed on pages 33 and 34 of Horizon Utilities' GEA Plan, as can be found in Exhibit 4, Tab 2, Schedule 6, Appendix 4-3. For convenience, the discussion is re-produced below:

> "<u>Consultations with Hydro One</u>
>
> Projects in this GEA Plan that are not capacity allocation exempt are subject to the availability of generation capacity on the transmission system. The expansions included in this GEA Plan do not affect generation capacity on the transmission system.
>
> Horizon Utilities has discussed with Hydro One the rationale behind Hydro One's generation capacity limits at transformer stations (emails available as supporting documentation). Horizon Utilities plans on further discussing this with Hydro One.

Since the Ontario Power Authority ("OPA") has been assessing generation capacity on the transmission system and at transformer stations for FIT projects, Horizon Utilities has not seen the need to discuss specific expansions with Hydro One. Moreover, the expansions included in this GEA Plan do not require expansions at transformer stations (e.g. new breaker positions) and will not go forward before the projects get FIT contracts (and therefore can be accommodated on the transmission system).

Through the Economic Connection Test process, the OPA works with Hydro One on any required expansions to the transmission system, and with Horizon Utilities on any required expansions to the distribution system. So far, two FIT projects have failed the Transmission Availability Test and will be part of the Economic Connection Test process. Since it is not expected that these projects will be impacted by limitations on Horizon Utilities' distribution system, Horizon Utilities will not be involved in the Economic Connection Test for these projects. However, Horizon Utilities may be involved in discussions with the OPA, Hydro One and the FIT project applicants to facilitate possible solutions to the transmission system limitations"

b) Horizon Utilities has not had any planning meetings with the OPA. The OPA has not requested such meetings, because the Economic Connection Test process has not yet started. However, Horizon Utilities has actively participated in the OPA's presentations and web-enabled conference calls regarding FIT planning. Horizon Utilities has also been an active member of the Electricity Distributors' Assocation's FIT/microFIT working group, of which the OPA and OEB are also members.

In its Letter of Comment filed along with the GEA Plan and this Application, the OPA confirmed that Horizon Utilities' GEA Plan is in line with current and anticipated FIT activity. The OPA stated that Horizon Utilities' GEA Plan "…is generally consistent with the OPA's information regarding renewable energy generation connections."

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
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DELIVERED: January 24th, 2011

Question 33

Reference: Ref: E4/T2/S6/Appendix 4-3/page 8 Constraints on Renewable Connections

On page 8, Horizon states:

> "Constraints on renewable connections are therefore expected to result from limitations of reverse power flow and short circuit capability and short circuit capability at Hydro One transformer stations and Horizon substations."

a) Please list all those substations which would be affected by the constraints at Allanburg 115kV TS, insofar as it may relate to connecting FIT and microFIT projects.

b) Please provide the short circuit level at Allanburg TS, and Horizon's substations.

c) Please provide further details on "reverse power flow" limitations at Allanburg TS.

d) With respect to the limitations at Allanburg TS, has Horizon sought confirmation from Hydro One as to when these limitations might be alleviated?

e) If upgrade work at Allanburg TS is delayed, how many of the FIT and microFIT projects in Horizon's service territory (based on estimates and actual FIT applications to date) can be connected?

f) Are there any other substations with significant capacity constraints?

Please provide a table showing the short circuit capacity on all of Horizon's buses directly connected to major supply points. Please provide the margin between current operating condition and the short circuit capacity ratings provided.

Response:

a) Horizon Utilities' St. Catharines service area is supplied from Hydro One's Bunting Transformer Station ("TS"), Carlton TS, Glendale TS, and Vansickle TS. As indicated by the OPA in its Letter of Comment filed in Horizon Utilities' GEA Plan, Horizon Utilities' St. Catharines service area is affected by the constraints at Hydro One's Allanburg TS. In other words, the constraints at Allanburg TS affect the ability to connect FIT and microFIT projects at Bunting TS, Carlton TS, Glendale TS, and Vansickle TS.

b) While Horizon Utilities is aware that there are short circuit constraints at Allanburg TS, Horizon Utilities does not have information on the short circuit levels at Allanburg TS.

The table below lists maximum short circuits at Horizon Utilities' substations under normal switching configurations:

Substation	Short Circuit Level [kA]
Aberdeen	10.6
Baldwin	12.1
Bartonville	13.4
Caroline	11.8
Central	20.1
Cope	11.3
Deerhurst	6.3
Dewitt	9.3
Eastmount	10.6
Elmwood	10.0
Galbraith	11.4
Grantham	18.2
Highland	10.1
Hughson	19.0
John	10.3
Kenilworth	15.8
Mohawk	13.8
Mountain	14.0
Ottawa	11.8
Parkdale	12.8
Spadina	11.9
Strouds Lane	13.2
Taylor	11.5
Vine	15.8
Webster	3.3
Welland	16.6
Wellington	11.8
Wentworth	12.6
Whitney	10.8
York	10.1

c) Horizon Utilities is not aware of any reverse power flow limitations at Allanburg TS. Horizon Utilities is aware that there are short circuit limitations at Allanburg TS, but does not have information on the short circuit levels at Allanburg TS.

d) Horizon Utilities has requested information from Hydro One regarding modifications to equipment at Allanburg TS to alleviate short circuit constraints. Hydro One has referred Horizon Utilities to Hydro One's responses to the OEB's interrogatories in relation to Hydro One's transmission rate application [EB-2010-002]. On Page 2 of

Exhibit I, Tab 1, Schedule 111 of Hydro One's rate application [EB-2010-002], Hydro One states:

> "Subsequent to the filing of this rate application, Hydro One identified that the short circuit levels at Allanburg TS have exceeded the station capability. Presently Hydro One has implemented an interim operating measure to manage the situation. This mitigating measure reduces the current levels of reliability and operational flexibility. Hydro One is currently developing a plan that would involve replacing lower rated breakers to increase the station short circuit capability and restore reliability.
>
> The breakers at Allanburg are of the same type and model as the Toronto station breakers with short circuit capability below the 50kA level established in the TSC for 115kV transmission facilities. The breakers have an average age of 45 years and with typical breaker life expectancy of 30-55 years, these breakers are approaching the upper limits of expected life. They will need to be replaced over the next 5 -10 years.
>
> Hydro One has received information from the OPA that in the Allanburg area as much as 68 MW of FIT Launch applications are currently impacted by the short circuit limitations.
>
> The need to upgrade the Hawthorne 115kV station was also identified subsequent to the rate application filing. The short circuit limitations at Hawthorne impacts as much as 155 MW of FIT Launch applications in the greater Ottawa and surrounding areas. The breakers are again of the same type and model as Toronto and Allanburg stations and are rated below the 50kA TSC level. The average age is 42 years and these breakers would also need to be replaced over the next 5 to 10 years. Hydro One is developing a plan to replace the lower rated breakers to address the issues of end-of-life management, meet TSC short circuit levels and connect significant levels of renewable generation.

> The earliest that both the Allanburg and Hawthorne TS projects can be completed is 2013 and as a result they will not affect the test year revenue requirement. Hydro One expects to manage the capital expenditures for this project within the Development Capital spending levels requested in this application."

e) The number of anticipated FIT and microFIT projects in St. Catharines appears in Table 6 on page 32 of Horizon Utilities' GEA Plan, in Exhibit 4, Tab 2, Schedule 6, Appendix 4-3.

Horizon Utilities understands that, due to the constraints at Allanburg TS, there is a risk that the OPA may not offer contracts to some of the FIT and microFIT projects in St. Catharines that have not yet been offered contracts from the OPA. In recent discussions with Hydro One, Hydro One indicated that it will provide to Horizon Utilities information regarding the upgrade work at Allanburg TS and direction as to how to deal with FIT and microFIT projects in St. Catharines. Until then, Horizon Utilities is not able to provide a figure of how many of the anticipated projects would be impacted by the scheduling of the upgrade work at Allanburg TS.

f) Horizon Utilities does not own any transformer stations connected to the transmission system. Hydro One owns all of the transformer stations that supply Horizon Utilities' distribution system. Hydro One provides a list of station capacity, including short circuit constraints, on its website at:

http://www.hydroone.com/Generators/Pages/AvailableCapacity.aspx

Below is a list of transformer stations that are constrained due to short circuit capacity:

Hamilton		
Station	**Bus**	**Voltage (kV)**
Lake	BY	27.6
Kenilworth	B1Y1	13.8
	DK	13.8
	EJ	13.8
Gage	T3T4 (DESN 2)	13.8
	T5T6 (DESN 3)	13.8
	T8T9 (DESN 4)	13.8

St. Catharines		
Station	**Bus**	**Voltage (kV)**
Bunting	J	13.8
	Q	13.8
Carlton	T1T4	13.8
	BY	13.8
	KH	13.8
Glendale	BJ	13.8
	DQ	13.8
Vansickle	BY	13.8

HORIZON UTILITIES CORPORATION (“HORIZON UTILITIES”)
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 34

Reference: E4/T2/S6/Appendix 4-3/pages 32 and 36
Planned Development of the System to Accommodate Renewable Generation Connections

Horizon provided the number of renewable generation connections that are expected over the next five years in Hamilton and St. Catharines at page 32, Tables 5 and 6, respectively. Board staff notes that October 21, 2009 is the date associated with cost-responsibility rules as set out in the DSC and thus under the provincial recovery mechanism as set out in section 79.1 of the *OEB Act*.

a) Were all FIT and micro-FIT project applications filed on or after the October 21, 2009 date? If not, please indicate which projects were filed prior to October 21, 2009, and under what scheme. (e.g. RESOP)

b) Please provide a table with the following information in column form for each FIT and microFIT project at page 35-36, Tables 9, 10, and 11:

i. Final approval from OPA? (Y/N);

ii. Nameplate capacity of project;

iii. Available capacity? (Y/N);

iv. Station and Feeder connection (e.g. M22, etc.), MW, and voltage level;

v. Time to completion; and

vi. Expected completion or in-service date.

Response:

a) The OPA received microFIT and FIT project applications for Horizon Utilities' service area on or before October 21, 2009. The OPA received three microFIT applications and seven FIT applications. All applications were for new projects (i.e. non-RESOP projects). Those applications are listed below.

MicroFIT		
Application #	**Application Time**	**Capacity (kW)**
FIT-QJQHMW	15/10/2009 14:26	3
FIT-IIRYTW	15/10/2009 14:29	9.9
FIT-G8IAGD	18/10/2009 19:03	0.32

FIT		
Application #	**Application Time**	**Capacity (kW)**
FIT-FR9E7MJ	04/10/2009 15:02	250
FIT-FVL0HF5	08/10/2009 4:02	250
FIT-FQ0LY2D	08/10/2009 20:02	250
FIT-FKF63UG	09/10/2009 2:02	250
FIT-F7ZV8R9	11/10/2009 17:02	375
FIT-FSML5UA	13/10/2009 2:02	100
FIT-FWF41DB	21/10/2009 12:01	250

Horizon Utilities received two applications to connect microFIT projects on or before October 21, 2009. An application for OPA application #FIT-QJQHMW was received on October 16, 2009, and an application for OPA application #FIT-G8IAGD was received on October 21, 2009. These projects appear in the table above.

The two microFIT projects, for which Horizon Utilities received connection applications on or before October 21, 2009, were connected after October 21, 2009. These two projects did not involve any Expansions. Therefore, these two projects were not impacted by the amendments to the Distribution System Code that came into force on October 21, 2009, regarding connection cost responsibility for renewable distributed generation.

Horizon Utilities did not receive any applications to connect FIT projects on or before October 21, 2009.

b) The following table provides further information on the projects listed in Tables 9, 10 and 11 in the GEA Plan:

OPA FIT Reference Number	Final Approval from OPA?	Nameplate Capacity (kW)	Available Capacity?	Station	Feeder Breaker	Feeder	Voltage (kV)	Time to Completion (Days)	Expected Commercial Operation Date
FIT-FR9E7MJ	Y	250	Y	Mohawk TS	M73	0731X	13.86	487	1-Dec-2012
FIT-FSML5UA	Y	100	N	Lake TS DESN 1	M2	121X	27.6	487	1-Dec-2012
FIT-FWF41DB	Y	250	N	Carlton TS DESN 1	M18	CTM18	13.86	247	31-Dec-2011
FIT-FQ0LY2D	Y	250	N	Carlton TS DESN 1	M20	CTM20	13.86	487	1-Dec-2012
FIT-FKF63UG	Y	250	N	Carlton TS DESN 1	M18	CTM18	13.86	487	1-Dec-2012
FIT-F7ZV8R9	Y	375	Y	Nebo TS DESN 1	M4	341X	27.6	487	1-Dec-2012
FIT-FE9YT1S	N	6500	N	Beach TS DESN 2	M43	7432X	13.86	367	15-Jun-2012
FIT-FZF8GNC	N	4000	N	Carlton TS DESN 2	M17	CTM17	13.86	637	28-Jun-2013

Please note the following:

- Horizon Utilities has interpreted an OPA application status of “capacity-exempt-approved” as a final approval from the OPA.
- Capacity availability was determined using Hydro One’s List of Station Capacity, available on Hydro One’s website at: http://www.hydroone.com/Generators/Pages/AvailableCapacity.aspx

The list is updated on a regular basis and capacity availability is subject to change.

- Station name, feeder designation and feeder voltage are provided for each project. However, Horizon Utilities is not clear as to what the Board intends when it requests “MW” for each project. The nameplate capacity in kW is provided for each project.
- Horizon Utilities has interpreted “time to completion” as the number of business days to the commercial operation date.
- The OPA uses the term “Commercial Operation Date” instead of “completion date” or “in-service date.” Horizon Utilities has used “Commercial Operation Date” in order to accurate reproduce the data from the OPA. Horizon Utilities considers the Commercial Operation Date as the completion or in-service date.

**HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
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DELIVERED: January 24th, 2011

Question 35

Reference: Exhibit 4 / Tab 2/ Schedule 6/ Appendix 4-3/ Page 41 and *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence*, issued March 25, 2010 [EB-2009-0397] – Green Energy Expenditures under GEA Plan – Smart Grid

The *Filing Requirements* state:

> "At the present time, smart grid development activities and expenditures should be limited to smart grid demonstration projects, smart grid studies or planning exercises and smart grid education and training… …the Board does not expect distributors to be engaging in the research and development activities related to smart grid development at this time."

At page 40 of Appendix 4-3, Horizon indicates that, as part of its Smart Grid projects, that it will be performing feeder automation and substation automation.

a) Please provide Horizon's views as to whether the activity falls within the limits that the Filing requirements describe?

b) Please provide the main drivers to undertake feeder automation at this time.

c) Will the contemplated feeder automation program increase the system capacity available or otherwise widen safe operating limits to facilitate an increase in the connection of renewable generation through the FIT program?

d) Which feeders will be automated as a result of the feeder automation program?

e) What improvements in performance are to be expected from the feeder automation program?

Response:

a) With regard to Feeder Automation, Horizon Utilities' GEA Plan calls for investigations and planning exercises during the early years of the five-year forecast period. On Page 45 of the GEA Plan, in Exhibit 4, Tab 2, Schedule 6, Appendix 4-3 of the Application, Horizon Utilities states that the Feeder Automation "…initiative is intended to investigate the technology, monitor other LDC pilots, and establish a business case for implementation of the technology in relation to Horizon Utilities' aging feeders." For the purpose of illustrating potential capital expenditures, Horizon Utilities has forecasted capital costs in 2014 and 2015 that are dependent upon the results of the planning activities conducted in 2011, 2012 and 2013.

Regarding Substation Automation, Horizon Utilities' GEA Plan only calls for investigations and planning exercises during the five-year forecast period. On page 46 of the GEA Plan, in Exhibit 4, Tab 2, Schedule 6, Appendix 4-3 of the Application, Horizon Utilities states that the Substation Automation "…initiative is intended to investigate the technology, monitor other LDC pilots, and establish a business case for implementation of the technology in relation to Horizon Utilities' aging stations." Due to uncertainty regarding the need for Substation Automation at Horizon Utilities' substations, and in light of Horizon Utilities' voltage conversion plans, Horizon Utilities has not forecasted any capital expenditures for Substation Automation.

The Feeder Automation and Substation Automation initiatives described in Horizon Utilities' GEA Plan focus on investigations and planning exercises, and therefore, fall within the limits of the Filing Requirements.

b) Horizon Utilities does not intend to implement Feeder Automation at this time. At the present time, Horizon Utilities does not anticipate any capital expenditures related to Feeder Automation until 2014. Please refer to the response to a) of this Interrogatory, above.

As discussed in the Feeder Automation section of Horizon Utilities' GEA Plan, the main drivers for Feeder Automation are improved reliability and reduced safety risk to field staff. With Feeder Automation, outage duration is reduced due to automated switching, thereby improving reliability. Safety risk to field staff is reduced as switching would be performed automatically instead of manually by field staff.

c) On Page 8 the GEA Plan, in Exhibit 4, Tab 2, Schedule 6, Appendix 4-3, Horizon Utilities states that "constraints on renewable connections are therefore expected to result from limitations of reverse power flow and short circuit capability at Hydro One transformer stations and Horizon Utilities substations." It is not expected that Feeder Automation will alleviate these constraints. However, Horizon Utilities will consider renewable generation integration in its investigations and planning exercises for Feeder Automation.

d) As part of the Feeder Automation planning exercises, Horizon Utilities will determine which feeders warrant automation. This will be undertaken in 2012.

e) On Page 45 of the GEA Plan, in Exhibit 4, Tab 2, Schedule 6, Appendix 4-3 of the Application, Horizon Utilities states the following:

"Currently Horizon Utilities' system operators respond to system outages by dispatching crews to sectionalize faulted feeders through manual switching, in order to identify the fault location and restore power to as many customers as possible. This is a laborious and time-consuming process, leading to significant inconvenience (residential), financial loss (commercial) or health risk (hospitals or seniors' residences) for customers during extended outages. Further, manual switching operations also inevitably involve a safety risk factor for field staff.

The Smart Grid feeder automation strategy calls for the use of automated switches, intelligent sensors and relaying and communications with the SCADA system. These components are designed to improve safety by eliminating many manual operations and improve reliability by operating in teams to "self-heal" the supply within seconds of system failure."

Feeder Automation entails automatically isolating the faulted portion of the distribution system and automatically restoring power to customers supplied from the remaining portions of the distribution system, all within seconds of the occurrence of the fault. By significantly reducing outage duration, Feeder Automation will result in significant improvement to reliability, particularly, CAIDI and SAIDI.

On Page 19 of Horizon Utilities' Engineering, Operating, & Operational Improvement Business Plan, in Exhibit 1, Tab 2, Schedule 2, Appendix 1-9(f), Horizon Utilities has identified as a key opportunity the expected improvement in reliability presented by Feeder Automation. Horizon Utilities states, "Distribution technology such as self-healing switches and line sensors will be key elements to improve system reliability and response time for outage restoration. The plan will follow the Horizon Utilities' GEA Plan."

HORIZON UTILITIES CORPORATION (“HORIZON UTILITIES”)
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DELIVERED: January 24th, 2011

Question 36

Reference: E4/T2/S6/Appendix 4-3/page 32 and *Report of the Board*: *Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09*, Issued June 10, 2010 [EB-2009-0349], Executive Summary and Page 15, footnote 9 – Green Energy Expenditures under GEA Plan – Relief Sought and Contribution Factors

Horizon states at page 32 of its GEA Plan that, “The tables [outlining costs] indicate a zero provincial recovery because at this point in time the calculation for direct benefits for Horizon is not defined.” Staff concludes from the tables provided that Horizon is requesting that provincial ratepayers contribute 0% of the cost of renewable enabling investments, and 0% of the cost of expansion investments.

In the Report of the Board, under the Executive Summary section, the Board states that, “Distributors that file a Basic GEA Plan will be permitted to undertake a basic (i.e., standardized) direct benefit assessment, while essentially all distributors required to file a Detailed GEA Plan will be required to undertake a detailed direct benefit assessment based on the principles and criteria set out in this Report. Further at page 15, footnote 9 of the Report of the Board, it stated that, “For example, based on the provisionally approved methodology and allocation (i.e., dollar amounts) proposed by Hydro One as part of its 2010 and 2011 distribution rates application, those dollar amounts represent 6% for REI

[Renewable Enabling Improvement] investments and 17% for Expansion investments."

Page 3 of the Report of the Board also clearly indicates that investments which enable generation from the FIT program are considered "eligible investment".

> "Not all investments made by a distributor to accommodate renewable generation will qualify as an "eligible investment". **Investments to connect such generation that is contracted under the feed-in tariff ("FIT") program will be treated as an "eligible investment".** [Emphasis added]

Page 15 and 16 of the Report of the Board also commented on the suitability of the percentages for Hydro One's Expansion and REI investments, and their applicability to other distributors:

> "Hydro One Distribution in relation to Expansion and REI investments should provide a reasonable estimate for other distributors until more distributors complete detailed benefit assessments…"

a) Why has Horizon chosen not to adopt Hydro One's provisional percentages for direct benefits given the Board's comment on appropriate percentages in the absence of a detailed benefit assessment?

b) In the event that Horizon is directed by the Board to implement the provisional direct benefits in this proceeding (as were applied in Hydro One), please identify the components and proportions of the plan that Horizon expects to be borne by Horizon's ratepayers and the components and proportions to be borne by the provincial ratepayers.

Please exclude and make note of any costs expected to be recovered by generators. Please specifically indicate the approximate percentages that would apply with respect to REI investments and expansion investments from provincial ratepayers.

c) With respect to part b), please recreate tables 12 through 17 on pages 36 and 37 with the direct benefit percentages provisionally approved in Hydro One's decision (EB-2009-0096).

Response:

a) On page 16 of the *Report of the Board: Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09*, issued June 10, 2010 (EB-2009-0349), the Board states the following:

> "The Board has only approved the allocation of costs proposed by Hydro One, on a provisional basis, at this time. The Board's Partial Decision notes that "the allocation methodology and the resulting responsibility for Green Energy Plan costs for 2010 and 2011 will be subject to later revision to reflect the Board's final policy determination in EB-2009-0349." As such, the percentages that are initially to be used by distributors undertaking a basic benefit assessment will be the percentages based on the methodology and allocation that are approved by the Board on a final basis subsequent to the issuance of this Board Report. Those revised percentages will be communicated by the Board when they become available."

Horizon Utilities interpreted the Report of the Board to give distributors the option to adopt the percentages proposed by Hydro One. Horizon Utilities chose not to adopt such percentages, and instead wait for the Board to provide final direction on the issue.

b) In estimating the costs of renewable generation connections, Horizon Utilities made the following assumptions:

- No Micro renewable generation connections would require Expansions or Renewable Enabling Improvements;
- Very few Micro renewable generation connections would require upgrades to connection assets, typically transformer upgrades;

- A portion of Small renewable generation connections would require upgrades to connection assets, typically transformer upgrades;
- Very few Small renewable generation connections would require Expansions;
- A portion of Small renewable generation connections would require Renewable Enabling Improvements, specifically real-time monitoring;
- All Mid-sized renewable generation connections would require new connections or upgrades to connection assets;
- Some Mid-sized renewable generation connections would require Expansions; and
- All Mid-sized renewable generation connections would require real-time monitoring and Transfer Trip, however, the costs would be borne by the generators because real-time monitoring and Transfer Trip would be implemented through transformer stations owned by Hydro One and therefore would not be considered Renewable Enabling Improvements.

