

Horizon Holdings Inc.

Management's Discussion and Analysis

For the year ended December 31, 2010

and

Auditors' Report to the Shareholders and Consolidated Financial Statements

Year ended December 31, 2010 and December 31, 2009

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Management's Discussion and Analysis

For the year ended December 31, 2010

(amounts in thousands of dollars unless otherwise noted)

The following discussion and analysis should be read in conjunction with the consolidated financial statements of Horizon Holdings Inc. for the year ended 2010 and accompanying Auditors' Report. References to financial statements or related note disclosures in this document refer to these consolidated financial statements and notes. These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles.

Overview

Horizon Holdings Inc. (the "Corporation") is an investment holding company that owns 100% of the common equity of each of Horizon Utilities Corporation ("Horizon Utilities"), Horizon Energy Solutions Inc. ("Horizon Energy"), and Horizon Solar Corp. ("Horizon Solar"). The Corporation also indirectly owns a 100% ownership interest in Solar Sunbelt General Partnership ("Solar Sunbelt GP") which is held through Horizon Utilities (99.9%) and Horizon Solar (0.1%).

The common shareholdings of the Corporation are owned by Hamilton Utilities Corporation ("HUC") (78.9%) and St. Catharines Hydro Inc. ("SCHI") (21.1%).

Horizon Utilities

The Corporation's principal operating subsidiary, Horizon Utilities, is an electricity distributor for residential and business customers within the municipalities of Hamilton and St. Catharines; the activities of which are regulated by the Ontario Energy Board ("OEB"), a Crown Corporation of the Province of Ontario. The OEB is the regulator of Ontario's natural gas and electricity industries. Horizon Utilities also provides certain non-regulated water billing and customer care services to the City of Hamilton.

Horizon Utilities is one of the largest municipally owned electricity distribution companies in Ontario. The Corporation distributes electricity through approximately 3,400 kilometers of a low-voltage distribution system to approximately 237,000 residential and business customers. The distribution system serves all residents and businesses within the borders of Hamilton and St. Catharines with the exception of approximately 25,000 rural customers located in Hamilton, which are served by another electricity distributor.

The Corporation earns revenue from this business by charging its customers for the use of the distribution system. Such electricity distribution services charges, or distribution charges, comprise a fixed periodic service charge combined with a volumetric charge based on electricity consumption. The distribution charges are subject to the approval of the OEB.

Pursuant to industry regulation, the Corporation is required to be the default billing and collecting agent for all electricity related charges for all electricity industry participants, which, in addition to its own distribution charges, include: transmission charges accruing to the provincially owned Hydro One Networks Inc.; commodity costs for electricity payable to the Independent Electricity System Operator ("IESO") and accruing to generators such as the provincially owned Ontario Power Generation Inc. ("OPGI"); service charges for market participants such as the IESO; and the "Debt Retirement Charge", which is a provincial charge directed to the repayment of certain stranded debt obligations of the former Ontario Hydro which continue in the provincially owned Ontario Electricity Financial Corporation ("OEFC"). These other non-distribution charges represent "pass-through" charges accruing to these and other electricity industry participants and amounted to approximately 83% (2009 – 82%) of gross annual amounts billed by the Corporation. With the exception of the Debt Retirement Charge, the Corporation must remit these non-distribution charges to other industry participants, irrespective of whether or not such charges are ultimately collected from customers, thus exposing the Corporation to credit risk well in excess of its own capacity to generate revenue. The Corporation has instituted credit policy to mitigate such risk.

Horizon Energy

Horizon Energy provides non-regulated energy services, the scope of which presently comprises sales and marketing services, water heater rentals, and meter services.

Horizon Solar

Horizon Solar holds a nominal partnership interest in Solar Sunbelt GP.

Solar Sunbelt GP

Solar Sunbelt GP provides a commercial rooftop solar-photovoltaic generation business ("Solar PV Business"). This partnership will develop, construct, own, finance, and operate rooftop solar photovoltaic generation equipment ("Solar PV Property"). It is the intention of Solar Sunbelt GP that the electricity generated by the Solar PV Property will be sold to the Ontario Power Authority ("OPA") under its Feed-in-Tariff ("FIT") long-term power purchase agreements ("FIT Agreements"). Horizon Utilities is the managing partner of the Partnership.

Electricity Regulation

The *Ontario Energy Board Act, 1998 (Ontario)* ("OEBA") conferred on the 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 residential 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 electricity distribution rates and other regulated charges of the Corporation are determined in a manner that provides shareholders with 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.

In December 2009, the OEB concluded a Cost of Capital proceeding with the issuance of its final report thereon. The report principally dealt with the adequacy and determination of the Maximum Allowable Return on Equity ("MARE"). The Board has acknowledged that it needs to refine and reset its current formula for determining MARE to:

- i) acknowledge and incorporate a utility spread off of Canada long-bonds within the Equity Risk Premium ("ERP") to better reflect utility borrowing costs (initially 141.5bps);
- ii) to include a 50bps "transaction cost" component within the ERP to reflect estimated transaction costs related to utility borrowings;
- iii) reduce MARE volatility from annual changes in the Canada long-bond by reducing the annual adjustment factor from 0.75 to 0.5; and
- iv) reflect a more realistic and "fair" base risk premium for Local Distribution Companies ("LDCs").

The method of transition to the new MARE is through a cost of service review application, further described below.

Rate Applications

The OEB regulates the electricity distribution rates charged by LDCs, such as Horizon Utilities, using a combination of annual incentive rate mechanism ("IRM") adjustments and periodic cost of service reviews. Both such adjustments and reviews are based on applications made by LDCs to the OEB. The current ratemaking policy of the OEB requires a cost of service review every four years, which is followed by three successive years of IRM adjustments.

IRM adjustments to LDC rates are principally formulaic in nature and based on the annual change in the Gross Domestic Product Inflationary Price Index for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "Stretch Factor" determined by the relative efficiency of an electricity distributor.

The rate adjustment resulting from a cost of service review is normally based on forecast test year data, including the amount of operating and capital expenses, debt, and shareholder's equity required to support an LDC's business. The aggregate amount of debt and equity upon which an LDC may recover interest charges and MARE is equal to the "rate base" of an LDC, which is determined as the aggregate of its fixed assets in support of regulated electricity distribution activities and a working capital allowance. The proportion of debt and equity upon which an LDC may recover interest and MARE is generally 60% and 40%, respectively.

Rates have historically, and typically, been effective from May 1st to April 30th.

The last cost of service review application ("COS Application") of the Corporation was approved by the OEB on October 3, 2008, with rates effective May 1, 2008. Such approval effectively provided for 2008 service distribution revenue requirement and rate base of \$93,632 and \$346,420, respectively. Such amounts do not include provision for the investment of the Corporation in the Smart Meter Initiative, further elaborated below.

The Corporation had filed IRM applications to adjust its rates effective May 1, 2009 and May 1, 2010. As a result of such filings, the OEB approved electricity distribution rate adjustments for the Corporation of 1.18% effective May 1, 2009 and 0.18% effective May 1, 2010.

The Corporation has submitted a COS Application for rates effective January 1, 2011 ("2011 COS Application"). Such application was filed on August 26, 2010. However, a decision of the OEB on the 2011 COS Application is unlikely until April or May of 2011. The 2011 COS Application requests a service distribution revenue requirement and rate base of \$108,708 and \$376,890, respectively.

On June 23, 2009, Horizon Utilities submitted an application to the OEB for the recovery of lost revenue and shared savings related to its Conservation and Demand Management ("CDM") programs. Such recoveries proceed through prescribed Lost Revenue Adjustment Mechanism ("LRAM") and Shared Savings Mechanism ("SSM") and relate to activities for the years 2007 and 2008. On October 23, 2009, an amount of \$840 was approved to be recovered through a rate rider for the period commencing November 1, 2009 through April 30, 2010.

Smart Meter Initiative and Time of Use Electricity Distribution Rates

The Province of Ontario has committed to have "Smart Meter" electricity meters installed in all 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 (Time of Use or "TOU" rates). The OEB requires that TOU rates be implemented for all residential and small commercial electricity distribution customers of the Corporation by June 2011.

In support of this initiative, the Corporation has substantially completed its deployment of Smart Meters to all residential and small commercial with 226,000 Smart Meter installations as at December 31, 2010.

The Corporation's Smart Meter capital expenditures and related operating expenses are currently being funded through a Utility-Specific Smart Meter Funding Adder in accordance with the Smart Meter Funding and Cost Recovery Guideline of the OEB. The current approved Smart Meter Funding Adder rate is \$1.56 per metered customer per month. On September 24, 2010, the Corporation submitted a new application for a Utility-Specific Smart Meter Funding Adder which provides for a new rate adder of \$2.14 per metered customer per month commencing March 1, 2011. OEB approval of this application is pending.

