Table of Contents – Exhibit 1

APPENDIX D: Financial Statements – Year Ending December 31, 2015

APPENDIX E: Conditions of Service

APPENDIX F: Board Governance

Administration

Ex.1/Tab 6/Sch.1 – Table of Contents

Exhibit 1 Table of Contents

Please refer to Pages 1 through 4 of this document.

Exhibit 2 Table of Contents

Table of Contents

Exhibit 3 Table of Contents

Table of Contents

Exhibit 4 Table of Contents

Table of Contents

Exhibit 5 Table of Contents

Table of Contents

Exhibit 6 Table of Contents

Contents

Exhibit 7 Table of Contents

Contents

Exhibit 8 Table of Contents

Exhibit 9 Table of Contents

Contents

Ex.1/Tab 6/Sch.2 – Contact Information

Application contact information is as follows:

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Ex.1/Tab 6/Sch.3 - Legal Application

In the matter of; the Ontario Energy Board Act, 1998;S.O. 1998, c.15, Schedule B, as amended; and in the matter of; an Application by InnPower Corporation for an Order or Orders approving or fixing just and reasonable distribution rates effective January 1, 2017, January 1, 2018, January 1, 2019, January 1, 2020 and January 1, 2021.

InnPower Corporation is a distributor of electricity pursuant to a distribution license ED-2002-0520 issued by the Ontario Energy Board (the "Board") under the Ontario Energy Board Act, 1998 (the "Act").

InnPower Corporation hereby applies to the Board pursuant to section 78 of the Act for an Order or Orders approving or fixing just and reasonable distribution rates effective January 1, 2017, January 1, 2018, January 1, 2019, January 1, 2020 and January 1, 2021 via a Custom IR application for a 5 year period.

InnPower Corporation accordingly applies to the Board for the following Order or Orders:

- The Applicant applies for an Order or Orders approving the proposed distribution rates and other charges set out in Exhibit 8 to this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective January 1, 2017, January 1, 2018, January 1, 2019, January 1, 2020 and January 1, 2021, or as soon as possible thereafter.

Background

1. The Applicant is a corporation incorporated pursuant to the *Business Corporations Act (Ontario)*, with its head office at 7251 Yonge Street, Innisfil. The Applicant carries on the business of distributing electricity to the Town of Innisfil and South Barrie.

2. The Application has been prepared pursuant to the OEB`s Renewed Regulatory Framework for Electricity Distributors as detailed in the Report of the Board dated October 18, 2012 (the `RRFE`).

3. Unless specifically stated otherwise in the Application, the Applicant followed Chapter 2 of the OEB`s Filing Requirements for Electricity Distribution Rate Applications last revised July 16, 2015 in preparing this application.

4. The Applicant has prepared a Consolidated Distribution System Plan (`DSP`) in accordance with Chapter 5 of the OEB`s Filing Requirements for Electricity Transmission and Distribution Applications.

Approvals Requested

In this proceeding InnPower Corporation is requesting the following approvals:

- Approval to charge distribution rates effective for January 1, 2017, January 1, 2018, January 1, 2019, January 1, 2020 and January 1, 2021 to recover the following Service Revenue Requirements as outlined below and detailed in Exhibit 6;

	Service Revenue Requirement	Revenue Deficiancy /Sufficiency
2017	$ 13,273,194	$ 3,449,787
2018	$ 14,466,303	$ 518,953
2019	$ 15,436,183	-$ 84,850
2020	$ 16,272,853	-$ 195,033
2021	$ 17,100,775	-$ 166,588

- Approval of the Distribution System Plan as outlined in Exhibit 2.
- Approval of revised Low Voltage rates as proposed and described in Exhibit 8.
- Approval to adjust the Retail Transmission Rates (Network and Connection) as detailed in Exhibit 8.
- Approval of the Proposed Loss Factors as detailed in Exhibit 8.
- Approval of the Rate Riders for a two year disposition of the Group 1 and Group 2 and Other Deferral and Variance Accounts as detailed in Exhibit 9.
- Approval of the Rate Riders for a 2 year disposition of the Lost Revenue Adjustment Mechanism Variance Account (`LRAMVA`) for lost revenue from the 2011 -2014 IESO provincial programs as detailed in Exhibit 4.
- Interim approval of Z Factor rate rider as a result of a major event which occurred in March 2016 and detailed in Exhibit 9.
- Approval of an interim Pole Attachment rate
- Approval of a new microFIT rate

Proposed Effective Date of Rate Order

The Applicant requests that the OEB make its Rate Order effective January 1, 2017 in accordance with the Filing Requirements.

In the event that the OEB is unable to provide a Decision and Order in this Application for implementation by the Applicant as of January 1, 2017, the Applicant requests that the OEB declare its current rates interim, effective January 1, 2017, pending the implementation of the OEB`s Rate Order for the 2016 rate year.

All is which respectfully submitted,

Original signed by

Robert Lake
President and CEO

Ex.1/Tab 6/Sch.4 – Confirmation of Internet Address

InnPower Corporation’s website address is www.innpower.ca. The Application and related materials will be posted on InnPower Corporation`s website, once the Notice of Application and Hearing has been published in the local paper.

Ex.1/Tab 6/Sch.5 – Statement of Publication

All of InnPower Corporation’s customers may be affected by this application.

Upon receiving the Letter of Direction and the Notice of Application and Hearing from the Board, InnPower Corporation will immediately arrange to have the Notice of Application and Hearing for this proceeding published in the local community not-paid-for newspaper which has the highest circulation in its service area namely; “Innisfil Examiner”.

Once the Notice of Application and Hearing has been published in the above listed newspapers, InnPower Corporation will immediately file an Affidavit of Publication together with proof.

Ex.1/Tab 6/Sch.7 - Statement as to the Form of Hearing Requested

This Application is supported by written evidence. The written evidence will be pre-filed and may be amended from time to time, prior to the Board's final decision on the Application.

InnPower Corporation requests that, pursuant to Section 34.01 of the Board's Rules of Practice and Procedure, this proceeding be conducted by way of written/oral hearing.

Ex.1/Tab 6/Sch.9 - Statement of Deviation of Filing Requirements

Except where specifically identified in the Application, InnPower Corporation followed Chapter 2 of the OEB's "Filing Requirements for Electricity Transmission and Distribution Applications", dated July 18, 2014 (the "Filing Requirements") in order to prepare this application. The excel version of the complete 2016 Cost of Service checklist is being filed in conjunction with this application.

Ex.1/Tab 6/Sch.10 – Changes in Methodologies

InnPower Corporation has no change in methodologies to report with the filing of this application.

Ex.1/Tab 6/Sch.11 - Board Directive from Pervious Decisions

The Board did not issue specific directives in previous decisions.

Ex.1/Tab 6/Sch.12 - Conditions of Service

InnPower Corporation’s conditions of services are found at: http://www.innpower.ca/service.php?id=10.

A copy is found in Appendix E.

Ex.1/Tab 6/Sch.13 - Accounting Standards for Regulatory and Financial Reporting

InnPower Corporation has adopted the change in useful lives in our previous COS application EB-2013-0139.The useful lives proposed by InnPower Corporation in this Application are consistent with the useful lives in the Kinectrics Report and are explained further in Exhibit 2.

InnPower Corporation attests that it has not nor will not capitalize administration and other general overhead costs no longer permitted under IFRS, as clarified by the Board in its letter dated February 24, 2010. InnPower Corporation has also adopted the various account changes prescribed by the Board in relation to the USoA (Article 210 – Chart of Accounts and Account 220 – Account Descriptions).

Regulatory costs and the incremental one-time cost have been normalized by allocating one fifth of that total to the 2017 Test Year.

InnPower Corporation is not proposing other changes in methodology.

Ex.1/Tab 6/Sch.14 - Accounting Treatment of Non-Utility Related Business

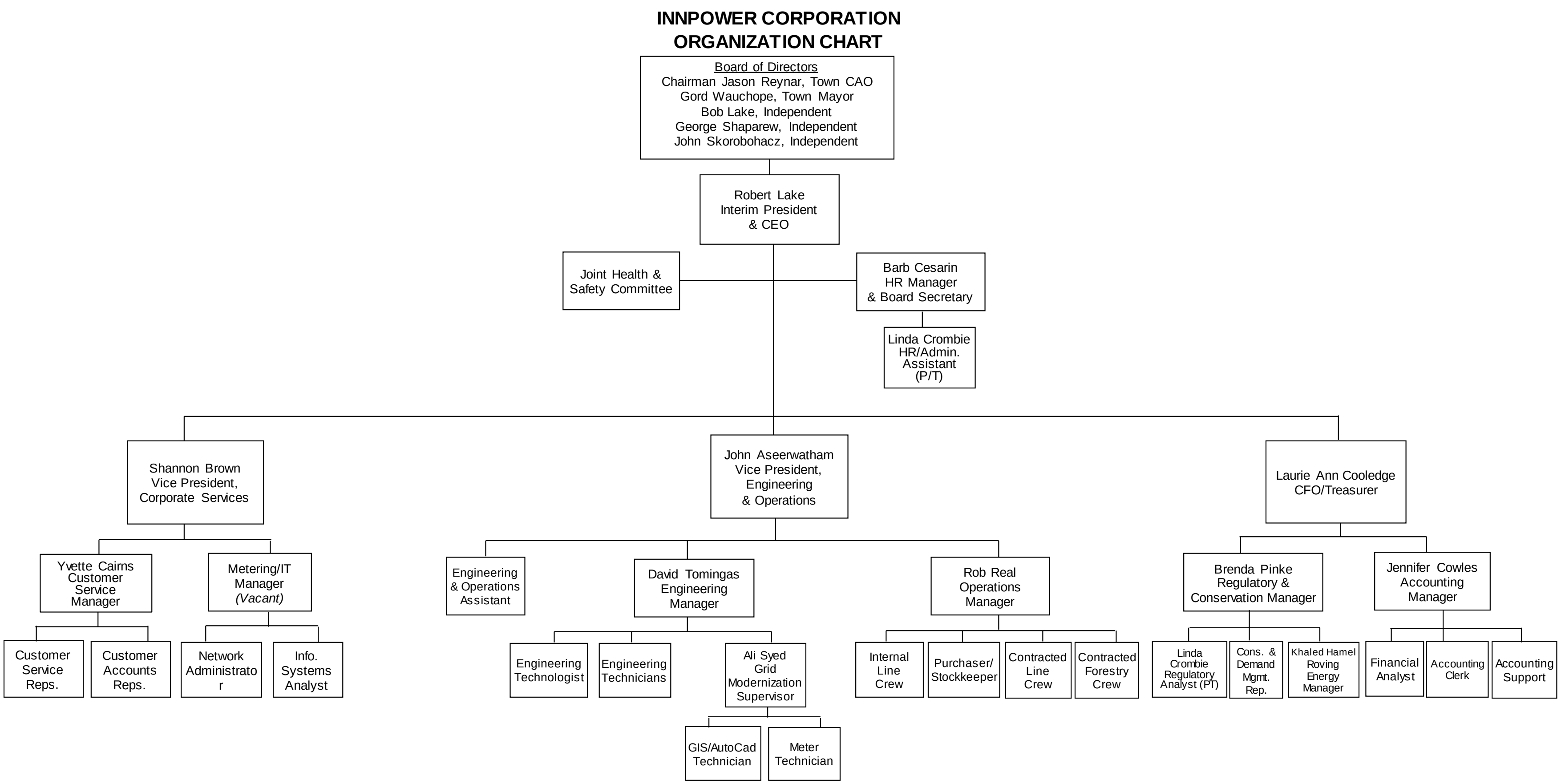
InnPower Corporation provides non-utility services for the Town of Innisfil for “Water and Sewer – customer service and billing”.

Non-utility business will be recorded in both accounts 4375 for income and 4380 for expenses, which again, shall have no effect on the revenue requirement of InnPower Corporation but shall adhere to the OEB Accounting Procedure Handbook.

Ex.1/Tab 6/Sch.16 - Corporate Organization

The following table provides InnPower Corporation`s corporate organization.  As identified in Exhibit 4, InnPower Corporation is requesting approval for additional FTE`s throughout the 2017 – 2021 timeframe.

Table: 1.12 – Organizational Chart



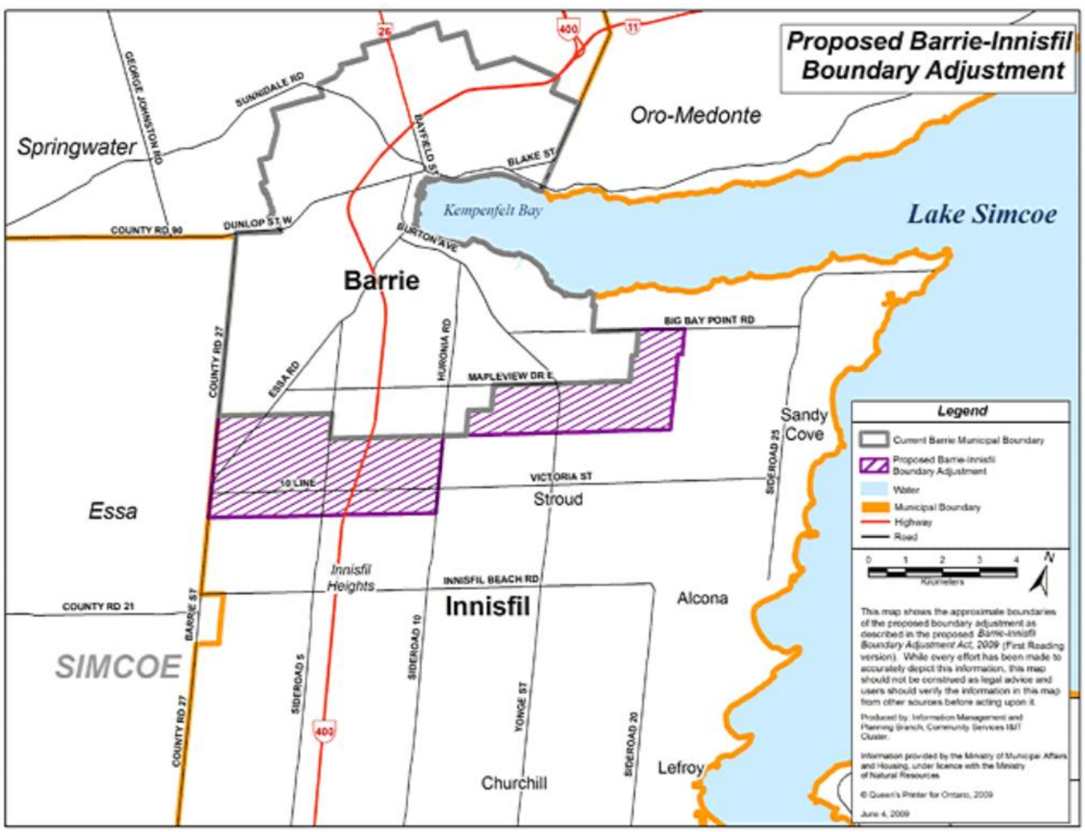
Management Discussion and Analysis

Ex.1/Tab 1/Sch.1 – Management Discussion and Analysis

Overview of InnPower Corporation

InnPower Corporation is a unique utility company, 292 square kilometers (approximately the size of the City of Mississauga) which is located north of the Oak Ridges Moraine. InnPower Corporation's service territory encompasses the lands of South Barrie and all of the Town of Innisfil, which includes the communities of Stroud, Alcona, Lefroy, Churchill, Cookstown, Gilford, Sandy Cove, and Big Bay Point.

Figure 1-1: Barrie – Innisfil Boundary Adjustment



InnPower Corporation has a challenge that is different from many LDC's which are facing infrastructure replacements. InnPower Corporation is facing growth challenges.

Following the *Oak Ridges Moraine protection Act, 2001*, property developers have been acquiring parcels of land within the Town of Innisfil for the purpose of development. The projected population and employment growth within the Town of Innisfil vary between the official plans of the Town of Innisfil, the Count of Simcoe and the Province of Ontario: but all agree that the growth will be significant. The following Table presents the past and future population and employment forecast:

Table 1.1: Town of Innisfil Population and Employment Forecasts

Source	Population	Employment
Innisfil 2011 Census and 2006 Employment estimate	33,080	5,700
Innisfil Offical Plan, 2031	55,500	27,750
Simcoe County Offical Plan 2031	65,000	13,100
Provincial Growth Plan, 2031	56,000	13,100
Provincial Growth Plan 2031: plus Friday Harbor and Sleeping Lion	65,240	13,100

Note: The Provincial Growth Plan is taken from the Intergovernmental Action Plan for Simcoe, Barrie and Orillia, but did not include 2 developments approved by the Town of Innisfil, known as Friday Harbour and Sleeping Lion.

Designated as a rural service territory (219 sq km rural) currently servicing 18,208 customers/ connections for EOY 2015 (total for Residential, >50 and <50 is $18,208), InnPower Corporation has planned for significant densification with this Custom IR Application.
Using growth projections from all available sources, the following comprises the parameters for long range growth projections:

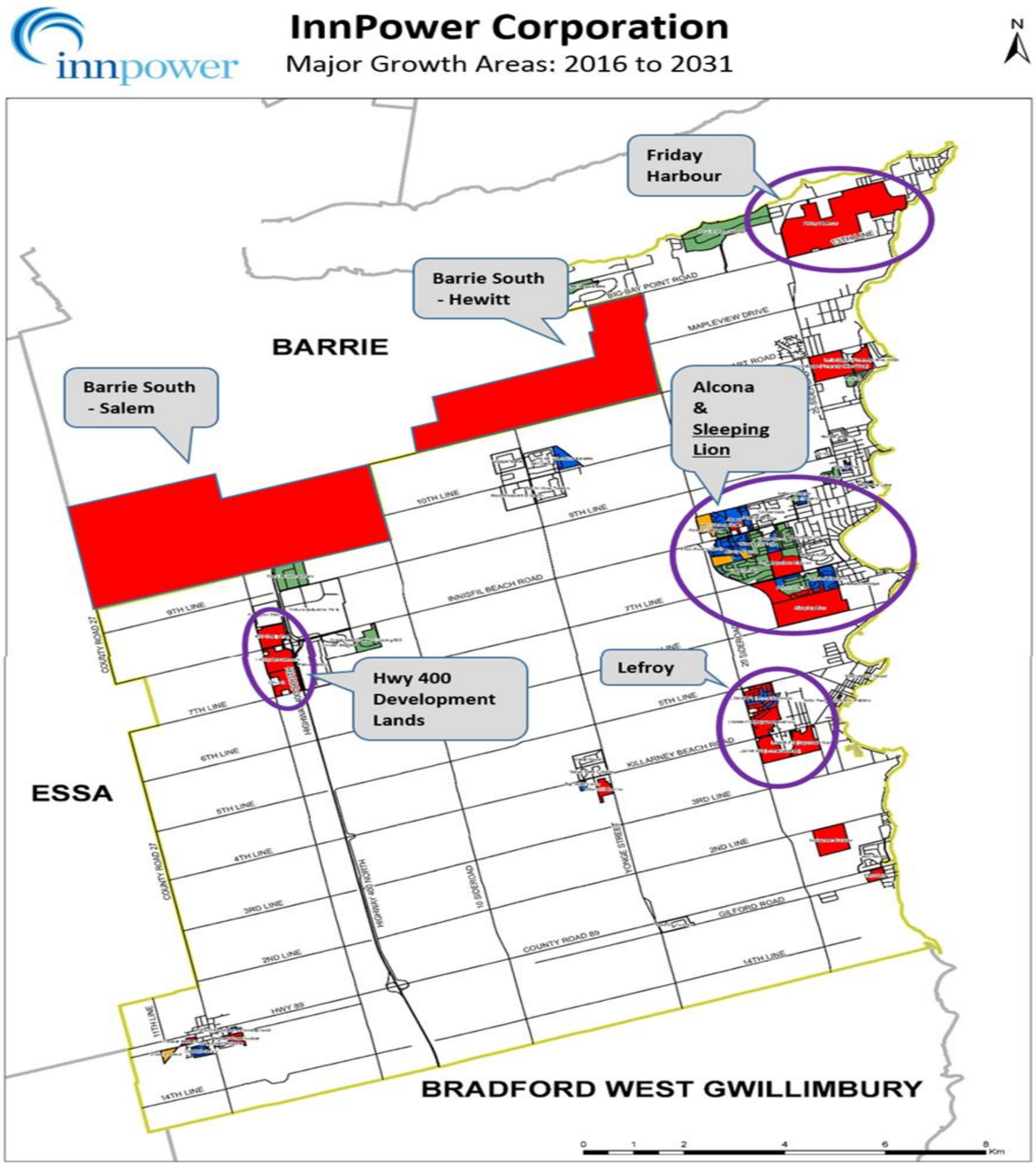
- Town of Innisfil population in 2031: 56,000.
- South Barrie (serviced by InnPower Corporation) population in 2031: 40,788.
- Friday Harbour development: 1,600 units and commercial load.

Summary of Residential Development

The development plans which pertain to InnPower Corporation's Distribution Plan (Ex 2/Tab 2/Asch 2) for this Custom IR Application have been summarized below:

1. The City of Barrie's official plan estimates 40,788 residents with 68 MW of demand by 2031 in the South Barrie area that will be served by InnPower. Customer connections in this area are expected to increase over the 2017-2021 forecast timeframe.
2. A new resort community named Friday Harbour has been approved by the Council of the Town of Innisfil and the Ontario Municipal Board. This 600 acre site is currently under construction and is expected to amount to approximately 1,600 customers over the next ten (10) years.
3. There are five (5) commercial development sites located close to the Innisfil Beach Road interchange of Highway 400. Three (3) of the sites were approved in 1990, 1991, and 1993, respectively and environmental impact assessments are ongoing.
4. The Lefroy area has development approval which will lead to approximately 2,300 new customers.
5. A development named Sleeping Lion is currently being built for an estimated 5,000 residents around the existing Alcona area.