As per the requirements of the Distribution System Code, generators are responsible for the costs of new or upgraded connection assets. The costs of Expansions, if pre-approved by the Board, are the responsibility of the distributor. The costs of Renewable Enabling Improvements are the responsibility of the distributor. Should the Board direct Horizon Utilities to implement the provisional direct benefits that were applied to Hydro One (6% for Renewable Enabling Improvements and 17% for Expansions), the costs to be recovered from provincial ratepayers would be as follows:

Costs Recovered from Provincial Ratepayers	2011	2012	2013	2014	2015
Expansions ($000s)	0	90	80	289	90
Renewable Enabling Improvements ($000s)	0	45	90	79	79
Total ($000s)	**0**	**135**	**170**	**368**	**169**
Percentage of Gross Cost (%)	0	13	14	27	15

c) Tables 12 through 17 have been recreated to include the provisional direct benefits that were applied to Hydro One (6% for Renewable Enabling Improvements and 17% for Expansions, as can be found in the Report of the Board [EB-2009-0349]).

Table 12

Residential Micro Solar PV (≤ 10 kW)	($000s)				
	2011	2012	2013	2014	2015
Gross Cost	49	49	49	49	49
Less Generator Contribution	49	49	49	49	49
Less Provincial Recovery - Expansion	0	0	0	0	0
Less Provincial Recovery - REI	0	0	0	0	0
Net Distributor Cost	0	0	0	0	0

Table 13

Commercial Micro Solar PV (≤ 10 kW)	($000s)				
	2011	2012	2013	2014	2015
Gross Cost	41	41	41	41	41
Less Generator Contribution	41	41	41	41	41
Less Provincial Recovery - Expansion	0	0	0	0	0
Less Provincial Recovery - REI	0	0	0	0	0
Net Distributor Cost	0	0	0	0	0

Table 14

Small Solar PV (>10 kW, ≤ 250 kW)	($000s)				
	2011	2012	2013	2014	2015
Gross Cost	32	254	390	216	216
Less Generator Contribution	32	170	270	156	156
Less Provincial Recovery - Expansion	0	40	40	0	0
Less Provincial Recovery - REI	0	34	68	56	56
Net Distributor Cost	0	10	12	4	4

Table 15

Small Solar PV (>250 kW, ≤ 500 kW)	($000s)				
	2011	2012	2013	2014	2015
Gross Cost	7	30	154	154	154
Less Generator Contribution	7	18	82	82	82
Less Provincial Recovery - Expansion	0	0	40	40	40
Less Provincial Recovery - REI	0	11	23	23	23
Net Distributor Cost	0	1	10	10	10

Table 16

Mid-sized Generation (up to 10 MW)	($000s)				
	2011	2012	2013	2014	2015
Gross Cost	78	648	588	888	648
Less Generator Contribution	78	588	588	588	588
Less Provincial Recovery - Expansion	0	50	0	249	50
Less Provincial Recovery - REI	0	0	0	0	0
Net Distributor Cost	0	10	0	51	10

Table 17

Renewable Connections - Capex	($000s)				
	2011	2012	2013	2014	2015
Gross Cost	207	1,022	1,221	1,347	1,107
Less Generator Contribution	207	866	1,029	915	915
Less Provincial Recovery - Expansion	0	90	80	289	90
Less Provincial Recovery - REI	0	45	90	79	79
Net Distributor Cost	0	21	22	64	23

EB-2010-0131

HORIZON UTILITIES CORPORATION (“HORIZON UTILITIES”)
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 37

Reference: E4/T2/S6/Appendix 4-3/page 34 Generation Capacity limits at Transformer Stations

Please provide the referenced e-mail correspondence between Hydro One and Horizon with respect to generation capacity limits at transformer stations.

Response:

The document is being provided in confidence for reasons which are outlined in the cover letter accompanying Horizon Utilities’ interrogatory responses.

EB-2010-0131

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 38

Reference: E4/T2/S6/Appendix 4-3/ page 39

OM&A: Dedicated full time equivalent engineer for connections process

Horizon indicates that a labour expense of $50,000 is expected in 2011 for the FTE engineer to manage the connections process. In 2012, $100,000 is allocated for the same FTE engineer.

a) For clarification purposes, is the $50,000 a reflection that Horizon intends to hire this employee by mid-year 2011? If not, please provide an explanation.

b) Does Horizon intend to hire the individual on a permanent or contract basis?

Response:

a) Horizon Utilities has forecasted $50,000 in 2011 and $100,000 in 2012 through 2015 for a full time equivalent engineer and consultant assistance. The $50,000 expenditure in 2011 is for consultant assistance. Horizon Utilities intends to hire the full time equivalent engineer in 2012.

b) Horizon Utilities intends to hire the full time equivalent engineer on a permanent basis.

EB-2010-0131

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 39

Reference: E4/T2/S6/Appendix 4-3/pages 41-42 – OM&A: Dedicated Full-Time Equivalents for Smart Grid Investigations

Horizon indicates that the costs of two dedicated full time equivalents and consultant support are included for Smart Grid Investigations.

a) Please indicate why the expected outlay in 2011 is $200,000, compared to $300,000 in 2012-2015. Is this the result of partial work years from these positions based on expected start date? If not, please provide an explanation.

b) Does Horizon intend to hire for these positions on a permanent or contract basis? If it is a contract will there be a competition held?

Response:

a) On Page 41 of the GEA Plan, in Exhibit 4, Tab 2, Schedule 6, Appendix 4-3, Horizon Utilities has stated that the operating expenditures are for two dedicated full time equivalents and consultant support. In 2011, Horizon Utilities intends to hire only one dedicated full time equivalent for the Smart Grid Investigations initiative. The rest of the operating expenditures in 2011 reflect consultant support. Horizon Utilities intends to hire the second dedicated full time equivalent in 2012.

b) Horizon Utilities intends to hire for the two full time equivalent positions on a permanent basis, with one in 2011 and the other in 2012 (as indicated in the response to question 39a).

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 40

Reference: Ref: E4/T2/S7 Regulatory Costs

Horizon states on page 1 that it "expects to incur $960,000 in costs in respect of the completion of the 2011 EDR COS application [i.e. this application] including its preparation and the proceeding that will follow." It states that it has included 1/3 of these costs in the 2010 bridge year and 2011 test year. The costs associated with this current application are identified as "one-time" costs.

In Table 4-10 of this exhibit, Horizon shows one-time costs in the 2011 test year of $10,000 for OEB Hearing Assessments, $135,000 for Legal Costs for Regulatory Matters, and $62,000 for intervenor costs. These costs would total $207,000, different than $320,000 (1/3 of $960,000).

a) Please provide a detailed breakdown of Horizon's expected regulatory costs associated with this proceeding, identifying separately: a) Board costs; b) Legal and Consulting fees; and c) intervenor costs.

b) Please reconcile Table 4-10 with the test on page 1 of E4/T2/S7, and clearly show how Horizon has proposed to allocate the costs between the 2010 bridge, 2011 test and 2012 years.

Response:

a) Please see below Horizon Utilities' expected regulatory costs associated with this proceeding.

Regulatory Cost Schedule	
Regulatory Cost Category	**Total**
Board Costs	50,000
Legal and Consulting Costs	724,000
Intervenor Costs	186,000
Total	960,000

b) Please see below Horizon Utilities' reconciliation of Table 4-10 on page 1 of Exhibit 4, Tab 2, Schedule 7.

Regulatory Cost Schedule								
Regulatory Cost Category	USoA Account	Ongoing or One Time Cost?	2008 Actuals	2009 Actuals	Bridge Year 2010	% Change in Bridge Year vs. Last Year of Actuals	Test Year 2011	% Change in Test Year vs. Bridge Year
1. OEB Annual Assessment	5655	Ongoing	553,296	627,630	665,000	6%	690,600	4%
2. OEB Hearing Assessments (applicant initiated)	5655	One time	19,650	15,000	20,000	25%	10,000	-100%
3. OEB Section 30 Costs (OEB initiated)	5655	Ongoing	8,039	32,166	25,000	-29%	10,000	-150%
4. Legal Costs for Regulatory Matters	5630	One time	253,826	75,668	135,000	44%	135,000	0%
5. Consultants Costs for Regulatory Matters	5630	Ongoing		-	91,000	100%	91,000	0%
6. Other costs for regulatory matters. (Z-factor Application, Lead/Lag Study)	5655/5630	One time		74,491	86,411			
7. Intervenor Costs	5655/5630	One time			62,000		62,000	
Total Regulatory Cost From Table 4-10					1,084,411		998,600	
Reconciliation								
Horizon 2011 COS Application (Board Costs)					20,000		10,000	
Horizon 2011 COS Application (Legal, Consulting and Lead/Lag Study)					272,000		226,000	
Horizon 2011 COS Application (Intervenor Costs)					62,000		62,000	
Subtotal					354,000		298,000	
Other Horizon Utilities Regulatory Costs					730,411		700,600	
Total					1,084,411		998,600	

Horizon Utilities' proposed allocation of costs between the 2010 bridge, 2011 test and 2012 years is provided below.

Regulatory Cost Schedule						
Regulatory Cost Category	**USoA Account**	**Ongoing or One Time Cost?**	**Bridge Year 2010**	**Test Year 2011**	**2012**	**Total**
Board Costs	5655	One time	20,000	10,000	20,000	50,000
Legal and Consulting Costs	5655	One time	272,000	226,000	226,000	724,000
Intervenor Costs	5630/5655	One time	62,000	62,000	62,000	186,000
Total			354,000	298,000	308,000	960,000

EB-2010-0131

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 41

Reference: E4/T2/S7 – 2014 Rebasing

On page 1 of this exhibit, Horizon states that it "is anticipating that it may be three years before its next cost of service distribution rate service application filing in 2013 for 2014 implementation."

The normal period between cost of service rebasing under the 3rd Generation IRM plan for electricity distributors is 4 years. Why does Horizon anticipate that it will be necessary for it to rebase within 3 years following this application?

Response:

In 2006, the Board established a multi-year Electricity Rate Setting Plan for the rate years 2008 to 2010, based on an assumption that all electricity distributors would be rebased over a three-year period (EB-2009-0028). It is on this basis that Horizon Utilities stated that "it is anticipating that its next cost of service distribution rate service application filing in 2013 for 2014 implementation."

However, in its communication to all licensed electricity distributors and to all other interested parties dated January 29, 2009 (attached), the Board stated that it "has decided to extend the number of years for rebasing to include 2010 and 2011 rate years" thereby extending the 3GIRM plan to a four year cycle.

Barring any unforeseen circumstances, Horizon Utilities anticipates that its next Cost of Service Application will be filed in 2014 for electricity distribution rates effective January 1, 2015.

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Ontario

BY E-MAIL AND WEB POSTING ONLY

January 29, 2009

To: **All Licensed Electricity Distributors**
All Other Interested Parties

Re: **Multi-year Electricity Distribution Rate Setting Plan**
Board File No.: EB-2009-0028

In 2006 the Board established a multi-year Electricity Rate Setting Plan for the rate years 2008 to 2010, based on an assumption that all electricity distributors would be rebased over a three-year period. In the interim, those not rebasing would stay on an incentive regulation plan (known as "2nd Generation IRM").

The Board has reviewed the process in light of the 2008 and 2009 rate applications experience and considered the views of stakeholders expressed to Board staff. The Board recognizes the cost of service process is effort intensive for applicants, the Board and intervenors. The Board has decided to extend the number of years for rebasing to include 2010 and 2011 rate years. In the interim those distributors whose rates have not been rebased will stay on 2nd Generation IRM until rebased.

The Board has considered previously stated preferences and applied the criteria set out in the Board's March 12, 2007 report entitled *LDC Screening Methodology to Establish a Rebasing Schedule for Electricity LDCs*, which is available from the Board's website at www.oeb.gov.on.ca. The criteria include financial attributes and other attributes such as the need for rate harmonization and issues arising from prior Board proceedings. The Board attaches as Schedules A and B preliminary lists for 2010 and 2011 and invites comment from interested parties.

All parties that wish to comment on Schedules A and B are requested to file a letter with the Board Secretary by **February 13, 2009**. Any distributor wishing to be considered in the alternate year should provide their reasons. The letter in the subject line should state **"2010-2011 Distributor Rebasing, Board File EB-2009-0028"**. Letters of comment will be posted on the Board's website. No costs will be awarded in respect of these submissions as the matters on which submissions may be made are not so complex as to warrant extensive work by interested parties. Upon considering the comments the Board will post the final lists on the Board's website by March 1, 2009. After publishing the final lists, the Board will provide direction to the distributors on the lists.

Yours truly,

Original singed by

Kirsten Walli
Board Secretary

Schedule A
Selection of Electricity Distributors for Rate Rebasing in 2010

1	Brant County Power Inc.
2	Burlington Hydro Inc.
3	Clinton Power Corporation
4	Essex Powerlines Corporation
5	Festival Hydro Inc.
6	Fort Frances Power Corporation
7	Haldimand County Hydro Inc.
8	Hearst Power Distribution Company Limited
9	Hydro Hawkesbury Inc.
10	Kenora Hydro Electric Corporation Ltd
11	North Bay Hydro Distribution Limited
12	Oakville Hydro Electricity Distribution Inc.
13	Orillia Power Distribution Corporation
14	Renfrew Hydro Inc.
15	Veridian Connections Inc.
16	Whitby Hydro Electric Corporation

Schedule B
Selection of Electricity Distributors for Rate Rebasing in 2011

1	Attawapiskat Power Corporation
2	Cambridge and North Dumfries Hydro Inc.
3	Chatham-Kent Hydro Inc.
4	Cooperative Hydro Embrun Inc.
5	Dutton Hydro Limited *
6	E.L.K. Energy Inc.
7	Fort Albany Power Corporation
8	Grimsby Power Incorporated
9	Hydro One Brampton Networks Inc.
10	Kashechewan Power Corporation
11	Kingston Electricity Distribution Limited
12	Kitchener-Wilmot Hydro Inc.
13	Middlesex Power Distribution Corporation *
14	Milton Hydro Distribution Inc.
15	Newbury Power Inc. *
16	Niagara Peninsula Energy Inc.
17	Orangeville/Grand Valley
18	Ottawa River Power Corporation
19	Parry Sound Power Corporation
20	St. Thomas Energy Inc.
21	Wasaga Distribution Inc.
22	Waterloo North Hydro Inc.
23	Woodstock Hydro Services Inc.

* Amalgamation proposal currently before the Board that could affect the year of rebasing.

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES") RESPONSES TO BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 42

Reference: E4/T2/S13 – Depreciation Expense

Section 2.1.2 of Chapter 2 of the *Board's Filing Requirements for Transmission and Distribution Applications*, updated and issued on June 28, 2010, states that data must be provided for:

- Test Year = Prospective Rate Year;
- Bridge Year = Current Year;
- Three Most Recent Historical Years (or number of years necessary to
- provide actuals back to and including the most recent Board Approved
- Test Year, but not less than three years);
- Most recent Board Approved Test Year.

Please provide tables showing depreciation expense, similar to tables 4-33, 4-34 and 4-35 for 2007 and 2008 actuals and for 2008 Board-Approved.

Response:

Horizon Utilities' Depreciation/Amortization/Depletion schedules for 2007 and 2008 actuals for 2008 Board Approved are set out in the tables below.

Horizon Utilities Corporation

Depreciation/Amortization/Depletion Schedule

2007 Actual

OEB	Asset Description	Opening Balance	Less: Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	Depreciation Expense
1805	Land - Substations	415,141.45	-	415,141.45	-	415,141.45	0		-
1808	Buildings - Substations	2,041,560.11	-	2,041,560.11	83,043.18	2,124,603.29	30	3.33%	78,908.04
1810	Leasehold Improvements	20,885.65	-	20,885.65	-	20,885.65	5	20.00%	-
1820	Substation Equipment	11,368,736.61	-	11,368,736.61	81,750.21	11,450,486.82	25	4.00%	316,778.35
1830	Poles, Towers & Fixtures	53,506,171.79	833,193.52	52,672,978.27	5,008,004.86	57,680,983.13	25	4.00%	2,204,464.39
1835	OH Conductors & Devices	64,925,060.74	908,466.50	64,016,594.24	2,880,569.45	66,897,163.69	25	4.00%	2,608,040.03
1840	UG Conduit	105,057,289.48	-	105,057,289.48	3,060,535.34	108,117,824.82	25	4.00%	4,142,187.33
1845	UG Conductors & Devices	100,790,475.32	-	100,790,475.32	4,984,166.45	105,774,641.77	25	4.00%	3,929,617.24
1850	Line Transformers	82,395,993.49	-	82,395,993.49	3,262,931.70	85,658,925.19	25	4.00%	3,198,310.24
1855	Services (OH & UG)	19,804,746.13	319,988.36	19,484,757.77	1,497,253.21	20,982,010.98	25	4.00%	876,487.96
1860	Meters	30,725,884.22	-	30,725,884.22	1,178,884.45	31,904,768.67	25	4.00%	1,206,773.43
1860	Smart Meters	-	-	-	-	-	25	4.00%	0.00
1905	Land	1,078,176.33	10,546.92	1,067,629.41	(0.00)	1,067,629.41	0		-
1906	Land Rights	144,877.41	-	144,877.41	12,668.30	157,545.71	50	2.00%	3,370.24
1908	Buildings & Fixtures	23,512,923.45	-	23,512,923.45	3,314,802.52	26,827,725.97	30	3.33%	982,267.52
1910	Leasehold Improvements	-	-	-	-	-	5	20.00%	-
1915	Office Furniture & Equipment	3,785,800.77	-	3,785,800.77	318,709.10	4,104,509.87	10	10.00%	153,296.30
1920	Computer - Hardware	5,613,068.40	-	5,613,068.40	-	5,613,068.40	5	20.00%	96,920.81
1920	Computer - Hardware post Mar 22/04	1,066,300.49	-	1,066,300.49	634,391.30	1,700,691.79	5	20.00%	298,023.13
1925	Computer - Software	4,358,908.62	-	4,358,908.62	383,480.96	4,742,389.58	3	33.33%	279,482.37
1930	Transportation Equipment	15,617,084.67	948,694.86	14,668,389.81	1,907,548.52	16,575,938.33	8	12.50%	1,021,865.13
1935	Stores Equipment	508,476.86	-	508,476.86	4,648.00	513,124.86	10	10.00%	13,507.56
1940	Tools, Shop & Garage Equipment	6,332,026.22	-	6,332,026.22	351,278.27	6,683,304.49	10	10.00%	305,555.70
1945	Measurement & Testing Equipment	1,176,326.05	-	1,176,326.05	134,323.33	1,310,649.38	10	10.00%	78,399.07
1950	Power operated Equipment	144,034.63	-	144,034.63	-	144,034.63	10	10.00%	17,496.53
1955	Communications Equipment	890,155.93	-	890,155.93	375,276.18	1,265,432.11	10	10.00%	107,162.94
1960	Load Management controls	192,511.50	-	192,511.50	322,818.49	515,329.99	10	10.00%	45,574.45
1980	System Supervisory Equipment	3,302,877.86	-	3,302,877.86	13,060.84	3,315,938.70	25	4.00%	166,544.82
1995	Hydro One S/S Contribution	3,396,683.12	-	3,396,683.12	-	3,396,683.12	25	4.00%	136,119.67
1995	Contributions & Grants	(13,924,030.93)	-	(13,924,030.93)	(3,401,684.06)	(17,325,714.99)	25	4.00%	(499,009.59)
2105	Sub-Total	528,248,146.37	3,020,890.16	525,227,256.21	26,408,460.60	551,635,716.81			21,768,143.64
								Less Fleet	1,021,865.13
								Less Stores	13,507.56
								Net Depreciation	20,732,770.95

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Horizon Utilities Corporation

Depreciation/Amortization/Depletion Schedule

2008 Actual

OEB	Asset Description	Opening Balance	Less: Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	Depreciation Expense
1805	Land - Substations	415,141.45	400.00	414,741.45	-	414,741.45	0		-
1808	Buildings - Substations	2,124,603.29	-	2,124,603.29	9,963.94	2,134,567.23	30	3.33%	87,205.45
1810	Leasehold Improvements	20,885.65	-	20,885.65	-	20,885.65	5	20.00%	0.04
1820	Substation Equipment	11,450,486.82	-	11,450,486.82	17,445.80	11,467,932.62	25	4.00%	317,917.38
1830	Poles, Towers & Fixtures	57,680,983.13	262,994.11	57,417,989.02	5,694,014.88	63,112,003.90	25	4.00%	2,401,768.96
1835	OH Conductors & Devices	66,897,163.69	1,646,724.26	65,250,439.43	2,763,187.63	68,013,627.06	25	4.00%	2,690,818.08
1840	UG Conduit	108,117,824.82	197,612.67	107,920,212.15	2,821,545.28	110,741,757.43	25	4.00%	4,302,973.50
1845	UG Conductors & Devices	105,774,641.77	91.01	105,774,550.76	5,901,654.92	111,676,205.68	25	4.00%	4,140,422.18
1850	Line Transformers	85,658,925.19	1,465,067.80	84,193,857.39	4,234,436.60	88,428,293.99	25	4.00%	3,412,762.41
1855	Services (OH & UG)	20,982,010.98	351,096.27	20,630,914.71	1,789,580.36	22,420,495.07	25	4.00%	994,287.38
1860	Meters	31,904,768.67	-	31,904,768.67	5,403,195.52	37,307,964.19	25	4.00%	1,377,635.23
1860	Smart Meters	-	-	-	-	-	25	4.00%	-
1905	Land	1,067,629.41	-	1,067,629.41	-	1,067,629.41	0		-
1906	Land Rights	157,545.71	-	157,545.71	5,090.67	162,636.38	50	2.00%	4,083.02
1908	Buildings & Fixtures	26,827,725.97	-	26,827,725.97	526,308.89	27,354,034.86	30	3.33%	1,221,094.04
1910	Leasehold Improvements	-	-	-	-	-	5	20.00%	-
1915	Office Furniture & Equipment	4,104,509.87	-	4,104,509.87	288,038.22	4,392,548.09	10	10.00%	184,136.03
1920	Computer - Hardware	5,613,068.40	-	5,613,068.40	-	5,613,068.40	5	20.00%	36,136.68
1920	Computer - Hardware post Mar 22/04	1,700,691.79	-	1,700,691.79	917,963.04	2,618,654.83	5	20.00%	442,876.11
1925	Computer - Software	4,742,389.58	-	4,742,389.58	5,515,242.79	10,257,632.37	3	33.33%	732,796.53
1930	Transportation Equipment	16,575,938.33	599,815.44	15,976,122.89	1,740,111.93	17,716,234.82	8	12.50%	1,361,868.05
1935	Stores Equipment	513,124.86	-	513,124.86	267,944.45	781,069.31	10	10.00%	10,978.47
1940	Tools, Shop & Garage Equipment	6,683,304.49	-	6,683,304.49	337,441.19	7,020,745.68	10	10.00%	298,562.35
1945	Measurement & Testing Equipment	1,310,649.38	-	1,310,649.38	79,305.13	1,389,954.51	10	10.00%	76,726.93
1950	Power operated Equipment	144,034.63	-	144,034.63	-	144,034.63	10	10.00%	13,021.50
1955	Communications Equipment	1,265,432.11	-	1,265,432.11	45,164.15	1,310,596.26	10	10.00%	120,503.07
1960	Load Management controls	515,329.99	-	515,329.99	-	515,329.99	10	10.00%	51,533.01
1980	System Supervisory Equipment	3,315,938.70	-	3,315,938.70	-	3,315,938.70	25	4.00%	109,479.55
1995	Hydro One S/S Contribution	3,396,683.12	-	3,396,683.12	2,289,371.43	5,686,054.55	25	4.00%	150,555.32
1995	Contributions & Grants	(17,325,714.99)	-	(17,325,714.99)	(6,197,958.07)	(23,523,673.06)	25	4.00%	(773,620.40)
2105	Sub-Total	551,635,716.81	4,523,801.56	547,111,915.25	34,449,048.75	581,560,964.00			23,766,520.88
								Less Fleet	1,361,868.05
								Less Stores	10,978.47
								Net Depreciation	22,393,674.36