The Corporation commenced billing TOU rates for 10,000 residential customers, as part of a pilot project, in January 2010. As at December 31, 2010, TOU rates have been implemented for approximately 157,000 customers.

The Corporation anticipates meeting the June 2011 deadline of the OEB for full implementation of TOU rates.

Green Energy Act

In 2009, the government enacted the *Green Energy Act* ("GEA"). This legislation made fundamental changes to the roles and responsibilities of LDCs in the areas of renewable power generation, conservation and demand management delivery, and the development of smart distribution grids.

The GEA provides LDCs with the freedom to own and operate a portfolio of renewable power generation and will permit them to provide district heating services in their communities through co-generation. LDCs will also bear added responsibilities to assist and enable consumers to reduce their peak demand and conserve energy in an effort to meet provincial conservation targets. LDCs will also gain new responsibilities in transforming their local distribution networks into smart grids harnessing advanced technologies to facilitate the connection of small-scale generators and the two-way flow of information.

New LDC License Requirements – Conservation and Demand Management Targets

On November 12, 2010, the OEB amended LDC licenses to include requirements for achieving certain CDM targets over a four year period commencing January 1, 2011. The Corporation's CDM targets include a demand reduction target of 60.36MW and a consumption reduction target of 281.42GWh. LDCs must also comply with a new CDM Code of the OEB, which provides LDC requirements for the development and delivery of CDM Strategy to the OEB for the achievement of LDC-specific CDM targets, annual accounting and reporting to the OEB, and eligibility criteria for performance incentive payments. The Corporation has filed its CDM Strategy with the OEB.

Other Matters

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between the OEB and interested stakeholders, may affect future electricity distribution rates and other permitted regulatory recoveries of the Corporation.

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.

Results of Operations

Year Ended December 31, 2010 compared to Year Ended December 31, 2009.

Net Income

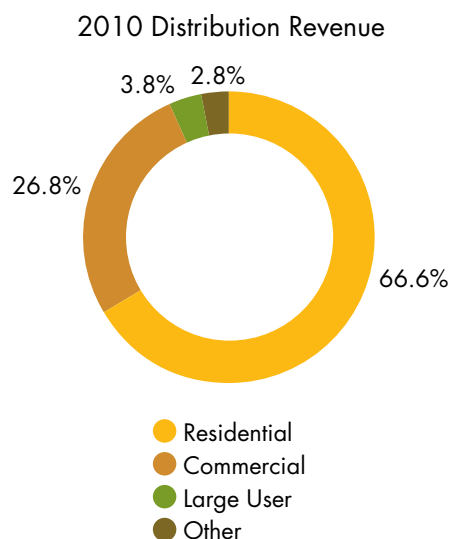
Net income for the year of \$12,708 was lower by \$813 or 6.0% compared to \$13,521 in the prior year, reflecting a decrease in income from operating activities and higher net financing costs, net of lower income taxes. The decrease in income from operating activities principally reflects a start-up operating loss of \$1,281 attributable to the Solar PV Business.

Revenues

	2010	2009
Electricity distribution service charges	\$91,217	\$88,583

Electricity distribution service charges for the year increased by \$2,634 or 3.0% compared to the prior year, primarily reflecting higher energy consumption and an increase in distribution rates. Distribution revenue in the current year also reflects a regulatory recovery of \$1,102 related to a class action settlement liability approved by the OEB. Such recovery will be collected through a fixed rate rider over a 12 month period commencing May 1, 2011 (see Note 14).

Residential consumption increased by 5.5% over 2009, principally reflecting a warmer than normal summer. Large commercial consumption increased by 16.7% during the year, but overall consumption from this customer class remains approximately 18% lower than expected from the 2008 electricity distribution rate application and underlying current distribution rates.



	2010	2009
Other income from operations	\$10,763	\$10,369

Other income from operations comprises income from regulated services as well as non-regulated services.

Other income from regulated services includes rate charges to customers for connection, reconnection, late payments and ancillary services as well as pole attachment charges to other utility service providers attaching to poles owned by the Corporation. Other income from regulated services in 2010 was consistent with 2009 levels.

Other income from non-regulated services includes water billing and customer care services provided to the City of Hamilton, management and other incentive fees earned for the delivery of conservation and demand management programs through programs funded by the Ontario Power Authority ("OPA"), water heater rentals, and meter services revenue. Other income from non-regulated services revenue increased by approximately \$370 or 7.1% in 2010, reflecting an increase in meter services revenue earned on the construction of large scale meter upgrades.

Expenses

	2010	2009
Operating expenses	\$46,881	\$44,855

Operating expenses principally include salaries and benefits, materials, fleet amortization, and other third party service costs in support of the activities underlying the businesses of the Corporation including: operation and maintenance of the distribution system; development of the Solar PV Business; billing and collection; and general administration costs.

Operating expenses increased by \$2,026, or 4.5% in 2010. Included in operating expenses for the year were \$1,100 with respect to the Corporation's share of a class action settlement liability in respect of late payment penalties (Note 14) and \$1,281 in start-up costs with respect to the launch of the Solar PV Business. Start-up costs for the Solar PV Business include professional service fees related to financial and engineering due diligence with respect to potential suppliers and manufacturers of solar panels, legal and tax consulting costs, and sales and marketing related expenditures.

Excluding the settlement liability amount and start-up costs for the solar generation business, operating expenses were slightly lower in 2010, reflecting the Corporation's continued cost deferral efforts in response to lower distribution revenue from its larger commercial customers. Such cost deferrals generally comprise business and operational improvement initiatives, human resources, facilities, and other maintenance expenditures. The Corporation has provided for these deferred costs within its 2011 COS Application.

	2010	2009
Depreciation and amortization	\$27,069	\$25,012

The increase in depreciation principally reflects increased levels of capital investments over the past three years with respect to the Smart Meter Initiative and distribution system renewal. In 2010, the electricity distribution business invested approximately \$39,193 in capital assets, as compared to approximately \$44,775 in 2009 and \$42,045 in 2008. The Corporation has applied consistent amortization rates to its capital assets throughout the reporting period.

	2010	2009
Interest income	\$ (70)	\$ (24)
Interest expense	\$9,709	\$9,209

Net interest expense increased by \$454 or 4.9% over the prior year and primarily reflects a higher average level of debt during the year.

	2010	2009
Payments in lieu of income taxes	\$5,782	\$6,471

The Corporation is currently exempt from taxes under the *Income Tax Act (Canada)* and the *Ontario Corporations Tax Act* (collectively referred to as the "Tax Acts").

The Corporation is required to compute taxes under the Tax Acts and remit such amounts to OEFC to be applied against certain stranded debt obligations of the former Ontario Hydro continuing in OEFC.

The tax basis of the Corporation's assets was valued at fair value pursuant to the provisions of the Tax Acts as at the date the Corporation became subject to PILs. This results in a long-term favourable impact on effective tax rates, resulting from a tax basis of depreciable capital property and eligible capital expenditure in excess of the book basis.

The effective rate of PILs expense in 2010 was 31.3% (2009 – 32.4%) as compared to the statutory rate of 31.0% (2009 – 33.0%).

Liquidity and Capital Resources

Sources of Liquidity and Capital Resources

The principal sources of liquidity and capital resources comprise funds generated from operations and the financing activities of the Corporation.

Funds Generated from Operating Activities

Cash provided from operations was \$43,730 in 2010 as compared to \$27,715 in 2009. The increase in 2010 was primarily the result of a relatively insignificant change in other assets and liabilities as compared to the change in 2009. Excluding changes in other assets and liabilities, principally resulting from timing differences between the realization of receivables and accounts payable, operating cash flows were largely consistent between 2010 and 2009.

Financing Activities

On June 30, 2010, the Corporation entered into a Credit Facility Agreement ("Credit Facility") with a Canadian chartered bank. The Corporation can borrow up to \$100,000, on a revolving basis, to finance general corporate requirements, capital investments, working capital requirements, and its prudential obligations to the IESO. Borrowings may be in the form of Bankers' Acceptances ("BAs"), prime rate loans, letters of credit, and/or current account overdrafts. The Credit Facility matures on June 30, 2013. Interest rates payable on the Credit Facility are based on a margin relative to the prime or BA rate, as the case may be, determined by reference to the Corporation's debt rating.

On July 21, 2010, the Corporation issued \$40,000 in Senior Unsecured Debentures bearing interest at 4.77% per annum, payable semi-annually on January 21 and July 21. The debentures mature on July 21, 2020. The proceeds of the debenture were used to reduce short-term bank indebtedness and to finance capital expenditures.