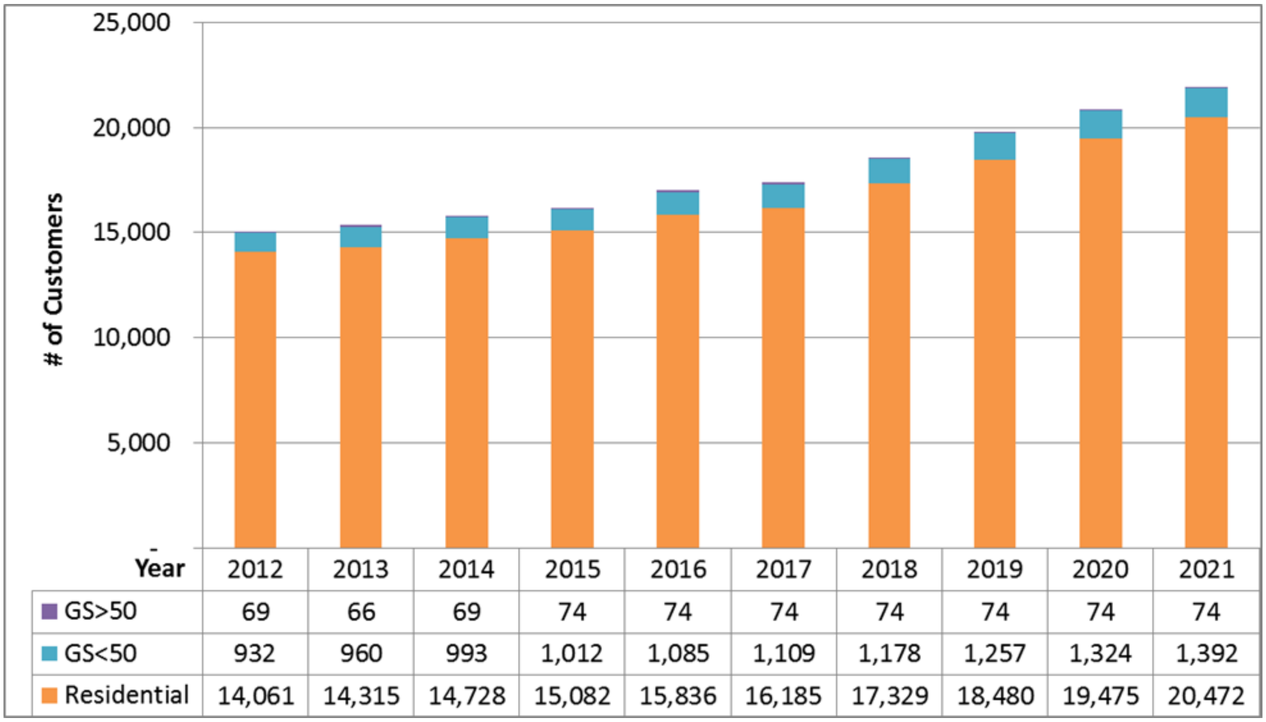
Figure 1-2: InnPower Corporation Major Growth Areas



Customer Counts

InnPower Corporation's customer base has faced consistent growth over the past ten (10) years and this trend is expected to significantly increase into the next decade. Conservative customer growth estimates have been made by considering a lower absorption rate than the development estimates. Even so, it is predicted that InnPower Corporation's customer base will double in the next fifteen (15) years.

Figure 1-3: Year End (2012-2014) and Forecasted (2015- 2021) Customer Counts



Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
GS>50	69	66	69	74	74	74	74	74	74	74
GS<50	932	960	993	1,012	1,085	1,109	1,178	1,257	1,324	1,392
Residential	14,061	14,315	14,728	15,082	15,836	16,185	17,329	18,480	19,475	20,472

Peak Demand

Similarly, the peak demand forecast is driven by load growth. Peak demand is expected to increase from approximately 52 MW in 2015 to approximately 80 MW in 2021, including embedded generation. The summer and winter peak loads including embedded generation is presented in the Distribution System Plan in Exhibit 2 (see table below), based on historical data for 2012 to 2015 and forecast data for 2016 to 2021.

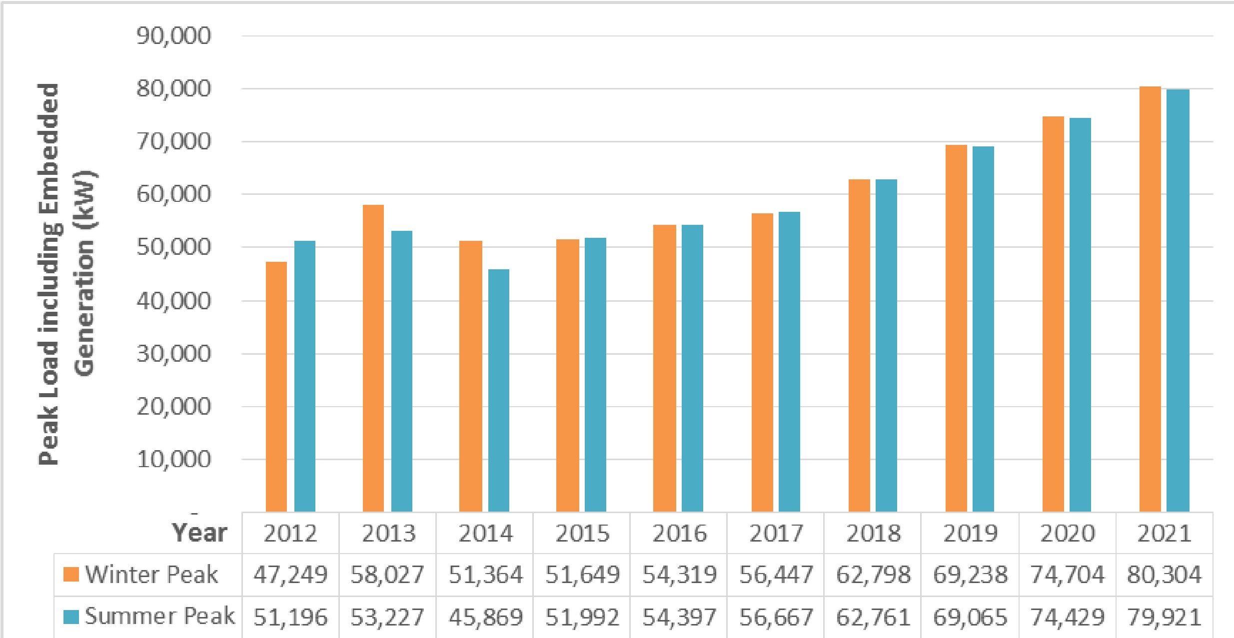
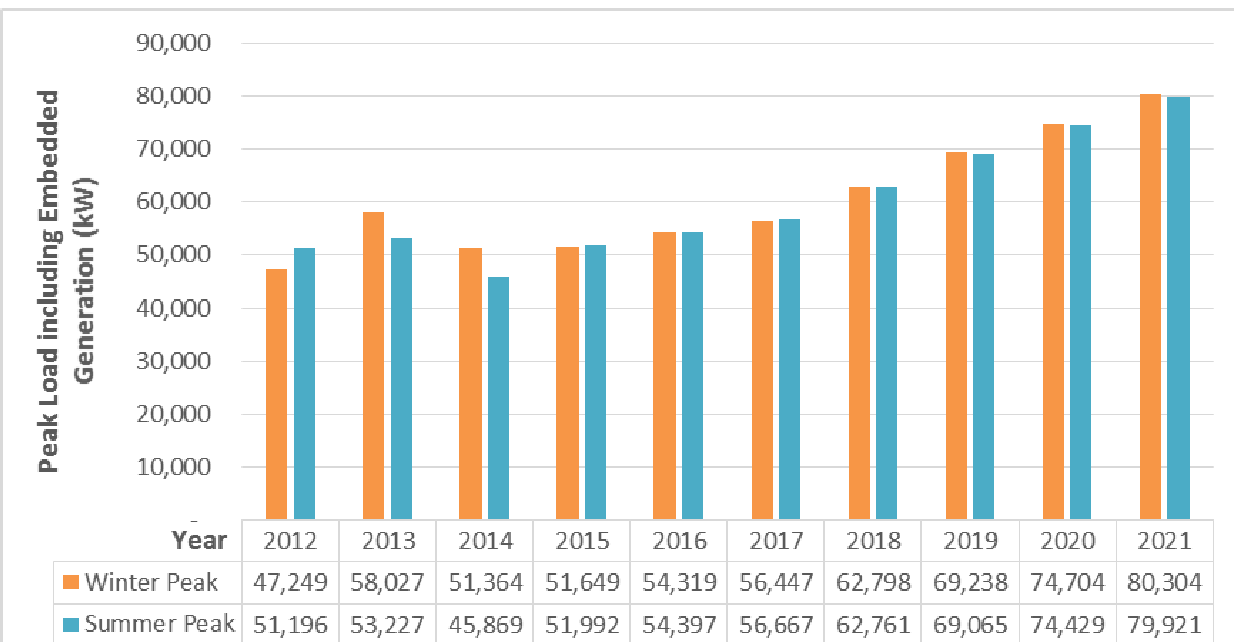


Figure 1-4: Historical (2012 -2015) and Forecasted (2016 - 2021) Peak Loads



Managing our Assets

Each year InnPower Corporation maintains, refurbishes and replaces assets as they age, deteriorate or cannot perform their intended functions in a safe and reliable manner.

With managing existing assets there is a balancing act that InnPower Corporation must consider system reliability versus building new infrastructure for future connections.

Summary of InnPower Corporation's Key Drivers for the EB-2016-0086 Custom IR

InnPower Corporation is entering a timeframe where new infrastructure costs due to future growth and on-going maintenance will precede the customer connections that will provide an adequate rate of return and stabilize rate increases.

Increases in System Access and System Service capital projects which are primarily driven by customer demand have increased InnPower Corporation's overall capital spend by approximately $1,267,000 compared to the 2013 Board Approved capital spend of $5,400,000.

Table 1.2: Summary of Capital Investment Categories for the 2017 – 2021 Test Years

	2013 Actual *$'000*	2017 Test Year *$'000*	2017 Increase over 2013	2018 Test Year *$'000*	2018 over 2017	2019 Test Year *$'000*	2019 over 2018	2020 Test Year *$'000*	2020 over 2019	2021 Test Year *$'000*
System Access	974	1,754	80.1%	1,984	13.11%	1,595	-19.6%	1,598	0.2%	2,013
System Renewal	987	1,216	23.2%	1,140	-6.25%	2,919	156.1%	2,400	-17.8%	2,109
System Service	1,377	2,338	69.8%	2,829	21.00%	1,276	-54.9%	1,556	21.9%	1,402
General Plant	1,348	1,500	11.3%	1,423	-5.13%	897	-37.0%	680	-24.2%	706
Total	4,686	6,808	45.3%	7,376	8.34%	6,687	-9.3%	6,234	-6.8%	6,230

System Access and System Service capital investment categories and associate capital projects contribute 55.0% to the overall 5 year plan.

Table 1:3: Summary of Capital Investment Categories for the 2017 – 2021 Test Years by %

	2017	2018	2019	2020	2021	5 Year Average	% of Capital
System Access	1,754	1,984	1,595	1,598	2,013	1,789	26.8%
System Renewal	1,216	1,140	2,919	2,400	2,109	1,957	29.4%
System Service	2,338	2,829	1,276	1,556	1,402	1,880	28.2%
General Plant	1,500	1,423	897	680	706	1,041	15.6%
Total	**6,808**	**7,376**	**6,687**	**6,234**	**6,230**	**6,667**	**100.0%**

Alignment with the RRFE

On October 18, 2012, the Ontario Energy Board ("The Board") issued its "Report of the Board: A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach", and subsequently commenced implementation of the Renewed Regulatory Framework. This report set out a comprehensive performance-based approach for the Renewed Regulatory Framework which promotes the achievement of outcomes that will benefit existing and future customers; will align customer and distributor interests; will continue to support the achievement of important public policy objectives; and will place a greater focus on delivering value for money. Under this approach, a distributor is expected to demonstrate continuous improvement in its understanding of the needs and expectations of its customers and its delivery of services.

On March 5, 2014, the Board issued its report on "Performance Measurement for Electricity Distributors: A Scorecard Approach". InnPower staff prepares a monthly Performance Scorecard, which is reviewed and certified by each responsible Manager. The Performance Scorecard is made available to staff monthly and a Year-End review is presented annually at an All Staff meeting.

With the above in mind, InnPower Corporation would like to provide an overview of this utility in terms of the Renewed Regulatory Framework and the Distributor Scorecard. Since these are the measures to which a utility is held accountable, these are also the measures a utility should address during rate application process. The metrics achieved support alignment with the RRFE Performance Outcomes.

At the time of filing, InnPower Corporation's 2015 Distributor Scorecard has not yet been published, however InnPower Corporation has completed the 2015 Performance Based Reporting (PBR) and will provide updates on 2015 trends.

CUSTOMER FOCUS:

In terms of service quality, InnPower Corporation has always maintained the highest standards possible. In a regulatory environment, there are numerous SQR targets that a utility must achieve. In most cases, InnPower Corporation consistently meets and exceeds these targets. In terms of customer satisfaction, InnPower Corporation has always strived for strong customer relations and increase customer engagement within the community. This effort is support by the customer satisfaction survey measure on the Distributor Scorecard. In 2015, InnPower Corporation achieved a customer satisfaction rating of “A” on its Distributor Scorecard, which is better than the Provincial and National averages. In terms of customer engagement, InnPower Corporation has numerous methodologies by which it engages its customers. This allows InnPower Corporation to keep in touch with customers at both the individual and community levels.

OPERATIONAL EFFECTIVENESS:

In regards to Safety, InnPower Corporation is committed to delivering a world class health and safety environment across all of its operations. At InnPower Corporation, we always strive to put safety first by creating an injury-free environment, both in the workplace and in the field. InnPower Corporation’s public Safety measure in the InnPower 2015 Corporation Distributor Scorecard is one of the highest in the industry at 86%. In regards to reliability, InnPower Corporation continues to hold the reliability of distribution system to the highest standards. In regards to the Distribution system plan, InnPower Corporation has implemented new processes to expand its planning horizon to a 10 year horizon (5 historical years and 5 forecasted years). Full details on the Distribution System Plan can be found in Exhibit 2/Tab 2/Schedule 2.

Following are some of our initiatives that have been implemented and/or improved upon since our 2013 Rate Application:

1. Supporting Renewable Energy Generation:
    a. There are approximately 1,681 kW of renewable energy installations connected to InnPower’s distribution system; and
    b. 500kW of renewable energy installations connected to InnPower’s sub-transmission system.

    This includes 7 FIT projects and 78 microFIT projects.
2. Supporting Subdivision Development:
    a. Individual meetings with business developers.
    b. Work with developers to establish economic evaluations.
3. Building a Connected Grid featuring Intelligent Energy Systems.
    a. Enhancing Connectivity

            i. Building a new Radio Communication Network with the Town of Innisfil
    b. Remote monitoring and Control of our Grid.
            i. Outage Management System.
            ii. 24/7 notification of outages.

4. Supporting County Road Widening.
5. System expansion and upgrading to support Load Growth.
6. Infrastructure Repair and Replacement
7. Prudent Investment in Technology & Systems to enhance productivity:
    a. Geographic Information Systems
    b. Circuit Simulation Software
    c. Pole Stress Calculator
8. Developing new Engineering Design Standards.
9. Building strategic partnerships with third parties to improve and enhance design and construction.
10. Work Order Process Automation (hand-held tablets for lines staff and technicians).
11. Utility Locate Process Automation.
12. Building a Mobile Workforce.
13. Staff Training to adapt to New Technology and Processes.

PUBLIC POLICY RESPONSIVENESS:

InnPower Corporation has achieved 84.4% of its Net Cumulative Energy Savings target of 9.2 GWh over the last 4 years (2011 – 2014). 2015 was a transition year for InnPower Corporation to the Conservation First Framework (2015 – 2020), however, continues its efforts to instill a conservation culture through promotion and adoption of conservation and demand management programs. InnPower Corporation's CDM initiatives allows the utility to reach out primarily to our residential and GS < 50 kW customer classes. These outreach programs are making a difference and have become an integral component of InnPower Corporation's communications and customer engagement strategy. In addition to the above, InnPower Corporation has entered into an agreement to share a "Roving Energy Manager" (REM). This shared service is a cost effective solution to engage and address some of the needs of our larger customers. This has been an extremely successful venture that creates a win-win situation by providing additional energy savings to the utility, while improving the competitive position and the bottom line of our larger demand users. Furthermore, InnPower Corporation also engages its customers and shares it expertise in other areas of conservation such as renewable energy initiatives and community energy planning.

Please refer to Ex. 1/Tab 3/Sch.5 – Meetings for more details.

FINANCIAL PERFORMANCE:

InnPower Corporation's financial performance continues to remain strong despite recent economic and industry challenges posed by increased activity, complex operational demands and market evolution. The main factors contributing to the utility's financial pressures are the ability to finance capital expenditures to build the required infrastructure ahead of new customer connections. The Distribution System Plan (presented later in this document in Exhibit 2/Tab 2/Schedule 2) will support the capital and maintenance programs needed to maintain and enhance the reliability of InnPower Corporation's distribution system as we move into the future.

With this filing, InnPower Corporation looks to the future in terms of carrying a strong and sound foundation forward. By building on this foundation through continuous improvement, technological investment, and a stronger financial investment, InnPower Corporation plans to continue to provide the highest value in electrical distribution services, at a justified cost, to our community and the customer.

Executive Summary

Ex.1/Tab2/Sch.1 – Custom IR Application

InnPower Corporation Custom IR Application

The OEB's RRFE Report provided three different approaches to rate setting. InnPower Corporation reviewed all of the options as presented by the Board, and determined that the Custom IR Application is the best option for InnPower Corporation. On January 22, 2016 the OEB issued EB-2014-0219 – New Policy Options for the Funding of Capital Investments. The report states:

"*The OEB will not alter its policy of allowing the half-year rule (or analogous approaches) to persist through the Price Cap IR period. It is not appropriate to adjust for one factor, such as any shortfall due to the use of the half year rule, without considering all other factors that arise through an IR period. The OEB has already included several options that distributors can leverage to address their unique circumstances. In 2012, the OEB established rate-setting options for distributors, including the custom IR method."*

InnPower Corporation will be experiencing substantial growth in terms of demand and customers through the 2017 – 2021 timeframe which presents pressures on cash flow and the ability to borrow for capital expenditures. The can also be attested to by InnPower Corporation's achieved Rate of Return which has not been achieved since 2012.

Table 1.5: InnPower Corporation Achieved ROE

	2012	2013	2014	2015
Deemed	8.01	8.98	8.98	8.98
Achieved	1.90	5.70	5.83	7.68

Note: 2015 ROE incresed due to ICM Rate Riders for the Corporate Headquarters

InnPower Corporation has explored multiple options to ease the financial pressures until our customer count densifies. These options are outlined below:

1. InnPower Corporation is actively seeking an equity partner for an equity injection to ease the debt to equity issue.
2. Shareholder dividends of $625,000 annually have been suspended from the 2015 – 2023 timeframe.
3. Rebasing on an annual basis to ensure that additional assets were included in the Rate Base calculation.

Option 1 is still being actively pursued by InnPower Corporation and Option 2 has been accepted by the shareholder. Option 3 - Re-basing on an annual basis presented resourcing and costs concerns for InnPower Corporation, customer confusion, and impacts for the Ontario Energy Board. With these considerations, InnPower Corporation was of the view that a Custom IR would address some immediate issues and provide some relief until the densification of InnPower Corporation occurred.

InnPower Corporation raised the concern of the debt equity issue in its 2012 Rate Application EB-2012-0139.

Except from EB-2012-0139 Exhibit 1/Tab1/Schedule 3/Page 2/line 46-55

"*The depreciation expense has been reduced from the historic 25 year level to 45 years in many cases which means that a greater proportion of capital investments and economic evaluation contributions will be financed by debt. Maximum bank amortization limits remains at 25 years so even when assets get depreciated over 45 years; they are still paid for in 25 years. The long range financial forecast indicates that the 60% debt ceiling will be breached in 2013. IHDSL must borrow funds to pay for new development and will not get recovery for the interest on the debt above 60%. IHDSL's bank has confirmed that traditional debt/equity covenants of 75/25% are common for riskier enterprises than LDCs. IHDSL submits that the debt ceiling of 60% is not sustainable for high growth LDCs like IHDSL and requests that the debt ceiling be raised to 75%.*"

The outcome of InnPower Corporation's request was that the debt to equity ratios were "deemed" and that an LDC could go beyond the deemed thresholds. InnPower Corporation has breached the debt equity ratios and, as such, is submitting a Custom IR for a five year period from 2017 - 2021 to help mitigate the financial pressure of financing forecasted capital requirements as outlined in our Distribution System Plan.

Ex.1/Tab2/Sch. 2 – Annual Adjustments

Annual Adjustments

InnPower Corporation is proposing annual adjustments for recurring events that are mechanical in nature. The proposed adjustment calculation will be derived based on year-end audited financial statements and or parameters issued by the OEB or the federal or provincial government.