Horizon Utilities Corporation

Depreciation/Amortization/Depletion Schedule

2008 Board Approved

OEB	Asset Description	Opening Balance	Less: Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	Depreciation Expense
1805	Land - Substations	415,141.45	-	415,141.45	-	415,141.45	0		-
1808	Buildings - Substations	2,173,768.11	-	2,173,768.11	185,530.00	2,359,298.11	30	3.33%	79,733.00
1810	Leasehold Improvements	20,885.65	-	20,885.65	-	20,885.65	5	20.00%	3,068.00
1820	Substation Equipment	11,458,083.61	-	11,458,083.61	16,533.00	11,474,616.61	25	4.00%	319,756.00
1830	Poles, Towers & Fixtures	59,658,137.79	908,758.90	58,749,378.89	7,019,043.00	65,768,421.89	25	4.00%	2,518,493.00
1835	OH Conductors & Devices	66,688,238.35	1,089,058.76	65,599,179.59	1,754,856.00	67,354,035.59	25	4.00%	2,658,645.00
1840	UG Conduit	108,067,770.48	-	108,067,770.48	3,883,844.00	111,951,614.48	25	4.00%	4,275,212.00
1845	UG Conductors & Devices	105,192,009.32	-	105,192,009.32	5,421,970.00	110,613,979.32	25	4.00%	4,117,087.00
1850	Line Transformers	87,312,867.49	1,038,320.79	86,274,546.70	5,558,831.00	91,833,377.70	25	4.00%	3,461,162.00
1855	Services (OH & UG)	20,277,797.77	333,525.85	19,944,271.92	1,240,253.00	21,184,524.92	25	4.00%	905,432.08
1860	Meters	32,451,648.50	-	32,451,648.50	2,419,914.00	34,871,562.50	25	4.00%	1,329,143.84
1860	Smart Meters	-	-	-	-	-	25	4.00%	-
1905	Land	1,078,176.33	-	1,078,176.33	-	1,078,176.33	0		-
1906	Land Rights	144,877.41	-	144,877.41	24,000.00	168,877.41	50	2.00%	3,669.00
1908	Buildings & Fixtures	26,336,779.45	-	26,336,779.45	492,000.00	26,828,779.45	30	3.33%	1,182,312.00
1910	Leasehold Improvements	-	-	-	-	-	5	20.00%	-
1915	Office Furniture & Equipment	4,316,200.77	-	4,316,200.77	203,880.00	4,520,080.77	10	10.00%	199,543.00
1920	Computer - Hardware	5,613,068.40	-	5,613,068.40	-	5,613,068.40	5	20.00%	718,437.60
1920	Computer - Hardware post Mar 22/04	1,840,015.49	-	1,840,015.49	1,221,721.00	3,061,736.49	5	20.00%	
1925	Computer - Software	4,769,288.62	-	4,769,288.62	4,147,715.00	8,917,003.62	3	33.33%	953,852.00
1930	Transportation Equipment	16,803,108.96	-	16,803,108.96	1,904,733.00	18,707,841.96	8	12.50%	1,195,680.00
1935	Stores Equipment	517,976.86	-	517,976.86	184,350.00	702,326.86	10	10.00%	23,232.00
1940	Tools, Shop & Garage Equipment	6,782,976.22	-	6,782,976.22	277,529.00	7,060,505.22	10	10.00%	313,174.15
1945	Measurement & Testing Equipment	1,328,930.05	-	1,328,930.05	110,604.00	1,439,534.05	10	10.00%	90,292.00
1950	Power operated Equipment	144,034.63	-	144,034.63	-	144,034.63	10	10.00%	18,043.00
1955	Communications Equipment	1,359,125.93	-	1,359,125.93	242,506.00	1,601,631.93	10	10.00%	141,213.00
1960	Load Management controls	192,512.00	-	192,512.00	-	192,512.00	10	10.00%	44,760.00
1980	System Supervisory Equipment	3,350,877.86	-	3,350,877.86	-	3,350,877.86	25	4.00%	111,433.00
1995	Hydro One S/S Contribution	3,396,683.12	-	3,396,683.12	-	3,396,683.12	25	4.00%	135,867.00
1995	Contributions & Grants	(16,779,022.93)	-	(16,779,022.93)	(3,329,432.00)	(20,108,454.93)	25	4.00%	(739,443.00)
2105	Sub-Total	554,911,957.69	3,369,664.30	551,542,293.39	32,980,380.00	584,522,673.39			24,059,796.67
								Less Fleet	1,195,680.00
								Less Stores	23,232.00
								Net Depreciation	22,840,884.67

HORIZON UTILITIES CORPORATION (“HORIZON UTILITIES”)
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 43

Reference: E4/T3/S2 – Taxes and PILs

Please provide tables similar to Table 4-37 showing the detailed tax calculations for actual Property, Capital and Income Taxes paid for: 2008 Board-approved and for each of 2007, 2008 and 2009 Actuals.

Response:

Please see the tables below showing detailed calculations for actual Property, Capital and Income Taxes paid for 2008 Board-approved and for each of 2007,2008 and 2009 actuals.

2009 Capital Taxes		
Description	OCT	LCT
Total Rate Base	334,507,686	334,507,686
Exemption	13,141,245	0
Deemed Taxable Capital	321,366,441	334,507,686
Rate	0.2250%	0.00%
Gross Tax Payable	723,074	0
Surtax	0	0
Net Capital Tax Payable	723,074	0
2009 Property Taxes	$713,583	

2009 PILs Schedule	
Description	Tax Payable
Accounting Income	13,242,451
Tax Adj to Accounting Income	5,337,794
Taxable Income	18,580,245
Combined Income Tax Rate	33.07%
Total Income Taxes	6,143,931
Investment Tax Credits	0
Apprentice Tax Credits	69,631
Other Tax Credits	3,000
Dividend Refund	21,194
Total PILs	6,050,106

2009 Total Taxes	
Description	Tax Payable
Total PILs	6,050,106
Net Capital Tax Payable	723,074
PILs including Capital Taxes	6,773,180
Regulatory Adjustments	1,277,180
PILs for Regulatory Purposes	5,496,000

2008 Capital Taxes		
Description	OCT	LCT
Total Rate Base	319,804,895	319,804,895
Exemption	13,000,645	0
Deemed Taxable Capital	306,804,250	319,804,895
Rate	0.2250%	0.00%
Gross Tax Payable	690,310	0
Surtax	0	0
Net Capital Tax Payable	690,310	0
2008 Property Taxes	$774,572	

2008 PILs Schedule	
Description	Tax Payable
Accounting Income	15,215,803
Tax Adj to Accounting Income	5,784,027
Taxable Income	20,999,830
Combined Income Tax Rate	33.64%
Total Income Taxes	7,064,632
Investment Tax Credits	0
Apprentice Tax Credits	47,000
Other Tax Credits	0
Dividend Refund	52,201
Total PILs	6,965,431

2008 Total Taxes	
Description	Tax Payable
Total PILs	6,965,431
Net Capital Tax Payable	690,310
PILs including Capital Taxes	7,655,741
Regulatory Adjustments	1,430,741
PILs for Regulatory Purposes	6,225,000

Board Approved								
2008 Capital Taxes				2008 PILs Schedule			2008 Total Taxes	
Description	OCT	LCT		Description	Tax Payable		Description	Tax Payable
Total Rate Base	346,420,224	0		Accounting Income	11,563,269		Total PILs	3,873,695
Exemption	15,000,000	0		Tax Adj to Accounting Income	0		Net Capital Tax Payable	745,696
Deemed Taxable Capital	331,420,224	0		Taxable Income	11,563,269		PILs including Capital Taxes	4,619,391
Rate	0.2250%	0.00%		Combined Income Tax Rate	33.50%			
Gross Tax Payable	745,696	0		Total Income Taxes	3,873,695			
Surtax	0	0		Investment Tax Credits	0			
Net Capital Tax Payable	745,696	0		Apprentice Tax Credits	0			
				Other Tax Credits	0			
				Dividend Refund	0			
				Total PILs	3,873,695			
Property Taxes	Property taxes were not specifically approved but formed part of OM&A expenses.							

2007 Capital Taxes				2007 PILs Schedule			2007 Total Taxes	
Description	OCT	LCT		Description	Tax Payable		Description	Tax Payable
Total Rate Base	0	0		Accounting Income	0		Total PILs	0
Exemption	0	0		Tax Adj to Accounting Income	0		Net Capital Tax Payable	0
Deemed Taxable Capital	0	0		Taxable Income	0		PILs including Capital Taxes	0
Rate	0.2250%	0.00%		Combined Income Tax Rate	#DIV/0!			
Gross Tax Payable	0	0		Total Income Taxes	0			
Surtax	0	0		Investment Tax Credits	0			
Net Capital Tax Payable	0	0		Apprentice Tax Credits	0			
				Other Tax Credits	0			
				Dividend Refund	0			
				Total PILs	0			
2007 Property Taxes	**$769,303**							

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HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 44

Reference: E5/T1/S2 – Deemed Capital Structure and Cost of Capital

In Table 5-2 of 5/T1/S2, Horizon shows a deemed capital structure of 60% long-term debt and 40% equity, with a long-term debt rate of 6.10% and a return on equity (ROE) of 9.00%.

a) Please confirm that the Board-approved deemed capital structure for Horizon for the 2008 test year was 56% long-term debt, 4% short-term debt and 40% equity, with approved rates of 6.10% for long-term, 1.33% short-term and 8.57% for ROE in Horizon's 2008 Cost of Service rebasing application, considered under Board File No. EB-2007-0697.

b) Please explain the deemed capital structure and rates shown for 2008 and 2009 in Table 5-2.

c) As necessary please update Table 5-2 to show the deemed capital structure and rates consistent with the Board's Decision and Order in EB-2007-0697.

Response:

a) Horizon Utilities confirms that the Board-approved deemed 2008 Capital Structure is 56% long-term debt, 4% short-term debt and 40% equity, with approved rates of 6.10% for long-term debt, and 8.57% for ROE. The short-term rate of 1.33% as noted in the question is not correct. The correct short-term rate is 4.47% as per the Decision with Reasons EB-2007-0697 page 24.

b) Horizon Utilities used the deemed capital structure and rates for 2008 and 2009 using prior information. The restated tables are included in the answer to part c) of this Interrogatory.

c) Please see Table 5-2 below updated to show the deemed capital structure and rates consistent with the Board's Decision and Order in EB-2007-0697. The tables for 2010 and 2011 remain unchanged but are included for information purposes.

Deemed Capital Structure for 2007

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	201,664,675	60.00%	6.10%	12,301,545
Short Term Debt				
Total Debt	201,664,675	60.00%		12,301,545
Common Share Equity	134,443,116	40.00%	9.00%	12,099,880
Total equity	134,443,116	40.00%		12,099,880
Total Rate Base	336,107,791	100.00%	7.26%	24,401,426

Board Approved Deemed Capital Structure for 2008

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	193,995,325	56.00%	6.10%	11,833,715
Short Term Debt	13,856,809	4.00%	4.47%	619,399
Total Debt	207,852,134	60.00%		12,453,114
Common Share Equity	138,568,090	40.00%	8.57%	11,875,285
Total equity	138,568,090	40.00%		11,875,285
Total Rate Base	346,420,224	100.00%	7.02%	24,328,400

Deemed Capital Structure for 2008

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	191,135,083	56.00%	6.10%	11,659,240
Short Term Debt	13,652,506	4.00%	4.47%	610,267
Total Debt	204,787,589	60.00%		12,269,507
Common Share Equity	136,525,059	40.00%	8.57%	11,700,198
Total equity	136,525,059	40.00%		11,700,198
Total Rate Base	341,312,648	100.00%	7.02%	23,969,705

Deemed Capital Structure for 2009

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	196,656,754	56.00%	6.10%	11,996,062
Short Term Debt	14,046,911	4.00%	4.47%	627,897
Total Debt	210,703,665	60.00%		12,623,959
Common Share Equity	140,469,110	40.00%	8.57%	12,038,203
Total equity	140,469,110	40.00%		12,038,203
Total Rate Base	351,172,775	100.00%	7.02%	24,662,162

Deemed Capital Structure for 2010

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	206,732,160	56.00%	5.85%	12,093,831
Short Term Debt	14,766,583	4.00%	2.07%	305,668
Total Debt	221,498,743	60.00%		12,399,500
Common Share Equity	147,665,828	40.00%	9.85%	14,545,084
Total equity	147,665,828	40.00%		14,545,084
Total Rate Base	369,164,571	100.00%	7.30%	26,944,584

Deemed Capital Structure for 2011

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	211,058,415	56.00%	5.80%	12,241,388
Short Term Debt	15,075,601	4.00%	2.07%	312,065
Total Debt	226,134,016	60.00%		12,553,453
Common Share Equity	150,756,010	40.00%	9.85%	14,849,467
Total equity	150,756,010	40.00%		14,849,467
Total Rate Base	376,890,026	100.00%	7.27%	27,402,920

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 45

Reference: E7/T1/S1/Table 7-1 Cost Allocation

Board staff has replicated Table 7-1 below:

Revenue-to-Cost Ratios

Customer Class	OEB Range Low	OEB Range High	2008 Board Approved	2009 and 2010 Actual	2011 Cost Allocation	2011 Proposed
Residential	85.00%	115.00%	111.60%	106.40%	110.20%	104.00%
General Service < 50	80.00%	120.00%	92.50%	88.10%	102.70%	102.70%
General Service >50	80.00%	180.00%	86.30%	98.00%	85.10%	91.30%
Large Use	85.00%	115.00%	92.10%	95.20%	68.60%	91.30%
Street Lighting	70.00%	120.00%	43.00%	70.00%	61.90%	91.30%
Sentinel	70.00%	120.00%	70.00%	72.30%	75.10%	91.30%
Unmetered Scattered Load	80.00%	120.00%	80.00%	62.00%	129.00%	120.00%
Standby Power	n/a	n/a	65.80%	65.80%	79.80%	91.30%

Source: E7/T1/S1/Table 7-1

a) Please provide a detailed description of why the revenue-to-cost (R/C) ratio for Unmetered Scattered Load has changed from being significantly below 100% to significantly above 100% between the 2008 and 2011 Cost Allocation studies.

b) What is the basis for the proposed R/C ratio of 91.30% for GS > 50kW, Large Use, Streetlighting, Sentinel lighting and Standby Power?

Response:

a) The 2008 revenue-to-cost ratio for Unmetered Scattered Load ("USL") was based on the original cost allocation study filed with the Board on March 30, 2007. In this study, the weather normalized load forecast for USL was 19,513,517 (kWh) for 3,169 USL connections or 6,158 kWh per connection. In the 2011 revised cost allocation study, the weather normalized load forecast for USL is 12,541,586 (kWh) for 3,228 USL connections or 3,886 kWh per connection. This 37% decline in usage per connection reflects actual historical usage data from 2004 to 2009 and has been included in the 2011 load forecast for USL. The load forecast for USL directly impacts the demand level assumed in the cost allocation study for the USL class. The level of demand is one of the main cost drivers in the cost allocation study. A 37% decline in the usage per connection translates into a significant reduction in the demand cost driver. Therefore, on a relative basis, demand cost allocated to the USL should be reduced by approximately 37%. Such reduction causes the revenue to cost ratio for USL, which was below 100% in 2008, to be above 100% in the 2011 cost allocation study.

b) Exhibit 7, Tab 1, Schedule 2, Page 4, lines 1 to 5 states:

"*Consistent with the approach to cost allocation approved by the Board in its 2008 EDR COS Application, Horizon Utilities submits that is just and reasonable to adjust it revenue to cost ratios, as proposed in Table 7-13 above, which more fairly allocates the recovery of its distribution costs among rate classes and continues to bring the revenue to cost ratios closer to parity*"

In order to implement the above position, Horizon Utilities reduced the revenue to cost ratio for the Residential class from 110.2% to 104%. In addition, the revenue to cost ratio for the USL class was reduced from 129% to 120% in order for this class to be within the Board target range. Consequently, and in order to maintain revenue neutrality, those classes that had revenue to cost ratios of less than 100% were increased to 91.3%.

**HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES**

DELIVERED: January 24th, 2011

Question 46

Reference: E7/T1/S1 – Cost Allocation

On page 3 of E7/T1/S1, Horizon states:

> "Horizon Utilities submits that a managed transition towards 100% revenue to cost ratios for rate classifications continues to be fair and reasonable for the following reasons:
>
> - Customer class revenues will more closely reflect the actual costs of providing distribution service to that class;
> - Rate impacts on total bill will be mitigated for certain classes; and
> - Partial reallocation provides time for further refinement of the cost allocation model and movement between classes."

As noted in Board staff IR # 44, Table 7-1 shows some volatility in the R/C ratios for some customer classes between the 2008 and 2011 Cost Allocation studies. Cost allocation is not an exact methodology, and the data used in the study is not perfect in many respects. The Board's guidelines state that R/C ratios within the range (i.e. between the high and low thresholds) may be equally valid. However, Horizon is proposing further movement towards unity (R/C ratio = 100%). Please provide further explanation, with supporting evidence, for Horizon's proposal that "further movement towards unity" is necessary given that there will be some volatility in the results of any cost allocation study based on a given set of historical data and that the Board in previous rate decisions has been satisfied when the R/C ratios are within their applicable ranges.

Response:

In this Application, Horizon Utilities has updated its cost allocation study to reflect test year data, which means the study is no longer based on a given set of historical data. In Horizon Utilities' view, a cost allocation study that is run on a test year basis increases the accuracy of the study. In addition, as outlined in response to Board staff Interrogatory 45b), consistent with the approach to cost allocation approved by the Board in its 2008 EDR COS Application, Horizon Utilities submits that is equitable across ratepayer classes to adjust its revenue to cost ratios in a manner that more fairly allocates the recovery of its distribution costs among rate classes and continues to bring the revenue to cost ratios closer to unity.

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 47

Reference: E8/T1/S1/Tables 8-6 and 8-7 Fixed/Variable Charges

Board staff has prepared the following table comparing the current and proposed fixed charge split for all customer classes based on the information shown in Tables 8-6 and 8-7

Customer Class	Current Fixed Charge Split	Proposed Fixed Charge Split
Residential	62.3%	62.32%
GS < 50 kW	59.8%	59.78%
GS > 50 kW	49.4%	49.40%
Large Use	34.3%	49.40%
Sentinel Lights	60.7%	60.66%
Streetlighting	67.9%	67.91%
Unmetered Scattered Load	66.7%	66.68%
Standby Power	0.0%	0.0%

In E8/T1/S1/pp. 5-8, Horizon provides its reasons for proposing the increase of the fixed charge split from 34.3% to 49.4% for the Large Use class, to equate it with the GS > 50 kW class.

a) Did Horizon examine the fixed/variable split for the Large Use class for other large Ontario distributors (e.g. Toronto Hydro-Electric System Limited, Enersource Hydro Mississauga, PowerStream, etc.)

i. If yes, please provide the results of such analysis.

ii. If no, why not?

b) Please provide any empirical data or analysis that Horizon has done or is aware of to support its proposal that the fixed charge revenue split for the Large Use and GS > 50 kW classes should be equal.

c) Please provide the bill impacts, for the largest and smallest consumption Large Use customers, in the bill impact format shown in Appendix 8-1.

Response:

a) No, Horizon Utilities did not examine the fixed/variable split for the Large Use class for other large Ontario distributors (e.g. Toronto Hydro-Electric System Limited, Enersource Hydro Mississauga, PowerStream). Horizon Utilities' submits its distinctiveness from other large Ontario distributors with respect to the composition and level of volume risk associated with the Large Use class, as Horizon Utilities has experienced in recent years. At Exhibit 1, Tab 2, Schedule 1, pages 2 and 3 of its Application, Horizon Utilities discusses several features that distinguish it from other Ontario distributors. In part, Horizon Utilities states:

> "The electricity sector in Ontario currently comprises approximately 80 Local Electricity Distribution Companies ("LDCs") that share similar service offerings and customer classes. However, many possess distinct operational and service territory-related attributes. In this regard, Horizon Utilities has many unique features compared to most other LDCs.
>
> …
>
> Horizon Utilities' service territory covers two of Ontario's most industrial cities: Hamilton and St. Catharines. Horizon Utilities' customer and load profiles differ from those of other LDCs because of the extent of Horizon Utilities' industrial load. Only 30 of Ontario's 80 LDCs have customers in the "Large Use" category and the average number of Large Users for such 30 LDCs is six and the median is three. Horizon Utilities has twelve Large Use customers. While two LDCs have more Large Use customers, Horizon Utilities has the largest average Large Use customer consumption (kWh) of any LDC. The average consumption of all Ontario large users 13 is 48,289,486 kWh (as of 2008), but the average consumption of Horizon Utilities' Large Use customer class is three times greater at 145,665,275 kWh and the next highest average Large Use consumption is just over 100,000,000 kWh annually[1]. Consequently, Horizon Utilities also bears the

[1] Horizon Utilities' number is actually much higher however the OEB yearbook does not include

largest concentration risk with respect to Large Use customers with related revenue and credit loss risks. Horizon Utilities experiences a greater level of exposure to adverse economic conditions compared to other LDCs, and certainly more so than most suburban LDCs, which are generally servicing a more diverse customer base."

b) Horizon Utilities does not have any empirical data nor does it have analysis to support its proposal that the fixed charge revenue split for the Large Use and GS > 50 kW classes should be equal. However, as noted in Horizon Utilities' response to Board Staff Interrogatory #15, above, in rejecting Horizon Utilities' Z-Factor Application, the Board wrote:

> "…Horizon has not demonstrated that the revenue losses experienced are an event genuinely external to the regulatory regime for which the management of the Applicant could not plan and budget, and thus has failed to establish that a Z-factor event has occurred." (at page 9)

The Board's expectation appears to be that utilities plan for such revenue volatility, and Horizon Utilities submits that an increase in the fixed component of the distribution charge can assist a utility in addressing the likelihood of ongoing revenue volatility.