Requirements for Liquidity and Capital Resources

The Corporation's principal liquidity and capital resource requirements comprise its ongoing commitment to maintain, improve, and expand its distribution, Solar PV Business, and other infrastructure assets on a sustainable basis and in accordance with governing statutes and regulations; working capital requirements, cost of power expense; the servicing and repayment of debt obligations; and the payment of dividends to its shareholders.

Capital Expenditures

Table 1: Capital Expenditures

	2010	2009
Distribution system	\$31,757	\$33,188
Smart meters	1,370	6,044
Other	6,066	5,543
Total	\$39,193	\$44,775

Total capital expenditures for 2010 were \$39,193; a decrease of \$5,582 from the prior year. The decrease principally reflects the substantial completion of Smart Meter investment by the Corporation in 2009.

Capital expenditures for 2011 are expected to increase to \$58,000, and principally comprise: distribution system capital expenditures of \$35,000; anticipated investment in Solar PV Property of \$11,800; investments in fleet vehicles supporting the distribution system of \$1,400; Smart Meter expenditures of \$1,600; technology upgrades and enhancements \$5,000; facilities upgrades, and other.

Distribution System

Distribution system capital expenditures decreased by \$1,431 in 2010, primarily reflecting lower capital expenditures related to renewal projects, partially offset by an increase in customer demand projects. Renewal projects in the prior year included the completion of several large multi-year voltage conversion projects deferred from 2008. The value of renewal projects will vary year over year based on the assets that are scheduled for renewal in accordance with the Corporation's asset management plan and the relative ranking of such projects in relationship to the overall capital expenditure budget. Customer demand projects in 2010 included approximately \$4,000 related to the expansion and construction of two hospitals located in the cities of Hamilton and St. Catharines.

Distribution capital expenditures for 2011 reflect investments required to expand, refurbish, and replace distribution infrastructure consistent with government policy, local area supply requirements, and preventative and corrective maintenance needs to manage an aging asset infrastructure in order to ensure an adequate and reliable supply of electricity to customers.

Smart Meters

The Corporation has substantially completed its deployment of Smart Meters to all residential and small commercial customers. The Corporation has installed approximately 226,000 Smart Meters representing a total cumulative capital investment of approximately \$26,000. In the latter part of 2009, the Corporation commenced the installation of Smart Meters to all General Service > 50kw customers. The Corporation expects the installation of meters in this customer class to be completed by 2012, at a total investment of \$2,900.

Solar PV

In 2010, approximately \$180 was incurred with respect to feasibility studies for the installation of solar rooftop equipment. The Corporation anticipates further investment of \$11,800 in Solar PV Property in 2011.

Other

Other capital expenditures include computer hardware and software, facilities, transportation equipment, furniture and office equipment and other work-related equipment.

Dividend Requirements

The Corporation paid dividends in the amount of \$8,113 in 2010 to its shareholders, compared to \$9,063 paid in 2009. Dividends on common shares are declared at the discretion of the Board of Directors, based on its approved dividend policy and the recommendations of management. The dividend policy of the Corporation targets regular dividends of up to 60% of annual consolidated net earnings, subject to certain prudential considerations including statutory and contractual compliance, financial prudence, and providing for sustainable investment in electricity distribution infrastructure.

Risk Factors

The Audit and Risk Management Committee of the Board of Directors has adopted a mandate to identify the principal control risks in the business of the Corporation and to verify that effective control systems are in place to manage and mitigate these risks. The President and Chief Executive Officer has ultimate accountability for risk management and the Senior Vice-President and Chief Financial Officer is responsible to the President and Chief Executive Officer for the ongoing monitoring and review of the risk profile, policies, and practices of the Corporation and ensuring that the risk management program is an integral part of business strategy and planning.

Significant risk factors affecting the businesses of the Corporation include:

Regulatory Risk Related to the Electricity Distribution Business

Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a regulatory regime that imposes conditions that restrict the electricity distribution business from achieving an acceptable rate of return that permits financial sustainability of its operations including the recovery of expenses incurred for the benefit of other market participants in the electricity industry such as transition costs and other regulatory assets. All requests for changes in electricity distribution charges require the approval of the OEB.

Credit Risk

Credit risk is the risk that one party to a financial instrument will fail to discharge an obligation and cause the other party to incur a financial loss.

The principal source of credit risk for the Corporation relates to the realization of its customer receivables. The legislation governing the operation of Ontario's electricity industry exposes the Corporation, through its electricity distribution operations, to credit risk of several multiples of its means to generate revenue. Pursuant to Provincial regulation, electricity distribution companies in Ontario are required to act as the billing agent for all industry participants and must remit billed amounts accruing to these participants irrespective of whether such amounts are ultimately collected. With the exception of the debt retirement charge, electricity distribution companies are exposed to losses for entire amounts billed to customers. Electricity distribution companies are not compensated for assuming this level of risk nor is there a clear and mechanistic regulatory means to recover losses for non-distribution charges.

Management has implemented credit and collection policies in accordance with the OEB regulation to mitigate the exposure of the Corporation to credit risk. OEB regulation continues to impose certain restrictions on credit policy that exposes electricity distribution corporations to unmitigated and uncompensated credit risk of several multiples of their means to generate revenue.

In 2010, the OEB released new province-wide residential customer service regulations and amendments to the *Distribution Settlement Code*, *Retail Settlement Code*, and *Standard Supply Service Code* (the "Codes") which are intended to further standardize customer service rules, particularly as such apply to low income energy consumers.

These changes effectively extend the period between non-payment and disconnection from approximately 150 days to 210 days; reduce the effectiveness of security deposits and eliminate the right of distributors to request such in certain circumstances; and require distributors to provide an "arrears management program" for qualifying low income customers providing for the payment of arrears over an extended period.

The amendments to the Codes were implemented effective October 1, 2010 and January 1, 2011. As at December 31, 2010, the Corporation had approximately 900 customers, with overdue accounts receivable balances of approximately \$200, that were enrolled in the Arrears Management Program.

The Corporation earns its revenue from a broad base of customers located in the City of Hamilton and the City of St. Catharines. There is one large commercial customer that accounts for 3% (2009 – 3%) of revenue. No other single customer in either year would account for revenue in excess of 1% of the respective reported balances.

No single customer accounts for more than 1% of accounts receivable at year-end.

Management actively monitors and manages its exposure to credit risk, within regulatory constraints, and records credit losses in the period in which, in management's opinion, the collection of related receivables becomes doubtful.

Labour Relations Risk

Approximately 71% of the Corporation's employees are represented by the International Brotherhood of Electrical Workers Union ("IBEW"). The existing collective agreement with the IBEW expires on May 31, 2011. The Corporation bears financial risk related to the ability to negotiate a collective agreement consistent with its rate orders. In the event of a labour dispute, the Corporation could face some degree of operational risk related to continued compliance with its license requirements of providing service to customers.

Workforce Demographics

Approximately 21% of the Corporation's employees in skilled trade positions are expected to retire within the next five years. Recent studies have indicated that more than 28% of the workforce in the distribution sector is expected to retire by 2012. The Corporation's inability to attract and retain the appropriate level of qualified staff to replace retiring workers may have a material adverse effect on its operations.

Condition of Distribution Assets

The Corporation continually monitors the condition and age of its distribution assets. The Corporation's capital and maintenance programs have been increasing to maintain the performance and replacement of a mature distribution system. The Corporation's ability to continue to maintain and operate the distribution system reliably and safely in the future will depend on, among other things, the OEB allowing recovery of costs in respect of the Corporation's maintenance program and capital expenditure requirements for distribution plant refurbishment and replacement.

Information Systems Technology

The Corporation's ability to operate efficiently and effectively is in part dependent upon the development, maintenance and management of complex information technology infrastructure, which is employed to operate the Corporation's distribution system, billing system, financial and other business systems. Information system failures or security breaches could have a material adverse effect on the operations of the Corporation.

Economic Conditions

The persisting general decline in the economy has impacted, and may continue to impact, overall electricity consumption; particularly in the commercial customer segments, which is the most sensitive to changing economic conditions.

Lower electricity consumption from commercial customers may continue to negatively impact the Corporation's revenue.

Extraordinary Event Risk

Unforeseen extraordinary events could disrupt the ability of the electricity distribution business to deliver electricity to all or some of its customers. These risks include weather disasters, major accidents or other involuntary events that may affect the electricity distribution system.

The Corporation has no obligation to deliver an uninterrupted supply of electricity due to extraordinary events, thereby avoiding third party liability concerns.

The Corporation may make application to the OEB for rate increases to recover costs incurred as a result of extraordinary circumstances impacting the electricity distribution system.

Emerging Accounting Changes

International Financial Reporting Standards (“IFRS”)

The Canadian Accounting Standards Board (“AcSB”) has adopted a strategic plan that will require publicly accountable enterprises to adopt IFRS in place of Canadian GAAP, for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011.