InnPower Corporation proposes annual adjustments to the following items:

- Changes in the cost of capital
- Changes to working capital
- Changes in tax rates
- Changes in other 3rd party pass through charges
- CDM results that vary from plan
- Disposition of deferral and variance accounts
- Any additional annual adjustments as identified by the Board in the continuous evolution of the Custom IR Application process

Reopeners

InnPower Corporation is proposing that adjustments outside the normal course of business will be sought for unexpected events that may have a material impact to the operation of the utility and are outside of Management’s control.

The following proposed reopeners are as follows:

- Changes to income tax rates and laws:
- Changes to Ontario Market Rules or OEB Codes that would impact costs or revenues
- Changes to Environmental laws that would impact business requirements and processes resulting in increased expenditures
- Changes to technical requirements that are beyond the control of the utility

- Events that would meet the OEC's Z Factor criteria as defined in Chapter 3 of the Board`s Filing Requirements for Transmission and Distribution that are material unforeseen events
- Ministerial Directives or similar required government action to provide a service to customers that is not already reflective in rates
- Accounting framework changes that have a significant impact on the recording of expenses and revenues

Off-Ramps

Under the RRFE, the Board expects that distributors that apply using the custom Rate-setting method will be committed to that method for the duration of the approved term. The board recognized that a distributor may need to seek early termination and had provided a mecjanism for regulatory review to be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels.

InnPower Corporation is proposing to apply the Boards existing policy in relation to off-ramps.

Ex.1/Tab2/Sch.2 - Proposed Revenue Requirement

InnPower Corporation proposes to recover through distribution rates a base revenue requirement of $12,056,989 in 2017, $12,863,960 in 2018, $13,493,357 in 2019, $13,986,316 in 2020 and $14,454,800 in 2021.

Table 1.1: 2017 - 2021 Proposed Revenue Requirements reflects the comparison of the proposed Base Revenue Requirements to the 2013 Board Approved Base Revenue Requirement.

Key drivers to the changes from the 2013 Board Approved Base Revenue to the 2017 Test Year Base Revenue, increase of Rate Base, increase of OM&A expense, increase in PILs/Property tax and the change in the Working Capital Allowance from 12% to 7.5%. All of these drivers are further explained in their respective Exhibits.

Table 1.6: 2017 – 2021 Proposed Revenue Requirements

	Board Approved 2013	2017 Test Year	2017 Variance to 2013 BA - $	2017 Variance to 2013 BA - %	2018 Test Year	2019 Test Year	2020 Test Year	2021 Test Year
OM&A Expenses	$ 4,900,000	$ 6,864,522	$ 1,964,522	40.1%	$ 7,361,400	$ 7,633,900	$ 7,833,300	$ 8,038,200
Amortization Expense	$ 1,280,461	$ 2,850,366	$ 1,569,905	122.6%	$ 3,254,557	$ 3,675,101	$ 4,073,356	$ 4,476,550
Total Distribution Expense	$ 6,180,461	$ 9,714,888	$ 3,534,427	57.2%	$ 10,615,957	$ 11,309,001	$ 11,906,656	$ 12,514,750
Regulated Return on Capital	$ 1,934,683	$ 3,289,371	$ 1,354,688	70.0%	$ 3,546,284	$ 3,788,956	$ 3,989,594	$ 4,175,369
Grossed Up PILS/Property Tax	$ 12,500	$ 268,934	$ 256,434	2051.5%	$ 304,063	$ 338,226	$ 376,603	$ 410,656
Service Revenue Requirement	$ 8,127,644	$ 13,273,194	$ 5,145,550	63.3%	$ 14,466,303	$ 15,436,183	$ 16,272,853	$ 17,100,775
Less: Revenue Offsets	$ 536,948	$ 1,216,205	$ 679,257	126.5%	$ 1,602,344	$ 1,942,827	$ 2,286,537	$ 2,645,975
Base Revenue Requirement	$ 7,590,696	$ 12,056,989	$ 4,466,293	58.8%	$ 12,863,960	$ 13,493,357	$ 13,986,316	$ 14,454,800
Overall Annual Incease in Base Revenue Requirement $		$ 4,466,293			$ 12,863,960	$ 1,436,368	$ 1,122,356	$ 961,443
Overall Annual Incease in Base Revenue Requirement %		58.8%			6.7%	11.9%	8.7%	7.1%

Ex.1/Tab 2/Sch.3 - Budget and Accounting Assumptions

The budget (Capital and OM&A) process at InnPower Corporation is an integral planning tool and ensures that appropriate resources are available to maintain and grow its infrastructure as required. It is the responsibility of each department to contribute in the preparation of the capital and operating budget, with the assistance of the Finance department. The responsibility of the Finance department is to coordinate the capital budget, OM&A budget and forecast process to compile a comprehensive Preliminary Budget to present to Senior Management for approval. Once the Preliminary Budget (Capital and OM&A) and long range forecast has been approved by Senior Management, it is presented to InnPower Corporation's Board of Directors as follows:

1. The Senior Management team presents the comprehensive Preliminary Budget, (Capital & OM&A) and long range forecast at the next meeting of the Board of Directors.
2. The feedback received from the Board of Directors is shared with the various department managers to make any revisions to the budget and long range forecast, as necessary.
3. The revised final version is then presented to the Board of Directors for approval.
4. It is then the responsibility of the Board of Directors, on behalf of the stakeholders, to approve the budget.
5. Once approved the complete finance package is presented to the shareholder, the Town of Innisfil.

Once the Board of Directors approves the annual budget, the budget amounts do not change but rather provide a plan against which actual results may be evaluated. In addition to the capital needs of the distribution system, InnPower Corporation plans for the required maintenance of its assets considering both performance and safety.

Budget Directives

InnPower compiles budget information for the three major components of the budgeting process:

1. Revenue forecasts;
2. Operating, maintenance, and administration **("OM&A")** expense forecast; and
3. Capital budget forecast under the RRFE investment categories

a. System access
b. System renewal
c. System service
d. General plant

1. Revenue Forecast

InnPower Corporation's revenue forecast is based on the forecasted energy consumption, peak load, and customer counts for the 2017 - 2021Test Years. InnPower prepares a weather normalized load forecast by customer class and monthly customer class data for the weather sensitive customer classes using the regression analysis and by average usage and forecasted customer growth for the non-weather sensitive customer classes. The forecast results are then used to calculate the 2017 Test Year revenue requirement at existing rates and proposed rates.

2. OM&A Expense Forecast

InnPower Corporation allocates available person-hours to the various OM&A programs and activities planned and budgeted for each year. Any remaining hours are allocated to identify capital projects. InnPower employs contract labour, utilizing long term contracts as well as on-demand labour, and such contract work is determined based on the level of work load and expertise required. InnPower reviews and establishes the budget based on historical trends and known factors as opposed to simply applying an arbitrary inflation factor. Labour costs are in accordance with InnPower Corporation's Collective Agreement.

The OM&A costs presented at Exhibit 4 are the result of a business planning and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place. The budgeting process used to determine the OM&A budget involves the following steps.

- Detailed expenses for prior 2-3 years are provided to the Managers. Current year to date actual expenses are also provided. Managers are required to update current year forecast to aid in development of full year forecast estimates.
- Outside expenses for all department budgets are built based on analysis including previous years actual information, current year forecast, known changes in external

costs, and changes in departmental activities or responsibilities in response to new legislation/regulations/industry activities;

- Variances in spending from prior years must be explained and documented, both at the time of creating forecast and on a monthly basis as actuals are compiled; and
- Review the headcount of the department for accuracy and outline any changes such as vacancies, retirements etc.

3. Capital Budget

InnPower Corporation's Asset Management Plan identifies the capital projects required and projected to be required over a five year period based on the best available information for each year. The capital budget forecast is influenced significantly by growth, customer requests including road works, reliability and the conversion of aging infrastructure, and the cost of support systems. All proposed capital projects for the Bridge Year and Test Year will be completed and in service in their respective year. InnPower acknowledges that, where the priority of projects changes or factors outside of its influence change, InnPower may be required to re-evaluate the future year's capital project forecast.

The forecasted capital budget is influenced, among other factors, by InnPower Corporation's capacity to finance capital projects. Also, the availability of the workforce to complete a planned capital project is equally influential. All proposed capital projects are assessed within the framework of its capital budget priority as outlined in Exhibit 2 (Capital Expenditures by Project). Topics included in the budget process include:

- Customer Demand and Capacity;
- Renewal;
- Reliability;
- Regulatory Requirements.

The Distribution System Plan presented in Exhibit 2/Tab 2/Sch 2 supports the capital and maintenance programs needed to maintain and enhance the reliability of InnPower Corporation's distribution system for the 2017 – 2021 timeframe.

Inflation:

Staff and management salaries are adjusted yearly to reflect the negotiated increase of the PWU Union Contract. InnPower Corporation current contract with PWU is up for renewal in July 2016. For the purposes of this application the 2015 rates have been applied.

Ex.1/Tab 2/Sch.4 - Load Forecast Summary

In summary, InnPower Corporation used the same regression analysis methodology approved by the Ontario Energy Board (the "OEB") in its 2013 Cost of Service ("COS") application (EB-2012-0139) and updated the analysis for actual data to the end of the 2015. The updated regression analysis used the some variables as those in the 2013 COS application since these variables continued to provide very good statistical results.

During the review process of previous COS applications for other applicants, parties have expressed concerns with the load forecasting weather normalization process being used in this application. It has been suggested the weather normalization should be conducted on an individual rate class basis and the regression analysis would be based on monthly consumed kWh by rate class. As undertaken in the 2013 COS application (EB-2013-0139), InnPower Corporation conducted a regression analysis on an individual rate class basis. Consistent with the results in the 2013 COS application the R square and Adjusted R square values for the rate class regression analysis were not acceptable compared to the results of the power purchased method. The R square and Adjusted R square values by rate class and power purchased method are shown in the following table. Based on these results, InnPower Corporation concluded using the equation resulting from the power purchased method would be the appropriate approach to prepare the load forecast.

Table 1.7: R Square and Adjusted R Square Values

Class	R Square	Adjusted R Square
Residential	78%	77%
General Service < 50 kW	72%	71%
General Service 50 to 4,999 kW	3%	0%
Power Purchased	94%	94%

The 2017 – 2021 Load Forecast is presented at the next page and detailed explanations of the load forecast can be found throughout Exhibit 3 of this Application.

Table 1.8: Load Forecast Customers or Connections

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load	Total
Number of Customers/Connections							
2013 Board Approved	14,189	910	66	237	2,889	78	18,369
2006 Actual	12,867	797	80	189	2,371	90	16,394
2007 Actual	12,991	819	71	186	2,489	89	16,645
2008 Actual	13,277	836	73	186	2,588	84	17,044
2009 Actual	13,533	855	72	193	2,625	83	17,361
2010 Actual	13,651	865	68	201	2,685	82	17,552
2011 Actual	13,779	896	67	225	2,728	81	17,776
2012 Actual	13,943	914	68	172	2,728	79	17,903
2013 Actual	14,181	949	67	168	2,843	78	18,286
2014 Actual	14,509	991	67	169	2,923	76	18,736
2015 Actual	14,862	1,001	72	166	2,898	76	19,073
2016 Bridge - Normalized	15,419	1,026	72	163	2,963	75	19,718
2017 Test - Normalized	15,930	1,052	72	161	3,030	74	20,319
2018 Test - Normalized	16,676	1,079	72	159	3,098	73	21,157
2019 Test - Normalized	17,824	1,107	72	157	3,168	72	22,400
2020 Test - Normalized	18,877	1,135	72	155	3,239	71	23,549
2021 Test - Normalized	19,853	1,164	72	153	3,312	70	24,624

Table 1.9: Forecasted kWh CDM Adjusted

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lighting	Unmetered Scattered Load
Forecast Annual kWh Usage per Customers/Connection						
2016	10,039	33,966	804,730	618	377	6,598
2017	9,916	33,735	847,471	611	373	7,145
2018	9,795	33,506	892,483	604	369	7,737
2019	9,675	33,278	939,886	597	365	8,378
2020	9,557	33,052	989,806	590	360	9,072
2021	9,440	32,827	1,042,378	584	356	9,824

Table 1.10: Forecasted kW CDM Adjusted

Year	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lighting	Total
Predicted Billed kW				
2016 Bridge - Normalized	154,174	280	1,854	156,308
2017 Test - Normalized	157,261	273	1,889	159,423
2018 Test - Normalized	163,334	267	1,923	165,523
2019 Test - Normalized	169,041	260	1,958	171,260
2020 Test - Normalized	175,664	254	1,993	177,911
2021 Test - Normalized	182,237	248	2,029	184,514

Ex.1/Tab 2/Sch.5 - Rate Base and Capital Planning

A rate base is the value of property on which a utility is permitted to earn a specified rate of return in accordance with rules set by the OEB. The rate base underlying InnPower Corporation's revenue requirement includes a forecast of net fixed assets, plus a working capital allowance defined as 7.5% of the sum of the cost of power and controllable expenses. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

The proposed Rate Base for the 2017 test year of $57,578,157 reflects an increase of $24,387,114 from the 2013 Board Approved. Table 1.11 shows the derivation of the proposed 2017 – 2021 rate base. This increase represents an average annual increase of $6,098,779 from 2013 to 2017.1 to 2016. Further details can be found at Exhibit 2.

InnPower Corporation is not proposing to recover any costs from any rate class renewable energy connections/expansions, smart grid, and regional planning initiatives.

Table 1.11: Rate Base Trend 2013 - 2021

	Last Board Approved 2013	2014	2015	2016 Bridge	2017 Test	2018 Test	2019 Test	2020 Test	2021 Test
Net Capital Assets in Service									
Opening Balance	$ 28,199,498	$ 30,850,492	$ 34,019,681	$ 49,145,019	$ 52,526,867	$ 56,747,200	$ 61,253,586	$ 64,900,451	$ 68,007,206
Ending Balance	$ 30,850,492	$ 34,019,681	$ 49,145,019	$ 52,526,867	$ 56,747,200	$ 61,253,586	$ 64,900,451	$ 68,007,206	$ 71,031,201
Average Balance	$ 29,524,995	$ 32,435,086	$ 41,582,350	$ 50,835,943	$ 54,637,033	$ 59,000,393	$ 63,077,019	$ 66,453,829	$ 69,519,204
Working Capital Allowance	$ 3,666,048	$ 3,961,443	$ 4,239,822	$ 4,587,055	$ 2,941,124	$ 3,074,834	$ 3,246,020	$ 3,381,234	$ 3,567,730
Total Rate Base	$ 33,191,043	$ 36,396,529	$ 45,822,172	$ 55,422,998	$ 57,578,157	$ 62,075,227	$ 66,323,039	$ 69,835,062	$ 73,086,933

The calculation of working capital allowance is reflected in the following table.

Table 1.12: Calculation of Working Capital Allowance 2013 – 2021

Expenses for Working Capital	Last Board Approved 2013	2014	2015	2016 Bridge	2017 Test	2018 Test	2019 Test	2020 Test	2021 Test
Eligible Distribution Expenses									
3500 Distribution - Operations	$ 1,323,999	$ 1,342,978	$ 1,377,569	$ 1,568,480	$ 1,843,870	$ 2,030,600	$ 2,083,700	$ 2,138,100	$ 2,194,100
3550 Distribution - Maintenance	$ 463,151	$ 471,477	$ 427,525	$ 530,250	$ 681,745	$ 699,600	$ 717,900	$ 736,700	$ 755,900
3650 Billing & Collecting	$ 1,054,939	$ 1,169,535	$ 1,096,116	$ 1,203,967	$ 1,184,825	$ 1,295,900	$ 1,329,700	$ 1,364,400	$ 1,400,100
3700 Community Relations	$ 5,419	$ 5,663	$ 8,066	$ 10,250	$ 12,000	$ 12,300	$ 12,600	$ 12,900	$ 13,300
3800 Admin & General	$ 2,147,695	$ 2,234,998	$ 2,648,314	$ 2,704,335	$ 3,142,082	$ 3,323,000	$ 3,490,000	$ 3,581,200	$ 3,674,800
6105 Taxes other than Income tax	$ 24,132	$ 13,463	$ 117,714	$ 88,900	$ 122,500	$ 125,700	$ 129,000	$ 132,400	$ 135,900
Total Eligible Distribution Expense	$ 5,019,335	$ 5,238,114	$ 5,675,305	$ 6,106,182	$ 6,987,022	$ 7,487,100	$ 7,762,900	$ 7,965,700	$ 8,174,100
3350 Power Supply Expenses	$ 25,531,064	$ 27,773,907	$ 29,656,547	$ 32,119,278	$ 32,227,960	$ 33,510,688	$ 35,517,366	$ 37,117,414	$ 39,395,629
Total Expenses for Working Capital	$ 30,550,399	$ 33,012,021	$ 35,331,852	$ 38,225,460	$ 39,214,982	$ 40,997,788	$ 43,280,266	$ 45,083,114	$ 47,569,729
Working Capital Factor	12%	12%	12%	12%	7.50%	7.50%	7.50%	7.50%	7.50%
Total Working Capital Allowance	$ 3,666,048	$ 3,961,443	$ 4,239,822	$ 4,587,055	$ 2,941,124	$ 3,074,834	$ 3,246,020	$ 3,381,234	$ 3,567,730

As described in the Distribution System Plan ("DSP"), InnPower Corporation's capital expenditures reflect the required capital projects to meet customer demand and maintain our infrastructure.

Details of these capital expenses above the materiality threshold of $50,000 are presented in the DSP contained in Exhibit 2.

Table 1.13: Capital Expenditure Summary by Investment Category

	2013 Actual *$'000*	2017 Test Year *$'000*	2017 Increase over 2013	2018 Test Year *$'000*	2018 over 2017	2019 Test Year *$'000*	2019 over 2018	2020 Test Year *$'000*	2020 over 2019	2021 Test Year *$'000*
System Access	974	1,754	80.1%	1,984	13.11%	1,595	-19.6%	1,598	0.2%	2,013
System Renewal	987	1,216	23.2%	1,140	-6.25%	2,919	156.1%	2,400	-17.8%	2,109
System Service	1,377	2,338	69.8%	2,829	21.00%	1,276	-54.9%	1,556	21.9%	1,402
General Plant	1,348	1,500	11.3%	1,423	-5.13%	897	-37.0%	680	-24.2%	706
Total	4,686	6,808	45.3%	7,376	8.34%	6,687	-9.3%	6,234	-6.8%	6,230

Ex.1/Tab 2/Sch.6 - Overview of Operation Maintenance and Administrative Costs

The increase of approximately $1,974,203 in OM&A spending from its 2013 Cost of Service to the 2017 Test Year can be attributed to several factors.

Table 1.14: Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year	2018 Test Year	2019 Test Year	2020 Test Year	2021 Test Year
Operations	$ 1,234,230	$ 1,323,999	$ 1,342,978	$ 1,377,569	$ 1,568,480	$ 1,843,870	$ 2,030,600	$ 2,083,700	$ 2,138,100	$ 2,194,100
Maintenance	$ 506,161	$ 463,151	$ 471,477	$ 427,525	$ 530,250	$ 681,745	$ 699,600	$ 717,900	$ 736,700	$ 755,900
Billing and Collecting	$ 997,953	$ 1,054,939	$ 1,169,535	$ 1,096,116	$ 1,203,967	$ 1,184,825	$ 1,295,900	$ 1,329,700	$ 1,364,400	$ 1,400,100
Community Relations	$ 8,587	$ 5,419	$ 5,663	$ 8,066	$ 10,250	$ 12,000	$ 12,300	$ 12,600	$ 12,900	$ 13,300
Administrative and General	$ 2,143,388	$ 2,147,695	$ 2,234,998	$ 2,648,314	$ 2,704,335	$ 3,142,082	$ 3,323,000	$ 3,490,000	$ 3,581,200	$ 3,674,800
Total	**$ 4,890,319**	**$ 4,995,203**	**$ 5,224,651**	**$ 5,557,590**	**$ 6,017,282**	**$ 6,864,522**	**$ 7,361,400**	**$ 7,633,900**	**$ 7,833,300**	**$ 8,038,200**
%Change (year over year)			4.6%	6.4%	8.3%	14.1%	7.2%	3.7%	2.6%	2.6%

Summary of cost drivers are explained in detail in Exhibit 4:

Ex.1/Tab 2/Sch.7 - Statement of Cost of Capital Parameters

InnPower Corporation has followed the Report of the Board on Cost of Capital Parameters for Ontario's Regulated Utilities, issued October 15, 2015, in determining the cost of capital.

In calculating the cost of capital, InnPower Corporation has used the deemed capital structure of 56% long-term debt, 4% short-term debt, and 40% equity, and the Cost of Capital parameters in the OEB letter of October 15, 2015, for the allowed return on equity and where appropriate for debt.

InnPower Corporation's cost of capital for 2017 has been calculated as 5.71%, as shown in Table: 1.7 below:

Table: 1.15 – Overview of Capital Structure

2017		
Description	**Deemed Portion**	**Effective Rate**
Long-Term Debt	56.00%	3.52%
Short-Tern Debt	4.00%	1.65%
Return On Equity	40.00%	9.19%
Weighted Debt Rate		3.39%
Regulated Rate of Return		5.71%

InnPower Corporation understands that the OEB will most likely update the ROE for 2017 at a later date. InnPower Corporation commits to updating its Capital Structure accordingly and as new information becomes available. The 2017 capital structure have been utilized for the 2018 – 2021 test years.

Ex.1/Tab 2/Sch.8 - Overview of Cost Allocation and Rate Design

The main objectives of a Cost Allocation study is to provide information on any apparent cross-subsidization among a distributor's rate classifications and to eventually be used in future rate applications.

InnPower Corporation has prepared and is filling a cost allocation information filing consistent with the utility's understanding of the Directions, the Guidelines, the Model and the Instructions issued by the Board back in November of 2006 and all subsequent updates.