With the Board's denial of Horizon Utilities' Z-factor application, Horizon Utilities reviewed alternatives that would assist it in better managing the volume risk associated with Large Use customers. At Exhibit 8; Tab 1; Schedule 1; Page 6 of 12, Horizon Utilities submits that the costs of providing distribution services are, for the most part, fixed, regardless of the level of consumption/demand, and that large declines in distribution revenue can result from significant reductions in commercial consumption when a significant component of such are recovered through a volumetric rate component (see also Horizon Utilities' Z-factor Oral Hearing transcript, January 28, 2010, p 66, line 27 – p.67, line 7).

As a result, Horizon Utilities considered proposing a 100% fixed charge in order to address the volume risk. Horizon Utilities submits there is support for such a position based on a statement that "The cost of energy distribution and customer care is driven,

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consumption of Wholesale Market Participants.

in the short run, chiefly by customer growth and is largely fixed with respect to system use." (p.iii, paragraph 2) from the Executive Summary on the Review of Distribution Revenue Decoupling Mechanisms, commissioned by the Board and undertaken by Pacific Economics Group. In order to address the volume risk associated with the Large Use class Horizon Utilities considered:

- a 100% fixed charge;
- a fixed charge that reflected the rate class with the highest proportion of fixed costs;
- a fixed charge that reflected the average proportion of fixed costs over all the rate classes, and;
- a fixed charge that reflected the rate class with the lowest proportion of fixed costs.

In order to reasonably balance the need to provide greater certainty of recovery of Horizon Utilities' cost of providing service to its Large Use customers while maintaining opportunities to reduce the distribution component of their electricity bills through efficiency improvements and demand management activities, Horizon Utilities proposes to move the fixed/variable split for the Large Use customer class to the same proportions as the General Service < 50 kW customer class which is the rate class with the next lowest proportion of fixed costs.

This notwithstanding, Horizon Utilities submits that this proposal leaves the utility and its customers with disproportionate risk with respect to revenue volatility and that the fixed component should be much higher still.

c) Horizon Utilities has provided the bill impacts, for the largest and smallest consumption Large Use customers, in the bill impact format shown in Appendix 8-1.

LARGE USER (> 5000 KW)

Largest Consumption

Consumption
37,529,632 kWh
64,673 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			11,151.32			26,699.15	15,547.83	139.43%	0.76%
Distribution (kW)	64,673	1.0123	65,468.48	64,673	1.2933	83,641.59	18,173.11	27.76%	2.40%
Low Voltage Rider (kW)	64,673	0.014	905.42	64,673	0.019320	1,249.48	344.06	38.00%	0.04%
Smart Meter Rider (per month)			1.56			1.56	0.00	0.00%	0.00%
LRAM & SSM Rider (kW)	64,673		0.00	64,673	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	37,529,632	0.0000	0.00	37,529,632	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW)	64,673	(0.6827)	-44,152.26	64,673	(0.6020)	(38,933.15)	5,219.11	(11.82%)	(1.12%)
Distribution Sub-Total			**33,374.52**			**72,658.64**	**39,284.11**	**117.71%**	**2.08%**
Retail Transmisssion (kW)	64,673	4.3886	283,823.93	64,673	4.409	285,143.26	1,319.33	0.46%	8.17%
Delivery Sub-Total			**317,198.45**			**357,801.89**	**40,603.44**	**12.80%**	**10.25%**
Other Charges (kWh)	37,781,080	0.0072	272,023.78	37,822,363	0.0072	272,321.01	297.23	0.11%	7.80%
Cost of Power Commodity (kWh)	37,781,080	0.0650	2,455,770.20	37,822,363	0.0650	2,458,453.57	2,683.37	0.11%	70.44%
SPC (kWh)	37,781,080	0.0003725	14,073.45	37,781,080	0.0000000	0.00	(14,073.45)	(100.00%)	0.00%
Total Bill Before Taxes			**3,059,065.88**			**3,088,576.48**	**29,510.59**	**0.96%**	**88.50%**
HST		13.00%	397,678.56		13.00%	401,514.94	3,836.38	0.96%	11.50%
Total Bill			**3,456,744.45**			**3,490,091.42**	**33,346.97**	**0.96%**	**100.00%**

LARGE USER (> 5000 KW)

Smallest Consumption

Consumption
3,672,395 kWh
5,886 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			11,151.32			26,699.15	15,547.83	139.43%	7.29%
Distribution (kW)	5,886	1.0123	5,958.40	5,886	1.2933	7,612.36	1,653.97	27.76%	2.08%
Low Voltage Rider (kW)	5,886	0.014	82.40	5,886	0.019320	113.72	31.31	38.00%	0.03%
Smart Meter Rider (per month)			1.56			1.56	0.00	0.00%	0.00%
LRAM & SSM Rider (kW)	5,886		0.00	5,886	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	3,672,395	0.0000	0.00	3,672,395	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW)	5,886	(0.6827)	-4,018.37	5,886	(0.6020)	(3,543.37)	475.00	(11.82%)	(0.97%)
Distribution Sub-Total			**13,175.31**			**30,883.42**	**17,708.11**	**134.40%**	**8.43%**
Retail Transmisssion (kW)	5,886	4.3886	25,831.30	5,886	4.409	25,951.37	120.07	0.46%	7.09%
Delivery Sub-Total			**39,006.61**			**56,834.79**	**17,828.18**	**45.71%**	**15.52%**
Other Charges (kWh)	3,697,000	0.0072	26,618.40	3,701,039	0.0072	26,647.48	29.09	0.11%	7.28%
Cost of Power Commodity (kWh)	3,697,000	0.0650	240,304.99	3,701,039	0.0650	240,567.56	262.58	0.11%	65.70%
SPC (kWh)	3,697,000	0.0003725	1,377.13	3,697,000	0.0000000	0.00	(1,377.13)	(100.00%)	0.00%
Total Bill Before Taxes			**307,307.13**			**324,049.84**	**16,742.71**	**5.45%**	**88.50%**
HST		13.00%	39,949.93		13.00%	42,126.48	2,176.55	5.45%	11.50%
Total Bill			**347,257.05**			**366,176.32**	**18,919.27**	**5.45%**	**100.00%**

EB-2010-0131

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 48

Reference: E8/T1/S3/Table 8-18 Retail Transmission Service Rates

a) In Table 8-18, Horizon documents that the unit of measurement ("UOM") for the Network Service Rate and for the Line and Transformation Connection Rate for the Unmetered Scattered Load Class is indicated as [per] kW. Please confirm whether the unit of measurement for the retail transmission service rates for this class should be per kW or per kWh.

b) In Table 8-18, Horizon documents that the unit of measurement for the Network Service Rate and for the Line and Transformation Connection Rate for the Streetlighting Class is indicated as [per] kWh. Please confirm whether the unit of measurement for the retail transmission service rates for this class should be per kW or per kWh.

Response:

a) Horizon Utilities confirms that in Table 8-18, the unit of measurement ("UOM") for the Network Service Rate and for the Line and Transformation Connection Rate for the Unmetered Scattered Load should be per kWh.

b) Horizon Utilities confirms that in Table 8-18, the unit of measurement for the Network Service Rate and for the Line and Transformation Connection Rate for the Streetlighting Class should be per kW.

EB-2010-0131

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question

Reference: E8/T1/S Retail Transmission Service Rates

On page 5, Horizon states:

> Horizon Utilities is aware that Retail Transmission rates will be subject to modifications for 2011, as a result of a Board Decision on Hydro One Networks' 2011/2012 Uniform Transmission Rate Adjustment Application as per the Board's Guideline G-2008-0001, Revision 2: July 8, 2010.

a) Is Horizon proposing that its evidence and proposed RTSRs for 2011 in this application should be updated on the record or possibly at the time of the Board's Decision and subsequent Rate Order process to reflect updated Uniform Transmission Rates for 2011?

b) If so, how does Horizon propose that the 2011 RTSRs should be updated?

Response:

a) Horizon Utilities was proposing that its evidence and proposed RTSRs for 2011 in this Application may be updated on the record or at the time of the Board's Decision and subsequent Rate Order to reflect updated Uniform Transmission Rates for 2011 as per the Board's *Guideline G-2008-0001, Electricity Distribution Retail Transmission*

Service Rates Revision 2: July 8, 2010 which states that, 'Once the January 1, 2011 UTR adjustment is determined, the Board will adjust each distributor's rate application model to incorporate this change, if any.'

b) Horizon Utilities proposes that if there is a January 1, 2011 UTR adjustment the Board would adjust Horizon's rate application model in part a), as noted above.

EB-2010-0131

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 50

Reference: Appendix 8-1

Horizon has separately filed an application for an increase to its Smart Meter Funding Adder and which is being dealt with separately under Board File No. EB-2010-0292. In that application, Horizon has proposed an increase in the Smart Meter Funding Adder from $1.56 to $2.45 per month per metered customer.

a) Please confirm whether the bill impacts documented in the Cost of Service Application, and specifically in the detailed bill impact tables provided in Appendix 8-1, reflect the impact of the proposed increase to the Smart Meter Funding Adder.

b) If the answer to a) is in the negative, please provide a version of Appendix 8-1 showing the combined impact of the proposed rate changes in this Cost of Service application and the Smart Meter Funding Adder application.

c) From the updated Appendix 8-1 in response to part b), please identify if there are rate classes or customer profiles for which the total bill impact would be greater than 10%.

d) If there are potential bill impacts exceeding 10% identified in part c), please provide Horizon's proposals, with explanation, for any appropriate rate mitigation to constrain bill impacts to no more than 10%.

Response:

a) The bill impacts documented in the Application and specifically in the detailed bill impact tables provided in Appendix 8 – 1, do not reflect the impact of the proposed Smart Meter Funding Adder (EB-2010-0292).

b) Please find below the Table of Rate and Bill Impacts as per Appendix 8 – 1 with the proposed Smart Meter Funding Adder of $2.45, as filed, included.

RESIDENTIAL

		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			12.68			14.71	2.03	16.01%	48.10%
100 kWh	Distribution (kWh)	100	0.0125	1.25	100	0.0145	1.45	0.20	16.00%	4.74%
	Low Voltage Rider (kWh)	100	0.0000	0.00	100	0.000050	0.01	0.01	#DIV/0!	0.02%
	Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	8.01%
	LRAM & SSM Rider (kWh)	100	0.0002	0.02	100		0.00	(0.02)	(100.00%)	0.00%
	Smart Meter Entity ($/Month)						0.00	0.00	#DIV/0!	0.00%
	Late Payment (kWh)	100		0.00	100	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh)	100	(0.0023)	(0.23)	100	(0.0020)	(0.20)	0.03	(13.04%)	(0.65%)
	Distribution Sub-Total			**15.28**			**18.42**	**3.14**	**20.52%**	**60.22%**
	Retail Transmisssion (kWh)	104	0.0108	1.13	104	0.0109	1.13	0.01	0.79%	3.71%
	Delivery Sub-Total			**16.41**			**19.55**	**3.14**	**19.16%**	**63.93%**
	Other Charges (kWh)	104	0.0072	0.75	104	0.0072	0.75	(0.00)	(0.13%)	2.45%
	Cost of Power Commodity (kWh)	104	0.0650	6.77	104	0.0650	6.76	(0.01)	(0.13%)	22.12%
	SPC (kWh)	104	0.0003725	0.04	104	0.0000000	0.00	(0.04)	(100.00%)	0.00%
	Total Bill Before Taxes			**23.97**			**27.06**	**3.09**	**12.88%**	**88.50%**
	HST		13.00%	3.12		13.00%	3.52	0.40	12.91%	11.50%
	Total Bill			**27.08**			**30.58**	**3.49**	**12.88%**	**100.00%**

RESIDENTIAL

		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			12.68			14.71	2.03	16.01%	31.06%
250 kWh	Distribution (kWh)	250	0.0125	3.13	250	0.0145	3.63	0.50	16.00%	7.65%
	Low Voltage Rider (kWh)	250	0.0000	0.00	250	0.000050	0.01	0.01	#DIV/0!	0.03%
	Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	5.17%
	LRAM & SSM Rider (kWh)	250	0.0002	0.05	250	0.0000	0.00	(0.05)	(100.00%)	0.00%
	Smart Meter Entity ($/Month)						0.00	0.00	#DIV/0!	0.00%
	Late Payment (kWh)	250	0.0000	0.00	250	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh)	250	(0.0023)	(0.58)	250	(0.0020)	(0.50)	0.08	(13.04%)	(1.06%)
	Distribution Sub-Total			**16.84**			**20.30**	**3.46**	**20.53%**	**42.85%**
	Retail Transmisssion (kWh)	261	0.0108	2.81	260	0.0109	2.84	0.02	0.79%	5.99%
	Delivery Sub-Total			**19.65**			**23.13**	**3.48**	**17.71%**	**48.84%**
	Other Charges (kWh)	261	0.0072	1.88	260	0.0072	1.87	(0.00)	(0.13%)	3.95%
	Cost of Power Commodity (kWh)	261	0.0650	16.93	260	0.0650	16.91	(0.02)	(0.13%)	35.70%
	SPC (kWh)	261	0.0003725	0.10	261	0.0000000	0.00	(0.10)	(100.00%)	0.00%
	Total Bill Before Taxes			**38.56**			**41.92**	**3.34**	**8.65%**	**88.50%**
	HST		13.00%	5.01		13.00%	5.45	0.44	8.71%	11.50%
	Total Bill			**43.57**			**47.37**	**3.77**	**8.66%**	**100.00%**

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RESIDENTIAL

		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			12.68			14.71	2.03	16.01%	19.52%
500 kWh	Distribution (kWh)	500	0.0125	6.25	500	0.0145	7.25	1.00	16.00%	9.62%
	Low Voltage Rider (kWh)	500	0.0000	0.00	500	0.000050	0.03	0.03	#DIV/0!	0.03%
	Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	3.25%
	LRAM & SSM Rider (kWh)	500	0.0002	0.10	500	0.0000	0.00	(0.10)	(100.00%)	0.00%
	Smart Meter Entity ($/Month)						0.00	0.00	#DIV/0!	0.00%
	Late Payment (kWh)	500	0.0000	0.00	500	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh)	500	(0.0023)	(1.15)	500	(0.0020)	(1.00)	0.15	(13.04%)	(1.33%)
	Distribution Sub-Total			**19.44**			**23.44**	**4.00**	**20.55%**	**31.10%**
	Retail Transmisssion (kWh)	521	0.0108	5.63	520	0.0109	5.67	0.04	0.79%	7.53%
	Delivery Sub-Total			**25.07**			**29.11**	**4.04**	**16.11%**	**38.63%**
	Other Charges (kWh)	521	0.0072	3.75	520	0.0072	3.75	(0.01)	(0.13%)	4.97%
	Cost of Power Commodity (kWh)	521	0.0650	33.87	520	0.0650	33.82	(0.05)	(0.13%)	44.89%
	SPC (kWh)	521	0.0003725	0.19	521	0.0000000	0.00	(0.19)	(100.00%)	0.00%
	Total Bill Before Taxes			**62.88**			**66.68**	**3.75**	**5.96%**	**88.50%**
	HST		13.00%	8.17		13.00%	8.67	0.49	6.03%	11.50%
	Total Bill			**71.06**			**75.34**	**4.24**	**5.97%**	**100.00%**

RESIDENTIAL

		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			12.68			14.71	2.03	16.01%	132.22%
680 kWh	Distribution (kWh)	680	0.0125	8.50	680	0.0145	9.86	1.36	16.00%	88.63%
	Low Voltage Rider (kWh)	680	0.0000	0.00	680	0.000050	0.03	0.03	#DIV/0!	0.31%
	Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	22.02%
	LRAM & SSM Rider (kWh)	680	0.0002	0.14	680	0.0000	0.00	(0.14)	(100.00%)	0.00%
	Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
	Late Payment (kWh)	680	0.0000	0.00	680	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh)	680	(0.0023)	(1.56)	680	(0.0020)	(1.36)	0.20	(13.04%)	(1.41%)
	Distribution Sub-Total			**21.31**			**25.69**	**4.38**	**20.56%**	**26.57%**
	Retail Transmisssion (kWh)	709	0.0108	7.65	708	0.0109	7.71	0.06	0.79%	7.98%
	Delivery Sub-Total			**28.97**			**33.41**	**4.44**	**15.34%**	**34.55%**
	Other Charges (kWh)	709	0.0072	5.10	708	0.0072	5.10	(0.01)	(0.13%)	5.27%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	40.33%
	Cost of Power Commodity (kWh)	109	0.0750	8.15	108	0.0750	8.08	(0.07)	(0.88%)	8.35%
	SPC (kWh)	709	0.0003725	0.26	709	0.0000000	0.00	(0.26)	(100.00%)	0.00%
	Total Bill Before Taxes			**81.48**			**85.58**	**4.10**	**5.03%**	**88.50%**
	HST		13.00%	10.59		13.00%	11.13	0.53	5.03%	11.50%
	Total Bill			**92.07**			**96.70**	**4.63**	**5.03%**	**100.00%**

2

RESIDENTIAL

Consumption
800 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			12.68			14.71	2.03	16.01%	13.19%
Distribution (kWh)	800	0.0125	10.00	800	0.0145	11.60	1.60	16.00%	10.40%
Low Voltage Rider (kWh)	800	0.0000	0.00	800	0.000050	0.04	0.04	#DIV/0!	0.04%
Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	2.20%
LRAM & SSM Rider (kWh)	800	0.0002	0.16	800	0.0000	0.00	(0.16)	(100.00%)	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	800	0.0000	0.00	800	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	800	(0.0023)	(1.84)	800	(0.0020)	(1.60)	0.24	(13.04%)	(1.43%)
Distribution Sub-Total			**22.56**			**27.20**	**4.64**	**20.57%**	**24.39%**
Retail Transmisssion (kWh)	834	0.0108	9.00	833	0.0109	9.07	0.07	0.79%	8.14%
Delivery Sub-Total			**31.56**			**36.27**	**4.71**	**14.93%**	**32.52%**
Other Charges (kWh)	834	0.0072	6.00	833	0.0072	5.99	(0.01)	(0.13%)	5.37%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	34.96%
Cost of Power Commodity (kWh)	234	0.0750	17.53	233	0.0750	17.44	(0.08)	(0.48%)	15.64%
SPC (kWh)	834	0.0003725	0.31	834	0.0000000	0.00	(0.31)	(100.00%)	0.00%
Total Bill Before Taxes			**94.40**			**98.71**	**4.31**	**4.56%**	**88.50%**
HST		13.00%	12.27		13.00%	12.83	0.56	4.56%	11.50%
Total Bill			**106.68**			**111.54**	**4.87**	**4.56%**	**100.00%**

RESIDENTIAL

Consumption
1,000 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			12.68			14.71	2.03	16.01%	10.79%
Distribution (kWh)	1,000	0.0125	12.50	1,000	0.0145	14.50	2.00	16.00%	10.64%
Low Voltage Rider (kWh)	1,000	0.0000	0.00	1,000	0.000050	0.05	0.05	#DIV/0!	0.04%
Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	1.80%
LRAM & SSM Rider (kWh)	1,000	0.0002	0.20	1,000	0.0000	0.00	(0.20)	(100.00%)	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	1,000	0.0000	0.00	1,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	1,000	(0.0023)	(2.30)	1,000	(0.0020)	(2.00)	0.30	(13.04%)	(1.47%)
Distribution Sub-Total			**24.64**			**29.71**	**5.07**	**20.58%**	**21.80%**
Retail Transmisssion (kWh)	1,042	0.0108	11.25	1,041	0.0109	11.34	0.09	0.79%	8.32%
Delivery Sub-Total			**35.89**			**41.05**	**5.16**	**14.37%**	**30.13%**
Other Charges (kWh)	1,042	0.0072	7.50	1,041	0.0072	7.49	(0.01)	(0.13%)	5.50%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	28.62%
Cost of Power Commodity (kWh)	442	0.0750	33.16	441	0.0750	33.05	(0.11)	(0.32%)	24.25%
SPC (kWh)	1,042	0.0003725	0.39	1,042	0.0000000	0.00	(0.39)	(100.00%)	0.00%
Total Bill Before Taxes			**115.94**			**120.60**	**4.66**	**4.02%**	**88.50%**
HST		13.00%	15.07		13.00%	15.68	0.61	4.02%	11.50%
Total Bill			**131.02**			**136.28**	**5.26**	**4.02%**	**100.00%**