In October 2010, the AcSB approved the incorporation of IFRS 1 into Part 1 of the CICA Handbook for qualifying entities with rate regulation. Part 1 of the CICA Handbook specifies that first-time adoption is mandatory for such entities for interim and annual financial statements relating to annual periods beginning on or after January 1, 2012.

Rate Regulated Accounting

In accordance with Canadian GAAP, the Corporation currently follows specific accounting policies unique to a rate regulated business.

Rate regulated entities reporting under Canadian GAAP recognize regulatory assets and liabilities in their financial statements. Regulatory assets and liabilities generally represent settlement variances arising from differences in amounts collected by a rate regulated entity from its customers on behalf of another unrelated entity and the amounts billed by the unrelated entity to the rate regulated entity. The amounts collected by the rate regulated entity are generally regulated and adjusted on a periodic basis to settle the regulatory variances.

IFRS does not currently provide guidance on accounting for the effects of rate regulation and the recognition of regulatory assets and liabilities. Currently, rate regulated entities reporting under IFRS do not recognize regulatory assets and liabilities in their financial statements. Differences between amounts collected from customers on behalf of another entity and amounts billed to the rate regulated entity by such unrelated entity are reported through income.

On July 23, 2009, the International Accounting Standards Board (“IASB”) issued an Exposure Draft – Rate Regulated Activities (“RRA ED”), allowing entities that are subject to “cost of service” regulation to continue to recognize regulatory assets and liabilities at the net present value of expected future cash flows.

The IASB received a significant number of comment letters with diverging opinions with respect to the RRA ED. In October 2010, the IASB concluded that it could not resolve the matter quickly and decided to defer consideration to 2011.

As a result of uncertainty with respect to the timing, scope, and extent, if any of adoption of rate regulated accounting under IFRS, and the potential material impact of rate regulated accounting on the Corporation’s financial statements, the Corporation has elected to defer the implementation of IFRS to January 1, 2012.

On July 28, 2009, the OEB issued its Report of the Board – Transition to IFRS, which provides recommendations on regulatory reporting requirements under IFRS.

IFRS Transition Plan

The Corporation commenced its IFRS conversion project in 2008. The IFRS conversion project has a formal governance structure, including an Executive Sponsor, Steering Committee, and Project Management. The Corporation has also engaged experienced external advisors to assist with this project.

The Corporation's IFRS conversion project consists of four phases: 1) initial assessment; 2) detailed assessment; 3) design; and 4) testing and implementation. The Corporation completed Phase 1 of the IFRS conversion project in December 2008. Phase 2 was completed in March 2009 and identified the areas of accounting differences with the highest potential impact to the Corporation; including rate regulated accounting, property, plant and equipment, as well as initial adoption of IFRS under the provisions of IFRS 1 First-Time Adoption of IFRS. The Corporation completed Phase 3 in May 2010, which included the recommendation of IFRS 1 elective exemptions, the selection of accounting policies, and analyzing and designing business processes and changes to related information systems. The Corporation has commenced Phase 4, testing and implementation, which will continue throughout 2011. Phase 4 involves the development of an accounting policies and procedures manual, training for the finance and operational teams, testing the effectiveness of the changes to the business processes and information systems, and preparation of financial reports, including the opening balance sheet as at the transition date.

As a first time adopter of IFRS, the Corporation is required to apply IFRS standards retrospectively and recognize any adjustments through opening retained earnings. IFRS 1 contains all of the transitional requirements applicable for the first-time adoption of IFRS, including mandatory and optional exemptions with respect to retrospective application of the IFRS standards.

The Corporation has completed an initial assessment as to the IFRS 1 exemptions that would be elected upon transition as follows:

IFRS 1 Standard	Summary of Exemption Available	IFRS 1 Selection
IAS 16 Property, Plant and Equipment ("PP&E")	Rate regulated entities may elect to use the previous GAAP carrying amount of certain items of PP&E as deemed cost at the date of transition to IFRS.	The Corporation plans to elect to use the GAAP carrying values as the deemed cost.
IAS 23 Borrowing Costs	The Corporation may prospectively capitalize borrowing costs related to qualifying assets for which the commencement date of capitalization is on or after the date of transition or early adoption is permitted.	The Corporation plans to elect the exemption to capitalize borrowing costs after the date of transition.
IFRIC 18 Transfers of Assets from Customers	The Corporation may apply the transitional provisions in IFRIC 18 and thereby prospectively apply the interpretation prospectively to transfers of assets from customers received on or after the date of transition or early adoption is permitted.	The Corporation plans to elect the exemption to apply IFRIC 18 prospectively effective the date of transition.

IFRS 1 Standard	Summary of Exemption Available	IFRS 1 Selection
IAS 37 Decommissioning Costs	The Corporation may adjust the cost of assets at the date of transition for changes in decommissioning, restoration, and similar liabilities, and depreciate the adjusted value of assets prospectively.	The Corporation plans to elect the exemption to apply IAS 37 prospectively effective the date of transition.
IAS 19 Employee Benefits	<p>The exemption allows the Corporation to reset all unamortized actuarial gains and losses to zero on transition to IFRS. There are several potential differences between IFRS and Canadian GAAP which will cause unamortized actuarial gains/losses and defined benefit obligations to be calculated at different amounts.</p> <p>The IAS 19 disclosure requirements provide for four years of disclosure with respect to defined benefit plans. The exemption provides for two years of comparative disclosure.</p>	<p>The Corporation plans to elect the exemption at the date of transition if it is determined that there is a material difference in the computation of the unamortized actuarial gains/losses under IFRS compared to Canadian GAAP.</p> <p>The Corporation plans to elect the disclosure exemption and therefore plans to disclose two years of comparative information effective the date of transition.</p>
IAS 3 Business Combinations	The exemption allows the Corporation to <u>not</u> apply IAS 3 to business combinations that occurred prior to January 1, 2011. Therefore, business combinations that occurred prior to the date of transition would not be restated.	The Corporation plans to elect the exemption and therefore will not apply IAS 3 to business combinations that occurred prior to January 1, 2011.
IAS 27 Investments in Subsidiaries, Jointly Controlled Entities, and Associates	The Corporation may record its investments in subsidiaries at cost or deemed cost at the date of the transition. Deemed cost is either the fair value of the investment at the date of the transition to IFRS, or the Corporation's previous Canadian GAAP carrying amount at that date.	The Corporation plans to elect the exemption to record its investments in subsidiaries at cost at the date of transition.

The Corporation has also completed a detailed assessment of the key accounting and disclosure differences between Canadian GAAP and IFRS and identified the following areas as having the potential to materially impact the consolidated financial statements on the date of transition to IFRS.

At this time, the Corporation cannot reasonably quantify the full impact of adopting IFRS to its future financial position and results of operations as a result of the uncertainty with respect to rate-regulated accounting and the impact of IFRS on the OEB electricity distribution rates application process.

IFRS Standard	Key Differences between IFRS and Canadian GAAP	Potential Impact
IAS 16 Property, Plant, and Equipment	<p>Costs that are not directly attributable to items of Property, Plant, and Equipment cannot be capitalized under IAS 16.</p> <p>IAS 16 requires that an item of PP&E be separated into components when those parts are significant in relation to the total cost of the item. Each component is to be depreciated over its estimated useful life, and derecognized separately.</p>	<p>General and administrative overhead, and other indirect costs, would not generally be capitalized in normal circumstances.</p> <p>Based on preliminary assessments, it is expected that less costs will be capitalized under IFRS.</p> <p>The Corporation has completed the componentization of its assets and assessed the respective useful lives. It is expected that the estimated useful lives will be longer, resulting in lower annual depreciation expense.</p>
IFRIC 18 Transfers of Assets from Customers	IFRIC 18 does not allow for the netting of capital contributions received against items of Property, Plant, and Equipment.	Based on preliminary assessments, there will be a reclassification between Property, Plant, and Equipment and unearned revenue liability, with no impact on profitability.
IAS 12 Income Taxes	IAS 12 is similar to Canadian GAAP in that it is based on the balance sheet liability approach, whereby an entity recognizes deferred tax assets and liabilities for temporary differences.	The full impact of IAS 12 cannot be determined as a result of the uncertainty with respect to rate regulated accounting and other IFRS standards under revision.

Outlook

The Corporation continues its principal focus on the delivery of safe, reliable, and cost-effective electricity distribution services, providing excellent customer value, and helping to create a culture of energy conservation in Ontario.

The Corporation remains committed to meeting its strategic objectives of being the best performing utility, being easy to do business with, financial excellence, and being a great place to work for its employees. Certain supporting initiatives in 2011 to meet these objectives include continued investment in capital infrastructure renewal, new investments in the Solar PV Business, productivity improvements enabled through investments in information technology, on-going commitment to workforce labour strategy, enabling Smart Meters through TOU rates, and the achievement of provincial conservation and demand management targets.