InnPower Corporation has prepared a Cost Allocation Study for 2017 – 2021 based on an allocation of the 2017 test year costs (i.e., the 2017 forecast revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh) by class, customer counts, etc.

InnPower Corporation has used the updated Board-approved Cost Allocation Model and followed the instructions and guidelines issued by the Board to enter the 2017 data into this model. No rate classes were outside of the Board range. Table 1.16 shows InnPower Corporation`s proposed Cost Ratio`s for 2017 – 2021.

Table 1.16: Proposed Cost Ratios

Customer Class	Target Range %	2013	5 Year Proposed Cost Ratios - % 2017	2018	2019	2020	2021	5 Year Average
Residential	85 - 115	97.7%	99.62	99.93	99.50	99.73	99.91	99.74
GS < 50	80 - 120	111.8%	104.52	101.00	105.00	105.00	104.00	103.90
GS > 50 to 4999 kW	80 - 120	120.0%	95.00	95.22	98.31	97.59	95.98	96.42
Street Lighting	70 - 120	97.7%	120.00	119.16	107.42	102.00	106.21	110.96
Sentinel Lighting	80 - 120	97.7%	99.83	105.14	106.24	104.98	104.07	104.05
USL	80 - 120	120.0%	100.58	104.39	120.00	120.00	120.00	112.99

Distribution revenue is derived through a combination of fixed monthly charges and volumetric charges based either on consumption (kWh's) or demand (kW's). Revenues are collected from 5 customer classes including: Residential, General Service less than 50 kW, General Service greater than 50 kW, Sentinel (USL) and Street Lighting.

Fixed rate revenue is determined by applying the current fixed monthly charge to the number of customers or connections in each of the customer classes in each month. Variable rate revenue is based on a volumetric rate applied to meter readings for consumption or demand volume. Existing volumetric rates include a component to recover allowances for transformer ownership. Commodity Charges and deferral and variance rate riders, along with InnPower Corporation specific other adders such and added to the distribution rates to arrive at a final all-encompassing bill.

Ex.1/Tab 2/Sch.9 - Overview of Deferral and Variance Account Disposition

InnPower Corporation proposes to dispose of a net debit of $768,368 related to Group 1 and Group 2 Variance/Deferral Accounts. InnPower Corporation also proposes to dispose of the following:

- A credit balance of $26,641 recorded in account 1568 being the Lost Revenue Adjustment Mechanism Variance Account

Group 1 and Group 2 DVA balances are proposed to be disposed of over 2 years.

InnPower Corporation has followed the OEB's guidance as provided in the OEB's Electricity Distributor's Disposition of Variance Accounts Reporting Requirements Report. As of December 31, 2014, InnPower Corporation recorded principal balances in the following Board-approved deferral and variance accounts.

Account Description	USoA		Total Claim
Group 1 Accounts			
LV Variance Account	1550	$	412,573
Smart Metering Entity Charge	1551	-$	10,343
RSVA -WMSC	1580	-$	526,878
RSVA - Retail Tranmission	1584	-$	5,075
RSVA- Retail Connection	1586	$	25,446
RSVA Power (exl GA)	1588	-$	329,267
RSVA - Glabal Adjustment	1589	$	818,091
DVA Reg Balances (2012)	1595	$	27,453
DVA Reg Balances (2013)	1595	$	95,256
DVA Reg Balances (2015)	1595	$	203,730
Sub Total (including 1589)		$	710,988
Sub Total (excluding 1589)		-$	107,104
Account Description	USoA		Total Claim
Group 2 Accounts			
Deferred IFRS Transaction Costs	1508	$	11,926
Retail Cost Variance Account	1518	$	61,824
Sub Total		$	73,749
PILS & Tax Variance for 2006 - Sub account HST/OVAT	1592	$	1,631
Total Including 1592		$	75,380
LRAM Account	1568	$	26,641
Group 1 & Group 2 Total (including 1562 & 1592)		**$**	**786,368**
Group 1 & Group 2 Total (including 1568)		**$**	**813,009**

Ex.1/Tab 2/Sch.10 - Overview of Bill Impacts

A summary of the bill impacts by class is presented below. Detailed explanations of the bill impacts are presented in Exhibit 8.

Table 1.17: Summary of Overall Invoice Bill Impacts 2017 - 2021

Rate Class	2017	2018	2019	2020	2021	5 Year Avg
Residential	10.05%	1.59%	-1.61%	-0.45%	-0.46%	1.82%
GS < 50 kW	14.52%	-5.01%	-0.52%	-0.86%	-1.04%	1.42%
GS >50 kW	23.23%	2.53%	0.43%	0.01%	0.06%	5.25%
Street Lighting	-1.20%	-24.55%	-1.61%	-3.12%	4.67%	-5.17%

The bill impacts vary by customer class and by the respective Test Year. Overall bill impacts greater than 10% impact the GS< 50 Rate Class and the GS > 50 Rate Class. Rate mitigation options are discussed in Exhibit 8.

For the Test Years of 2018 – 2021 InnPower Corporation assumed the same rate as 2017 for charges that could change annually, (RTSR & WMS). The following table shows only distribution impacts by the respective rate classes.

Table 1.18: Summary of Distribution Only Bill Impacts 2017 - 2021

Customer Class	Item Description	Unit	2016 Rate ($)	2017 Rate ($)	2018 Rate ($)	2019 Rate ($)	2020 Rate ($)	2021 Rate ($)	5 Year Average
Residential									
750 kWH	Monthly Service Charge	per month	27.06	40.37	47.27	51.42	50.72	50.08	
	Distribution Volumetric Rate	per kWh	0.0159	0.0131	0.0068	0.0000	0.0000	0.0000	
	Z Factor Rate Rider	per kWh		0.0004	0.0004				
	Total Distrubution Charge		$38.99	$50.50	$52.67	$51.42	$50.72	$50.08	
				29.5%	4.3%	-2.4%	-1.4%	-1.3%	5.8%
GS < 50 kW									
2000 kWH	Monthly Service Charge	per month	37.98	48.31	48.28	50.07	48.79	48.79	
	Distribution Volumetric Rate	per kWh	0.0092	0.0117	0.0117	0.0121	0.0118	0.0114	
	Z Factor Rate Rider	per kWh		0.0005	0.0005				
	Total Distribution Charge		$56.38	$72.71	$72.68	$74.27	$72.39	$71.59	
				29.0%	0.0%	2.2%	-2.5%	-1.1%	5.5%
GS >50 to 4999 kW									
100 kW	Monthly Service Charge	per month	167.72	231.42	250.14	272.04	272.59	272.59	
	Distribution Volumetric Rate	per kW	3.444	4.6768	5.0435	5.4725	5.4834	5.4848	
	Z Factor Rate Rider	per kW		1.2807	1.2807				
	Total Distribution Charge		$512.15	$827.17	$754.49	$819.29	$820.93	$821.07	
				61.5%	-8.8%	8.6%	0.2%	0.0%	12.3%
Street Lighting									
1 kW	Monthly Service Charge	per month	6.33	5.24	5.47	4.94	4.74	5.04	
4 Connections	Distribution Volumetric Rate	per kW	43.76	36.2173	37.7972	34.1867	32.7668	34.8318	
	Z Factor Rate Rider	per kW		0.9032	0.9032				
	Total Distribution Charge		$69.08	$42.36	$59.66	$53.96	$51.72	$54.98	
				-38.7%	40.8%	-9.6%	-4.2%	6.3%	-1.0%

Customer Engagement

Ex.1/Tab 3/Sch.1 - Overview of Customer Engagement

The Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach (the "RRFE Report") contemplates enhanced engagement between distributors and their customers to provide better alignment between distributor operational plans and customer needs and expectations. InnPower Corporation always has, and always will, focus on its customers by striving to provide superior service to its customer base. InnPower Corporation is also becoming more customer-centric by investing in new capabilities, programs, and technologies that allow us to communicate more effectively and efficiently with our customers. Some of our current initiatives to maintain or improve our level of customer engagement are as outlined on the next few pages.

1 ***Table 1.19: Appendix 2-AC Customer Engagement Summary***

Appendix 2-AC
Customer Engagement Activities Summary

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
Annual Community Events (2013-2015) -Celebrate Lake Simcoe -Innisfil Family Day -Innisfil Farmers Market -Innisfil Pitch-in Day -Innisfil Summerfest -Sandycove Acres Home Show -Wing Ding Fest	1. Promotion of CDM programs, conservation tips, energy efficiency prizes. 2. Understanding bills. 3. Renewable energy. 4. Collect feedback from customers (ex. New administrative facility)	Annual Community Events are primarily a CDM function, needs identified that are unable to be met by CDM and/or support staff are directed to the appropriate internal department. Response to customer within two business days.
In-Office Customer Engagement (2013-2015)	On average InnPower services 6,000 walk-in customers annually. Common customer inquiries are around: 1. Understanding bills and establishing payment arrangements 2. CDM, FIT and microFIT Program information 3. E-Billing/Customer Connect	Front desk staff explain bills and accept payments, address customer inquiries or connect customer with appropriate department. Where possible staff from applicable department can be made available to address customer needs immediately, otherwise response is communicated through a phone call, email and/or scheduled appointment.
CDM On-Site Visits (2013-2015) -InnPower Roving Energy Manager (REM) -InnPower CDM Representative	1. REM customer energy assessments, recommend efficiency improvement opportunities. 2. Assistance in prioritizing efficiency projects, understanding costs, benefits, incentive funding availabe, payback periods, etc. 3. Support with saveONenergy applications. 4. Connect customer with appropriate department should needs outside of CDM need to be addressed.	CDM program information made available on InnPower website. CDM staff available to provide support to customers from recommendation of energy efficiency projects, saveONenergy application submission and saveONenergy incentive payment approval.
Customer Education Literature (2013-2015)	1. CDM Program, conservation tips, renewable energy information. 2. Electrical safety information. 3. Industry informational material (IESO/OPA, OEB, MOE, etc.)	Relevant literature available in customer service area.
E-Billing/Customer Connect - Online Account Services (2013-2015)	Online access to customer bills and consumption information.	Information related to Customer Connect and E-Billing is actively communicated to walk-in customers via front desk staff. Additionally Customer Connect is communicated through Customer Service staff, CDM staff, bill messaging, community events, etc.. Front Desk and Customer Service staff able to assist customers.
InnPower Public Open House (2015)	1.Desire to understand the need for, and impacts of new InnPower administrative facility. 2. Facility/departmental tours, overview of departmental functions. 3. Staff available from all departments to address questions. 4. General awareness, conservation and safety information.	Public Open House was held in response to rising levels of interest from customers around InnPower, and new administrative facility. Event aimed to educate customers and showcase high levels of service and reliability provided by InnPower to our community.
Ontario Electricity Support Program (OESP) (2015)	Support required with OESP application submissions.	Hosted a series of 5 information sessions on OESP in the community and at InnPower's administrative facility providing overview of bill impacts to all customers, instruction and support with OESP applications. OESP information communicated through InnPower website, Customer Service staff, bill messaging.
saveONenergy Regional Symposium (2014)	General information on saveONenergy for Business	Collaborative Symposium with neighbouring LDCs and IESO. Included CDM program information, case studies, opportunitiy to engage with LDC staff.
2017 Rate Overview Session Mrch 9, 2016	Overview of COS process and projected capital and OM&A budgets	Reviewed key drivers and asked attendees to complete survey

2

Ex.1/Tab 3/Sch.2 - Customer Satisfaction Survey

InnPower Corporation conducted a customer satisfaction survey with its residential and GS<50 classes. InnPower Corporation engaged UtilityPULSE to conduct independent customer satisfaction survey for 2014. The survey asks customers questions on a wide range of topics, including: (a) power quality and reliability; (b) price; (c) billing and payment; (d) communications; and (e) the customer service experience. UtilityPULSE conducted the 2014 survey in April of 2014, with final results available in June 2014. The results are compiled into a final report outlining the overall customer satisfaction within the community as well as benchmarking the results against other Provincial and National participants. These results are then used to support internal discussions surrounding what is currently being done well, and what needs improvement.

InnPower Corporation`s overall rating was ``A``.

CHEC's UtilityPULSE Report Card®

Performance

	CATEGORY	CHEC	National	Ontario
1	**Customer Care**	**B+**	**B+**	**B**
	Price and Value	B	B	C+
	Customer Service	A	B+	B
2	**Company Image**	**A**	**B+**	**B+**
	Company Leadership	A	B+	B+
	Corporate Stewardship	A	A	B+
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	B+
	Power Quality and Reliability	A+	A	A
	OVERALL	**A**	**B+**	**B+**

Base: total respondents

UtilityPULSE 15
June 2014

Copies of the Executive Summary consultant's report and the communication to InnPower Corporation, has been provided in Appendix A to this Exhibit.

Ex.1/Tab 3/Sch.3 – Front Desk Support

InnPower Corporation currently maintains front desk support allowing the customer and the utility to interact on a direct basis. InnPower Corporation assists over 6,000 customers annually at our front desk. Social interaction is still one of the best ways to be in close contact with the customer. People love being heard and they love giving feedback, which is conveniently done when paying your electrical bill at the front counter of your local utility.

With a front desk, information is exchanged regularly with every customer interaction. Data gathered though these interactions can then be used to improve business outcomes. In this sense, front desk staff becomes pivotal to the business and bridges the gap between the customer and other utility staff. InnPower Corporation plans on continuing its front desk operations as a form of customer engagement and to ensure expected customer service levels are maintained.

Ex.1/Tab 3/Sch.4 – Publications

The majority of InnPower Corporation's customers receive a physical bill in the mail, and InnPower Corporation takes advantage of this opportunity to communicate additional information via messages on the outside of the envelope, separate inserts, and messages on the bill itself. Many of these messages are coordinated with announcements from the OEB, IESO, and other agencies, and include information about retailers, rate changes, conservation and demand management programs, electrical safety, and references to our website.

Ex.1/Tab 3/Sch.5 – Meetings

In April, 2015 InnPower hosted an all-day Public Open house for customers and their families, in response to rising levels of interest from customers in the area, and the new administrative facility. The event was highly successful and was aimed at educating customers and showcase high levels of service and reliability provided by InnPower to the community.

The session was advertised during the month preceding the event, was posted on our website, the Town of Innisfil's website, and twice in Innisfil's local newspapers.

The event included:

- facility/departmental tours, including the new control room;
- overviews of departmental functions;
- general awareness, conservation and safety information;
- bucket rides for families;
- train ride, provided by the Rotary Club;
- educational Science Fair;
- roving magician; and an
- LED light exchange.

A copy of the advertisement material follows:

InnPower Corporation hosted a rate overview session on March 9, 2016 for Innisfil customers, which provided an opportunity for all customers to learn about the company's distribution system investment plans and the potential rate impacts associated with these plans. The forums were led by senior management who were well-informed of the issues at hand.

The session was advertised during the month preceding the event, was posted on our website, the Town of Innisfil's website, and twice in Innisfil's local newspapers.

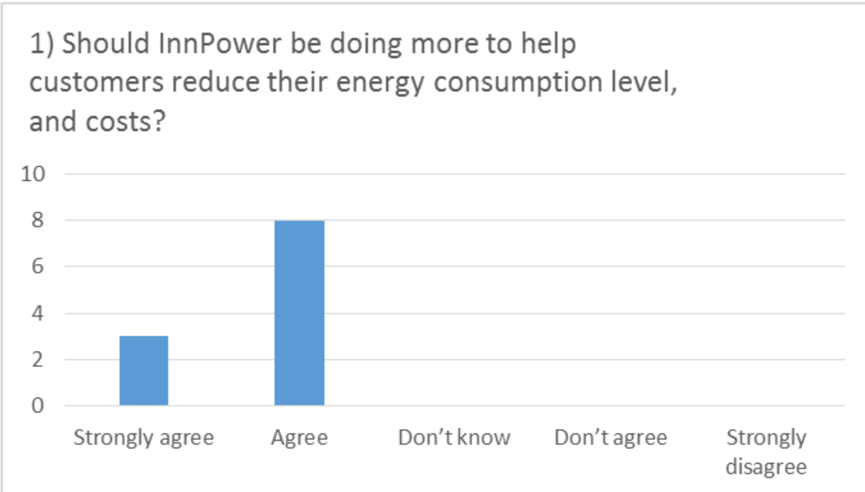
A copy of the advertisement follows:

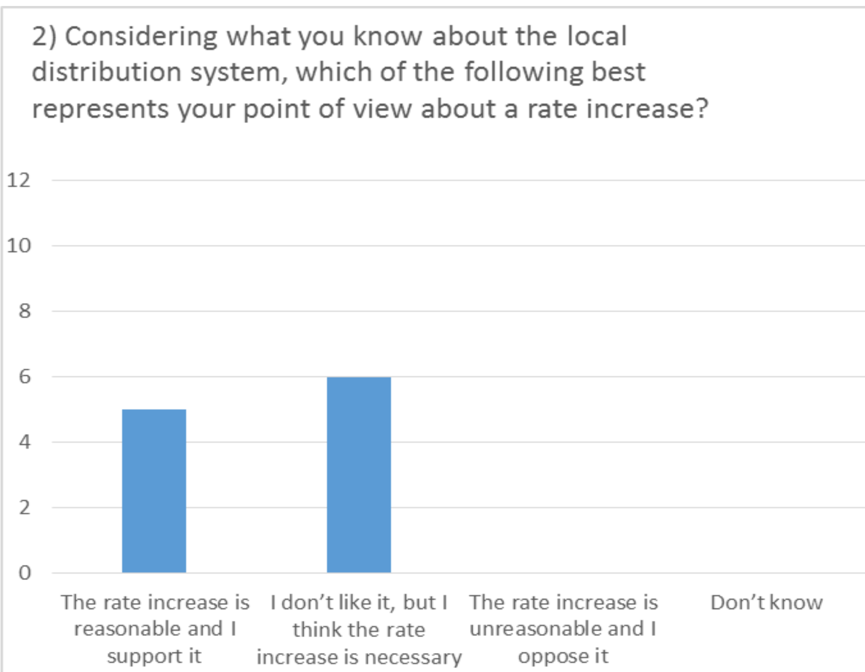
The session focused on:

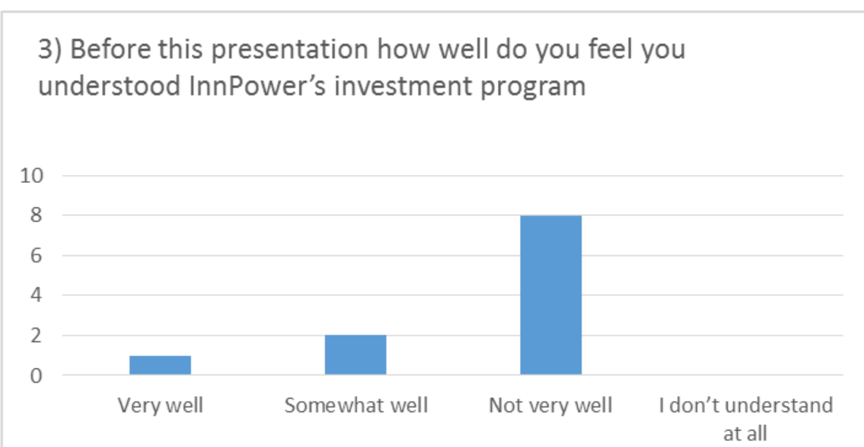
- Understanding your electricity invoice;
- Components of the invoice that InnPower Corporation influences;
- 5 Year Capital Plan and associated drivers; and
- 5 Year OM&A plan and associated drivers.

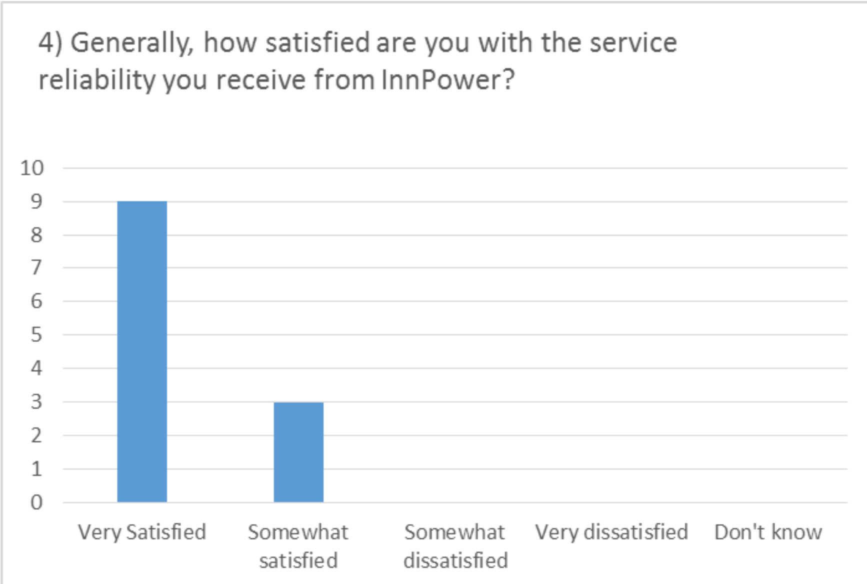
A total of 16 customers attended, with 13 completing a follow-up survey. The results of the survey indicate that customers are aware of InnPower's cost drivers and, although increases are not liked, they are necessary.