RESIDENTIAL

Consumption
1,500 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			12.68			14.71	2.03	16.01%	7.43%
Distribution (kWh)	1,500	0.0125	18.75	1,500	0.0145	21.75	3.00	16.00%	10.98%
Low Voltage Rider (kWh)	1,500	0.0000	0.00	1,500	0.000050	0.08	0.08	#DIV/0!	0.04%
Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	1.24%
LRAM & SSM Rider (kWh)	1,500	0.0002	0.30	1,500	0.0000	0.00	(0.30)	(100.00%)	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	1,500	0.0000	0.00	1,500	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	1,500	(0.0023)	(3.45)	1,500	(0.0020)	(3.00)	0.45	(13.04%)	(1.51%)
Distribution Sub-Total			**29.84**			**35.99**	**6.15**	**20.59%**	**18.16%**
Retail Transmisssion (kWh)	1,563	0.0108	16.88	1,561	0.0109	17.02	0.13	0.79%	8.59%
Delivery Sub-Total			**46.72**			**53.00**	**6.28**	**13.44%**	**26.75%**
Other Charges (kWh)	1,563	0.0072	11.25	1,561	0.0072	11.24	(0.02)	(0.13%)	5.67%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	19.69%
Cost of Power Commodity (kWh)	963	0.0750	72.24	961	0.0750	72.08	(0.16)	(0.22%)	36.38%
SPC (kWh)	1,563	0.0003725	0.58	1,563	0.0000000	0.00	(0.58)	(100.00%)	0.00%
Total Bill Before Taxes			**169.80**			**175.32**	**5.52**	**3.25%**	**88.50%**
HST		13.00%	22.07		13.00%	22.79	0.72	3.25%	11.50%
Total Bill			**191.87**			**198.11**	**6.24**	**3.25%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
2,000 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			27.45			33.87	6.42	23.39%	12.84%
Distribution (kWh)	2,000	0.0072	14.40	2,000	0.0089	17.80	3.40	23.61%	6.75%
Low Voltage Rider (kWh)	2,000	0.0000	0.00	2,000	0.000040	0.08	0.08	#DIV/0!	0.03%
Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	0.93%
LRAM & SSM Rider (kWh)	2,000	0.0000	0.00	2,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	2,000	0.0000	0.00	2,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	2,000	(0.0025)	(5.00)	2,000	(0.0023)	(4.60)	0.40	(8.00%)	(1.74%)
Distribution Sub-Total			**38.41**			**49.60**	**11.19**	**29.13%**	**18.81%**
Retail Transmisssion (kWh)	2,084	0.0097	20.22	2,081	0.0097	20.19	(0.03)	(0.13%)	7.66%
Delivery Sub-Total			**58.63**			**69.79**	**11.16**	**19.04%**	**26.46%**
Other Charges (kWh)	2,084	0.0072	15.01	2,081	0.0072	14.99	(0.02)	(0.13%)	5.68%
Cost of Power Commodity (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	18.49%
Cost of Power Commodity (kWh)	1,334	0.0750	100.07	1,331	0.0750	99.86	(0.21)	(0.21%)	37.86%
SPC (kWh)	2,084	0.0003725	0.78	2,084	0.0000000	0.00	(0.78)	(100.00%)	0.00%
Total Bill Before Taxes			**223.22**			**233.38**	**$10.16**	**4.55%**	**88.50%**
HST		13.00%	29.02		13.00%	30.34	1.32	4.55%	11.50%
Total Bill			**252.24**			**263.72**	**$11.48**	**4.55%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
5,000 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			27.45			33.87	6.42	23.39%	5.55%
Distribution (kWh)	5,000	0.0072	36.00	5,000	0.0089	44.50	8.50	23.61%	7.29%
Low Voltage Rider (kWh)	5,000	0.0000	0.00	5,000	0.000040	0.20	0.20	#DIV/0!	0.03%
Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	0.40%
LRAM & SSM Rider (kWh)	5,000	0.0000	0.00	5,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	5,000	0.0000	0.00	5,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	5,000	(0.0025)	(12.50)	5,000	(0.0023)	(11.50)	1.00	(8.00%)	(1.88%)
Distribution Sub-Total			**52.51**			**69.52**	**17.01**	**32.39%**	**11.39%**
Retail Transmisssion (kWh)	5,211	0.0097	50.54	5,204	0.0097	50.47	(0.07)	(0.13%)	8.27%
Delivery Sub-Total			**103.05**			**119.99**	**16.94**	**16.44%**	**19.66%**
Other Charges (kWh)	5,211	0.0072	37.52	5,204	0.0072	37.47	(0.05)	(0.13%)	6.14%
Cost of Power Commodity (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	7.99%
Cost of Power Commodity (kWh)	4,461	0.0750	334.54	4,454	0.0750	334.01	(0.52)	(0.16%)	54.72%
SPC (kWh)	5,211	0.0003725	1.94	5,211	0.0000000	0.00	(1.94)	(100.00%)	0.00%
Total Bill Before Taxes			**525.80**			**540.22**	**$14.43**	**2.74%**	**88.50%**
HST		13.00%	68.35		13.00%	70.23	1.88	2.74%	11.50%
Total Bill			**594.15**			**610.45**	**$16.30**	**2.74%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
10,000 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			27.45			33.87	6.42	23.39%	2.85%
Distribution (kWh)	10,000	0.0072	72.00	10,000	0.0089	89.00	17.00	23.61%	7.49%
Low Voltage Rider (kWh)	10,000	0.0000	0.00	10,000	0.000040	0.40	0.40	#DIV/0!	0.03%
Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	0.21%
LRAM & SSM Rider (kWh)	10,000	0.0000	0.00	10,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	10,000	0.0000	0.00	10,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	10,000	(0.0025)	(25.00)	10,000	(0.0023)	(23.00)	2.00	(8.00%)	(1.94%)
Distribution Sub-Total			**76.01**			**102.72**	**26.71**	**35.14%**	**8.64%**
Retail Transmisssion (kWh)	10,421	0.0097	101.08	10,407	0.0097	100.95	(0.14)	(0.13%)	8.49%
Delivery Sub-Total			**177.09**			**203.67**	**26.57**	**15.01%**	**17.14%**
Other Charges (kWh)	10,421	0.0072	75.03	10,407	0.0072	74.93	(0.10)	(0.13%)	6.31%
Cost of Power Commodity (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	4.10%
Cost of Power Commodity (kWh)	9,671	0.0750	725.33	9,657	0.0750	724.28	(1.05)	(0.14%)	60.95%
SPC (kWh)	10,421	0.0003725	3.88	10,421	0.0000000	0.00	(3.88)	(100.00%)	0.00%
Total Bill Before Taxes			**1,030.08**			**1,051.62**	**$21.54**	**2.09%**	**88.50%**
HST		13.00%	133.91		13.00%	136.71	2.80	2.09%	11.50%
Total Bill			**1,163.99**			**1,188.33**	**$24.34**	**2.09%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
12,500 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			27.45			33.87	6.42	23.39%	2.29%
Distribution (kWh)	12,500	0.0072	90.00	12,500	0.0089	111.25	21.25	23.61%	7.53%
Low Voltage Rider (kWh)	12,500	0.0000	0.00	12,500	0.000040	0.50	0.50	#DIV/0!	0.03%
Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	0.17%
LRAM & SSM Rider (kWh)	12,500	0.0000	0.00	12,500	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	12,500	0.0000	0.00	12,500	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	12,500	(0.0025)	(31.25)	12,500	(0.0023)	(28.75)	2.50	(8.00%)	(1.95%)
Distribution Sub-Total			**87.76**			**119.32**	**31.56**	**35.96%**	**8.08%**
Retail Transmisssion (kWh)	13,026	0.0097	126.35	13,009	0.0097	126.18	(0.17)	(0.13%)	8.54%
Delivery Sub-Total			**214.11**			**245.50**	**31.39**	**14.66%**	**16.62%**
Other Charges (kWh)	13,026	0.0072	93.79	13,009	0.0072	93.66	(0.13)	(0.13%)	6.34%
Cost of Power Commodity (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	3.30%
Cost of Power Commodity (kWh)	12,276	0.0750	920.72	12,259	0.0750	919.41	(1.31)	(0.14%)	62.24%
SPC (kWh)	13,026	0.0003725	4.85	13,026	0.0000000	0.00	(4.85)	(100.00%)	0.00%
Total Bill Before Taxes			**1,282.22**			**1,307.32**	**$25.10**	**1.96%**	**88.50%**
HST		13.00%	166.69		13.00%	169.95	3.26	1.96%	11.50%
Total Bill			**1,448.91**			**1,477.28**	**$28.36**	**1.96%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
15,000 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			27.45			33.87	6.42	23.39%	1.92%
Distribution (kWh)	15,000	0.0072	108.00	15,000	0.0089	133.50	25.50	23.61%	7.56%
Low Voltage Rider (kWh)	15,000	0.0000	0.00	15,000	0.000040	0.60	0.60	#DIV/0!	0.03%
Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	0.14%
LRAM & SSM Rider (kWh)	15,000	0.0000	0.00	15,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	15,000	0.0000	0.00	15,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	15,000	(0.0025)	(37.50)	15,000	(0.0023)	(34.50)	3.00	(8.00%)	(1.95%)
Distribution Sub-Total			**99.51**			**135.92**	**36.41**	**36.59%**	**7.70%**
Retail Transmisssion (kWh)	15,632	0.0097	151.63	15,611	0.0097	151.42	(0.20)	(0.13%)	8.57%
Delivery Sub-Total			**251.14**			**287.34**	**36.21**	**14.42%**	**16.27%**
Other Charges (kWh)	15,632	0.0072	112.55	15,611	0.0072	112.40	(0.15)	(0.13%)	6.36%
Cost of Power Commodity (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	2.76%
Cost of Power Commodity (kWh)	14,882	0.0750	1,116.11	14,861	0.0750	1,114.54	(1.58)	(0.14%)	63.10%
SPC (kWh)	15,632	0.0003725	5.82	15,632	0.0000000	0.00	(5.82)	(100.00%)	0.00%
Total Bill Before Taxes			**1,534.37**			**1,563.02**	**$28.66**	**1.87%**	**88.50%**
HST		13.00%	199.47		13.00%	203.19	3.73	1.87%	11.50%
Total Bill			**1,733.84**			**1,766.22**	**$32.38**	**1.87%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
30,000 kWh
100 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			250.33			332.50	82.17	32.82%	9.46%
Distribution (kW)	100	1.7875	178.75	100	2.2606	226.06	47.31	26.47%	6.43%
Low Voltage Rider (kW)	100	0.0121	1.21	100	0.018250	1.83	0.62	50.83%	0.05%
Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	0.07%
LRAM & SSM Rider (kW)	100		0.00	100	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	30,000	0.0000	0.00	30,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW)	100	(1.0002)	(100.02)	100	(0.9295)	(92.95)	7.07	(7.07%)	(2.65%)
Distribution Sub-Total			**331.83**			**469.89**	**138.06**	**41.60%**	**13.38%**
Retail Transmisssion (kW)	100	3.8311	383.11	100	3.8489	384.89	1.78	0.46%	10.96%
Delivery Sub-Total			**714.94**			**854.78**	**139.84**	**19.56%**	**24.33%**
Other Charges (kWh)	31,263	0.0072	225.09	31,221	0.0072	224.79	(0.30)	(0.13%)	6.40%
Cost of Power Commodity (kWh)	31,263	0.0650	2,032.10	31,221	0.0650	2,029.37	(2.73)	(0.13%)	57.77%
SPC (kWh)	31,263	0.0003725	11.65	31,263	0.0000000	0.00	(11.65)	(100.00%)	0.00%
Total Bill Before Taxes			**2,983.77**			**3,108.93**	**125.16**	**4.19%**	**88.50%**
HST		13.00%	387.89		13.00%	404.16	16.27	4.19%	11.50%
Total Bill			**3,371.66**			**3,513.09**	**141.43**	**4.19%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
75,000 kWh
250 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			250.33			332.50	82.17	32.82%	4.05%
Distribution (kW)	250	1.7875	446.88	250	2.2606	565.15	118.28	26.47%	6.88%
Low Voltage Rider (kW)	250	0.0121	3.03	250	0.018250	4.56	1.54	50.83%	0.06%
Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	0.03%
LRAM & SSM Rider (kW)	250		0.00	250	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	75,000	0.0000	0.00	75,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW)	250	(1.0002)	(250.05)	250	(0.9295)	(232.38)	17.68	(7.07%)	(2.83%)
Distribution Sub-Total			**451.74**			**672.29**	**220.55**	**48.82%**	**8.18%**
Retail Transmisssion (kW)	250	3.8311	957.78	250	3.8489	962.23	4.45	0.46%	11.71%
Delivery Sub-Total			**1,409.52**			**1,634.51**	**225.00**	**15.96%**	**19.90%**
Other Charges (kWh)	78,158	0.0072	562.73	78,053	0.0072	561.98	(0.76)	(0.13%)	6.84%
Cost of Power Commodity (kWh)	78,158	0.0650	5,080.24	78,053	0.0650	5,073.41	(6.82)	(0.13%)	61.76%
SPC (kWh)	78,158	0.0003725	29.11	78,158	0.0000000	0.00	(29.11)	(100.00%)	0.00%
Total Bill Before Taxes			**7,081.60**			**7,269.90**	**188.30**	**2.66%**	**88.50%**
HST		13.00%	920.61		13.00%	945.09	24.48	2.66%	11.50%
Total Bill			**8,002.21**			**8,214.99**	**212.78**	**2.66%**	**100.00%**

GENERAL SERVICE > 50 kW

		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			250.33			332.50	82.17	32.82%	3.04%
100,000 kWh	Distribution (kW)	350	1.7875	625.63	350	2.2606	791.21	165.59	26.47%	7.24%
350 kW	Low Voltage Rider (kW)	350	0.0121	4.24	350	0.018250	6.39	2.15	50.83%	0.06%
	Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	0.02%
	LRAM & SSM Rider (kW)	350		0.00	350	0.0000	0.00	0.00	#DIV/0!	0.00%
	Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
	Late Payment (kWh)	100,000	0.0000	0.00	100,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW)	350	(1.0002)	(350.07)	350	(0.9295)	(325.33)	24.75	(7.07%)	(2.98%)
	Distribution Sub-Total			**531.68**			**807.22**	**275.54**	**51.82%**	**7.39%**
	Retail Transmisssion (kW)	350	3.8311	1,340.89	350	3.8489	1,347.12	6.23	0.46%	12.33%
	Delivery Sub-Total			**1,872.57**			**2,154.34**	**281.77**	**15.05%**	**19.72%**
	Other Charges (kWh)	104,210	0.0072	750.31	104,070	0.0072	749.30	(1.01)	(0.13%)	6.86%
	Cost of Power Commodity (kWh)	104,210	0.0650	6,773.65	104,070	0.0650	6,764.55	(9.10)	(0.13%)	61.92%
	SPC (kWh)	104,210	0.0003725	38.82	104,210	0.0000000	0.00	(38.82)	(100.00%)	0.00%
	Total Bill Before Taxes			**9,435.35**			**9,668.19**	**232.85**	**2.47%**	**88.50%**
	HST		13.00%	1,226.59		13.00%	1,256.86	30.27	2.47%	11.50%
	Total Bill			**10,661.94**			**10,925.06**	**263.12**	**2.47%**	**100.00%**

GENERAL SERVICE > 50 kW

		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			250.33			332.50	82.17	32.82%	0.42%
800,000 kWh	Distribution (kW)	2,000	1.7875	3,575.00	2,000	2.2606	4,521.20	946.20	26.47%	5.65%
2,000 kW	Low Voltage Rider (kW)	2,000	0.0121	24.20	2,000	0.018250	36.50	12.30	50.83%	0.05%
	Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	0.00%
	LRAM & SSM Rider (kW)	2,000		0.00	2,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
	Late Payment (kWh)	800,000	0.0000	0.00	800,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW)	2,000	(1.0002)	(2,000.40)	2,000	(0.9295)	(1,859.00)	141.40	(7.07%)	(2.32%)
	Distribution Sub-Total			**1,850.69**			**3,033.65**	**1,182.96**	**63.92%**	**3.79%**
	Retail Transmisssion (kW)	2,000	3.8311	7,662.20	2,000	3.8489	7,697.80	35.60	0.46%	9.62%
	Delivery Sub-Total			**9,512.89**			**10,731.45**	**1,218.56**	**12.81%**	**13.41%**
	Other Charges (kWh)	833,680	0.0072	6,002.50	832,560	0.0072	5,994.43	(8.06)	(0.13%)	7.49%
	Cost of Power Commodity (kWh)	833,680	0.0650	54,189.20	832,560	0.0650	54,116.40	(72.80)	(0.13%)	67.60%
	SPC (kWh)	833,680	0.0003725	310.55	833,680	0.0000000	0.00	(310.55)	(100.00%)	0.00%
	Total Bill Before Taxes			**70,015.13**			**70,842.28**	**827.15**	**1.18%**	**88.50%**
	HST		13.00%	9,101.97		13.00%	9,209.50	107.53	1.18%	11.50%
	Total Bill			**79,117.10**			**80,051.78**	**934.68**	**1.18%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
1,600,000 kWh
4,000 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			250.33			332.50	82.17	32.82%	0.21%
Distribution (kW)	4,000	1.7875	7,150.00	4,000	2.2606	9,042.40	1,892.40	26.47%	5.66%
Low Voltage Rider (kW)	4,000	0.0121	48.40	4,000	0.018250	73.00	24.60	50.83%	0.05%
Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	0.00%
LRAM & SSM Rider (kW)	4,000		0.00	4,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	1,600,000	0.0000	0.00	1,600,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW)	4,000	(1.0002)	(4,000.80)	4,000	(0.9295)	(3,718.00)	282.80	(7.07%)	(2.33%)
Distribution Sub-Total			**3,449.49**			**5,732.35**	**2,282.86**	**66.18%**	**3.59%**
Retail Transmisssion (kW)	4,000	3.8311	15,324.40	4,000	3.8489	15,395.60	71.20	0.46%	9.64%
Delivery Sub-Total			**18,773.89**			**21,127.95**	**2,354.06**	**12.54%**	**13.23%**
Other Charges (kWh)	1,667,360	0.0072	12,004.99	1,665,120	0.0072	11,988.86	(16.13)	(0.13%)	7.51%
Cost of Power Commodity (kWh)	1,667,360	0.0650	108,378.40	1,665,120	0.0650	108,232.80	(145.60)	(0.13%)	67.76%
SPC (kWh)	1,667,360	0.0003725	621.09	1,667,360	0.0000000	0.00	(621.09)	(100.00%)	0.00%
Total Bill Before Taxes			**139,778.37**			**141,349.61**	**1,571.24**	**1.12%**	**88.50%**
HST		13.00%	18,171.19		13.00%	18,375.45	204.26	1.12%	11.50%
Total Bill			**157,949.56**			**159,725.06**	**1,775.50**	**1.12%**	**100.00%**

LARGE USER (> 5000 kW)

Consumption
2,800,000 kWh
6,500 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			11,151.32			26,699.15	15,547.83	139.43%	8.74%
Distribution (kW)	6,500	1.0123	6,579.95	6,500	1.2933	8,406.45	1,826.50	27.76%	2.75%
Low Voltage Rider (kW)	6,500	0.014	91.00	6,500	0.019320	125.58	34.58	38.00%	0.04%
Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	0.00%
LRAM & SSM Rider (kW)	6,500		0.00	6,500	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	2,800,000	0.0000	0.00	2,800,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW)	6,500	(0.6827)	-4,437.55	6,500	(0.6020)	(3,913.00)	524.55	(11.82%)	(1.28%)
Distribution Sub-Total			**13,386.28**			**31,320.63**	**17,934.35**	**133.98%**	**10.25%**
Retail Transmisssion (kW)	6,500	4.3886	28,525.90	6,500	4.409	28,658.50	132.60	0.46%	9.38%
Delivery Sub-Total			**41,912.18**			**59,979.13**	**18,066.95**	**43.11%**	**19.63%**
Other Charges (kWh)	2,917,880	0.0072	21,008.74	2,913,960	0.0072	20,980.51	(28.22)	(0.13%)	6.87%
Cost of Power Commodity (kWh)	2,917,880	0.0650	189,662.20	2,913,960	0.0650	189,407.40	(254.80)	(0.13%)	62.00%
SPC (kWh)	2,917,880	0.0003725	1,086.91	2,917,880	0.0000000	0.00	(1,086.91)	(100.00%)	0.00%
Total Bill Before Taxes			**253,670.03**			**270,367.04**	**16,697.02**	**6.58%**	**88.50%**
HST		13.00%	32,977.10		13.00%	35,147.72	2,170.61	6.58%	11.50%
Total Bill			**286,647.13**			**305,514.76**	**18,867.63**	**6.58%**	**100.00%**

LARGE USER (> 5000 kW)

Consumption		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
3,100,000 kWh	Monthly Service Charge			11,151.32			26,699.15	15,547.83	139.43%	7.93%
7,500 kW	Distribution (kW)	7,500	1.0123	7,592.25	7,500	1.2933	9,699.75	2,107.50	27.76%	2.88%
	Low Voltage Rider (kW)	7,500	0.014	105.00	7,500	0.019320	144.90	39.90	38.00%	0.04%
	Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	0.00%
	LRAM & SSM Rider (kW)	7,500		0.00	7,500	0.0000	0.00	0.00	#DIV/0!	0.00%
	Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
	Late Payment (kWh)	3,100,000	0.0000	0.00	3,100,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW)	7,500	(0.6827)	(5,120.25)	7,500	(0.6020)	(4,515.00)	605.25	(11.82%)	(1.34%)
	Distribution Sub-Total			**13,729.88**			**32,031.25**	**18,301.37**	**133.30%**	**9.51%**
	Retail Transmisssion (kW)	7,500	4.3886	32,914.50	7,500	4.409	33,067.50	153.00	0.46%	9.82%
	Delivery Sub-Total			**46,644.38**			**65,098.75**	**18,454.37**	**39.56%**	**19.33%**
	Other Charges (kWh)	3,230,510	0.0072	23,259.67	3,226,170	0.0072	23,228.42	(31.25)	(0.13%)	6.90%
	Cost of Power Commodity (kWh)	3,230,510	0.0650	209,983.15	3,226,170	0.0650	209,701.05	(282.10)	(0.13%)	62.27%
	SPC (kWh)	3,230,510	0.0003725	1,203.36	3,230,510	0.0000000	0.00	(1,203.36)	(100.00%)	0.00%
	Total Bill Before Taxes			**281,090.57**			**298,028.22**	**16,937.66**	**6.03%**	**88.50%**
	HST		13.00%	36,541.77		13.00%	38,743.67	2,201.90	6.03%	11.50%
	Total Bill			**317,632.34**			**336,771.89**	**19,139.55**	**6.03%**	**100.00%**

LARGE USER (> 5000 kW)

Consumption		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
4,200,000 kWh	Monthly Service Charge			11,151.32			26,699.15	15,547.83	139.43%	6.00%
10,000 kW	Distribution (kW)	10,000	1.0123	10,123.00	10,000	1.2933	12,933.00	2,810.00	27.76%	2.91%
	Low Voltage Rider (kW)	10,000	0.014	140.00	10,000	0.019320	193.20	53.20	38.00%	0.04%
	Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	0.00%
	LRAM & SSM Rider (kW)	10,000		0.00	10,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
	Late Payment (kWh)	4,200,000	0.0000	0.00	4,200,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW)	10,000	(0.6827)	(6,827.00)	10,000	(0.6020)	(6,020.00)	807.00	(11.82%)	(1.35%)
	Distribution Sub-Total			**14,588.88**			**33,807.80**	**19,218.92**	**131.74%**	**7.60%**
	Retail Transmisssion (kW)	10,000	4.3886	43,886.00	10,000	4.409	44,090.00	204.00	0.46%	9.92%
	Delivery Sub-Total			**58,474.88**			**77,897.80**	**19,422.92**	**33.22%**	**17.52%**
	Other Charges (kWh)	4,376,820	0.0072	31,513.10	4,370,940	0.0072	31,470.77	(42.34)	(0.13%)	7.08%
	Cost of Power Commodity (kWh)	4,376,820	0.0650	284,493.30	4,370,940	0.0650	284,111.10	(382.20)	(0.13%)	63.90%
	SPC (kWh)	4,376,820	0.0003725	1,630.37	4,376,820	0.0000000	0.00	(1,630.37)	(100.00%)	0.00%
	Total Bill Before Taxes			**376,111.65**			**393,479.67**	**17,368.02**	**4.62%**	**88.50%**
	HST		13.00%	48,894.51		13.00%	51,152.36	2,257.84	4.62%	11.50%
	Total Bill			**425,006.16**			**444,632.02**	**19,625.86**	**4.62%**	**100.00%**

LARGE USER (> 5000 kW)

Consumption		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
4,700,000 kWh	Monthly Service Charge			11,151.32			26,699.15	15,547.83	139.43%	5.24%
13,900 kW	Distribution (kW)	13,900	1.0123	14,070.97	13,900	1.2933	17,976.87	3,905.90	27.76%	3.53%
	Low Voltage Rider (kW)	13,900	0.014	194.60	13,900	0.019320	268.55	73.95	38.00%	0.05%
	Smart Meter Rider (per month)			1.56			2.45	0.89	57.05%	0.00%
	LRAM & SSM Rider (kW)	13,900		0.00	13,900	0.0000	0.00	0.00	#DIV/0!	0.00%
	Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
	Late Payment (kWh)	4,700,000	0.0000	0.00	4,700,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW)	13,900	(0.6827)	(9,489.53)	13,900	(0.6020)	(8,367.80)	1,121.73	(11.82%)	(1.64%)
	Distribution Sub-Total			**15,928.92**			**36,579.22**	**20,650.30**	**129.64%**	**7.18%**
	Retail Transmisssion (kW)	13,900	4.3886	61,001.54	13,900	4.409	61,285.10	283.56	0.46%	12.02%
	Delivery Sub-Total			**76,930.46**			**97,864.32**	**20,933.86**	**27.21%**	**19.20%**
	Other Charges (kWh)	4,897,870	0.0072	35,264.66	4,891,290	0.0072	35,217.29	(47.38)	(0.13%)	6.91%
	Cost of Power Commodity (kWh)	4,897,870	0.0650	318,361.55	4,891,290	0.0650	317,933.85	(427.70)	(0.13%)	62.38%
	SPC (kWh)	4,897,870	0.0003725	1,824.46	4,897,870	0.0000000	0.00	(1,824.46)	(100.00%)	0.00%
	Total Bill Before Taxes			**432,381.13**			**451,015.46**	**18,634.33**	**4.31%**	**88.50%**
	HST		13.00%	56,209.55		13.00%	58,632.01	2,422.46	4.31%	11.50%
	Total Bill			**488,590.68**			**509,647.47**	**21,056.79**	**4.31%**	**100.00%**

Horizon Utilities filed its Interrogatory Responses to the Smart Meter Funding Adder Application (EB-2010-0292) on January 13, 2011. In its response to Board staff Interrogatory 5, Horizon Utilities proposed an implementation date of March 1, 2011 for the Smart Meter Funding Adder and a revised amount of $2.15 per metered customer per month. The following tables show the bill impacts of the $2.15 Smart Meter Funding Adder.