While the overall financial position and prospects of the Corporation remain strong, the current economic climate continues to expose the Corporation to significant revenue risk related to electricity consumption in its larger commercial customer classes. Although the nature of electricity distribution costs are largely fixed, regulated electricity distribution revenues are disproportionately weighted towards electricity consumption. The Corporation has addressed this risk through its 2011 COS Application, which is pending the approval of the OEB.

Overall, management believes that the Corporation is well positioned to meet its strategic objectives while continuing to maintain a healthy financial condition.

Forward Looking Statements and Information

Certain information included herein constitutes "forward looking information". Forward looking information means disclosures regarding possible events, conditions or results that are based on assumptions about future economic conditions and courses of action. In some cases, forward looking information can be identified by terminology such as "may", "will", "should", "expect", "anticipate", "believe", "estimate", "predict", "potential", "continue" or the negative of these terms or other comparable terminology. Although the Corporation believes that it has a reasonable basis for the forward looking information included herein, such information is subject to a number of risks and uncertainties that may cause actual events, conditions or results to differ materially from those contemplated by the forward looking information. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and weather. The Corporation does not undertake any obligation to update publicly or to revise any of the forward looking information included herein after the date hereof, whether as a result of new information, future events or otherwise.

This management's discussion and analysis is dated as at February 24, 2011.

Management's Responsibility for Financial Reporting

The accompanying Consolidated Financial Statements of Horizon Holdings Inc. (the "Corporation") are the responsibility of management and have been approved by the Board of Directors. In management's opinion, the Consolidated Financial Statements have been prepared in accordance with Canadian generally accepted accounting principles. The significant accounting principles are disclosed in note 2 to the Consolidated Financial Statements. The preparation of financial statements necessarily requires judgement and estimation when events affecting the current year depend on determinations to be made in the future. Management has exercised careful judgement where estimates were required, and these Consolidated Financial Statements reflect all information available to February 24, 2011.

Management maintains systems of internal controls designed to provide assurance that the assets of the Corporation are safeguarded, that transactions are properly authorized and that reliable financial information is relevant, accurate and available on a timely basis. The internal control systems include formal policies and procedures and an organizational structure that provides for a proper delegation of authority and segregation of incompatible responsibilities. The internal control systems are monitored by management which reports regularly to the Audit and Risk Committee of the Board of Directors.

The Consolidated Financial Statements have been examined by KPMG LLP, the external auditors of the Corporation. The responsibility of the external auditors is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with Canadian generally accepted accounting principles. The Auditor's Report, which appears on the following page, outlines the scope of their audit examination and states their opinion.

The Board of Directors, through the Audit and Risk Committee, is responsible for ensuring that management fulfills its responsibility for financial reporting and internal controls. The Audit Committee, which is comprised of independent directors, meets regularly with management and the external auditors to satisfy itself that each group is discharging its responsibilities with respect to internal controls and financial reporting. The Audit and Risk Committee reviews the Consolidated Financial Statements and recommends their approval to the Board of Directors. The external auditors have full and open access to the Audit and Risk Committee, with and without the presence of management.

On behalf of the management of Horizon Holdings Inc.:



Max A. Cananzi
President and
Chief Executive Officer



John G. Basilio
Senior Vice President and
Chief Financial Officer

February 24, 2011

Horizon Holdings Inc.

Auditors' Report to the Shareholders and Consolidated Financial Statements

Year ended December 31, 2010 and December 31, 2009



KPMG LLP
Chartered Accountants
Box 976
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Hamilton ON L8N 3R1

Telephone (905) 523-8200
Telefax (905) 523-2222
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Auditors' Report to the Shareholders

We have audited the accompanying financial statements of Horizon Holdings Inc. ("the Entity"), which comprise the balance sheet, as at December 31, 2010 and the statements of income and retained earnings and cash flow for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

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

Auditors' Responsibility

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

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

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

Opinion

In our opinion, the financial statements present fairly, in all material respects, the balance sheet of Horizon Holdings Inc. as at December 31, 2010, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Chartered Accountants, Licensed Public Accountants

Hamilton, Ontario
February 24, 2011

Consolidated Balance Sheet


(in thousands)

As at December 31, 2010	2010	2009
ASSETS		
Current assets		
Cash and cash equivalents	\$ 9,712	\$ –
Accounts receivable	88,567	89,801
Inventory [note 3]	6,042	6,341
Other assets [note 4]	2,389	1,730
	106,710	97,872
Fixed assets [note 5]	332,919	321,595
Future payments in lieu of taxes [note 6]	10,770	9,939
Intangible assets [note 7]	4,444	5,064
Goodwill	18,923	18,923
Total assets	\$ 473,766	\$ 453,393
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Bank indebtedness	\$ –	\$ 23,967
Accounts payable and accruals	58,010	55,233
Accounts payable to corporations under common control	12,674	12,364
Credit support for service delivery [note 8]	20,008	22,451
	90,692	114,015
Long-term liabilities		
Long-term borrowings [note 9]	155,554	116,000
Employee future benefits [note 10]	16,670	16,421
Net regulatory liabilities [note 11]	28,455	29,157
	200,679	161,578
Total liabilities	291,371	275,593
Shareholders' equity		
Share capital [note 12]	123,594	123,594
Contributed surplus	15,218	15,218
Retained earnings	43,583	38,988
Total shareholders' equity	182,395	177,800
Total liabilities and shareholders' equity	\$ 473,766	\$ 453,393
Commitments and contingencies [note 14]		

On behalf of the Board:



Director



Director

Consolidated Statement of Income and Retained Earnings

(in thousands)

For the year ended December 31, 2010	2010	2009
Electricity distribution service charges [note 15]	\$ 91,217	\$ 88,583
Other income from operations [note 16]	10,763	10,369
	101,980	98,952
Expenses:		
Operating expenses	46,881	44,855
Depreciation and amortization [note 5]	27,069	25,012
	73,950	69,867
Income from operating activities	28,030	29,085
Gain on sale of assets	99	92
Interest income	70	24
Interest expense [note 9]	(9,709)	(9,209)
Income before payments in lieu of taxes	18,490	19,992
Payments in lieu of income taxes [note 6]	(5,782)	(6,471)
Net income	12,708	13,521
Retained earnings, beginning of year	38,988	34,530
Dividends paid	(8,113)	(9,063)
Retained earnings, end of year	\$ 43,583	\$ 38,988

Consolidated Statement of Cash Flows

(in thousands)

For the year ended December 31, 2010	2010	2009
OPERATING ACTIVITIES		
Net income	\$ 12,708	\$ 13,521
Add (deduct) non-cash items:		
Depreciation and amortization	28,444	26,344
Future payments in lieu of taxes	(831)	(1,628)
Net change in employee future benefits	249	127
Gain on sale of assets	(99)	(92)
Net change in other assets and liabilities	3,259	(10,557)
Cash provided by operating activities	43,730	27,715
INVESTING ACTIVITIES		
Additions to fixed assets	(39,193)	(44,775)
Proceeds received on sale of fixed assets	144	142
Cash used in investing activities	(39,049)	(44,633)
FINANCING ACTIVITIES		
Long-term borrowings	39,554	–
Net change in credit support for service delivery	(2,443)	(2,341)
Dividends paid in the year	(8,113)	(9,063)
Cash provided by (used in) financing activities	28,998	(11,404)
Net increase (decrease) in cash and cash equivalents during the year	33,679	(28,322)
Cash and cash equivalents (bank indebtedness), beginning of year	(23,967)	4,355
Cash and cash equivalents (bank indebtedness), end of year	\$ 9,712	\$ (23,967)
Supplemental disclosure of cash flow information		
Interest received	\$ 62	\$ 39
Interest paid	\$ (9,136)	\$ (9,186)
Taxes paid	\$ (7,244)	\$ (8,420)

Five-Year Consolidated Summary

(in thousands)