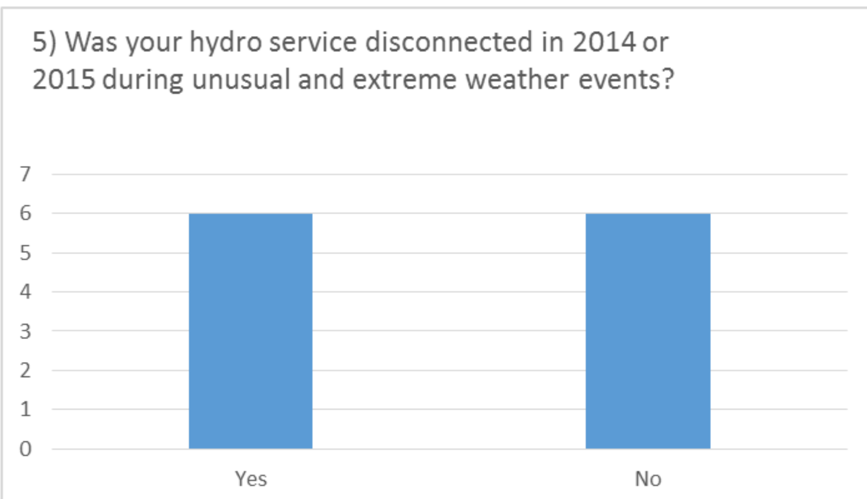
The survey results are as follows:

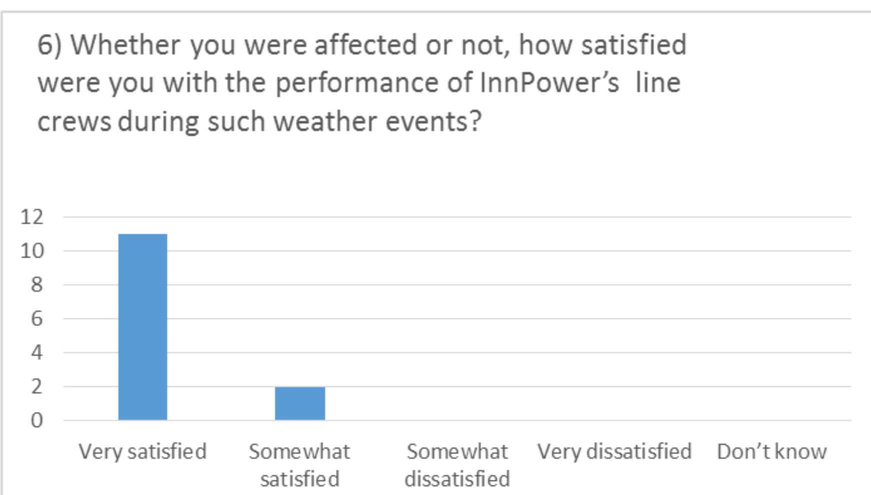


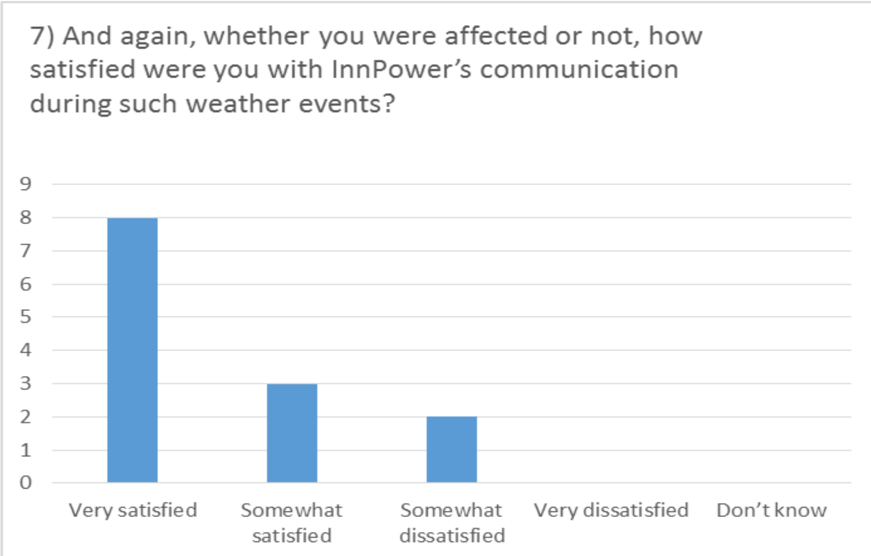


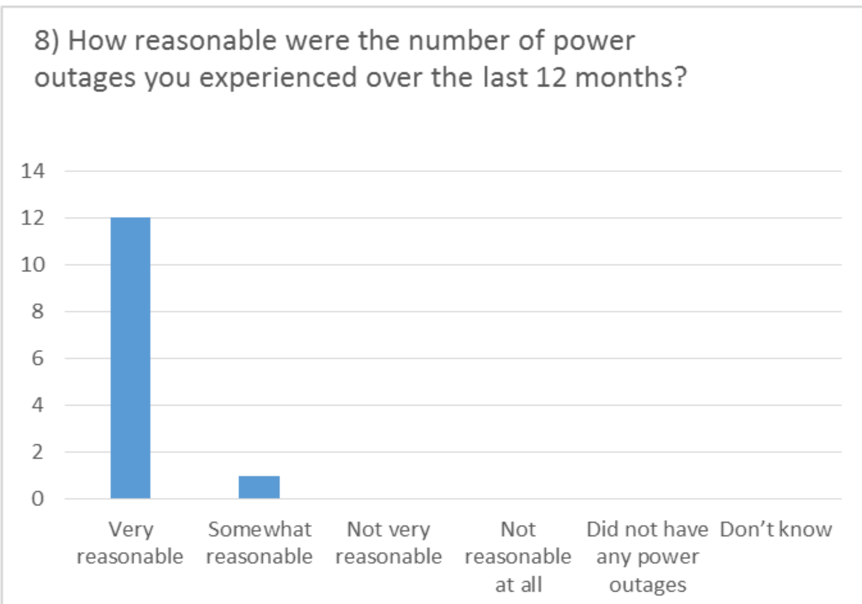


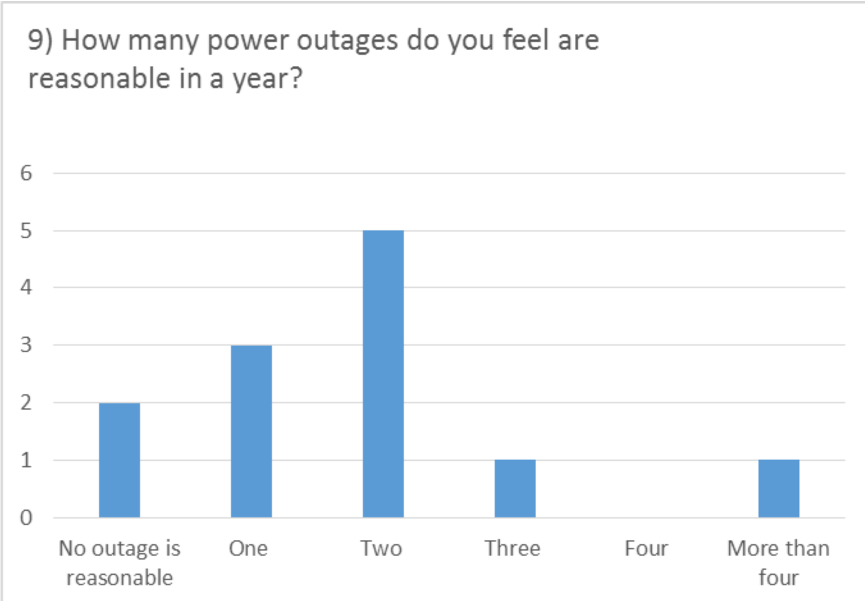

4) Generally, how satisfied are you with the service reliability you receive from InnPower?
10
9
8
7
6
5
4
3
2
1
0
Very Satisfied
Somewhat satisfied
Somewhat dissatisfied
Very dissatisfied
Don't know


5) Was your hydro service disconnected in 2014 or 2015 during unusual and extreme weather events?
7
6
5
4
3
2
1
0
Yes
No


6) Whether you were affected or not, how satisfied were you with the performance of InnPower's line crews during such weather events?
12
10
8
6
4
2
0
Very satisfied
Somewhat satisfied
Somewhat dissatisfied
Very dissatisfied
Don't know


7) And again, whether you were affected or not, how satisfied were you with InnPower's communication during such weather events?
9
8
7
6
5
4
3
2
1
0
Very satisfied
Somewhat satisfied
Somewhat dissatisfied
Very dissatisfied
Don't know

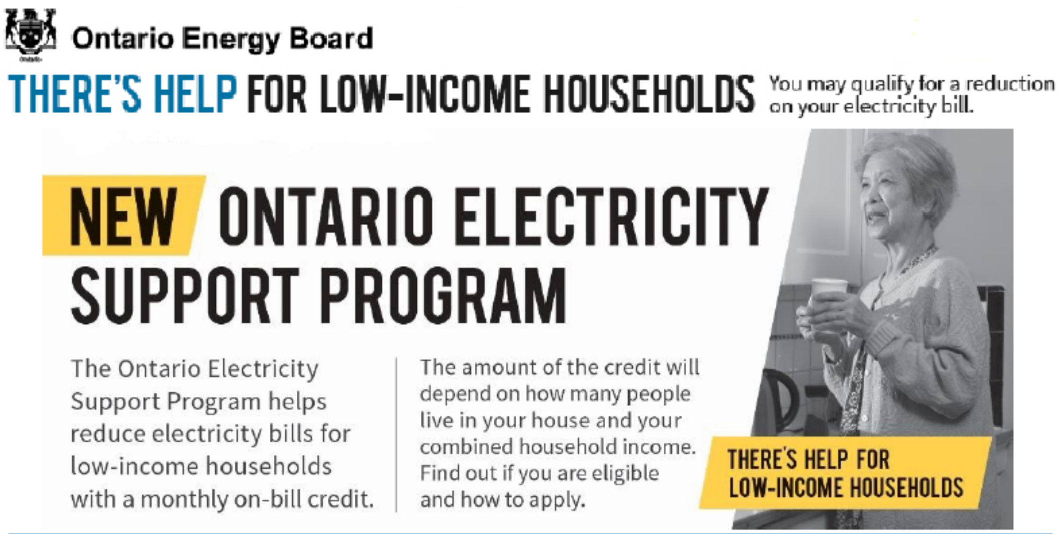

8) How reasonable were the number of power outages you experienced over the last 12 months?
14
12
10
8
6
4
2
0
Very reasonable
Somewhat reasonable
Not very reasonable
Not reasonable at all
Did not have any power outages
Don't know



In 2014, InnPower participated in a saveONenergy Regional Symposium which was a collaborative symposium with neighbouring LDC's and IESO. Included were CDM program information, case studies, and an opportunity to engage with LDC staff.

InnPower Corporation hosted a series of 5 information sessions on OESP in the community and at InnPower Corporation`s administrative facility. Staff provided an overview of bill impacts to all customers, instruction and support with OESP applications. OESP information was communicated through InnPower Corporations website, Customer Service staff and bill messaging.

Please refer to the poster below:



InnPower Information Sessions—InnPower Administrative Building

7251 Yonge Street, Innisfil

December 1st 1:00pm to 4:00pm

December 3rd 4:30pm to 7:30pm

innpower

How to learn more...

For more information on the Ontario Electricity Support Program (OESP), attend one of InnPower's information sessions at the InnPower Administrative Building. InnPower will present an overview of the program, review eligibility requirements, and provide assistance with your application.

The following documentation will be required as part of your OESP application, if you wish to apply with the support of InnPower, please ensure to bring your documentation to the session.

- A copy of your hydro bill
- Birthdates and names of all residents in your home
- Social Insurance Numbers, Individual Tax Numbers, or temporary taxation numbers for residents over the age of 16

Questions?

Visit OntarioElectricitySupport.ca or contact InnPower for more information at 705-431-4321.

Additional communications were also issued in the forms of local newspaper advertisements. When customers are affected by upgrades and/or other special projects, notices are sent out in advance to customers providing specific and relevant information regarding the project at hand. These notices are provided not only to inform customers of coming events, but to also provide contact information in case they have any comments, concerns or questions related to the project.

Ex.1/Tab 3/Sch.6 – Conservation and Demand Management

Conservation and Demand Management ("CDM") work conducted by InnPower Corporation includes a number of initiatives that involves outreach to our customers. Reaching out to customers through CDM programs helps customers to better understand their local utility, while they become more knowledgeable about energy conservation. InnPower Corporation continues to participate in a number of community events to highlight CDM program offerings.

In addition to the above, a number of customers have expressed the need for extra consultation and assistance with various CDM programs. In response to this, utility staff makes direct contact with customers to assist them with their concerns and/or CDM program applications on an individual basis. These efforts provide a communication channel to energy conscious customers so that the needs and desires of these customers are better understood and addressed.

One extremely important CDM initiative that InnPower Corporation has undertaken for the past several years is that of the Roving Energy Manager (REM) program. CHEC Association Members, including InnPower Corporation, currently share a REM across their respective distribution territories in order to make this position as cost effective as possible. Key areas of responsibility for the REM include performing site visits, assessing potential areas for energy savings, and providing written reports where required.

The REM has been instrumental in assisting InnPower Corporation with meeting its CDM goals and objectives, while engaging InnPower Corporation's institutional, commercial, and industrial customers. Under the REM program, a mutually beneficial relationship is created whereby the needs and wants of the utilities larger customers are satisfied through CDM offerings, while the REM becomes a significant resource of knowledge to the utility. At the present time, InnPower Corporation expects the REM program to continue into the foreseeable future.

Ex.1/Tab 3/Sch.7 – Community Involvement

It is important to InnPower Corporation and its Shareholders that its employees support and give back to their community, and as such the utility participates in several community projects and events such as:

- Celebrate Lake Simcoe;
- Innisfil Family Day;
- Innisfil Farmers Market;
- Innisfil Pitch-In Day;
- Innisfil Summerfest;
- Cookstown Wing Ding; and
- Sandycove Acres Home Show
- Town of Innisfil's Permit Palooza

Community involvement is a key opportunity to obtain feedback from our customers and answer questions on conservation initiatives, bill questions in an informal setting.

Ex.1/Tab 3/Sch.8 – Social Services

Financial Assistance Program: InnPower Corporation provides support through partnerships with the province’s Low-income Energy Assistance Program (LEAP) program. InnPower Corporation has partnered with Simcoe County United Way as a delivery partner for this program in our community.

Ex.1/Tab 3/Sch.9 – Other Engagement Activities

Other Customer Activities Include:

- Newsletters, bill inserts, information bulletins, press releases.
- Materials (Publications) – New accounts, developers, people with disabilities, etc.
- Meetings – Town Hall, customer specific, Chamber of Commerce, etc.
- Meetings – Association (i.e. EDA, ESA, CHEC, etc.), social entities, OEB.
    - Forming alliances with other industry companies to improve service, reduce costs.
- Education – Customers, school programs, etc.
- Outage Notification – Planned and unplanned (OMS).
- Use of Social Media, contests, promotions, etc.
- Collecting, tracking and reviewing key customer service/care metrics via monthly Performance Scorecard.
- Supporting charitable or not-for-profit organizations in the community, such as: Kiwanis Club, Innisfil Community Guide, Innisfil Firefighters, Children's Wish Foundation, Sandy Cove Directory, Sunset Speedway, etc.
- Service Orders (i.e.: Arranging for shut off/turn on, service calls, etc.).
- Data Analysis (i.e.: billing information, usage data, conservation data, etc.).
- Maintaining information about an account, preferences or permissions.
- Responding to & tracking customer complaints.
- Responding to & tracking customer suggestions.
- Website, Twitter, Facebook – mobile friendly.

InnPower Corporation is of the opinion that Utilities have a higher chance of successfully engaging their customers when they think about what will please those customers. It is critical for utilities to understand what really has meaning to their customers and how their customers form an opinion of the utility. Effective customer engagement addresses each of these through presenting meaningful information in an accessible manner.

Financial Information

Ex.1/Tab 4/Sch.1 - Historical Financial Statements

The following attachments are presented as Appendices at the end of Exhibit 1:

- APPENDIX B: Year ended 31 December, 2013
- APPENDIX C: Year ended 31 December, 2014
- APPENDIX D: Year ended 31 December, 2015

Ex.1/Tab 4/Sch.2 - Reconciliation between Financial Statements and Results Field

A detailed reconciliation between the financial results shown in InnPower Corporation's RRR filings, Audited Financial Statements and with the regulatory financial results filed in the application is presented at the next page. All variances are as a result of the audit which was conducted in February 2016. Changes include revisions to various USoA accounts as instructed in the Board communication dated December 20, 2011.

Ex.1/Tab 4/Sch.3 - Annual Report

InnPower Corporation does not publish an annual report to its shareholders. Financial statements are presented yearly to the shareholder in a special meeting.

Ex.1/Tab 4/Sch.4 - Prospectus and Recent Debt/Share Issuance Update

InnPower Corporation does not issue debt or share nor do they publish any prospectus.

Ex.1/Tab 4/Sch.5 - Other Relevant Information

The Applicant is not seeking any changes to its tax status in this application.

Materiality Threshold

Ex.1/Tab 5/Sch.1 - Materiality Threshold

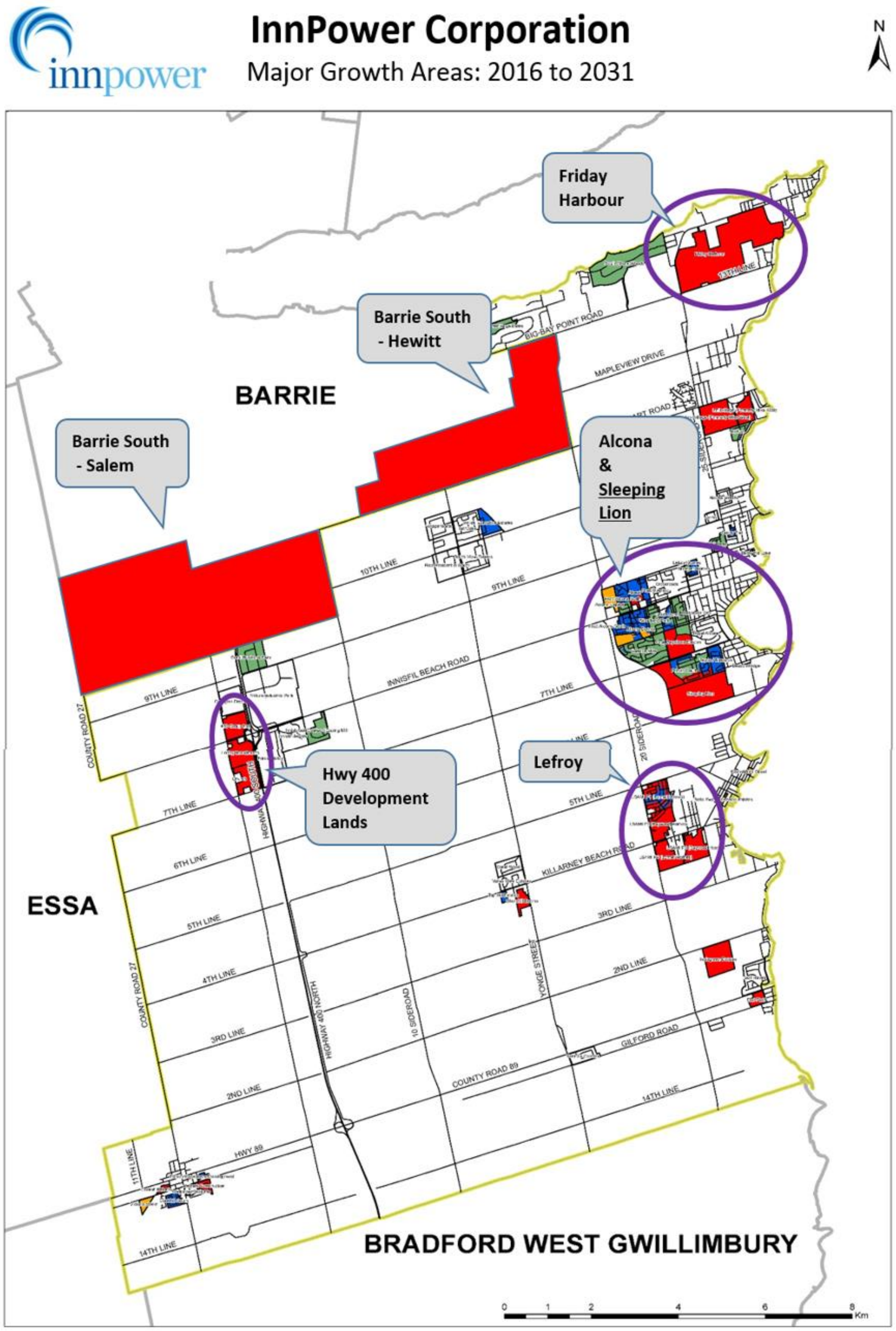
The Minimum Filing Requirements state that a distributor with a distribution revenue requirement less than $10 million must use $50,000 as a materiality threshold. With a proposed base revenue requirement of $11,920,340 for the 2017 Test Year, InnPower Corporation has used this amount as a materiality threshold throughout this application.