RESIDENTIAL

Consumption
100 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			12.68			14.71	2.03	16.01%	48.64%
Distribution (kWh)	100	0.0125	1.25	100	0.0145	1.45	0.20	16.00%	4.79%
Low Voltage Rider (kWh)	100	0.0000	0.00	100	0.000050	0.01	0.01	#DIV/0!	0.02%
Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	7.11%
LRAM & SSM Rider (kWh)	100	0.0002	0.02	100		0.00	(0.02)	(100.00%)	0.00%
Smart Meter Entity ($/Month)						0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	100		0.00	100	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	100	(0.0023)	(0.23)	100	(0.0020)	(0.20)	0.03	(13.04%)	(0.66%)
Distribution Sub-Total			**15.28**			**18.12**	**2.84**	**18.55%**	**59.90%**
Retail Transmisssion (kWh)	104	0.0108	1.13	104	0.0109	1.13	0.01	0.79%	3.75%
Delivery Sub-Total			**16.41**			**19.25**	**2.84**	**17.34%**	**63.65%**
Other Charges (kWh)	104	0.0072	0.75	104	0.0072	0.75	(0.00)	(0.13%)	2.48%
Cost of Power Commodity (kWh)	104	0.0650	6.77	104	0.0650	6.76	(0.01)	(0.13%)	22.37%
SPC (kWh)	104	0.0003725	0.04	104	0.0000000	0.00	(0.04)	(100.00%)	0.00%
Total Bill Before Taxes			**23.97**			**26.76**	**2.79**	**11.62%**	**88.50%**
HST		13.00%	3.12		13.00%	3.48	0.36	11.66%	11.50%
Total Bill			**27.08**			**30.24**	**3.15**	**11.63%**	**100.00%**

RESIDENTIAL

Consumption
250 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			12.68			14.71	2.03	16.01%	31.28%
Distribution (kWh)	250	0.0125	3.13	250	0.0145	3.63	0.50	16.00%	7.71%
Low Voltage Rider (kWh)	250	0.0000	0.00	250	0.000050	0.01	0.01	#DIV/0!	0.03%
Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	4.57%
LRAM & SSM Rider (kWh)	250	0.0002	0.05	250	0.0000	0.00	(0.05)	(100.00%)	0.00%
Smart Meter Entity ($/Month)						0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	250	0.0000	0.00	250	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	250	(0.0023)	(0.58)	250	(0.0020)	(0.50)	0.08	(13.04%)	(1.06%)
Distribution Sub-Total			**16.84**			**20.00**	**3.16**	**18.75%**	**42.52%**
Retail Transmisssion (kWh)	261	0.0108	2.81	260	0.0109	2.84	0.02	0.79%	6.03%
Delivery Sub-Total			**19.65**			**22.83**	**3.18**	**16.18%**	**48.55%**
Other Charges (kWh)	261	0.0072	1.88	260	0.0072	1.87	(0.00)	(0.13%)	3.98%
Cost of Power Commodity (kWh)	261	0.0650	16.93	260	0.0650	16.91	(0.02)	(0.13%)	35.96%
SPC (kWh)	261	0.0003725	0.10	261	0.0000000	0.00	(0.10)	(100.00%)	0.00%
Total Bill Before Taxes			**38.56**			**41.62**	**3.04**	**7.87%**	**88.50%**
HST		13.00%	5.01		13.00%	5.41	0.40	7.93%	11.50%
Total Bill			**43.57**			**47.03**	**3.43**	**7.88%**	**100.00%**

RESIDENTIAL

Consumption 500 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			12.68			14.71	2.03	16.01%	19.61%
Distribution (kWh)	500	0.0125	6.25	500	0.0145	7.25	1.00	16.00%	9.67%
Low Voltage Rider (kWh)	500	0.0000	0.00	500	0.000050	0.03	0.03	#DIV/0!	0.03%
Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	2.87%
LRAM & SSM Rider (kWh)	500	0.0002	0.10	500	0.0000	0.00	(0.10)	(100.00%)	0.00%
Smart Meter Entity ($/Month)						0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	500	0.0000	0.00	500	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	500	(0.0023)	(1.15)	500	(0.0020)	(1.00)	0.15	(13.04%)	(1.33%)
Distribution Sub-Total			**19.44**			**23.14**	**3.70**	**19.01%**	**30.84%**
Retail Transmisssion (kWh)	521	0.0108	5.63	520	0.0109	5.67	0.04	0.79%	7.56%
Delivery Sub-Total			**25.07**			**28.81**	**3.74**	**14.92%**	**38.41%**
Other Charges (kWh)	521	0.0072	3.75	520	0.0072	3.75	(0.01)	(0.13%)	5.00%
Cost of Power Commodity (kWh)	521	0.0650	33.87	520	0.0650	33.82	(0.05)	(0.13%)	45.09%
SPC (kWh)	521	0.0003725	0.19	521	0.0000000	0.00	(0.19)	(100.00%)	0.00%
Total Bill Before Taxes			**62.88**			**66.38**	**3.45**	**5.49%**	**88.50%**
HST		13.00%	8.17		13.00%	8.63	0.45	5.56%	11.50%
Total Bill			**71.06**			**75.00**	**3.90**	**5.50%**	**100.00%**

RESIDENTIAL

Consumption 680 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			12.68			14.71	2.03	16.01%	132.69%
Distribution (kWh)	680	0.0125	8.50	680	0.0145	9.86	1.36	16.00%	88.94%
Low Voltage Rider (kWh)	680	0.0000	0.00	680	0.000050	0.03	0.03	#DIV/0!	0.31%
Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	19.39%
LRAM & SSM Rider (kWh)	680	0.0002	0.14	680	0.0000	0.00	(0.14)	(100.00%)	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	680	0.0000	0.00	680	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	680	(0.0023)	(1.56)	680	(0.0020)	(1.36)	0.20	(13.04%)	(1.41%)
Distribution Sub-Total			**21.31**			**25.39**	**4.08**	**19.15%**	**26.35%**
Retail Transmisssion (kWh)	709	0.0108	7.65	708	0.0109	7.71	0.06	0.79%	8.00%
Delivery Sub-Total			**28.97**			**33.11**	**4.14**	**14.30%**	**34.36%**
Other Charges (kWh)	709	0.0072	5.10	708	0.0072	5.10	(0.01)	(0.13%)	5.29%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	40.47%
Cost of Power Commodity (kWh)	109	0.0750	8.15	108	0.0750	8.08	(0.07)	(0.88%)	8.38%
SPC (kWh)	709	0.0003725	0.26	709	0.0000000	0.00	(0.26)	(100.00%)	0.00%
Total Bill Before Taxes			**81.48**			**85.28**	**3.80**	**4.66%**	**88.50%**
HST		13.00%	10.59		13.00%	11.09	0.49	4.66%	11.50%
Total Bill			**92.07**			**96.36**	**4.29**	**4.66%**	**100.00%**

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RESIDENTIAL

Consumption: 800 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			12.68			14.71	2.03	16.01%	13.23%
Distribution (kWh)	800	0.0125	10.00	800	0.0145	11.60	1.60	16.00%	10.43%
Low Voltage Rider (kWh)	800	0.0000	0.00	800	0.000050	0.04	0.04	#DIV/0!	0.04%
Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	1.93%
LRAM & SSM Rider (kWh)	800	0.0002	0.16	800	0.0000	0.00	(0.16)	(100.00%)	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	800	0.0000	0.00	800	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	800	(0.0023)	(1.84)	800	(0.0020)	(1.60)	0.24	(13.04%)	(1.44%)
Distribution Sub-Total			**22.56**			**26.90**	**4.34**	**19.24%**	**24.19%**
Retail Transmisssion (kWh)	834	0.0108	9.00	833	0.0109	9.07	0.07	0.79%	8.16%
Delivery Sub-Total			**31.56**			**35.97**	**4.41**	**13.98%**	**32.35%**
Other Charges (kWh)	834	0.0072	6.00	833	0.0072	5.99	(0.01)	(0.13%)	5.39%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	35.07%
Cost of Power Commodity (kWh)	234	0.0750	17.53	233	0.0750	17.44	(0.08)	(0.48%)	15.68%
SPC (kWh)	834	0.0003725	0.31	834	0.0000000	0.00	(0.31)	(100.00%)	0.00%
Total Bill Before Taxes			**94.40**			**98.41**	**4.01**	**4.25%**	**88.50%**
HST		13.00%	12.27		13.00%	12.79	0.52	4.25%	11.50%
Total Bill			**106.68**			**111.20**	**4.53**	**4.25%**	**100.00%**

RESIDENTIAL

Consumption: 1,000 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			12.68			14.71	2.03	16.01%	10.82%
Distribution (kWh)	1,000	0.0125	12.50	1,000	0.0145	14.50	2.00	16.00%	10.67%
Low Voltage Rider (kWh)	1,000	0.0000	0.00	1,000	0.000050	0.05	0.05	#DIV/0!	0.04%
Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	1.58%
LRAM & SSM Rider (kWh)	1,000	0.0002	0.20	1,000	0.0000	0.00	(0.20)	(100.00%)	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	1,000	0.0000	0.00	1,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	1,000	(0.0023)	(2.30)	1,000	(0.0020)	(2.00)	0.30	(13.04%)	(1.47%)
Distribution Sub-Total			**24.64**			**29.41**	**4.77**	**19.36%**	**21.63%**
Retail Transmisssion (kWh)	1,042	0.0108	11.25	1,041	0.0109	11.34	0.09	0.79%	8.34%
Delivery Sub-Total			**35.89**			**40.75**	**4.86**	**13.54%**	**29.98%**
Other Charges (kWh)	1,042	0.0072	7.50	1,041	0.0072	7.49	(0.01)	(0.13%)	5.51%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	28.69%
Cost of Power Commodity (kWh)	442	0.0750	33.16	441	0.0750	33.05	(0.11)	(0.32%)	24.31%
SPC (kWh)	1,042	0.0003725	0.39	1,042	0.0000000	0.00	(0.39)	(100.00%)	0.00%
Total Bill Before Taxes			**115.94**			**120.30**	**4.36**	**3.76%**	**88.50%**
HST		13.00%	15.07		13.00%	15.64	0.57	3.76%	11.50%
Total Bill			**131.02**			**135.94**	**4.92**	**3.76%**	**100.00%**

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RESIDENTIAL

Consumption
1,500 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			12.68			14.71	2.03	16.01%	7.44%
Distribution (kWh)	1,500	0.0125	18.75	1,500	0.0145	21.75	3.00	16.00%	11.00%
Low Voltage Rider (kWh)	1,500	0.0000	0.00	1,500	0.000050	0.08	0.08	#DIV/0!	0.04%
Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	1.09%
LRAM & SSM Rider (kWh)	1,500	0.0002	0.30	1,500	0.0000	0.00	(0.30)	(100.00%)	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	1,500	0.0000	0.00	1,500	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	1,500	(0.0023)	(3.45)	1,500	(0.0020)	(3.00)	0.45	(13.04%)	(1.52%)
Distribution Sub-Total			**29.84**			**35.69**	**5.85**	**19.59%**	**18.04%**
Retail Transmisssion (kWh)	1,563	0.0108	16.88	1,561	0.0109	17.02	0.13	0.79%	8.60%
Delivery Sub-Total			**46.72**			**52.70**	**5.98**	**12.80%**	**26.65%**
Other Charges (kWh)	1,563	0.0072	11.25	1,561	0.0072	11.24	(0.02)	(0.13%)	5.68%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	19.72%
Cost of Power Commodity (kWh)	963	0.0750	72.24	961	0.0750	72.08	(0.16)	(0.22%)	36.45%
SPC (kWh)	1,563	0.0003725	0.58	1,563	0.0000000	0.00	(0.58)	(100.00%)	0.00%
Total Bill Before Taxes			**169.80**			**175.02**	**5.22**	**3.08%**	**88.50%**
HST		13.00%	22.07		13.00%	22.75	0.68	3.08%	11.50%
Total Bill			**191.87**			**197.77**	**5.90**	**3.08%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
2,000 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			27.45			33.87	6.42	23.39%	12.86%
Distribution (kWh)	2,000	0.0072	14.40	2,000	0.0089	17.80	3.40	23.61%	6.76%
Low Voltage Rider (kWh)	2,000	0.0000	0.00	2,000	0.000040	0.08	0.08	#DIV/0!	0.03%
Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	0.82%
LRAM & SSM Rider (kWh)	2,000	0.0000	0.00	2,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	2,000	0.0000	0.00	2,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	2,000	(0.0025)	(5.00)	2,000	(0.0023)	(4.60)	0.40	(8.00%)	(1.75%)
Distribution Sub-Total			**38.41**			**49.30**	**10.89**	**28.35%**	**18.72%**
Retail Transmisssion (kWh)	2,084	0.0097	20.22	2,081	0.0097	20.19	(0.03)	(0.13%)	7.67%
Delivery Sub-Total			**58.63**			**69.49**	**10.86**	**18.53%**	**26.38%**
Other Charges (kWh)	2,084	0.0072	15.01	2,081	0.0072	14.99	(0.02)	(0.13%)	5.69%
Cost of Power Commodity (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	18.51%
Cost of Power Commodity (kWh)	1,334	0.0750	100.07	1,331	0.0750	99.86	(0.21)	(0.21%)	37.91%
SPC (kWh)	2,084	0.0003725	0.78	2,084	0.0000000	0.00	(0.78)	(100.00%)	0.00%
Total Bill Before Taxes			**223.22**			**233.08**	**$9.86**	**4.42%**	**88.50%**
HST		13.00%	29.02		13.00%	30.30	1.28	4.42%	11.50%
Total Bill			**252.24**			**263.38**	**$11.14**	**4.42%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
5,000 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			27.45			33.87	6.42	23.39%	5.55%
Distribution (kWh)	5,000	0.0072	36.00	5,000	0.0089	44.50	8.50	23.61%	7.29%
Low Voltage Rider (kWh)	5,000	0.0000	0.00	5,000	0.000040	0.20	0.20	#DIV/0!	0.03%
Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	0.35%
LRAM & SSM Rider (kWh)	5,000	0.0000	0.00	5,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	5,000	0.0000	0.00	5,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	5,000	(0.0025)	(12.50)	5,000	(0.0023)	(11.50)	1.00	(8.00%)	(1.88%)
Distribution Sub-Total			**52.51**			**69.22**	**16.71**	**31.82%**	**11.35%**
Retail Transmisssion (kWh)	5,211	0.0097	50.54	5,204	0.0097	50.47	(0.07)	(0.13%)	8.27%
Delivery Sub-Total			**103.05**			**119.69**	**16.64**	**16.15%**	**19.62%**
Other Charges (kWh)	5,211	0.0072	37.52	5,204	0.0072	37.47	(0.05)	(0.13%)	6.14%
Cost of Power Commodity (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	7.99%
Cost of Power Commodity (kWh)	4,461	0.0750	334.54	4,454	0.0750	334.01	(0.52)	(0.16%)	54.75%
SPC (kWh)	5,211	0.0003725	1.94	5,211	0.0000000	0.00	(1.94)	(100.00%)	0.00%
Total Bill Before Taxes			**525.80**			**539.92**	**$14.13**	**2.69%**	**88.50%**
HST		13.00%	68.35		13.00%	70.19	1.84	2.69%	11.50%
Total Bill			**594.15**			**610.11**	**$15.96**	**2.69%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
10,000 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			27.45			33.87	6.42	23.39%	2.85%
Distribution (kWh)	10,000	0.0072	72.00	10,000	0.0089	89.00	17.00	23.61%	7.49%
Low Voltage Rider (kWh)	10,000	0.0000	0.00	10,000	0.000040	0.40	0.40	#DIV/0!	0.03%
Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	0.18%
LRAM & SSM Rider (kWh)	10,000	0.0000	0.00	10,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	10,000	0.0000	0.00	10,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh)	10,000	(0.0025)	(25.00)	10,000	(0.0023)	(23.00)	2.00	(8.00%)	(1.94%)
Distribution Sub-Total			**76.01**			**102.42**	**26.41**	**34.75%**	**8.62%**
Retail Transmisssion (kWh)	10,421	0.0097	101.08	10,407	0.0097	100.95	(0.14)	(0.13%)	8.50%
Delivery Sub-Total			**177.09**			**203.37**	**26.27**	**14.84%**	**17.12%**
Other Charges (kWh)	10,421	0.0072	75.03	10,407	0.0072	74.93	(0.10)	(0.13%)	6.31%
Cost of Power Commodity (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	4.10%
Cost of Power Commodity (kWh)	9,671	0.0750	725.33	9,657	0.0750	724.28	(1.05)	(0.14%)	60.97%
SPC (kWh)	10,421	0.0003725	3.88	10,421	0.0000000	0.00	(3.88)	(100.00%)	0.00%
Total Bill Before Taxes			**1,030.08**			**1,051.32**	**$21.24**	**2.06%**	**88.50%**
HST		13.00%	133.91		13.00%	136.67	2.76	2.06%	11.50%
Total Bill			**1,163.99**			**1,188.00**	**$24.00**	**2.06%**	**100.00%**

GENERAL SERVICE < 50 kW

		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			27.45			33.87	6.42	23.39%	2.29%
12,500 kWh	Distribution (kWh)	12,500	0.0072	90.00	12,500	0.0089	111.25	21.25	23.61%	7.53%
	Low Voltage Rider (kWh)	12,500	0.0000	0.00	12,500	0.000040	0.50	0.50	#DIV/0!	0.03%
	Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	0.15%
	LRAM & SSM Rider (kWh)	12,500	0.0000	0.00	12,500	0.0000	0.00	0.00	#DIV/0!	0.00%
	Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
	Late Payment (kWh)	12,500	0.0000	0.00	12,500	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh)	12,500	(0.0025)	(31.25)	12,500	(0.0023)	(28.75)	2.50	(8.00%)	(1.95%)
	Distribution Sub-Total			**87.76**			**119.02**	**31.26**	**35.62%**	**8.06%**
	Retail Transmisssion (kWh)	13,026	0.0097	126.35	13,009	0.0097	126.18	(0.17)	(0.13%)	8.54%
	Delivery Sub-Total			**214.11**			**245.20**	**31.09**	**14.52%**	**16.60%**
	Other Charges (kWh)	13,026	0.0072	93.79	13,009	0.0072	93.66	(0.13)	(0.13%)	6.34%
	Cost of Power Commodity (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	3.30%
	Cost of Power Commodity (kWh)	12,276	0.0750	920.72	12,259	0.0750	919.41	(1.31)	(0.14%)	62.25%
	SPC (kWh)	13,026	0.0003725	4.85	13,026	0.0000000	0.00	(4.85)	(100.00%)	0.00%
	Total Bill Before Taxes			**1,282.22**			**1,307.02**	**$24.80**	**1.93%**	**88.50%**
	HST		13.00%	166.69		13.00%	169.91	3.22	1.93%	11.50%
	Total Bill			**1,448.91**			**1,476.94**	**$28.02**	**1.93%**	**100.00%**

GENERAL SERVICE < 50 kW

		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			27.45			33.87	6.42	23.39%	1.92%
15,000 kWh	Distribution (kWh)	15,000	0.0072	108.00	15,000	0.0089	133.50	25.50	23.61%	7.56%
	Low Voltage Rider (kWh)	15,000	0.0000	0.00	15,000	0.000040	0.60	0.60	#DIV/0!	0.03%
	Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	0.12%
	LRAM & SSM Rider (kWh)	15,000	0.0000	0.00	15,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
	Late Payment (kWh)	15,000	0.0000	0.00	15,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh)	15,000	(0.0025)	(37.50)	15,000	(0.0023)	(34.50)	3.00	(8.00%)	(1.95%)
	Distribution Sub-Total			**99.51**			**135.62**	**36.11**	**36.29%**	**7.68%**
	Retail Transmisssion (kWh)	15,632	0.0097	151.63	15,611	0.0097	151.42	(0.20)	(0.13%)	8.57%
	Delivery Sub-Total			**251.14**			**287.04**	**35.91**	**14.30%**	**16.25%**
	Other Charges (kWh)	15,632	0.0072	112.55	15,611	0.0072	112.40	(0.15)	(0.13%)	6.36%
	Cost of Power Commodity (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	2.76%
	Cost of Power Commodity (kWh)	14,882	0.0750	1,116.11	14,861	0.0750	1,114.54	(1.58)	(0.14%)	63.12%
	SPC (kWh)	15,632	0.0003725	5.82	15,632	0.0000000	0.00	(5.82)	(100.00%)	0.00%
	Total Bill Before Taxes			**1,534.37**			**1,562.72**	**$28.36**	**1.85%**	**88.50%**
	HST		13.00%	199.47		13.00%	203.15	3.69	1.85%	11.50%
	Total Bill			**1,733.84**			**1,765.88**	**$32.04**	**1.85%**	**100.00%**