As at December 31, 2010	2010	2009	2008	2007	2006
STATEMENT OF INCOME					
Electricity distribution service charges	\$ 91,217	\$ 88,583	\$ 88,335	\$ 84,797	\$ 79,610
Other income from operations	10,763	10,369	10,090	9,792	9,837
	101,980	98,952	98,425	94,589	89,447
Operating expenses	46,881	44,855	43,997	41,687	38,027
Depreciation and amortization	27,069	25,012	23,481	21,174	19,945
	73,950	69,867	67,478	62,861	57,972
Income from operating activities	28,030	29,085	30,947	31,728	31,475
Gain on sale of assets	99	92	45	384	50
Net interest (expense) income	(9,639)	(9,185)	(9,246)	(8,942)	(8,437)
Payments in lieu of taxes	(5,782)	(6,471)	(6,641)	(8,425)	(8,170)
Net income	\$ 12,708	\$ 13,521	\$ 15,105	\$ 14,745	\$ 14,918
BALANCE SHEET					
Assets					
Current assets	\$ 106,710	\$ 97,872	\$ 100,571	\$ 104,061	\$ 107,461
Capital assets	367,056	355,521	336,430	314,723	297,185
	\$ 473,766	\$ 453,393	\$ 437,001	\$ 418,784	\$ 404,646
Liabilities and shareholders' equity					
Current liabilities	\$ 90,692	\$ 114,015	\$ 96,739	\$ 95,316	\$ 93,433
Long-term debt	155,554	116,000	116,000	116,000	116,000
Other long-term liabilities	45,125	45,578	44,923	38,465	30,504
Shareholders' equity	182,395	177,800	179,339	169,003	164,709
	\$ 473,766	\$ 453,393	\$ 437,001	\$ 418,784	\$ 404,646
STATEMENT OF CASH FLOWS					
Cash provided by operating activities	\$ 43,730	\$ 27,715	\$ 39,852	\$ 41,306	\$ 19,848
Cash used in the purchase of capital assets	(39,193)	(44,775)	(42,045)	(39,253)	(31,425)
Cash provided by other investing activities	144	142	45	432	68
Cash provided by long-term borrowings	39,554	–	–	–	–
Cash used in financing activities	(10,556)	(11,404)	(7,903)	(7,695)	(4,504)
Net increase (decrease) in cash and cash equivalents	\$ 33,679	\$ (28,322)	\$ (10,051)	\$ (5,210)	\$ (16,013)

Notes to the Consolidated Financial Statements

December 31, 2010
(in thousands)

1) Business of Corporation

On October 18, 2006, Horizon Holdings Inc. (the "Corporation") was incorporated under the Business Corporations Act (Ontario). The Corporation is an investment holding company with a 100% ownership interest in Horizon Utilities Corporation ("Horizon Utilities"), Horizon Energy Solutions Inc. ("Horizon Energy"), and Horizon Solar Corp. ("Horizon Solar"). The Corporation also indirectly owns a 100% ownership interest in Solar Sunbelt General Partnership ("Solar Sunbelt GP"), which is held through Horizon Utilities (99.9%) and Horizon Solar (0.1%).

The common shareholdings of the Corporation are owned by Hamilton Utilities Corporation (78.9%) and St. Catharines Hydro Inc. (21.1%).

Horizon Utilities is one of Ontario's largest municipally owned electricity distribution companies in Ontario, delivering electricity and related utility services to more than 237,000 residential and commercial customers in Hamilton and St. Catharines. The Corporation also holds a 99.9% ownership interest in Solar Sunbelt GP, which has been established to undertake a solar generation business.

Horizon Energy was incorporated to provide non-regulated energy services, the scope of which presently comprises sales and marketing services, water heater rentals, and meter services.

Horizon Solar is an investment holding company.

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) Basis of consolidation

The consolidated financial statements include the accounts of the corporation and its 100% wholly owned subsidiaries. The principal operating companies are as follows:

- Horizon Utilities
- Horizon Energy
- Horizon Solar

All significant inter-company accounts and transactions have been eliminated.

b) 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 residential 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 electricity distribution rates and other regulated charges of the Corporation are determined in a manner that provides shareholders with 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.

In December 2009, the OEB concluded a Cost of Capital proceeding with the issuance of its final report thereon. The report principally dealt with the adequacy and determination of the Maximum Allowable Return on Equity ("MARE"). The Board has acknowledged that it needs to refine and reset its current formula for determining MARE to:

- i) acknowledge and incorporate a utility spread off of Canada long-bonds within the Equity Risk Premium ("ERP") to better reflect utility borrowing costs (initially 141.5bps);
- ii) to include a 50bps "transaction cost" component within the ERP to reflect estimated transaction costs related to utility borrowings;
- iii) reduce MARE volatility from annual changes in the Canada long-bond by reducing the annual adjustment factor from 0.75 to 0.5; and
- iv) reflect a more realistic and "fair" base risk premium for Local Distribution Companies ("LDCs").

The method of transition to the new MARE is through a cost of service review application, further described below.

Rate Applications

The OEB regulates the electricity distribution rates charged by an LDC, such as Horizon Utilities, using a combination of annual incentive rate mechanism ("IRM") adjustments and periodic cost of service reviews. Both such adjustments and reviews are based on applications made by LDCs to the OEB. The current ratemaking policy of the OEB requires a cost of service review every four years, which is followed by three successive years of IRM adjustments.

IRM adjustments to LDC rates are principally formulaic in nature and based on the annual change in the Gross Domestic Product Inflationary Price Index for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "Stretch Factor" determined by the relative efficiency of an electricity distributor.

The rate adjustment resulting from a cost of service review is normally based on forecast test year data, including the amount of operating and capital expenses, debt, and shareholder's equity required to support an LDC's business. The aggregate amount of debt and equity upon which an LDC may recover interest charges and MARE is equal to the "rate base" of an LDC, which is determined as the aggregate of its fixed assets in support of regulated electricity distribution activities and a working capital allowance. The proportion of debt and equity upon which an LDC may recover interest and MARE is generally 60% and 40%, respectively.

Rates have historically, and typically, been effective from May 1st to April 30th.

The last cost of service review application ("COS Application") of the Corporation was approved by the OEB on October 3, 2008, with rates effective May 1, 2008. Such approval effectively provided for 2008 service distribution revenue requirement and rate base of \$93,632 and \$346,420, respectively. Such amounts do not include provision for the investment of the Corporation in the Smart Meter Initiative, further elaborated below.

The Corporation had filed IRM applications to adjust its rates effective May 1, 2009 and May 1, 2010. As a result of such filings, the OEB approved electricity distribution rate adjustments for the Corporation of 1.18% effective May 1, 2009 and 0.18% effective May 1, 2010.

The Corporation has submitted a COS Application for rates effective January 1, 2011 ("2011 COS Application"). Such application was filed on August 26, 2010. However, a decision of the OEB on the 2011 COS Application is unlikely until April or May of 2011. The 2011 COS Application requests a service distribution revenue requirement and rate base of \$108,708 and \$376,890, respectively.

On June 23, 2009, Horizon Utilities submitted an application to the OEB for the recovery of lost revenue and shared savings related to its Conservation and Demand Management ("CDM") programs. Such recoveries proceed through prescribed Lost Revenue Adjustment Mechanism ("LRAM") and Shared Savings Mechanism ("SSM") and relate to activities for the years 2007 and 2008. On October 23, 2009, an amount of \$840 was approved to be recovered through a rate rider for the period commencing November 1, 2009 through April 30, 2010.

Smart Meter Initiative and Time of Use Electricity Distribution Rates

The Province of Ontario has committed to have "Smart Meter" electricity meters installed in all 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 (Time of Use or "TOU" rates). The OEB requires that TOU rates be implemented for all residential and small commercial electricity distribution customers of the Corporation by June 2011.

In support of this initiative, the Corporation has substantially completed its deployment of Smart Meters to all residential and small commercial with 226,000 Smart Meter installations as at December 31, 2010.

The Corporation's Smart Meter capital expenditures and related operating expenses are currently being funded through a Utility-Specific Smart Meter Funding Adder in accordance with the Smart Meter Funding and Cost Recovery Guideline of the OEB. The current approved Smart Meter Funding Adder rate is \$1.56 per metered customer per month. On September 24, 2010, the Corporation submitted a new application for a Utility-Specific Smart Meter Funding Adder which provides for a new rate adder of \$2.14 per metered customer per month commencing March 1, 2011. OEB approval of this application is pending.

The Corporation commenced billing TOU rates for 10,000 residential customers, as part of a pilot project, in January 2010. As at December 31, 2010, TOU rates have been implemented for approximately 157,000 customers.

The Corporation anticipates meeting the June 2011 deadline of the OEB for full implementation of TOU rates.

Green Energy Act

In 2009, the government enacted the *Green Energy Act* ("GEA"). This legislation made fundamental changes to the roles and responsibilities of LDCs in the areas of renewable power generation, conservation and demand management delivery, and the development of smart distribution grids.

The GEA provides LDCs with the freedom to own and operate a portfolio of renewable power generation and will permit them to provide district heating services in their communities through co-generation. LDCs will also bear added responsibilities to assist and enable consumers to reduce their peak demand and conserve energy in an effort to meet provincial conservation targets. LDCs will also gain new responsibilities in transforming their local distribution networks into smart grids harnessing advanced technologies to facilitate the connection of small-scale generators and the two-way flow of information.