Applicant Overview

Ex.1/Tab 7/Sch.1 – Applicant Overview

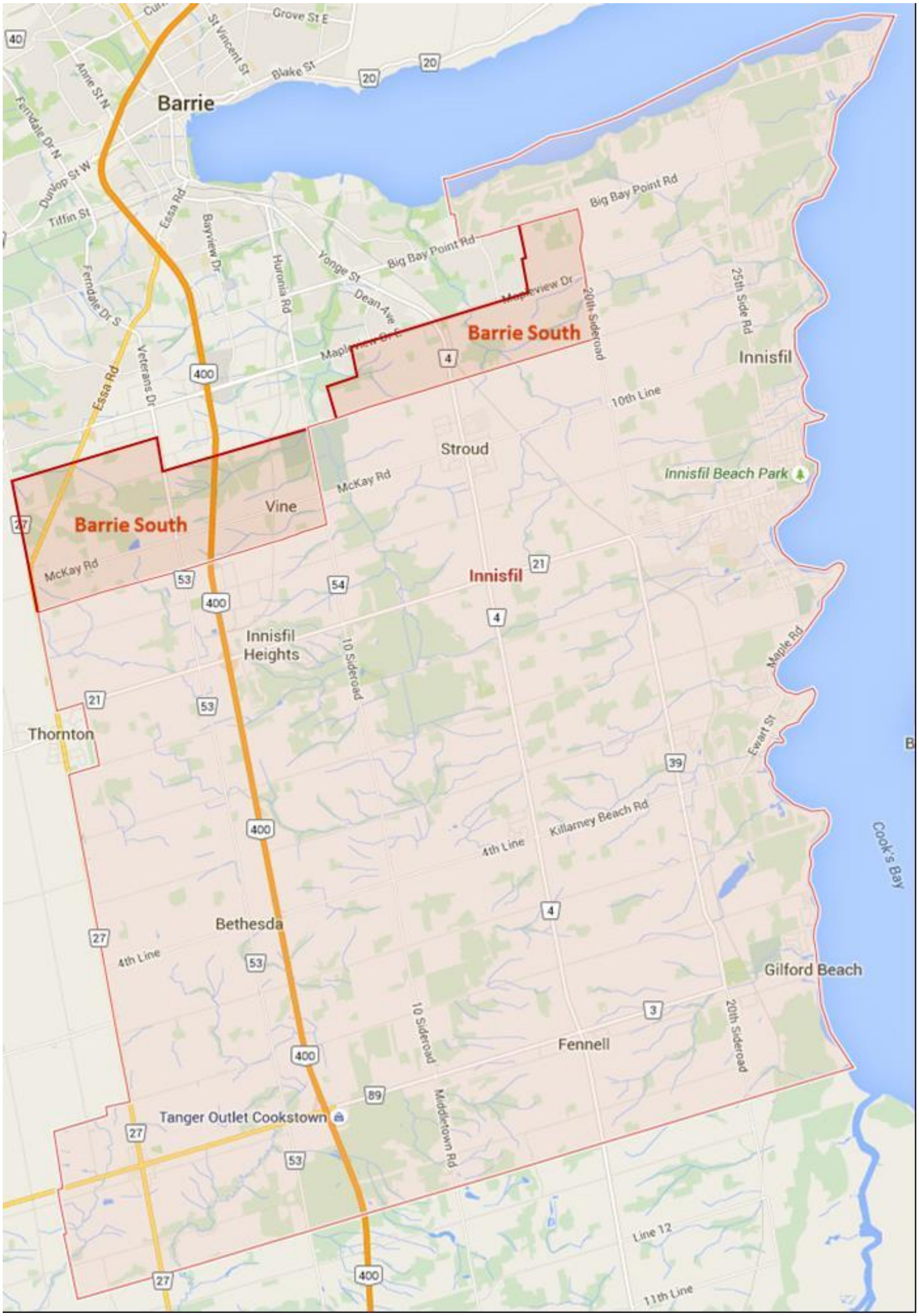
InnPower Corporation's service area is contained within the municipal boundaries of the Town of Innisfil and south Barrie. The area is embedded within the Hydro One Networks Inc. Maps of the service area served by InnPower Corporation are found on the following pages.

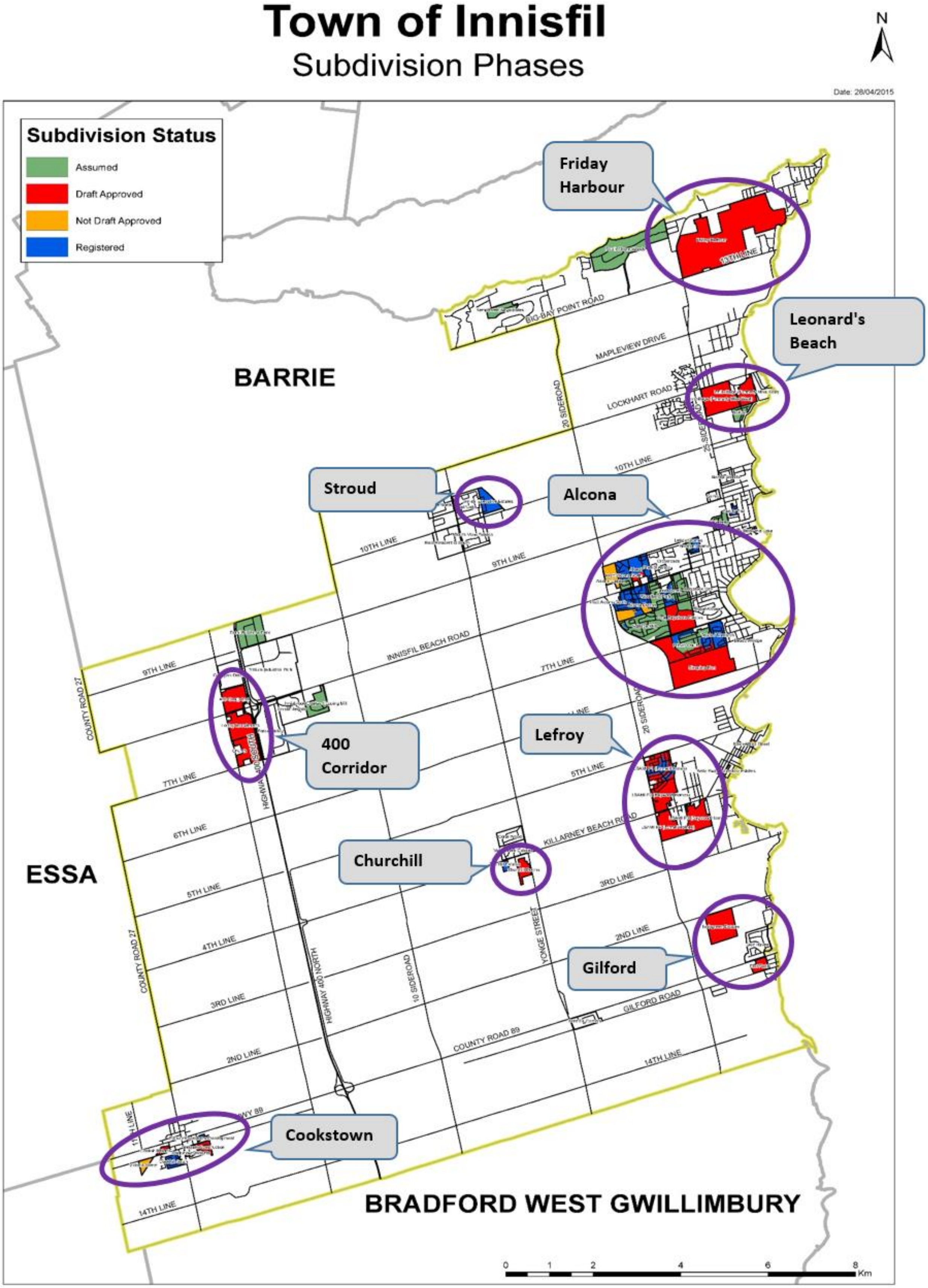
InnPower Corporation provides electrical distribution services to approximately 16,000 residential and commercial customers in its service area. InnPower Corporation's service territory covers approximately 292 square kilometers.


innpower
InnPower Corporation
Major Growth Areas: 2016 to 2031
N
Friday Harbour
Barrie South - Hewitt
BARRIE
Barrie South - Salem
Alcona & Sleeping Lion
Hwy 400 Development Lands
Lefroy
ESSA
BRADFORD WEST GWILLIMBURY
BIG BAY POINT ROAD
MAPLEVIEW DRIVE
10TH LINE
9TH LINE
INNISFIL BEACH ROAD
7TH LINE
6TH LINE
5TH LINE
4TH LINE
3RD LINE
2ND LINE
KILLARNEY BEACH ROAD
GILFORD ROAD
COUNTY ROAD 89
14TH LINE
HWY 89
11TH LINE
COUNTY ROAD 27
HIGHWAY 400 NORTH
10 SIDEROAD
YONGE STREET
20 SIDEROAD
0 1 2 4 6 8 Km

1

1


Barrie
Barrie South
Barrie South
Innisfil
Innisfil
Stroud
Vine
Innisfil Heights
Thornton
Bethesda
Fennell
Gilford Beach
Innisfil Beach Park
Tanger Outlet Cookstown
Cook's Bay
Big Bay Point Rd
Mapleview Dr
10th Line
McKay Rd
Killarney Beach Rd
4th Line
20th Sideroad
25th Side Rd
10 Sideroad
Maple Rd
Ewart St
Line 12
11th Line
Middletown Rd
Essa Rd
Veterans Dr
Huronia Rd
Bayview Dr
Yonge St
Dean Ave
Tiffin St
Dunlop St W
Ferndale Dr N
Ferndale Dr S
Anne St N
St Vincent St
Blake St
Grove St E


Town of Innisfil
Subdivision Phases
N
Date: 28/04/2015
Subdivision Status
Assumed
Draft Approved
Not Draft Approved
Registered
Friday Harbour
Leonard's Beach
BARRIE
Stroud
Alcona
400 Corridor
Lefroy
Churchill
Gilford
ESSA
Cookstown
BRADFORD WEST GWILLIMBURY
BIG BAY POINT ROAD
MAPLEVIEW DRIVE
LOCKHART ROAD
20 SIDEROAD
10TH LINE
9TH LINE
INNISFIL BEACH ROAD
7TH LINE
5TH LINE
KILLARNEY BEACH ROAD
3RD LINE
2ND LINE
GILFORD ROAD
COUNTY ROAD 89
14TH LINE
6TH LINE
4TH LINE
COUNTY ROAD 27
HIGHWAY 400 NORTH
10 SIDEROAD
YONGE STREET
0 1 2 4 6 8 Km

1

Ex.1/Tab 7/Sch.2 – Host /Embedded Distributor

InnPower Corporation is an embedded distributor who receives electricity at distribution level voltages from Hydro One Networks Inc. InnPower Corporation does not have any embedded distributors within its territory.

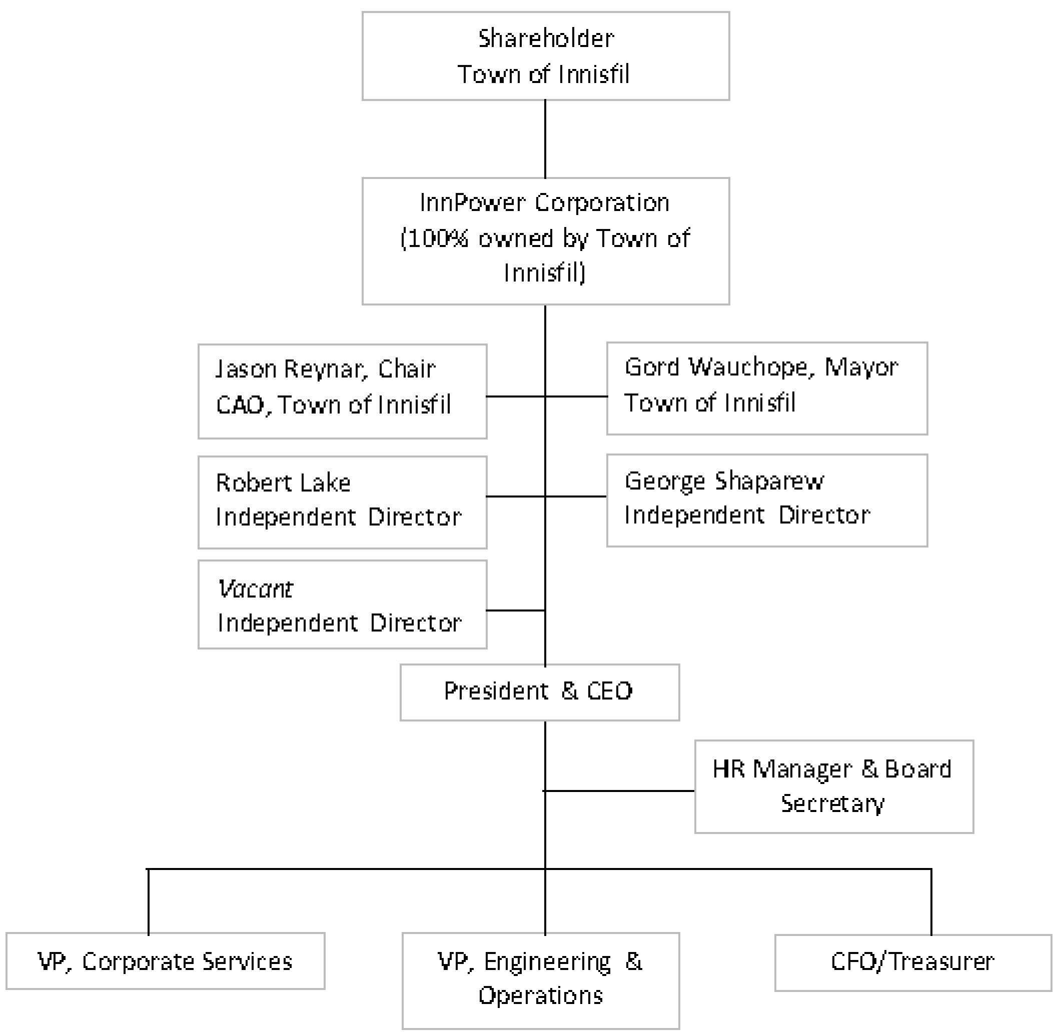
Ex.1/Tab 7/Sch.3 – Transmission or High Voltage Assets

The Applicant does not have any transmission or high voltage assets deemed by the Board as distribution assets and as such are not seeking approvals from the Board in that regards.

Corporate Governance

Ex.1/Tab 8/Sch.1 - Corporate Governance Structure

InnPower Corporation presents its Shareholder Declaration with the Town of Innisfil. This is the primary document that governs the Board of Director relationship between InnPower Corporation and the Town of Innisfil. The Shareholder Declaration is an organizational relationship chart that outlines the corporate entities relationships and the reporting relationships between utility management and the parent company officials. The name of the Directors, the schedule of meetings, and other pertinent information is discussed in more detail in subsequent sections, and in Appendix F – InnPower Corporation Board Governance.



Ex.1/Tab 8/Sch.2 – Board of Directors

InnPower Corporation has two corporate independent board members (meaning that they are not an employee or officer of the utility). This conforms to the Affiliate Relationship Code ("ARC") whereby at least one-third of its directors must remain independent from Affiliate Boards.

Management provides the InnPower Corporation Board with all the written reports, PowerPoint presentations, oral reports, verbal and written responses to InnPower Corporation Board inquires, that are crucial to the successful realization of InnPower Corporation's corporate goals and objectives.

The background of each InnPower Corporation Board Member is as follows:

1. Jason Reynar (Chair) Appointed 2015
    a. Chief Administrative Officer of the Town of Innisfil
2. Gord Wauchope, Appointed 2014
    a. Mayor, Town of Innisfil
    b. Retired Toronto Police Officer
3. Robert Lake, Appointed 2000
    a. Past President of Peterborough Utilities Group of Companies
4. George Shaparew, Appointed 2015
    a. Past President of InnPower Corporation

Please refer to Appendix F – InnPower Corporation Board Governance.

Ex.1/Tab 8/Sch.3 – Board Mandate

The InnPower Corporation Board mandate is as documented in Article 2.01 of the Corporation's By-Law No. 1:

> The Directors are responsible for the stewardship of the Corporation. The Ontario Business Corporations Act (OBCA), the statute which governs the Corporation, provides that the stewardship responsibility of the Board consists primarily of the duty to manage or supervise the management of the business and affairs of the corporation. The OBCA further authorizes the Board, subject to certain exemptions, to delegate to an officer or officers of the Corporation powers to manage the business and affairs of the Corporation. As authorized by the OBCA and for the purpose of effectively discharging the Board's stewardship responsibility,
>
> (a) The Board has delegated to the President/CEO of the Corporation many of the Board's powers and much of the Board's authority to manage the business and affairs of the Corporation, and
>
> (b) The Board has assumed the duty to supervise the President/CEO's management of the business and affairs of the Corporation."

Ex.1/Tab 8/Sch.4 – Board Meetings

The InnPower Corporation Board meetings are as documented in Article 3 of the Corporation's By-Law No. 1.

3.04 Regular Meetings - The board may appoint a day or days in any month or months for regular meetings at a place and hour to be named. A copy of any resolution of the board fixing the place and time of regular meetings of the board shall be sent to each director forthwith after being passed, but no other notice shall be required for any such regular meetings except where the Act requires the purpose thereof or the business to be transacted thereat to be specified.

Table: 1.13 – Board Meeting Schedule

January 18	July 18
February 22 *(rescheduled to March 2)*	August 15
March 21	September 19
April 18	October 17
May 16	November 21
June 20	December 12

The overall attendance of the InnPower Corporation Board members has been exemplary. At every meeting a majority number of directors is present to ensure a quorum.

Ex.1/Tab 8/Sch.5 – Orientation and Continuing Education

InnPower Corporation is committed to supporting the continuous learning needs of Board members. The corporation's Education, Training and Development policy provides clear and consistent direction for Board members regarding eligibility for and reimbursement of expenses related to continuing education. Board members also attend industry related meetings, such as EDA meetings.

The Corporation's orientation process includes, but is not limited to, the following information:

Orientation:

- Shareholder Direction
- Corporate Structure
- Operating By-law / Corporate Policies / Corporate Background / Organizational Chart
- Strategic Plan
- Current Year Budget

Ex.1/Tab 8/Sch.6 – Ethical Business Conduct

The InnPower Corporation Code of Conduct is as documented in the corporation's Code of Conduct policy. This policy reflects the practice and intention of the Company in all its business endeavours, and applies to each and every one of the Company's employees; employees defined as employees, officers and directors of the Company and its subsidiaries and affiliates.

Furthermore, every Board member is bound by Section 2.03 of By-Law No. 1, "Standard of Conduct".

Potential conflicts of interest are declared and assessed at the outset of all Board meetings.

Ex.1/Tab 8/Sch.7 – Nomination of Directors

Recommendations for nominations for InnPower Corporation Board of Directors are made by Board resolution prior to the Corporation's Annual General Meeting, where they are presented to the Shareholder. All Board appointments are made by the Shareholder.

It is essential that the Board of Directors be composed of highly qualified and respected individuals who are knowledgeable with respect to the challenges facing them and whose commitment to the interests of the Corporation is beyond reproach. Appointees are selected with this in mind.

Ex.1/Tab 8/Sch.8 – Board Committees

At the present time, there are no Board Committees

Letters of Comment

Ex.1/Tab 9/Sch.1 - Letter of Comment

At the time of submission InnPower Corporation has not received any letters of comment at the time of filing.

2014 InnPower Corporation Performance Scorecard

At the time of filing, InnPower Corporation's 2015 Distributor Scorecard has not yet been published; however InnPower Corporation has completed the 2015 Performance Based Reporting (PBR) and will provide updates on 2015 trends.

InnPower Corporation completed its annual PBR reporting effective April 31, 2016 for the 2015 year.

InnPower Corporation has met and or exceeded all the Performance Based Reporting.