GENERAL SERVICE > 50 kW

		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			250.33			332.50	82.17	32.82%	9.47%
30,000 kWh	Distribution (kW)	100	1.7875	178.75	100	2.2606	226.06	47.31	26.47%	6.44%
100 kW	Low Voltage Rider (kW)	100	0.0121	1.21	100	0.018250	1.83	0.62	50.83%	0.05%
	Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	0.06%
	LRAM & SSM Rider (kW)	100		0.00	100	0.0000	0.00	0.00	#DIV/0!	0.00%
	Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
	Late Payment (kWh)	30,000	0.0000	0.00	30,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW)	100	(1.0002)	(100.02)	100	(0.9295)	(92.95)	7.07	(7.07%)	(2.65%)
	Distribution Sub-Total			**331.83**			**469.59**	**137.76**	**41.51%**	**13.37%**
	Retail Transmisssion (kW)	100	3.8311	383.11	100	3.8489	384.89	1.78	0.46%	10.96%
	Delivery Sub-Total			**714.94**			**854.48**	**139.54**	**19.52%**	**24.32%**
	Other Charges (kWh)	31,263	0.0072	225.09	31,221	0.0072	224.79	(0.30)	(0.13%)	6.40%
	Cost of Power Commodity (kWh)	31,263	0.0650	2,032.10	31,221	0.0650	2,029.37	(2.73)	(0.13%)	57.77%
	SPC (kWh)	31,263	0.0003725	11.65	31,263	0.0000000	0.00	(11.65)	(100.00%)	0.00%
	Total Bill Before Taxes			**2,983.77**			**3,108.63**	**124.86**	**4.18%**	**88.50%**
	HST		13.00%	387.89		13.00%	404.12	16.23	4.18%	11.50%
	Total Bill			**3,371.66**			**3,512.75**	**141.09**	**4.18%**	**100.00%**

GENERAL SERVICE > 50 kW

		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			250.33			332.50	82.17	32.82%	4.05%
75,000 kWh	Distribution (kW)	250	1.7875	446.88	250	2.2606	565.15	118.28	26.47%	6.88%
250 kW	Low Voltage Rider (kW)	250	0.0121	3.03	250	0.018250	4.56	1.54	50.83%	0.06%
	Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	0.03%
	LRAM & SSM Rider (kW)	250		0.00	250	0.0000	0.00	0.00	#DIV/0!	0.00%
	Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
	Late Payment (kWh)	75,000	0.0000	0.00	75,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW)	250	(1.0002)	(250.05)	250	(0.9295)	(232.38)	17.68	(7.07%)	(2.83%)
	Distribution Sub-Total			**451.74**			**671.99**	**220.25**	**48.76%**	**8.18%**
	Retail Transmisssion (kW)	250	3.8311	957.78	250	3.8489	962.23	4.45	0.46%	11.71%
	Delivery Sub-Total			**1,409.52**			**1,634.21**	**224.70**	**15.94%**	**19.89%**
	Other Charges (kWh)	78,158	0.0072	562.73	78,053	0.0072	561.98	(0.76)	(0.13%)	6.84%
	Cost of Power Commodity (kWh)	78,158	0.0650	5,080.24	78,053	0.0650	5,073.41	(6.82)	(0.13%)	61.76%
	SPC (kWh)	78,158	0.0003725	29.11	78,158	0.0000000	0.00	(29.11)	(100.00%)	0.00%
	Total Bill Before Taxes			**7,081.60**			**7,269.60**	**188.00**	**2.65%**	**88.50%**
	HST		13.00%	920.61		13.00%	945.05	24.44	2.65%	11.50%
	Total Bill			**8,002.21**			**8,214.65**	**212.44**	**2.65%**	**100.00%**

1

GENERAL SERVICE > 50 kW

Consumption
100,000 kWh
350 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			250.33			332.50	82.17	32.82%	3.04%
Distribution (kW)	350	1.7875	625.63	350	2.2606	791.21	165.59	26.47%	7.24%
Low Voltage Rider (kW)	350	0.0121	4.24	350	0.018250	6.39	2.15	50.83%	0.06%
Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	0.02%
LRAM & SSM Rider (kW)	350		0.00	350	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	100,000	0.0000	0.00	100,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW)	350	(1.0002)	(350.07)	350	(0.9295)	(325.33)	24.75	(7.07%)	(2.98%)
Distribution Sub-Total			**531.68**			**806.92**	**275.24**	**51.77%**	**7.39%**
Retail Transmisssion (kW)	350	3.8311	1,340.89	350	3.8489	1,347.12	6.23	0.46%	12.33%
Delivery Sub-Total			**1,872.57**			**2,154.04**	**281.47**	**15.03%**	**19.72%**
Other Charges (kWh)	104,210	0.0072	750.31	104,070	0.0072	749.30	(1.01)	(0.13%)	6.86%
Cost of Power Commodity (kWh)	104,210	0.0650	6,773.65	104,070	0.0650	6,764.55	(9.10)	(0.13%)	61.92%
SPC (kWh)	104,210	0.0003725	38.82	104,210	0.0000000	0.00	(38.82)	(100.00%)	0.00%
Total Bill Before Taxes			**9,435.35**			**9,667.89**	**232.55**	**2.46%**	**88.50%**
HST		13.00%	1,226.59		13.00%	1,256.83	30.23	2.46%	11.50%
Total Bill			**10,661.94**			**10,924.72**	**262.78**	**2.46%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
800,000 kWh
2,000 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			250.33			332.50	82.17	32.82%	0.42%
Distribution (kW)	2,000	1.7875	3,575.00	2,000	2.2606	4,521.20	946.20	26.47%	5.65%
Low Voltage Rider (kW)	2,000	0.0121	24.20	2,000	0.018250	36.50	12.30	50.83%	0.05%
Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	0.00%
LRAM & SSM Rider (kW)	2,000		0.00	2,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	800,000	0.0000	0.00	800,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW)	2,000	(1.0002)	(2,000.40)	2,000	(0.9295)	(1,859.00)	141.40	(7.07%)	(2.32%)
Distribution Sub-Total			**1,850.69**			**3,033.35**	**1,182.66**	**63.90%**	**3.79%**
Retail Transmisssion (kW)	2,000	3.8311	7,662.20	2,000	3.8489	7,697.80	35.60	0.46%	9.62%
Delivery Sub-Total			**9,512.89**			**10,731.15**	**1,218.26**	**12.81%**	**13.41%**
Other Charges (kWh)	833,680	0.0072	6,002.50	832,560	0.0072	5,994.43	(8.06)	(0.13%)	7.49%
Cost of Power Commodity (kWh)	833,680	0.0650	54,189.20	832,560	0.0650	54,116.40	(72.80)	(0.13%)	67.60%
SPC (kWh)	833,680	0.0003725	310.55	833,680	0.0000000	0.00	(310.55)	(100.00%)	0.00%
Total Bill Before Taxes			**70,015.13**			**70,841.98**	**826.85**	**1.18%**	**88.50%**
HST		13.00%	9,101.97		13.00%	9,209.46	107.49	1.18%	11.50%
Total Bill			**79,117.10**			**80,051.44**	**934.34**	**1.18%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
1,600,000 kWh
4,000 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			250.33			332.50	82.17	32.82%	0.21%
Distribution (kW)	4,000	1.7875	7,150.00	4,000	2.2606	9,042.40	1,892.40	26.47%	5.66%
Low Voltage Rider (kW)	4,000	0.0121	48.40	4,000	0.018250	73.00	24.60	50.83%	0.05%
Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	0.00%
LRAM & SSM Rider (kW)	4,000		0.00	4,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	1,600,000	0.0000	0.00	1,600,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW)	4,000	(1.0002)	(4,000.80)	4,000	(0.9295)	(3,718.00)	282.80	(7.07%)	(2.33%)
Distribution Sub-Total			**3,449.49**			**5,732.05**	**2,282.56**	**66.17%**	**3.59%**
Retail Transmisssion (kW)	4,000	3.8311	15,324.40	4,000	3.8489	15,395.60	71.20	0.46%	9.64%
Delivery Sub-Total			**18,773.89**			**21,127.65**	**2,353.76**	**12.54%**	**13.23%**
Other Charges (kWh)	1,667,360	0.0072	12,004.99	1,665,120	0.0072	11,988.86	(16.13)	(0.13%)	7.51%
Cost of Power Commodity (kWh)	1,667,360	0.0650	108,378.40	1,665,120	0.0650	108,232.80	(145.60)	(0.13%)	67.76%
SPC (kWh)	1,667,360	0.0003725	621.09	1,667,360	0.0000000	0.00	(621.09)	(100.00%)	0.00%
Total Bill Before Taxes			**139,778.37**			**141,349.31**	**1,570.94**	**1.12%**	**88.50%**
HST		13.00%	18,171.19		13.00%	18,375.41	204.22	1.12%	11.50%
Total Bill			**157,949.56**			**159,724.72**	**1,775.16**	**1.12%**	**100.00%**

LARGE USER (> 5000 kW)

Consumption
2,800,000 kWh
6,500 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			11,151.32			26,699.15	15,547.83	139.43%	8.74%
Distribution (kW)	6,500	1.0123	6,579.95	6,500	1.2933	8,406.45	1,826.50	27.76%	2.75%
Low Voltage Rider (kW)	6,500	0.014	91.00	6,500	0.019320	125.58	34.58	38.00%	0.04%
Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	0.00%
LRAM & SSM Rider (kW)	6,500		0.00	6,500	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	2,800,000	0.0000	0.00	2,800,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW)	6,500	(0.6827)	-4,437.55	6,500	(0.6020)	(3,913.00)	524.55	(11.82%)	(1.28%)
Distribution Sub-Total			**13,386.28**			**31,320.33**	**17,934.05**	**133.97%**	**10.25%**
Retail Transmisssion (kW)	6,500	4.3886	28,525.90	6,500	4.409	28,658.50	132.60	0.46%	9.38%
Delivery Sub-Total			**41,912.18**			**59,978.83**	**18,066.65**	**43.11%**	**19.63%**
Other Charges (kWh)	2,917,880	0.0072	21,008.74	2,913,960	0.0072	20,980.51	(28.22)	(0.13%)	6.87%
Cost of Power Commodity (kWh)	2,917,880	0.0650	189,662.20	2,913,960	0.0650	189,407.40	(254.80)	(0.13%)	62.00%
SPC (kWh)	2,917,880	0.0003725	1,086.91	2,917,880	0.0000000	0.00	(1,086.91)	(100.00%)	0.00%
Total Bill Before Taxes			**253,670.03**			**270,366.74**	**16,696.72**	**6.58%**	**88.50%**
HST		13.00%	32,977.10		13.00%	35,147.68	2,170.57	6.58%	11.50%
Total Bill			**286,647.13**			**305,514.42**	**18,867.29**	**6.58%**	**100.00%**

LARGE USER (> 5000 kW)

Consumption
3,100,000 kWh
7,500 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			11,151.32			26,699.15	15,547.83	139.43%	7.93%
Distribution (kW)	7,500	1.0123	7,592.25	7,500	1.2933	9,699.75	2,107.50	27.76%	2.88%
Low Voltage Rider (kW)	7,500	0.014	105.00	7,500	0.019320	144.90	39.90	38.00%	0.04%
Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	0.00%
LRAM & SSM Rider (kW)	7,500		0.00	7,500	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	3,100,000	0.0000	0.00	3,100,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW)	7,500	(0.6827)	(5,120.25)	7,500	(0.6020)	(4,515.00)	605.25	(11.82%)	(1.34%)
Distribution Sub-Total			**13,729.88**			**32,030.95**	**18,301.07**	**133.29%**	**9.51%**
Retail Transmisssion (kW)	7,500	4.3886	32,914.50	7,500	4.409	33,067.50	153.00	0.46%	9.82%
Delivery Sub-Total			**46,644.38**			**65,098.45**	**18,454.07**	**39.56%**	**19.33%**
Other Charges (kWh)	3,230,510	0.0072	23,259.67	3,226,170	0.0072	23,228.42	(31.25)	(0.13%)	6.90%
Cost of Power Commodity (kWh)	3,230,510	0.0650	209,983.15	3,226,170	0.0650	209,701.05	(282.10)	(0.13%)	62.27%
SPC (kWh)	3,230,510	0.0003725	1,203.36	3,230,510	0.0000000	0.00	(1,203.36)	(100.00%)	0.00%
Total Bill Before Taxes			**281,090.57**			**298,027.92**	**16,937.36**	**6.03%**	**88.50%**
HST		13.00%	36,541.77		13.00%	38,743.63	2,201.86	6.03%	11.50%
Total Bill			**317,632.34**			**336,771.55**	**19,139.21**	**6.03%**	**100.00%**

LARGE USER (> 5000 kW)

Consumption
4,200,000 kWh
10,000 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			11,151.32			26,699.15	15,547.83	139.43%	6.00%
Distribution (kW)	10,000	1.0123	10,123.00	10,000	1.2933	12,933.00	2,810.00	27.76%	2.91%
Low Voltage Rider (kW)	10,000	0.014	140.00	10,000	0.019320	193.20	53.20	38.00%	0.04%
Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	0.00%
LRAM & SSM Rider (kW)	10,000		0.00	10,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	4,200,000	0.0000	0.00	4,200,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW)	10,000	(0.6827)	(6,827.00)	10,000	(0.6020)	(6,020.00)	807.00	(11.82%)	(1.35%)
Distribution Sub-Total			**14,588.88**			**33,807.50**	**19,218.62**	**131.73%**	**7.60%**
Retail Transmisssion (kW)	10,000	4.3886	43,886.00	10,000	4.409	44,090.00	204.00	0.46%	9.92%
Delivery Sub-Total			**58,474.88**			**77,897.50**	**19,422.62**	**33.22%**	**17.52%**
Other Charges (kWh)	4,376,820	0.0072	31,513.10	4,370,940	0.0072	31,470.77	(42.34)	(0.13%)	7.08%
Cost of Power Commodity (kWh)	4,376,820	0.0650	284,493.30	4,370,940	0.0650	284,111.10	(382.20)	(0.13%)	63.90%
SPC (kWh)	4,376,820	0.0003725	1,630.37	4,376,820	0.0000000	0.00	(1,630.37)	(100.00%)	0.00%
Total Bill Before Taxes			**376,111.65**			**393,479.37**	**17,367.72**	**4.62%**	**88.50%**
HST		13.00%	48,894.51		13.00%	51,152.32	2,257.80	4.62%	11.50%
Total Bill			**425,006.16**			**444,631.69**	**19,625.52**	**4.62%**	**100.00%**

LARGE USER (> 5000 kW)

Consumption
4,700,000 kWh
13,900 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			11,151.32			26,699.15	15,547.83	139.43%	5.24%
Distribution (kW)	13,900	1.0123	14,070.97	13,900	1.2933	17,976.87	3,905.90	27.76%	3.53%
Low Voltage Rider (kW)	13,900	0.014	194.60	13,900	0.019320	268.55	73.95	38.00%	0.05%
Smart Meter Rider (per month)			1.56			2.15	0.59	37.82%	0.00%
LRAM & SSM Rider (kW)	13,900		0.00	13,900	0.0000	0.00	0.00	#DIV/0!	0.00%
Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
Late Payment (kWh)	4,700,000	0.0000	0.00	4,700,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW)	13,900	(0.6827)	(9,489.53)	13,900	(0.6020)	(8,367.80)	1,121.73	(11.82%)	(1.64%)
Distribution Sub-Total			**15,928.92**			**36,578.92**	**20,650.00**	**129.64%**	**7.18%**
Retail Transmisssion (kW)	13,900	4.3886	61,001.54	13,900	4.409	61,285.10	283.56	0.46%	12.03%
Delivery Sub-Total			**76,930.46**			**97,864.02**	**20,933.56**	**27.21%**	**19.20%**
Other Charges (kWh)	4,897,870	0.0072	35,264.66	4,891,290	0.0072	35,217.29	(47.38)	(0.13%)	6.91%
Cost of Power Commodity (kWh)	4,897,870	0.0650	318,361.55	4,891,290	0.0650	317,933.85	(427.70)	(0.13%)	62.38%
SPC (kWh)	4,897,870	0.0003725	1,824.46	4,897,870	0.0000000	0.00	(1,824.46)	(100.00%)	0.00%
Total Bill Before Taxes			**432,381.13**			**451,015.16**	**18,634.03**	**4.31%**	**88.50%**
HST		13.00%	56,209.55		13.00%	58,631.97	2,422.42	4.31%	11.50%
Total Bill			**488,590.68**			**509,647.13**	**21,056.45**	**4.31%**	**100.00%**

c) The residential class at 100kWh consumption is the only customer profile where the total bill impact is in excess of 10% whether using the as filed Smart Meter Funding Adder of $2.45 or the updated Smart Meter Funding Adder of $2.15.

d) Due to the limited customer profile, and the low absolute dollar impact, in which the bill impact is in excess of 10%, Horizon Utilities has not considered rate mitigation to constrain these impacts.

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 51

Reference: E9/T1/S1/pages 4-5 Deferral and Variance Accounts

Horizon is seeking Board's approval for a new variance account for the Provincial Meter Data Management and Repository (MDMR) Costs from the IESO for the Smart Meter Entity (SME). Since the IESO has not yet filed an application with the Board for the recovery of such costs, and this charge will affect all of the distributors in the province, why does Horizon consider it necessary to request such an account at this time?

Response:

Horizon Utilities expected that the Independent Electricity System Operator ("IESO") would be filing its application for a for the Provincial Meter Data Management and Repository ("MDMR") costs from the IESO for the Smart Meter Entity ("SME"), subsequent to the filing of this Application. Further, Horizon Utilities anticipated that such costs would be in place for 2011. Horizon Utilities notes that the IESO has not yet filed such application. Horizon Utilities does not therefore consider this request necessary, at this time.

EB-2010-0131

HORIZON UTILITIES CORPORATION ("HORIZON UTILITIES")
RESPONSES TO
BOARD STAFF INTERROGATORIES

DELIVERED: January 24th, 2011

Question 52

Reference: E9/T1/S1/page 5 Deferral and Variance Accounts

Horizon is seeking Board's approval for a new deferral account for OMERS contribution increase. The prefiled evidence (page 5, lines 12-13) indicates that these costs are included in Horizon's OM&A costs for 2011. Please state:

a) Whether or not the forecasted 2011 OM&A costs include the OMERS base costs as well as the contribution increase for 2011 announced by OMERS on July 5, 2010.

b) If the OM&A costs include both cost components referred to in a) (i.e. the base OMERS costs as well as the increase), why does Horizon consider it necessary to request a new deferral account?

c) What is the quantum of the OMERS contribution increase included in 2011 OM&A?

d) What are the forecasted increases in OMERS contribution forecasted in 2011 and beyond, by year. Please provide support for the forecasted increases.

e) An alternative to a deferral account could be to include an averaged or "normalized" level of OMERS contributions reflected the forecasted increases in 2011 to 2014. Please provide Horizon's views on the merits and appropriateness of such an approach. If possible, please provide an estimate of what the "normalized" level would be, showing its derivation.

Response:

a) Horizon Utilities confirms that the 2011 OM&A costs include the OMERS base contribution plus the increase in the contribution announced on July 5, 2010.

b) Horizon Utilities has requested a deferral account in order to track the difference between the actual OMERS contributions and the estimated contributions underlying the Application. The use of the deferral account will provide a mechanism to true-up estimated costs with actual costs for disposition at a later date.

While OMERS has laid out a temporary three year funding plan to address a $1.5 billion shortfall in the plan as at December 31, 2009, OMERS has also noted that the deficit is expected to increase over the next four years. This creates additional uncertainty with respect to the planned increases of 1% - 2011; 1% - 2012; 0.9% - 2013, which may also be sustained into 2014.

As noted in the Application, the proposed deferral account is also consistent with the Board's previous treatment of OMERS costs through its introduction of a new deferral account in 2005 following the end of the OMERS contribution holiday.

c) The increase in the OMERS contribution rate for the 2011 Test Year represents a total increase in payroll costs of approximately $340,000. Based on the level of total compensation costs charged to OM&A per Table 4-25, Horizon Utilities estimates the total impact on 2011 OM&A is approximately $235,000.

d) Based upon the information published by OMERS[1] in September 2010, the overall contribution levels for the OMERS plan are expected to increase as follows:

- 2011 – Effective with the first, full pay in 2011, contribution rates will increase, on average, by 1% per side (employee/employer) as a percentage of a member's earnings.

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[1] Source: http://www.omers.com

- 2012 – Effective with the first, full pay in 2012, contribution rates will increase, on average, by an additional 1% per side (employee/employer).

- 2013 – Effective with the first, full pay in 2013, contribution rates will increase, on average, by an additional 0.9% per side (employee/employer).

As part of the announced changes, OMERS also advised that it will continue to monitor the plans funded status, and to make any decisions on changes through their annual planning cycle.

Horizon Utilities would be open to the alternative suggested by Board Staff, provided there is a mechanism to provide for a future true-up, if such was required, as a result of changes implemented by OMERS beyond what is currently forecast.

Horizon Utilities estimates that the normalized level of OMERS contribution to be included in OM&A for the period 2011 to 2014 is $2,150,000 based upon the following assumptions:

- OMERS percentage increases identified in b) for 2011 through 2013 and assuming a 0.9% increase in 2014; and

- Annual salaries based on the number of employees underlying the 2011 Application and assuming a 3% wage increase year over year.

	2011	2012	2013	2014
	(1)	(2)	(2)	(2)
Salaries and Wages	$ 34,009,569	$ 35,029,856	$ 36,080,752	$ 37,163,174
% Increase in OMERS Contribution		1.0%	0.9%	0.9%
Estimated increase in OMERS Contribution		$ 350,299	$ 324,727	$ 334,469
Total Estimated OMERS Contribution Level	$ 2,606,736	$ 2,957,034	$ 3,281,761	$ 3,616,230
Allocation to OM&A (3)	69%	69%	69%	69%
OMERS Contribution in OM&A	$ 1,798,648	$ 2,040,354	$ 2,264,415	$ 2,495,199
Average OMERS Contribution Level 2011 to 2014				$ 2,149,654

Notes:
(1) Salaries and Wages as per Appendix 2-K - Employee Costs Total Company
(2) 3% salary and w age increase assumed in 2012, 2013, 2014
(3) Assumes allocation to OM&A is consistent w ith 2011 levels

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Question 53

Reference: E9/T1/S2/pages 4-6 Deferral and Variance Accounts

Horizon is using forecasted 2011 data for allocation by rate class. According to the EDDVAR Report:

> "With respect to the volume that should be used to calculate the rate riders, the Board agrees that the most recent Board-approved volumetric forecast should be used."

Please recalculate the rate riders using the most recent Board-approved volumetric forecasts for Horizon's service area.

Response:

Horizon Utilities has recalculated the rate riders using the most recent 2008 Board approved volumetric forecasts for Horizon Utilities' service area.