New LDC License Requirements – Conservation and Demand Management Targets

On November 12, 2010, the OEB amended LDC licenses to include requirements for achieving certain CDM targets over a four year period commencing January 1, 2011. The Corporation's CDM targets include a demand reduction target of 60.36MW and a consumption reduction target of 281.42GWh. LDCs must also comply with a new CDM Code of the OEB, which provides LDC requirements for the development and delivery of CDM Strategy to the OEB for the achievement of LDC-specific CDM targets, annual accounting and reporting to the OEB, and eligibility criteria for performance incentive payments. The Corporation has filed its CDM Strategy with the OEB.

Other Matters

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between the OEB and interested stakeholders, may affect future electricity distribution rates and other permitted regulatory recoveries of the Corporation.

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.

c) 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.

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
Bank indebtedness	Held-for-trading
Accounts receivable	Loans and receivables
Accounts payable and accruals	Other liabilities
Accounts payable and accruals to corporations under common control.....	Other liabilities
Credit support for service delivery.....	Other liabilities
Long-term borrowings	Other liabilities

Effective for the 2009 annual reporting period, the Corporation adopted the amended CICA Handbook Sections 3862, Financial Instruments Disclosures, which provide new financial instrument fair value measurement and liquidity risk management disclosures. The amendments require an entity to classify fair value measurements using a fair value hierarchy, which includes three levels of inputs that may be used to measure fair value:

- Level 1 – Unadjusted quoted market prices in active markets for identical assets or liabilities;
- Level 2 – Observable or corroborated inputs, other than level 1, such as quoted prices for similar assets or liabilities in inactive markets or market data for substantially the full term of the assets or liabilities; and
- Level 3 – Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets and liabilities.

The amendments also provide required liquidity risk disclosures.

d) 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.

e) 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.

f) 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.

g) 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 is not depreciated and comprises the cost of construction materials, applied labour, and overheads consumed in capital projects that are not available for productive use at the end of the fiscal year.

h) Intangible assets and amortization

Intangible assets include intangible software costs, which are stated at cost less accumulated amortization. The amortization of intangible software costs is recorded on a straight-line basis over an estimated service life of 3 years.

i) 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.

j) Credit support for service delivery

Credit support for service delivery represents cash deposits from electricity distribution customers, 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.

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 support of construction.

k) Deferred debt issue costs

Debt issue costs arising from the Corporation's debenture offering are recorded against the principle amount of the debentures. The debentures are accreted back to their face value using the effective interest rate method over the remaining period to maturity.

l) 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.

m) Pension plan

The Corporation provides a pension plan for its employees through 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.

n) Related party transactions

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

o) 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 the period that includes the date of enactment or substantive enactment.

p) Capital contributions in support of construction

Capital contributions arise from new connection charges which are provided and paid by developers and/or customers 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.

q) 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.

3) Inventory

The amount of inventories consumed by the Corporation and recognized as an expense during 2010 was \$ 1,182 (2009 – \$783).

4) Other Assets

Other assets comprise:

	2010	2009
Prepaid expenses	2,324	1,716
Other	65	14
	2,389	1,730

5) Fixed Assets

Fixed assets comprise:

	2010			2009		
	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	147	(56)	91	147	(53)	94
Buildings	28,230	(18,537)	9,693	27,612	(17,250)	10,362
Distribution stations	10,999	(7,666)	3,333	10,030	(7,371)	2,659
Distribution lines overhead and underground	360,619	(164,531)	196,088	348,293	(157,308)	190,985
Distribution transformers	93,014	(40,580)	52,434	89,462	(39,382)	50,080
Distribution meters	62,619	(19,474)	43,145	59,750	(16,565)	43,185
Other fixed assets	47,442	(30,127)	17,315	44,049	(27,618)	16,431
Work in process	9,337	–	9,337	6,316	–	6,316
	613,890	(280,971)	332,919	587,142	(265,547)	321,595

During the year, the Corporation received \$8,512 (2009 – \$7,962) of capital contributions from developers or customers to support new customer connections.

Total depreciation expense for the year is \$28,444 (2009 – \$26,344) of which \$1,375 (2009 – \$1,332) has been allocated to operating expenses and capital.

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:

	2010	2009
Basic rate applied to income before PILs	31.00%	33.00%
Increase (decrease) in PILs resulting from:		
Tax basis of depreciable capital assets and goodwill in excess of accounting basis	(4.26%)	(4.21%)
Revaluation of Future Tax Liability at 2014 statutory rate of 25.0%	3.76%	3.03%
Items not deductible for tax purposes and other	0.78%	0.55%
Effective rate applied to income before PILs	31.28%	32.37%

At December 31, 2010, based on substantively enacted income tax rates, future income tax assets of \$10,563 (2009 – \$11,867) have not been recorded. Such future income tax assets relate to tax bases of depreciable capital assets in excess of amounts recorded for accounting purposes at October 1, 2001. 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) Intangible Assets

Intangible assets comprise:

	2010	2009
Intangible software costs	12,782	11,740
Less: accumulated amortization	(8,338)	(6,676)
	4,444	5,064

8) Credit Support For Service Delivery

Credit support for service delivery comprises:

	2010	2009
Customer deposits	14,851	15,381
Construction deposits	5,157	7,070
	20,008	22,451

9) Long-Term Borrowings

Long-term borrowings comprise:

	2010	2009
\$116,000 Promissory note payable to Hamilton Utilities Corporation bearing interest at 7.0% and due July 30, 2012	116,000	116,000
\$40,000 Senior unsecured debentures bearing interest at 4.77% and due July 21, 2020	39,554	–
	155,554	116,000

On July 21, 2010, the Corporation issued \$40,000 in senior unsecured debentures. Interest is payable on such debentures semi-annually on January 21 and July 21. During the year, the Corporation accrued interest in respect of these senior unsecured debentures in the amount of \$857. There were no amounts paid in 2010.

Interest on the \$116,000 promissory note is payable semi-annually on January 30 and July 30. Interest expense of \$8,120 (2009 – \$8,120) was paid to Hamilton Utilities Corporation.

10) 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:

	2010	2009
Accrued benefit liability, beginning of year	16,421	16,294
Net benefit expense:		
Current service cost	288	222
Interest cost	1,048	1,059
Amortization of net actuarial loss	–	–
Net benefit expense for the year	1,336	1,281
Benefits paid for the year	(1,087)	(1,154)
Accrued benefit liability, end of year	16,670	16,421

An actuarial valuation of the plan obligations was completed as at December 31, 2010 resulting in an unamortized net actuarial loss of \$3,068. 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.

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 6% to 4% over two 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	2,203	173
1% decrease in health care trend rate	(1,762)	(105)

b) Interest (discount) rate

The obligations at the period end and the present value of future liabilities were determined using a discount rate of 5.3% (2009 – 6.4%) 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 3% (2009 – 3%) per year.

11) Net Regulatory Liabilities

Net regulatory liabilities (assets) comprise:

	2010	2009
Regulatory variances disposition account	15,054	4,444
Future payments in lieu of taxes	8,808	7,686
Settlement variances	5,044	16,315
Regulatory deferral account	397	624
Smart Meter deferral account	33	649
IFRS transition costs	(881)	(561)
	28,455	29,157

Net regulatory 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 or repayment in electricity distribution service charges.

Regulatory variances disposition account – represents approved regulatory asset and liability balances as at December 31, 2008, consisting of settlement variances and associated interest, less amounts paid to customers up to December 31, 2010. The recent OEB decision on the 2010 IRM Application provided for the disposition of \$19,467 of the Corporation’s net regulatory liabilities over a twenty-four month period commencing May 1, 2010.

Future payments in lieu of taxes – represents the amount of future income taxes expected to be included in future rates and recovered from or paid to customers through the rate setting process.

Settlement variances – represent amounts that have accumulated since January 1, 2009 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.

Regulatory deferral account – represents the deferral of various operating expenditures related to the GEA, retailer expenses, and the implementation of HST, which will be subject to future disposition in accordance with the directions set out by the OEB.

Smart Meter deferral account – represents the deferral of operating expenditures, capital expenditures, and revenues related to Smart Meters.

IFRS transition costs – represents the incremental costs incurred by the Corporation in relation to the transition from Canadian Generally Accepted Accounting Principles to International Financial Reporting Standards (IFRS). The Corporation is required to adopt IFRS no later than January 1, 2012. In its decision of July 28, 2009, the OEB provided that these costs be recorded by LDCs in a deferral account for a review of their recovery at their next respective COS Application. The Corporation anticipates full recovery of these costs.

12) Share Capital

Share capital comprises:

	2010	2009
Authorized:		
Unlimited Class 1 Common shares		
Unlimited Class A Common shares		
Issued:		
7,890 Class 1 Common shares	91,134	91,134
2,110 Class A Common shares	32,460	32,460
	123,594	123,594

Any invitation to the public to subscribe for shares of the Corporation is prohibited.