Table 4.5: E2.1.4 2015 Service Quality Indicator (PBR)

Appendix 2-G
Service Reliability Indicators
2012- 2015

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply				
	2012	2013	2014	2015	2016	2012	2013	2014	2015	2016
SAIDI	0.980	2.140	4.700	1.740		3.110	2.160	5.020	1.510	
SAIFI	1.110	1.100	3.140	0.990		1.690	1.100	3.930	1.080	

5 Year Historical Average

	Including outages caused by loss of supply	Excluding outages caused by loss of supply
SAIDI	2.390	2.950
SAIFI	1.585	1.950

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Indicator	OEB Minimum Standard	2012	2013	2014	2015	2016
Low Voltage Connections	90.0%	95.0%	97.0%	96.4%	97.9%	98.6%
High Voltage Connections	90.0%	n/a	n/a	n/a	n/a	n/a
Telephone Accessibility	65.0%	73.0%	68.0%	70.6%	80.4%	73.0%
Appointments Met	90.0%	64.0%	88.0%	94.4%	91.8%	90.0%
Written Response to Enquires	80.0%	100.0%	100.0%	98.4%	97.5%	98.0%
Emergency Urban Response	80.0%	n/a	n/a	n/a	n/a	n/a
Emergency Rural Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Call Abandon Rate	10.0%	6.7%	9.1%	7.5%	9.5%	8.2%
Appointment Scheduling	90.0%	98.0%	97.0%	97.7%	97.7%	97.6%
Rescheduling a Missed Appointment	100.0%	n/a	n/a	n/a	n/a	100.0%
Reconnection Performance Standard	85.0%	97.0%	99.0%	98.9%	99.7%	98.6%

Table 1.4: InnPower Corporations 2014 Scorecard

INNPOWER CORPORATION (IPC)

OEB PERFORMANCE SCORECARD - 2014

Performance Outcomes	Performance Categories	Measures	2014	2013	2012	2011	2010	Trend 2012 to 2013	Target: Industry	Target: Distributor
Customer Focus	Service Quality	**Performance Measure Definitions for Service Quality**								
		New Residential Services Connected on Time (DSC s7.2)	96.40%	89.90%	95.30%	81.20%	97.00%	↓	90.00%	
		Scheduled Appointments Met on Time (RRR 2.1.4.3)	94.40%	83.00%	64.30%	60.40%	84.00%	↓	90.00%	
		Telephone Calls Answered on Time (RRR 2.1.4.5)	70.60%	67.10%	74.60%	95.80%	89.00%	↓	65.00%	
	Customer Satisfaction	**Performance Measure Definitions for Customer Satisfaction**								
		First Contact Resolution - TBD	99.01%	TBD						
		Billing Accuracy - TBD	99.95%	TBD						
		Customer Satisfaction Survey Results - TBD	A	TBD						
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	**Performance Measure Definitions for Safety**								
		Public Safety - tbd		TBD						
	System Reliability	**Performance Measure Definitions for System Reliability**								
		Average # of Hours that Power to a Customer is Interrupted - SAIDI	4.70	2.1	1.34	0.98	1.34	↑	w/I 3 yr historical	
		Average # of Times that Power to a Customer is Interrupted - SAIFI	3.14	0.92	0.71	1.12	1.19	↓	w/I 3 yr historical	
	Asset Management	**Performance Measure Definitions for Asset Management**								
		Distribution System Plan Implementation Progress - tbd		TBD						
	Cost Control	**Performance Measure Definitions for Cost Control**								
		Efficiency Assessment	3.00	3.00	3.00					
		Total Cost per Customer (OM&A and PEG Capital Calculation)	$761	$ 732	$ 720	$ 695	$ 673			
		Total Cost per Km of Line	$ 14,693	$ 14,168	$ 13,842	$ 13,782	$ 13,154			
Public Policy Responsiveness	Conservation and Demand Management	**Performance Measurement Definitions for CDM**								
		Net Annual Peak Demand Savings Target (percent of target achieved)	49.27%	27.50%	5.00%	11.00%				
		Net Cumulative Energy Savings (percent of target achieved)	84.43%	74.50%	44.00%	24.00%				
	Connection of Renewable Generation	**Performance Measurement Definitions for Connection of Renewable Generation**								
		Renewable Generation Connection Impact Assessments Completed on Time	100%		100.00%	100.00%				
		New Micro-embedded Generation Facilities Connected on Time (RRR 2.1.19)	100%	100%					90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable	Financial Ratios	**Performance Measurement Definitions for Financial Ratios**								
		Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.41	0.63	1.10	0.61	0.65			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	2.04	1.30	0.93	0.84	0.80			
		Profitability: Regulated Return on Equity - Deemed (included in rates)	8.98%	8.98%	8.01%	8.01%				
		Profitability: Regulated Return on Equity - Achieved	5.82%	6.70%	1.96%	8.58%				
		TREND:	Increasing	↑	Decreasing	↓	Steady	↻		
			Target Met	●		Target Not Met		●		

Service Quality

New Residential/Small Business Services Connected on Time:

In 2014, InnPower connected a total of 504 low voltage (connections under 750 volts) for residential and small business customers of which 486 were within the five-day timeline as prescribed by the Ontario Energy Board (OEB) for an annual result of 96.43% exceeding the OEB target of 90%. This represents an increase of 37% in the total number of connections over 2013, which is driven primarily by customer growth. InnPower considers "New Services Connected on Time" as an important form of our customer engagement as it is another opportunity to meet and or exceed the customer's expectations.

Scheduled Appointments Met On Time:

InnPower scheduled and completed 497 AM/PM appointments in 2014 to connect services, disconnect services, or otherwise discuss service options requested by customers in which the customer was met on site. Of the 497 appointments, 469 of the appointments were met on time or 94.37%. This exceeds the Ontario Energy Board's prescribed target of 90% for this measure. Additionally, InnPower scheduled 5,173 customer appointments for work in which the customer was not met on site and completed in 5 business days. Of the 5173 scheduled appointments, 5,110 were completed in 5 business days for 98.78%. Scheduled appointments have increased from 3,702 in 2013 to 5,173 in 2014 for a 40% increase. The increase is primarily due to new construction within our service territory and the implementation of ON1Call program for cable locates.

Telephone Calls Answered On Time:

In 2014 InnPower's customer contact centre agents received over 22,203 calls from its customers – over 80 calls per working day. Additionally, contact centre agents assisted over 6,000 customers at our front desk. An agent answered a call in 30 seconds or less in 71% of these calls. This result significantly exceeds the OEB prescribed target of 65% for timely call response. Year over year, the 2014 result amounts to a 3% improvement over 2013, even though call volumes increased by approximately 8%. Favorable results were driven primarily by continuous training resulting from quality assurance monitoring. Call volume increases are attributed to continued customer growth of over 3% in 2014 combined with high bills due to increased commodity rates and weather impacts.

Customer Satisfaction

First Contact Resolution:

InnPower defines "First Contact Resolution" as the number of customer enquires that are resolved by the first contact at the utility, resulting in the enquiry being escalated to an alternate contact at the utility, typically a supervisor or a manager. This includes all customer enquires that are made to a customer service representative whether by telephone, letter, e-mail, or in person.

First Contact Resolution was measured based on live agent transactional logged inquiries. For the period October 1, 2014 to December 31, 2014, InnPower logged over 5600 inquiries and approximately 19 were not resolved on first contact.

InnPower endeavors to use the customer survey results to identify customer service improvements which will increase first contact resolution in the future.

Billing Accuracy:

For the period from October 1, 2014 – December 31, 2014 InnPower issued more than 46,000 bills and achieved a billing accuracy of 99.95%. This compares favorably to the prescribed OEB target of 98%.

InnPower continues to monitor its billing accuracy results and processes monthly to identify opportunities for improvement.

Customer Satisfaction Survey Results:

Customer Satisfaction Survey is a new scorecard measure introduced by the Ontario Energy Board for the 2014 scorecard. The Ontario Energy Board has not yet issued a common definition for this measure but is expected to do so within the next few years. As a result, this measure may differ from other utilities in the Province.

For 2014, InnPower engaged a third-party organization to conduct a customer satisfaction survey. This statistical survey canvassed a number of key areas including power quality and reliability, price, billing and payments, communications, and the overall customer service experience. InnPower considers this customer satisfaction survey to be useful tool for engaging the customer to get a better understanding of their wants and needs with respect to the provision of electricity services and for identifying areas that may require improvement. For 2014, InnPower received a rating of “A” on its customer satisfaction survey. InnPower will be expanding our customer engagement/satisfaction process to include transactional and online surveys to obtain customer feedback.

Safety

Public Safety:

Public Safety is a new scorecard measure introduced by the Ontario Energy Board for the 2014 scorecard. The Public Safety measure is generated by the Electrical Safety Authority and is comprised of three components: Public Awareness of Electrical Safety, Compliance with Ontario Regulation 22/04, and the Serious Electrical Incident Index. A breakdown of the three components is as follows:

Component A – Public Awareness of Electrical Safety:

Component A consists of a new statistical survey that gauges the public’s awareness of key electrical safety concepts related to electrical distribution equipment found in a utility’s territory. The survey also provides a benchmark of the levels of awareness including identifying gaps where additional education and awareness efforts may be required.

Component B – Compliance with Ontario Regulation 22/04:

Component B consists of a utilities compliance with Ontario Regulation 22/04 - Electrical Distribution Safety. Ontario Regulation 22/04 establishes the safety requirements for the design, construction, and maintenance of electrical distribution systems, particularly in relation to the approvals and inspections required prior to putting electrical equipment into service. Over the past five years, InnPower was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by our strong commitment to safety, and the adherence to company procedures and policies.

Component C – Serious Electrical Incident Index:

Component C consists of the number of serious electrical incidents, including fatalities, which occur within a utility's territory. In 2014, InnPower had zero (0) fatalities and zero (0) serious incidents within its territory. InnPower continues to perform site reviews, training to identify potential hazards and communicates findings and recommendations to all staff and the public.

System Reliability

InnPower exceeded the 3 year rolling averages for the system reliability targets. The February 5, 2014 outage referenced in the overview and the June 3, 2014 outage caused by severe weather were the prime contributors.

Average Number of Hours that Power to a Customer is interrupted:

The average number of hours that power to a customer is interrupted is a measure of system reliability or the ability of a system to perform its required function. InnPower views reliability of electrical service as a high priority for its customers and constantly monitors its system for signs of reliability degradation. InnPower regularly monitors and maintains its distribution system to ensure its level of reliability is kept as high as possible. Outside factors such as severe weather, defective equipment, or even regularly scheduled maintenance can greatly impact this measure. For 2014, InnPower achieved 4.81hours of interrupted power, which is outside the range of our historical performance for interrupted power.

Average Number of Times that Power to a Customer is interrupted:

The average number of times that power to a customer is interrupted is also a measure of system reliability and is also a high priority for InnPower. As outlined above, outside factors can also greatly impact this measure. For 2014, InnPower experienced interrupted power an average of 3.53 times during 2014, which is also outside the range of our historical performance for interrupted power.

Asset Management

Distribution System Plan Implementation Progress:

Distribution system plan implementation progress is a new performance measure instituted by the Ontario Energy Board beginning in 2013. The Distribution System Plan outlines InnPower's forecasted capital expenditures over the next five (5) years, which are required to maintain and expand the utility's electricity system to serve its current and future customers. The Distribution System Plan Implementation Progress measure is intended to assess InnPower's effectiveness at planning and implementing these capital expenditures. Consistent with other new measures, utilities were given an opportunity to define this measure in the manner that best fits their organization. As a result, this measure may differ from other utilities in the Province.
InnPower does not yet have a full distribution system plan in place and will therefore be using its capital asset management plan as a substitute. InnPower will implement its first full distribution system plan at its next regularly scheduled cost of service application, which is currently scheduled for 2017. At that time, the distribution plan will supersede the current asset management plan.
InnPower manages and monitors the capital planning and asset management process by means of planned versus actual costs. In 2014 InnPower's actual costs versus planned costs were 3% higher due to customer growth/demand.

Cost Control

Efficiency Assessment:

On an annual basis, each utility in Ontario is assigned an efficiency ranking based on its performance. To determine a ranking, electricity distributors are divided into five groups based on the magnitude of the difference between their actual costs and predicted costs. For 2014, InnPower was ranked in Group 3 in terms of efficiency, maintaining our 2013 efficiency ranking. Group 3 is considered average and is defined as having actual costs within +/- 5% of predicted costs. Although InnPower's forward looking goal is to advance to a "more efficient" group, management's expectation is that its efficiency performance will not decline in the foreseeable future.

Total Cost per Customer:

Total cost per customer is calculated as the sum of InnPower's capital and operating costs and dividing this cost figure by the total number of customers that InnPower serves. Similar to most distributors in the province, InnPower has experienced increases in its total costs required to deliver quality and reliable services to customers. Province wide programs such as Time of Use pricing, growth in wage and benefits costs for our employees, as well as investments in new information systems technology and the renewal and growth of the distribution system, have all contributed to increased operating and capital costs.
The total cost performance result for 2014 is $761/customer, which is a 4% increase over its 2013 result. On average, InnPower's total cost per customer has increased by 3% per annum for the period 2010 – 2014. Going forward, utility costs are expected to keep pace with economic fluctuations; however, InnPower will continue to implement productivity and efficiency improvements to help offset some of the costs associated with distribution system enhancements, while maintaining the reliability and quality of its distribution system.

Total Cost per Km of Line:

This measure uses the same total cost that is used in the Cost per Customer calculation above. Based on this, InnPower's rate is $14,693.00 per km of line, which is a 4% increase over its 2013 rate. InnPower's growth rate for its territory is considered to be relatively medium. A medium growth rate has assisted InnPower's ability to fund future capital projects and operating costs to support new infrastructure and growth. As a result, the cost per km of line is expected to increase as capital and operating costs also increase. As we progress into the future, InnPower will continue to seek innovative solutions to help ensure cost/km of line remains competitive and within acceptable limits to our customers.

Conservation & Demand Management

Late in 2010, the Ministry of Energy mandated a new 2011 - 2014 framework for electricity conservation and demand management (CDM) in Ontario. As a result, the OEB was required to establish CDM targets for the reduction of electrical consumption (kWh's) and electricity demand (kW's) to be met by certain licensed electricity distributors across the province. The Ontario Power Authority supported this initiative through the introduction of a number of OEB approved CDM programs designed to conserve electricity across all classes of electricity customers.

Net Annual Peak Demand Savings (Percent of target achieved):

InnPower achieved 1.2 MW of Net Annual Peak Demand (kW) Savings towards our target of 2.5 MW at the end of 2014 or 49.2%. Peak Demand Savings were a challenge for the Province of Ontario as the entire LDC community achieved 70% at the end of 2014 (based on 72 LDC's). Considering InnPower's service territory demographic rate class breakdown of 92% residential and minimal large business, the 1.2 MW is quite the accomplishment. This was primarily achieved through the use of a Roving Energy Manager who was retained to identify and pursue opportunities with the large commercial, institutional and industrial customers. Going forward, a new CDM framework and new targets are expected to be implemented for this measure for the period 2015 – 2020.

Net Cumulative Energy Savings (Percent of target achieved):

InnPower achieved 7.8 GWh Net Cumulative Energy (kWh's) Savings towards our target of 9.2 GWh at the end 2014 or 84.4%. From a Provincial perspective Ontario LDC's achieved 109% of the assigned Energy Savings target. This was achieved by leveraging the suite of OEB approved CDM programs primarily designed for the residential and small commercial classes of customers. Going forward, a new CDM framework and new targets will also be implemented for this measure for the period 2015 – 2020.

Connection of Renewable Generation

Renewable Generation Connection Impact Assessments Completed on Time:

Electricity distributors are required to conduct Connection Impact Assessments (CIA's) on all renewable generation connections within 60 days of the Generator meeting the requirements outlined in InnPower's Conditions of Service. InnPower has developed and implemented an internal procedure to ensure compliance with this regulation.

In 2014, InnPower completed 4 CIA's, all of which were completed within the prescribed time limit. In 2013, InnPower completed 3 CIA's, all of which were completed within the prescribed time limit.

New Micro-embedded Generation Facilities Connected On Time:

Micro-embedded generation facilities consist of solar, wind, or other clean energy projects of less than 10 kW that are typically installed by homeowners, farms or small businesses. In 2014, InnPower connected 9 new micro-embedded generation facilities within its territory. 100% of these projects were connected within the prescribed timeframe of five (5) business days, which significantly exceeds the Ontario Energy Board's mandated target of 90% for this measure. InnPower's process for these projects is well documented and InnPower staff work closely with its customers and their contractors to ensure the customer's needs are met and/or exceeded.

Financial Ratios

Liquidity: Current Ratio (Current Assets/Current Liabilities):

InnPower's current ratio decreased from 1.10 in 2012 to 0.63 and 0.41 in 2013 and 2014 respectively. This is due to the timeframe of the short term construction loan for the new Operations/Administration building. InnPower's current ratio is estimated to be in line with 2012 results as the new building loan converts to a long term mortgage.

Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio:

The OEB has developed a deemed utility capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40).

InnPower's 2014 debt to equity ratio is 2.04 compared to 2013 ratio of 1.3 due to the debt of the new Operations/Administration building. The new building is designed to service customer demand and territory growth in excess of 25 years in conjunction with the province and municipality's growth planning.

Profitability: Regulatory Return on Equity – Deemed (included in rates):

InnPower's current distribution rates are approved by the OEB and include a deemed regulatory return on equity of 8.98%. The OEB allows a distributor to earn within +/- 3% of the deemed return on equity.

Profitability: Regulatory Return on Equity – Achieved:

InnPower's return on equity achieved in 2014 was 5.82%. This is slightly outside the +/-3% range allowed by the OEB. InnPower achieved a lower return than the deemed rate in 2014 due to the increased costs associated with the implementation of the provincial regulatory requirements of ON1Call.

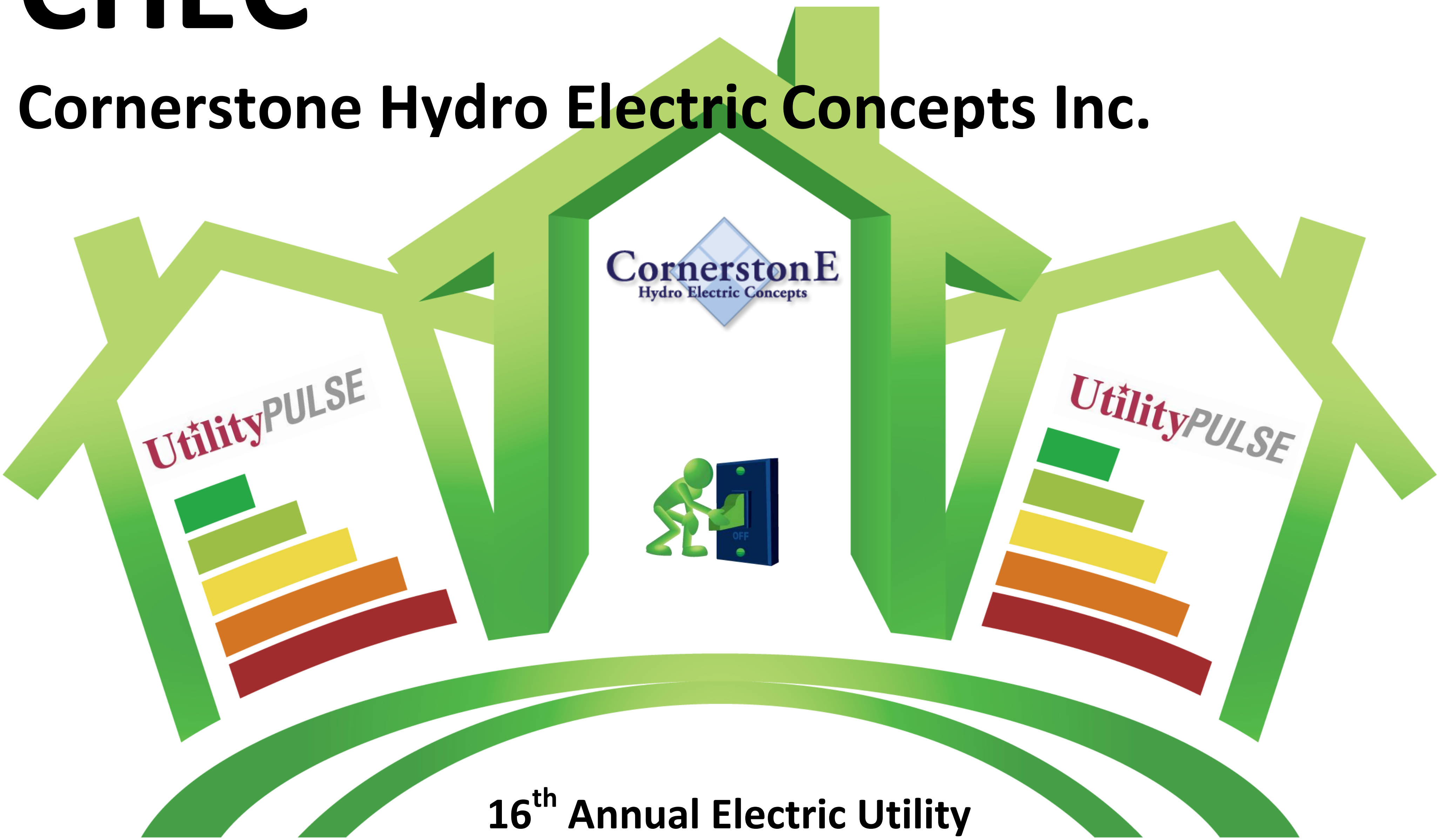
List of Appendices

A	UtilityPULSE 2014 Customer Survey
B	Financial Statements, YE December 31, 2013
C	Financial Statements, YE December 31, 2014
D	Financial Statements, YE December 31, 2015
E	Conditions of Service
F	Board Governance

APPENDIX A: UtilityPULSE 2014 Customer Survey

CHEC

Cornerstone Hydro Electric Concepts Inc.



16th Annual Electric Utility
Customer Satisfaction Survey

The purpose of this report is to profile the connection between Cornerstone Hydro Electric Concepts Inc. (CHEC) and its customers.

The primary objective of the Electric Utility Customer Satisfaction Survey is to provide information that will support discussions about improving customer care at every level in your utility.

The UtilityPULSE Report Card® and survey analysis contained in this report do not merely capture state of mind or perceptions about your customers' needs and wants - the information contained in this survey provides actionable and measurable feedback from your customers.

All comments and questions should be addressed to:

Sid Ridgley, UtilityPULSE division, Simul Corporation

Toll free: 1-888-291-7892 or Local: 905-895-7900

Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com

Executive summary

Rosemarie LeClair, Chair of the Ontario Energy Board, in a recent presentation (Ontario Energy Network, April 28, 2014) said the OEB's consumer centric regulatory framework defines the utility's obligation for planning, obligations for customer engagement and its responsibilities for monitoring and measuring performance results.

EB-2010-0379 Report of the Board: Scorecard Approach (ROB-SA) (March 5, 2014)

Throughout this report are connections to the OEB's Report of the Board. Where possible we have addressed the specifics in the document and, the "spirit" of the Scorecard Approach.

We believe that the data from interviewing over 10,000 electric utility customers so far, in 2014, supports 3 main conclusions:

1- Customers, almost universally, are concerned about the cost of electricity
2- Customers are resilient and can adapt to adversity, in fact, they are very tolerant when a utility goes through a very difficult situation
3- In a utility world that is used to "pushing information out", it has to invest in and hone its competencies in having 2-way interactions with customers.

Reasonable costs

9,943 Ontario survey respondents were asked if they agree or disagree with the following statement *"The cost of electricity is reasonable when compared to other utilities".* 50% agree in 2014, and 62% agreed in 2010. Satisfaction with the utility is about the same in those respective years.

We can also say that issues in the electricity industry, as a whole, show that satisfaction ratings and other important measures are lower in 2014 than they were in 2013. A customer may be upset with the amount that electricity costs, or what is going on in the industry, but that may not translate to being upset with their own local utility.