Table 9-9 - Proposed Rate Riders

PROPOSED RATES				
	All Classes		Non-Regulated Price Plan Customers Only	
Customer Class	Deferral and Variance Rates Riders ($) per kWh	Deferral and Variance Rates Riders ($) per kW	Non-RPP Global Adjustment Variance Rate Rider ($) per kWh	Non - RPP Global Adjustment Variance Rate Rider ($) per kW
RESIDENTIAL	0.0001		0.0004	
GENERAL SERVICE <50 KW	(0.0003)		0.0003	
GENERAL SERVICE >50 KW		(0.1556)		0.5827
LARGE USER		(0.1189)		0.3094
UNMETERED & SCATTERED LOADS	0.0000		0.0001	
SENTINEL LIGHTS		0.3514		0.0199
STREET LIGHTING		0.0574		0.6499
STANDBY		0.0298		0.0000

Table 9-8 - Billing Determinants and Allocators for Rate Rider Calculations

2008 Board Approved Billed Data By Class	kW	kWhs	Customer / Connection Counts	Metered Customers	Dx Revenue
RESIDENTIAL CLASS		1,698,681,251	214,658	214,658	60,820,364
GENERAL SERVICE <50 KW CLASS		633,227,782	17,931	17,931	12,191,419
GENERAL SERVICE >50 KW NON TIME OF USE	5,535,480	2,118,642,390	2,279	2,279	18,409,499
LARGE USER CLASS	3,876,319	1,088,833,225	12	12	7,782,749
UNMETERED & SCATTERED LOADS		18,237,718	1,879		636,137
SENTINEL LIGHTS	1,721	606,521	250		52,965
STREET LIGHTING	112,919	42,054,739	4		2,754,541
STANDBY	192,012				578,297
Totals	9,718,451	5,600,283,626	237,013	234,880	103,225,971

Allocators	kW	kWhs	Customer / Connection Counts	Metered Customers	Dx Revenue
RESIDENTIAL CLASS	0.0%	30.3%	90.6%	91.4%	58.9%
GENERAL SERVICE <50 KW CLASS	0.0%	11.3%	7.6%	7.6%	11.8%
GENERAL SERVICE >50 KW NON TIME OF USE	57.0%	37.8%	1.0%	1.0%	17.8%
LARGE USER CLASS	39.9%	19.4%	0.0%	0.0%	7.5%
UNMETERED & SCATTERED LOADS	0.0%	0.3%	0.8%	0.0%	0.6%
SENTINEL LIGHTS	0.0%	0.0%	0.1%	0.0%	0.1%
STREET LIGHTING	1.2%	0.8%	0.0%	0.0%	2.7%
STANDBY	2.0%	0.0%	0.0%	0.0%	0.6%
Totals	100%	100%	100%	100%	100%

Allocators - Non-RPP kWh			
Rate Class	**Total kWhs 2009**	**Non-RPP kWhs 2009**	**Ratio**
RESIDENTIAL CLASS	1,664,343,351	285,104,908	11.56%
GENERAL SERVICE <50 KW CLASS	601,884,833	93,367,393	3.79%
GENERAL SERVICE >50 KW NON TIME OF U	1,887,001,777	1,496,668,686	60.69%
LARGE USER CLASS	558,050,242	556,511,257	22.57%
UNMETERED & SCATTERED LOADS	13,271,876	432,122	0.02%
STREET LIGHTING	41,121,603	34,046,544	1.38%
SENTINEL LIGHTS	556,595	15,913	0.00%
STANDBY	-	-	0.00%
Total	4,766,230,277	2,466,146,824	100%

Table 9-7 - Calculation of Rate Riders

Group 1:	OEB	Allocator	Amount	RESIDENTIAL CLASS	GENERAL SERVICE <50 KW CLASS	GENERAL SERVICE >50 KW	LARGE USER CLASS	UNMETERED & SCATTERED LOADS	SENTINEL LIGHTS	STREET LIGHTING	STANDBY	Totals
Low Voltage	1550	kWh	69,410	21,053	7,848	26,258	13,495	226	8	521	0	69,410
RSVA - Wholesale Market Service Charge	1580	kWh	(2,016,350)	(611,600)	(227,990)	(762,805)	(392,028)	(6,566)	(218)	(15,142)	0	(2,016,350)
RSVA - Retail Transmission Network Charge	1584	kWh	919,083	278,777	103,921	347,698	178,692	2,993	100	6,902	0	919,083
RSVA - Retail Transmission Connection Charge	1586	kWh	(326,991)	(99,183)	(36,973)	(123,704)	(63,575)	(1,065)	(35)	(2,456)	0	(326,991)
RSVA - Power	1588	kWh	(1,412,127)	(428,327)	(159,670)	(534,222)	(274,552)	(4,599)	(153)	(10,604)	0	(1,412,127)
Sub-total RSVA			**(2,766,975)**	**(839,280)**	**(312,864)**	**(1,046,774)**	**(537,968)**	**(9,011)**	**(300)**	**(20,778)**	**0**	**(2,766,975)**
RSVA - Power Global Adjustment	1588	non-RPP kWh	5,315,314	614,490	201,236	3,225,787	1,199,455	931	34	73,381	0	5,315,314
Sub-total RSVA - Non-RPP			**5,315,314**	**614,490**	**201,236**	**3,225,787**	**1,199,455**	**931**	**34**	**73,381**	**0**	**5,315,314**
Group 2 Accounts:												
Other Regulatory Assets Deferred IFRS Transition Costs	1508	Dx Revenue	565,479	333,178	66,785	100,849	42,634	3,485	290	15,090	3,168	565,479
Other Regulatory Assets Incremental Capital Costs	1508	Dx Revenue	10,092	5,946	1,192	1,800	761	62	5	269	57	10,092
Other Regulatory Assets CDM Expenses	1508	Dx Revenue	445,690	262,599	52,638	79,485	33,603	2,747	229	11,893	2,497	445,690
Retail Cost Variance Account - Retail	1518	# customers	301,545	273,103	22,813	2,900	15	2,391	318	5	0	301,545
Retail Cost Variance Account - ST	1548	# customers	59,160	53,580	4,476	569	3	469	62	1	0	59,160
Sub-total Non-RSVA			**1,381,966**	**928,407**	**147,904**	**185,602**	**77,017**	**9,153**	**904**	**27,258**	**5,721**	**1,381,966**
Total to be Recovered over one year			**3,930,306**	**703,616**	**36,276**	**2,364,615**	**738,503**	**1,074**	**639**	**79,861**	**5,721**	**3,930,306**

Class	RESIDENTIAL CLASS	GENERAL SERVICE <50 KW CLASS	GENERAL SERVICE >50 KW	LARGE USER CLASS	UNMETERED & SCATTERED LOADS	SENTINEL LIGHTS	STREET LIGHTING	STANDBY
RSVA Account Recovery Rate Riders	(0.0005)	(0.0005)	(0.1891)	(0.1388)	(0.0005)	(0.1741)	(0.1840)	0.0000
Non-RSVA Account Recovery Rate Riders	0.0005	0.0002	0.0335	0.0199	0.0005	0.5256	0.2414	0.0298
	0.0001	(0.0003)	(0.1556)	(0.1189)	0.0000	0.3514	0.0574	0.0298
Billing Determinants	kWh	kWh	kW	kW	kWh	kW	kW	kW

Class	RESIDENTIAL CLASS	GENERAL SERVICE <50 KW CLASS	GENERAL SERVICE >50 KW	LARGE USER CLASS	UNMETERED & SCATTERED LOADS	SENTINEL LIGHTS	STREET LIGHTING	STANDBY
Applicable to Non-Regulated Price Plan Customers Only								
RSVA -Global Adjustment Account Recovery Rate Riders	0.0004	0.0003	0.5827	0.3094	0.0001	0.0199	0.6499	0.0000
Billing Determinants	kWh	kWh	kW	kW	kWh	kW	kW	kW

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Question 54

Reference: E9/T1/S2/Table 9-5 (Deferral and Variance Accounts for Disposition) and Table 9-6 (Deferral and Variance Accounts Not Included for Disposition

Account 1592 has not been listed in Table 9-5 or Table 9-6, although there is a balance in this account as per Horizon's RRR 2.1.7 filing with the Board for 2009.

Please refile Table 9-5 or Table 9-6, as appropriate, to include the balance in account 1592.

Response:

Account 1592 is now included in Table 9-6 below.

Table 9-6 Deferral and Variance Accounts Not Included for Disposition

		Closing Balance Dec. 31, 2009		
	OEB #	Principal	Carrying Charges	Total Balance
Other Regulatory Assets - Sub-Account - 2008 LRAM/SSM approved	1508	$517,823	$10,903	$528,726
Other Regulatory Assets - Sub-Account - 2009 LRAM/SSM approved	1508	$551,394	$721	$552,115
Smart Meter Capital and Recovery Offset Variance Capital	1555	$21,903,307	$489,836	$22,393,143
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	($7,451,996)	($9,482)	($7,461,479)
Sub-total 1555		$14,451,311	$480,354	$14,931,665
Smart Meter OM&A Variance	1556	$5,190,956	$132,658	$5,323,614
Deferred Payments in Lieu of Taxes	1562	($4,476,650)	$833,592	($3,643,058)
2006 PILs and Taxes Variance	1592	($877,121)	($45,835)	($922,956)
Disposition and Recovery of Regulatory Balances	1595	($3,731,348)	($1,094,156)	($4,825,504)
Total		$11,626,365	$318,236	$11,944,601

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Question 55

Reference: Account 1592, PILs and Tax Variances for 2006 and Subsequent Years

Please identify whether Horizon has posted any amounts to account 1592 since April 2006. If yes, please respond to the following questions. If not, please explain why Horizon has not posted any amounts to account for the changes in tax legislation that have occurred since 2006 as required by the Board’s methodology and prior decisions.

a) Please revise the deferral and variance account continuity schedule to include account 1592 as a group 2 account and enter all the required information for transaction, adjustments, interest carrying charges, etc. for all the relevant years.

b) Please describe each type of tax item that has been accounted for in account 1592.

c) Please provide the calculations that show how each item was determined and provide any pertinent supporting evidence.

d) Please confirm whether or not Horizon followed the guidance provided in the July 2007 FAQ. If not, please explain why not.

e) Please identify the account balance as of December 31, 2009 as per the 2009 audited financial statements. Please identify the account balance as of December 31, 2009 as per the April 2010 2.1.7 RRR filing to the Board. Please provide reconciliation if the balances provided in the above documents are not identical to each other and to the total amount shown on the continuity schedule.

f) Should the Board wish to dispose of this account at this time, please identify the following:

i. The allocator that, in Horizon's view, would be most appropriate to use in allocating the balance to the rate classes.

ii. The disposition period that Horizon would prefer, if different from the period proposed for the remaining deferral and variance accounts, and an explanation for such difference.

iii. The billing determinant that, in Horizon's view, would be most appropriate to use.

g) Please complete the following table based on the previous answers. Add rows as required to complete the analysis in an informative manner. If the Applicant uses Excel to prepare the table, please submit the live Excel spreadsheet.

Tax Item	$ Principal As of [December 31, 2009]
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from May 1, 2006 to April 30, 2007	
Large Corporation Tax from 2005 EDR application PILs model for the period from January 1, 2006 to April 30, 2006 (4 /12ths of approved grossed-up proxy) if not recorded in PILs account 1562	
Ontario Capital Tax rate decrease and increase in capital deduction for 2007	
Ontario Capital Tax rate decrease and increase in capital deduction for 2008	
Ontario Capital Tax rate decrease and increase in capital deduction for 2009	
Ontario Capital Tax rate decrease and increase in capital deduction for 2010	
Capital Cost Allowance class changes from 2006 EDR application for 2006	
Capital Cost Allowance class changes from 2006 EDR application for 2007	
Capital Cost Allowance class changes from 2006 EDR application for 2008	
Capital Cost Allowance class changes from 2006 EDR application for 2009	
Capital Cost Allowance class changes from 2006 EDR application for 2010	
Capital Cost Allowance class changes from any prior application not recorded above.	
Insert description of next item(s)	
Insert description of next item(s) and new rows if needed.	
Total	

Response:

Horizon Utilities has posted transactions to account 1592 since April 2006.

a) Horizon Utilities has revised the deferral and variance account continuity schedule to include account 1592 as a group 2 account and entered all of the required information for transaction, adjustments, interest carrying charges, etc. for all the relevant years. Please find the revised deferral and variance account continuity schedule attached as Appendix A.

b) The following types of tax items have been accounted for in account 1592:

- Large Corporation Tax elimination
- 2007 Ontario Capital Tax rate decrease
- 2008 Ontario Capital Tax rate decrease
- 2008 Income Tax rate decrease
- Capital Cost Allowance class changes

c) The calculations showing how each item was determined are detailed in the table below.

LCT Gross-up proxy from 2006 EDR Application PILs Model from May 1, 2006 to April 30, 2007 (monthly, 12mo)		296,128
Ontario Capital Tax rate decrease and increase in capital deduction from 2006 -> 2007 (Jan 1, 2007-Dec 31, 2007)		
- rate decrease 30bps to 22.5bps = 7.5bps		
- increase in capital deduction 2.5MM		
2006 Deemed Taxable Capital	317,617,011	
Change in capital deduction	-2,500,000	
Revised Deemed Taxable Capital	315,117,011	
Tax Rate - 2007	0.00225	
Revised Deemed Capital Tax	709,013	
2006 EDR Capital Tax	952,851	
Difference		243,838
Ontario Capital Tax rate decrease and increase in capital deduction from Jan 1, 2008 to April 30, 2008 (monthly, 4mo)		
- no change in 2008 rate from 2007		
- increase in capital deduction 2.5MM		
2006 Deemed Taxable Capital	317,617,011	
Change in capital deduction	-5,000,000	
Revised Deemed Taxable Capital	312,617,011	
Tax Rate - 2008	0.00225	
Revised Deemed Capital Tax	703,388	
2006 EDR Capital Tax	952,851	
Difference	249,463	
Prorated 4 mo to 2008 EDR		83,154
Income Tax Rate Reduction for Jan 1, 2008 to Apr 30, 2008:		
Regulatory Taxable Income 2006 EDR	14,559,233	
2008 Income Tax Rate	0.335	
	4,877,343	
Gross-up	0.665	
Revised Income Tax (grossed-up)	7,334,350	
2006 EDR Income Tax (grossed-up)	8,232,303	
Difference	897,953	
Pro-rated 4 mo to 2008 EDR (monthly, 4mo)	299,317	299,317
		922,437
Horizon Utilities had Tier 1 adjustments in the amount of 4,266,296 as additions to UCC Class 1. These Class 1 adjustments should, as a result of Ontario budget changes, have been classified as Class 47, which attracts an 8% CCA rate. The impact of this charge on the PILs proxy is as follows:		
2006 (Monthly, 8, Fiscal from May 1)	[(4,266,296*1/2/(8%-4%)] *36.12%/(1-36.12%) * 8/12	32,164
2007 (Monthly, 12)	[(4,266,296*1/2/(8%-4%)] *36.12%/(1-36.12%)	48,246
2008 (Monthly, 4)	[(4,266,296*1/2/(8%-4%)] *33.5%/(1-33.5%) *4/12	14,328
		1,017,175
Principal Balance per General Ledger		877,121
Adjustment Required		**140,054**

d) Horizon Utilities confirms that it followed the Board's guidance in the July 2007 FAQ. However, it was not possible to reconcile the entries that were made to this account due to a lack of continuity of staff that, at the time, had prepared the entries within this account. Horizon Utilities has recalculated the amounts for each component and, with consideration for related carrying charges, the corrected balance in account 1592 should be a credit of $1,089,186.

e) The account balance as of December 31, 2009 as per the 2009 audited financial statements is a 922,956.45 credit.

The account balance as of December 31, 2009 as per the April 2010 2.1.7 RRR filing to the Board is a credit of 922,956.45.

f) **i.** Should the Board wish to dispose of this account at this time, Horizon Utilities' submits that distribution revenue would be the most appropriate allocator to use in allocating the balance to the rate classes.

ii. Horizon Utilities submits its preference for the same disposition period of one year as proposed for the remaining deferral and variance accounts.

iii. Horizon Utilities submits that customer counts and connections would be the most appropriate billing determinant.

g) Please see response below

Tax Item	Principal as of December 31, 2009
Large Corporation Tax grossed-up proxy from 2006 EDR application PILS model for the period from May 1, 2006 to April 30, 2007	296,128
Large Corporation Tax grossed-up proxy from 2005 EDR application PILS model for the period from May 1, 2006 to April 30, 2006 (4/12th of approved grossed-up proxy if not recorded in PILS account 1562)	
Ontario Capital Tax rate decrease and increase in capital in capital deductions for 2007	326,992
Ontario Capital Tax rate decrease and increase in capital in capital deductions for 2008	
Ontario Capital Tax rate decrease and increase in capital in capital deductions for 2009	
Ontario Capital Tax rate decrease and increase in capital in capital deductions for 2010	
Capital Cost Allowance class changes from the 2006 EDR application for 2006	32,164
Capital Cost Allowance class changes from the 2006 EDR application for 2007	48,246
Capital Cost Allowance class changes from the 2006 EDR application for 2008	14,328
Capital Cost Allowance class changes from the 2006 EDR application for 2009	
Capital Cost Allowance class changes from the 2006 EDR application for 2010	
Capital Cost Allowance class changes from any prior applicaton not recorded above	
Income Tax Rate Reduction 2008	299,317
Total	**1,017,175**

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Question 56

Reference: E9/T1/S2 – Poly-phase Commercial Meters

In Table 9-10, Horizon documents that its smart meter deployment includes an "Other" category, in addition to Residential and GS < 50 kW customer classes. Horizon states that the "Other" category deals with conversion of "poly phase commercial meters" as the seals expire.

In E1/T2/S2/Appendix 1-9(d), the Customer Connections Business Plan for 2011,

at page 3 Horizon states that the conversion is to allow the poly phase commercial meters to use the AMI infrastructure.

a) Please define the "poly phase commercial meters" and the customers serviced by these meters. Are these interval meters of General Service customers served by 2-phase or 3-phase distribution service?

b) What customer class(es) are served by these "poly phase commercial meters"?

c) Please confirm whether the conversion of these poly phase

commercial meters meets or is beyond "minimum functionality" as defined in O.Reg. 425/06 and "Functional Specification for an Advanced Metering Infrastructure, Version 2", issued July 5, 2007, both available from the Ministry of Energy's website at

http://www.mei.gov.on.ca/en/energy/electricity/?page=regulations.

Response:

a) A poly phase (“three phase”) commercial meter is defined as, the meter which measure the power for three phase services. Such meters are used in commercial and industrial customer scenarios. Customers with >500 kW are interval metered. Poly phase metered customers that are not interval metered (<500 kW) will be converted to Smart Meters upon expiration of their meter seal (conversion to be completed by 2015).

b) The customer classes that can be served by a poly phase commercial meter service are commercial and industrial General Service customers with either greater than or less than 50 kW monthly demand.

c) Ontario Regulation (O.Reg.) 425/06 and the “Functional Specification for an Advanced Metering Infrastructure” includes smart meters for all General Service customers with up to 50 kW demand. This includes the poly phase (three phase) services. The poly phase meters installed on the services larger than 50 kW are beyond the minimum functionality requirements as noted in Horizon Utilities Smart Meter Funding Adder Application (EB-2009-0158).

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Question 57

Reference: E1/T1/S15 – Harmonized Sales Tax

On page 1 of this exhibit, Horizon states:

> At page 5 of its April 16, 2010 Decision and Order on Horizon Utilities' 2009 3rd Generation IRM application (EB-2009-0228) (Harmonized Sales Tax) the Board directed that "beginning July 1, 2010, Horizon shall record in deferral account 1592 (PILs and Tax Variances, Sub-account HST / OVAT Input Tax Credits (ITCs), ITC it receives on distribution revenue requirement items that were previously subject to PST and become subject to HST." There was no balance in this sub-account as of December 31, 2009. Horizon Utilities will be tracking these incremental amounts from July 1, 2010 to December 31, 2010. **For the 2011 Test Year, the incremental ITC has been included in Operating, Maintenance and Administration expenses.** *[Emphasis added]*

a) Please explain how the incremental ITCs in 2011 have been included in the OM&A expenses. Please quantify the incremental ITCs, and explain what savings and incremental costs have factored into this.

b) Please confirm that Horizon's capital expenditures for the 2011 Test Year do not include what would have been the PST on capital expenditures prior to July 1, 2010. Please explain how this has been done. In the alternative, please explain Horizon's reasons for not doing so.

Response:

a) Horizon Utilities' 2011 Test Year OM&A expenditures were budgeted on the basis that they exclude HST. In the preparation of the 2011 budget, direction was provided to the preparers of the 2011 departmental budgets to exclude HST from the amounts budgeted.

In light of this approach to the preparation of the 2011 budget, the OM&A expenditures for 2011 inherently reflect any incremental ITC impact arising from the implementation of the HST. As a result, it is difficult for Horizon Utilities to quantify the amount of incremental ITCs and/or savings included in the 2011 Test Year OM&A.

b) Consistent with the response to a) above, the budget for the 2011 Test Year capital expenditures was prepared on the basis that HST and/or PST was excluded from the amounts budgeted.

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Question 58

Reference: International Financial Reporting Standards (IFRS)

a) Please confirm that the revenue requirement numbers for 2011 are based on CGAAP, and not IFRS accounting principles. If confirmed, please identify the fiscal year which the applicant will begin reporting its (audited) actual results on an IFRS basis. If not confirmed, please provide a detailed revenue requirement impact statement comparing CGAAP with IFRS.

b) Please state whether or not Horizon has included an amount for IFRS transition costs in its Test Year revenue requirement.

i. If yes, please identify the amount and provide a breakdown with a detailed explanation of each cost item.

ii. If no, is Horizon recording IFRS transition costs in the deferral account established by the Board in October 2009?

Response:

a) Horizon Utilities confirms that the revenue requirement for 2011 is based on CGAAP and not IFRS accounting principles. At the time of filing the 2011 Electricity Distribution Rates Cost of Service Application, Horizon Utilities had planned to implement IFRS effective January 1, 2011. Due to the uncertainty around the accounting for rate-regulated entities under IFRS, Horizon Utilities has since deferred the implementation date of IFRS until January 1, 2012 as permitted under the Canadian Accounting Standards Board and as accepted by the Ontario Energy Board (*Transition to IFRS –*

Amendment to Board Policy, dated November 8, 2010). As such, Horizon Utilities will commence the reporting of actual audited financial results in accordance with IFRS as at December 31, 2012.

b) As noted in response to a) above, the 2011 Electricity Distribution Rates Cost of Service Application was filed on the basis that the implementation of IFRS would be completed and effective January 1, 2011 and that there would be no additional "transition" costs incurred in 2011.

This Application does provide for on-going training and development costs for Accounting and Regulatory staff with respect to accounting standards. As noted in Exhibit 4, Tab 2, Schedule 6, Page 13, "the introduction and implementation of International Financial Reporting Standards ("IFRS") requires specific training on business processes, systems, and new accounting policies and procedures. In addition, technical accounting standards training will be required for all finance and regulatory staff." The deferral of the implementation of IFRS to January 1, 2012 will not result in a deferral of the training requirements related to IFRS as it will be important for staff to be fully trained prior to the implementation date. Approximately $30,000 has been included in OM&A expenses in 2011 with respect to IFRS training and development.

In 2011, any costs specifically related to the implementation of IFRS, including information technology, project management, and other professional service fees to complete the balance of the implementation project, will continue to be recorded in the variance account established by the Board. As per Exhibit 9, Tab 1, Schedule 2, Page 2, Horizon Utilities incurred $560,752 in IFRS transition costs up to December 31, 2009 which it has included in the variance account established for IFRS. Implementation costs incurred throughout 2010 continued to be recorded in the above-mentioned variance account.