13) 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 6.4% for employee earnings up to the year's maximum pensionable earnings ("YMPE"), as prescribed by federal tax legislation, and 9.7% above the YMPE. During 2010, the Corporation recorded pension contributions expenses totaling \$2,130 (2009 – \$2,014). Contributions are expected to increase by approximately 1% per year over the next three years reflecting plan amendments recently announced by OMERS.

14) Commitments and Contingencies

Commitments

Contractual Obligations

a) Connection and Cost Recovery Agreement

Pursuant to the terms of a Connection and Cost Recovery Agreement dated December 10, 2008, the Corporation had committed to upgrade the capacity of one of its transformer stations. The total commitment over a three year period was approximately \$7,278 and the remaining commitment as at year-end is \$nil. (2009 – \$2,426).

b) Master CDM Agreement

On February 1, 2011, the Corporation entered into a Master CDM Agreement ("CDM Agreement") with the Ontario Power Authority ("OPA") for the period January 1, 2011 to December 31, 2014. The CDM Agreement provides terms under which the Corporation may engage the OPA to design and pay for Province-wide CDM programs in support of meeting its CDM Targets (Note 2(b)).

Subject to the terms of the CDM Agreement, all OPA CDM program costs are paid by the OPA. The Corporation effectively acts as a delivery agent for those programs that it participates in under the CDM Agreement. The Corporation estimates that, for those programs that it will participate in under the CDM Agreement, the total OPA CDM program costs over the four year period will be approximately \$57,000, of which approximately \$11,700 represent administration costs of the Corporation. The Corporation will be entitled to receive, in advance and in semi-annual installments each January and July, all of its estimated administration costs associated with each program. Any administration costs incurred by the Corporation in excess of the pre-approved estimate would not be recoverable. All other program costs incurred by the Corporation, (such as customer incentives and goods and services delivered under the programs) are recoverable from the OPA on an invoiced basis in accordance with the CDM Agreement.

Leases

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

2010	305
2011	255
	560

Credit Facility

On June 30, 2010, the Corporation entered into a Credit Facility Agreement ("Credit Facility") with a Canadian chartered bank. The Corporation can borrow up to \$100,000 to finance general corporate requirements, capital investments, working capital requirements, and prudential obligations. Borrowings may be in the form of Bankers' Acceptances ("BAs"), prime rate loans, letters of credit, and/or current account overdrafts. The Credit Facility matures on June 30, 2013. Interest rates payable on the Credit Facility are based on a margin relative to the prime or BA rate, as the case may be, determined by reference to the Corporation's debt rating. A standby fee is paid on any unutilized portion of the Credit Facility.

The Corporation has issued a \$9,100 letter of credit in favour of the Independent Electricity System Operator ("IESO") as security for Horizon Utilities' purchase of electricity through the IESO. At year end, no amounts were withdrawn on the letter of credit.

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 matters could reasonably be expected to have a materially adverse impact on its financial position, results of operations, or its ability to carry on any of its business activities.

Class Action

Pursuant to its order dated July 22, 2010 (the "Order"), the Ontario Superior Court of Justice approved the settlement of a class action lawsuit, which was served on the former Toronto Hydro-Electric Commission, continuing as Toronto Hydro Corporation, on November 18, 1998. The original class action was for the amount of \$500,000 and 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 Order formalized a settlement pursuant to which the defendant MEUs will pay the amount of \$17,000 plus costs and taxes in settlement of all claims. The amount allocated for payment by each MEU is based on its percentage of electricity distribution service revenue, relative to that of the entire Defendant Class, over the period for which it had exposure for repayment of late payment penalties exceeding the interest rate limit set out in the federal Criminal Code. The Corporation's share of the settlement is \$1,100, payable on June 30, 2011.

Under the terms of the settlement, all of the MEUs, including the Corporation, requested an order from the OEB allowing for future recovery from customers of all costs related thereto. On October 29, 2010, the OEB issued a notice of proceeding involving the entire Defendant Class to determine whether the costs and damages incurred by such are recoverable from electricity rate payers, and, if so, the form and timing of such recovery. On February 22, 2011, the OEB issued its decision on this matter and approved the recovery of all costs and damages arising from the settlement of the class action over a 12 month period commencing May 1, 2011, through a fixed rate rider.

As a result, the Corporation has recorded the settlement amount as an operating expense, with the corresponding regulatory recovery recorded through electricity distribution revenue.

15) 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:

	2010	2009
Gross customer billings	545,153	485,814
Less: Pass through charges billed by the Corporation		
Electricity charges paid through to generators	(332,094)	(286,387)
Transmission and miscellaneous charges	(55,509)	(48,351)
Market service charges	(32,778)	(30,564)
Debt retirement charges	(33,555)	(31,929)
	91,217	88,583

16) Other Income From Operations

Other income from operations comprises:

	2010	2009
Water and waste water billing and customer care charges	3,628	3,429
Collection and other service charges	1,629	1,618
Pole and other rental income	1,344	1,415
Late payment charges	1,201	1,168
Conservation and demand management programs	1,028	1,185
Meter services	649	353
Management and other support services	342	360
Scrap sales	327	434
Water heater rental income	298	310
Miscellaneous	317	97
	10,763	10,369

17) Capital Disclosures

The main objectives of the Corporation when managing financial capital are to:

- ensure ongoing cost effective access to such to provide adequate investment in support of its regulated electricity distribution business and its other businesses;
- compliance with covenants within its financial instruments;
- the prudent management of its capital structure, with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business; and
- deliver reasonable returns on the investments of its shareholders.

The Corporation's definition of capital includes shareholder's equity and long-term debt. This definition has remained unchanged from December 31, 2009.

The OEB regulates the amount of interest on debt and MARE that may be recovered by the regulated electricity distribution business of the Corporation through its electricity distribution rates. 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.

18) Related Party Transactions

Revenue

The Corporation provides certain water and wastewater billing and customer care services to the sole shareholder of Hamilton Utilities Corporation, the City of Hamilton. Other income includes \$3,628 (2009 – \$3,429) earned with respect to these services. Accounts payable and accruals included \$10,205 (2009 – \$9,790) owing to the City of Hamilton for amounts collected on its behalf with respect to these services.

The Corporation provides certain management, billing, and administrative services to Hamilton Utilities Corporation and its subsidiary, Hamilton Hydro Services Inc. Other income includes \$270 (2009 – \$270) earned with respect to these agreements.

19) Financial Instruments

Recognition and Measurement

The Corporation's fair value measurements are as follows:

- Level 1 – The carrying values of cash and cash equivalents, accounts receivable, credit support for service delivery, and accounts payable and accruals approximate their respective fair values because of the short maturity of these instruments.
- Level 2 – The \$40,000 4.77% senior unsecured debentures due July 21, 2020 [note 9] have a fair value of \$41,315, based on year-end quoted market prices for similar debt.
- Level 3 – It is not practicable to determine the fair value of the long-term borrowing from Hamilton Utilities Corporation 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 an 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. There is one large commercial customer that accounts for 3% (2009 – 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, 2010 is \$1,550 (2009 – \$1,150). No single customer accounts for more than 1% of accounts receivable at year-end.

The Corporation's credit risk associated with accounts receivable is primarily related to payments due from its electricity distribution customers. At December 31, 2010, approximately \$1,081 of such amounts are considered 60 days past due. The Corporation has approximately 237,000 electricity distribution customers, the majority of which are residential customers. Credit risk is managed by the Corporation through its credit policies, including the collection of security deposits from customers under conditions prescribed by the OEB.

At year end, the Corporation held security deposits in the amount of \$20,008 (2008 – \$22,451).

ii) Market Risk

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the rate of return applicable to the Corporation's distribution business (the MARE) is regulated and 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 with respect to its operational and investment requirements for financial capital. The Corporation seeks to ensure that it has sufficient financial liquidity to meet its obligations as such become due while minimizing interest expense. The Corporation has access to a revolving credit facility and may issue long-term debentures, from time to time, under its trust indenture.

Accounts payable, as reported on the financial statements, are generally due within 60 days of the receipt of an invoice.

20) Emerging Accounting Changes

International Financial Reporting Standards ("IFRS")

The Canadian Accounting Standards Board ("AcSB") has adopted a strategic plan that will require publicly accountable enterprises to adopt IFRS in place of Canadian GAAP, for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011.

In October 2010, the AcSB approved the incorporation of IFRS 1 into Part 1 of the Canadian Institute of Chartered Accountants ("CICA") Handbook for qualifying entities with activities subject to rate regulation. Part 1 of the CICA Handbook specifies that first-time adoption is mandatory for interim and annual financial statements relating to annual periods beginning on or after January 1, 2012.

The amendment also requires entities that do not prepare its interim and annual financial statements in accordance with Part 1 of the Handbook during the annual period beginning on or after January 1, 2011 to disclose that fact.

The Corporation has decided to defer its implementation of IFRS to January 1, 2012.

21) Comparative Figures

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



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