Data from the 2014 survey shows that respondents who give their utilities high marks for respect, trust, and social responsibility also give their utilities high marks for providing high quality services, and better marks for both cost efficiency and reasonableness of costs.

The attributes which help an LDC to be seen as trusted and highly credible are: knowledge, integrity, involvement and trust. On demonstrating Credibility and Trust, CHEC has done well.
Overall, CHEC 85% [Ontario 77%; National 80%].

EB-2010-0379 ROB-SA: Comparability

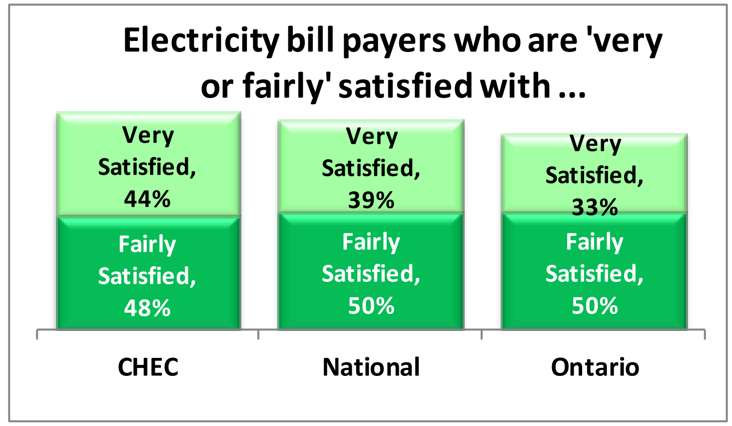
Your 2014 report contains data comparisons to:

- An Ontario-wide LDC benchmark
- A National LDC benchmark
- Previous year's ratings (where available)

- Ontario LDCs participating in the 2014 survey
- UtilityPULSE database

EB-2010-0379 ROB-SA: Customer Focus

There are 2 identified Performance Categories in the OEB Report, they are Customer Satisfaction & Service Quality. Performance measurements for these areas range from *'relatively easy to attain production statistics'* to '*harder to define and measure qualitative items'*. None-the-less this survey provides you with insights about how customers perceive performance of the utility.



Base: total respondents

EB-2010-0379 ROB-SA: Customer Focus - Customer Satisfaction - Satisfaction Survey Results

Customer satisfaction is one of the measures in the consumer centric regulatory framework. This rating is known as an effectiveness rating as it represents a sum total of perceptions and expectations that a customer has about their utility. Those expectations go far beyond “keeping the lights on”, “billing me properly”, and “restoring power quickly”.

CHEC SATISFACTION SCORES – Electricity customers' satisfaction					
Top 2 Boxes: 'very + fairly satisfied'	**2014**	**2013**	**2012**	**2011**	**2010**
PRE: Initial Satisfaction Scores	92%	92%	-	-	-
POST: End of Interview	93%	94%	-	-	-

Base: total respondents / (-) not a participant of the survey year

- ***Satisfaction*** *happens when utility core services meet or exceed customer's needs, wants, or expectations.*
- ***Loyalty*** *(Affinity) occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.*

Customer Affinity

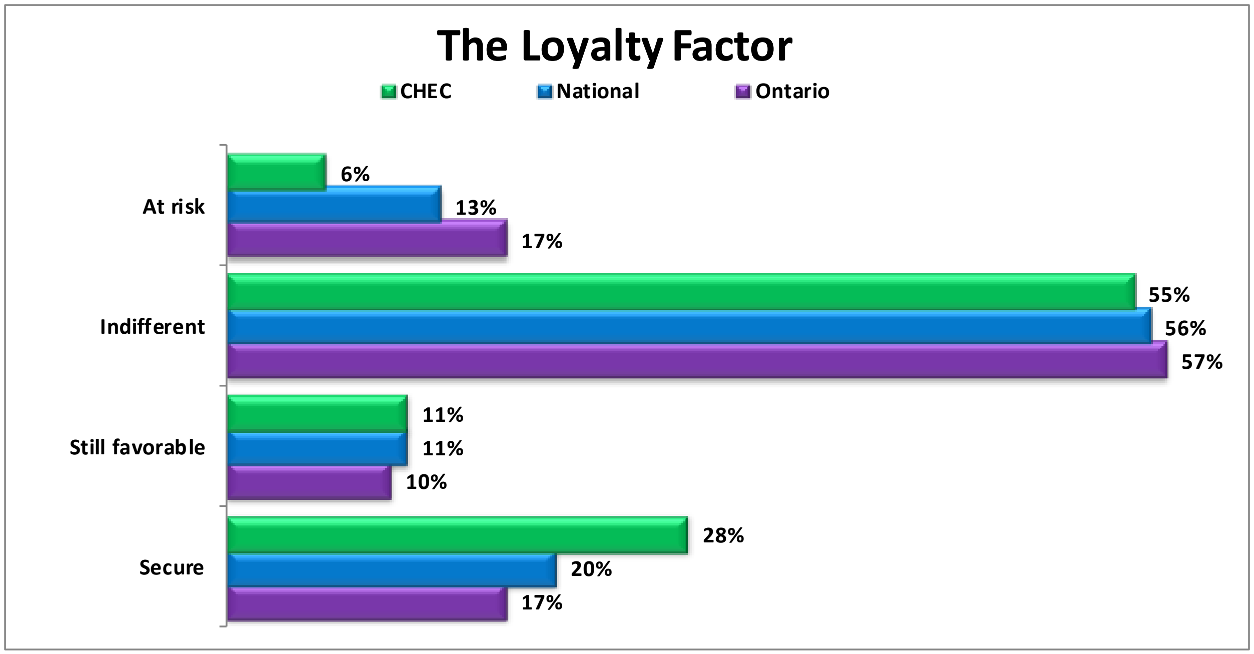
Loyalty, for private industry, is a behaviourial metric. Loyalty, for natural monopolies (like LDCs) is an attitudinal metric.

Customer Loyalty Groups				
	Secure	**Favorable**	**Indifferent**	**At Risk**
CHEC				
2014	28%	11%	55%	6%
2013	33%	13%	49%	5%

Base: total respondents

Even if customers can't defect, there is enormous value in making more of them loyal. Customers after all make the company's reputation. Reputation is ultimately what customers think – nothing else. To be successful and profitable, companies must take account of how they are perceived because companies do operate in a climate of opinion.

Loyal customers are more likely to see the world the way hydro management sees it. Customers feel their interests and the hydro's are often in common. Our survey results do reveal, loyal customers enhance the value of the utility. One example, 99% of Secure customers agree that overall CHEC 'provides excellent quality services' versus 58% of At Risk customers.



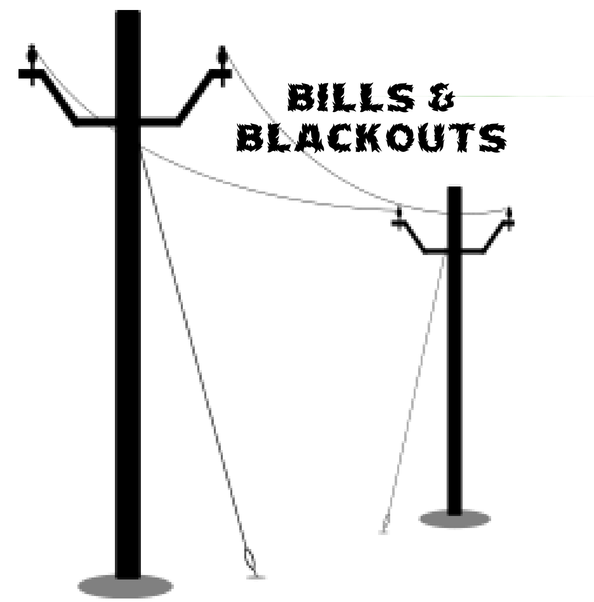
Base: total respondents

Utilities benefit from a trusted relationship with their empowered Customers. Higher levels of trust are the hallmarks of Secure customers. When people interact, either face-to-face, by telephone or on-line, if people do not trust each other, the interaction is not going to be efficient. Trust improves the speed at which the interaction can be accomplished. At Risk customers recall experiencing more outages and more billing problems than Secure customers. What makes matters worse is, At Risk customers are about 2X more likely to contact the utility to deal with it.

None-the-less problems will happen.

The Killer B's (Blackouts and Bills)

It is inevitable that there will be blackouts/power outages – the key is how a utility anticipates outages and more importantly, how it deals with them. It should also be noted that there is a disconnect between what a utility might call a "billing problem" and what a customer defines as a "billing problem". Though both viewpoints are valid, employees need to be trained to answer those which cause the most concern with customers.



Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months

	CHEC	National	Ontario
2014	36%	47%	49%
2013	36%	41%	35%
2012	-	44%	46%
2011	-	43%	43%
2010	-	45%	41%

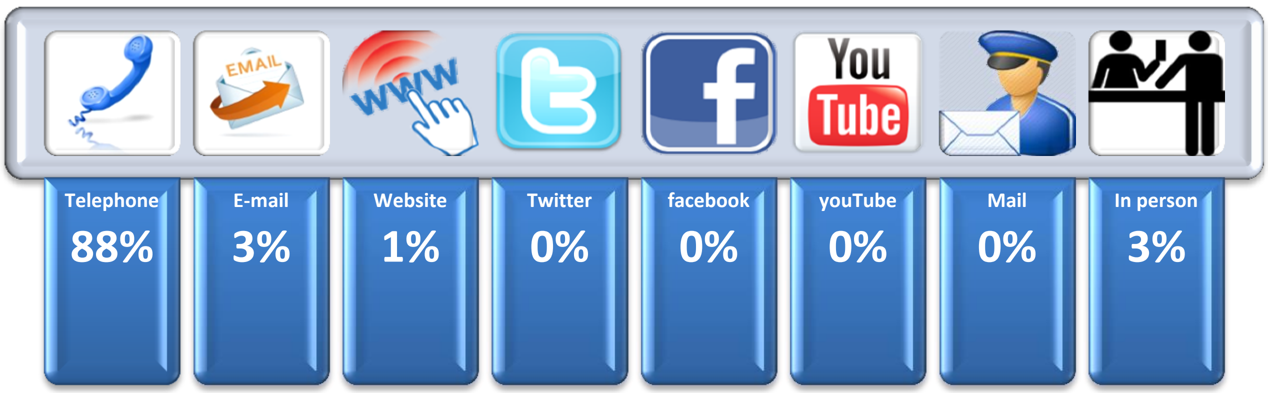
Base: total respondents / (-) not a participant of the survey year

Percentage of Respondents indicating that they had a Billing problem in the last 12 months			
	CHEC	**National**	**Ontario**
2014	12%	16%	25%
2013	10%	8%	10%
2012	-	12%	13%
2011	-	10%	16%
2010	-	10%	12%

Base: total respondents / (-) not a participant of the survey year

What method did you use to contact your electric utility when you had a problem?

Base: data from the full 2014 database



Customers may prefer a particular communication channel today (i.e., 88% telephone), however, that does not mean the customer who prefers the telephone will not want, or eventually want another channel for communications. In addition, there could be variances in preferences based on the type of issue or transaction.

EB-2010-0379 ROB-SA: Customer Focus – Customer Satisfaction – Billing Accuracy

There is a difference between what a customer believes is a billing problem versus a technical or production level measurement. Without the benefit of production level numbers, 88% of respondents 'agree strongly + somewhat' that the utility has "accurate billing". The Ontario benchmark rating is 77%.

EB-2010-0379 ROB-SA: Customer Focus – Customer Satisfaction – First Contact Resolution

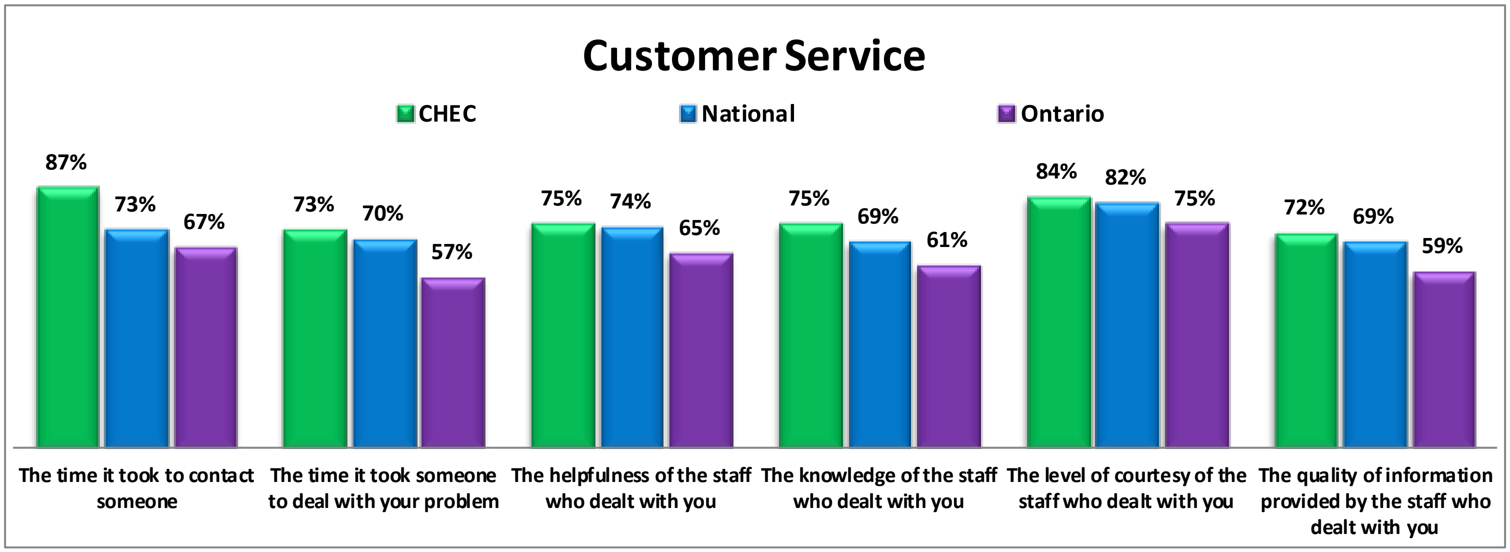
This performance measure is not defined in the EB-2010-0379 ROB-SA March 5, 2014 document. First contact resolution is an outcome base measurement which is affected by: type of problem, competency levels of staff, empowerment levels of staff, and organization culture to name a few.

Your 2014 survey gives you the following information from respondents:

1- Satisfaction with the contact experience
2- A problem solved rating
3- A Customer Experience Performance rating (CEPr)

Satisfaction with the contact experience

When there are problems, how they are handled can validate or invalidate a customer's perception about the utility's competency in handling the problem, and in running the operation. Here is how Customers, who contacted your LDC, rated their one-on-one transaction.



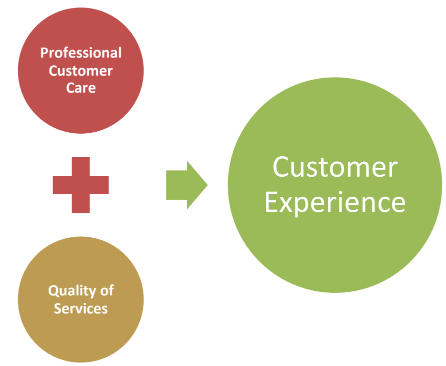
Base: total respondents who contacted the utility

Customer expectations are on the rise and continue to change. Customers expect their utility to have customer care practices and services that are in-line with any other organization that is important to their everyday life. Setting realistic expectations and consistently delivering to those expectations are keys to higher levels of Customer satisfaction. The setting of customer expectations is tough, but the harder part is to deliver consistency.

Overall satisfaction with most recent experience			
	CHEC	**National**	**Ontario**
Top 2 Boxes: ‘very + fairly satisfied’	78%	75%	62%

Base: total respondents who contacted the utility

Problem solved rating



Respondents who said that they contacted the utility were also asked “Do you consider the problem solved or not solved?” 72% of your LDC’s respondents said the problem was solved. The Ontario benchmark rating is 61%.

Customer Experience Performance rating (CEPr)

What do customers anticipate contact will be with their local utility when they have a problem? Will it be adversarial, or cooperative, or pleasant, etc. High numbers in CEPr indicate that a large majority of customers would agree that their next contact will be a good or positive one.

Customer Experience Performance rating (CEPr)			
	CHEC	**National**	**Ontario**
CEPr: all respondents	87%	82%	79%

Base: total respondents

EB-2010-0379 ROB-SA: Customer Focus – Service Quality

The three performance measures identified are all time based measures. They are: New Residential Services Connected on Time; Scheduled Appointments Met on Time; and, Telephone Calls Answered on Time. These are good examples of efficiency measures. In addition to time, there are other dimensions of Service Quality that Customers value.

Customer Service Quality			
Top 2 boxes, 'strongly + somewhat agree'	**CHEC**	**National**	**Ontario**
Deals professionally with customers' problems	87%	82%	78%
Pro-active in communicating changes and issues affecting Customers	81%	74%	73%
Quickly deals with issues that affect customers	85%	79%	74%
Customer-focused and treats customers as if they're valued	83%	74%	72%
Is a company that is 'easy to do business with'	88%	79%	75%
Cost of electricity is reasonable when compared to other utilities	64%	60%	55%
Provides good value for money	73%	67%	63%
Delivers on its service commitments to customers	89%	84%	82%

Base: total respondents with an opinion

EB-2010-0379 ROB-SA: Operational Effectiveness

With the exception of the Public Safety measure, which is yet to be defined, performance measures would typically take the form of a monitoring and measuring (quantitative) rating. Though customers may not have the benefit of numbers, they do have a perception.

Management Operations			
Top 2 boxes, 'strongly + somewhat agree'	**CHEC**	**National**	**Ontario**
Provides consistent, reliable electricity	92%	89%	86%
Quickly handles outages and restores power	90%	86%	83%
Makes electricity safety a top priority for employees and contractors	90%	89%	87%
Operates a cost effective electricity system	78%	69%	62%
Overall the utility provides excellent quality services	88%	83%	80%

Base: total respondents with an opinion

UtilityPULSE Report Card®

The purpose of the UtilityPULSE Report Card is to provide your utility with a snapshot of performance – it represents the sum total of respondents' ratings on 6 categories of attributes that research has shown are important to customers in influencing satisfaction and affinity levels with their utility.

CHEC's UtilityPULSE Report Card®

Performance

	CATEGORY	CHEC	National	Ontario
1	**Customer Care**	**B+**	**B+**	**B**
	Price and Value	B	B	C+
	Customer Service	A	B+	B
2	**Company Image**	**A**	**B+**	**B+**
	Company Leadership	A	B+	B+
	Corporate Stewardship	A	A	B+
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	B+
	Power Quality and Reliability	A+	A	A
	OVERALL	**A**	**B+**	**B+**

Base: total respondents

Corporate Image

Reputation, image, brand have to be actively managed. Positive impressions beget positive perceptions. Marketing communication includes positioning the utility in a way that makes customers want your utility and its services. Every utility has a brand, why not have the brand you want?

Attributes strongly linked to a hydro utility's image			
	CHEC	**National**	**Ontario**
Is a respected company in the community	88%	81%	78%
A leader in promoting energy conservation	84%	78%	77%
Keeps its promises to customers and the community	87%	79%	76%
Is a socially responsible company	88%	78%	77%
Is a trusted and trustworthy company	88%	82%	77%
Adapts well to changes in customer expectations	78%	71%	68%
Is 'easy to do business with'	88%	79%	75%
Provides good value for your money	73%	67%	63%
Overall the utility provides excellent quality services	88%	83%	80%
Operates a cost effective hydro-electric system	78%	69%	62%

Base: total respondents with an opinion

Customers, as human beings, are both rational and emotional. The rational side of the customer holds the LDC accountable for doing its job (as contracted), thereby fulfilling the customer's basic needs. The emotional side of the customer is about fulfilling expectations. Meeting rational needs – at best – gets the customer to a neutral state and at worst creates dissatisfaction. Emotional needs, when met, assuming base level rational needs are met, can move a customer from neutral to higher levels of satisfaction. The industry is obsessed with rational concerns about customer behaviour, but the real motivation for customer behaviour is emotional, not rational.

What do customers think about electricity costs?

Ask a utility customer – anywhere in the province of Ontario – what do they think about electricity, there is a very high probability they will say electricity costs are too high or too expensive. For customers who said that they had a billing problem in the last 12 months, and stated that the problem was "high bills" or "high rates or charges", there was very little variability between customers who could be called Secure, Favourable, Indifferent or At Risk. There was also very little variability between age groupings or income groupings.

Our survey database shows 50% more customers in 2014 citing complaints with "high bills" or "high rates or charges" than in 2010. There is a growing concern over electricity costs, especially as it relates to its portion of a household budget. This means the industry needs to monitor "ability to pay".

Is paying for electricity a worry or major problem …

	CHEC	National	Ontario
Not really a worry	66%	69%	59%
Sometimes I worry	22%	20%	26%
Often it is a major problem	8%	7%	11%
Depends	2%	3%	2%

Base: total respondents

Supplemental Insights

Recognizing that customers' interests and needs continue to shift, we have provided data and insights, on a number of subjects such as e-care, e-billing, conservation and more.

Electric Industry Knowledge & SMART Grid

Beyond knowing that they need electricity to maintain their day to day activities, does the average person feel that they are actually knowledgeable about the electric utility industry?

Knowledge level about the electric utility industry

	Ontario
Extremely knowledgeable	2%
Very knowledgeable	11%
Moderately knowledgeable	47%
Slightly knowledgeable	26%
Not very knowledgeable	14%
Don't know	1%

Base: total respondents in the Ontario Benchmark survey

Two-thirds (60%) of those polled in the Ontario Benchmark survey considered themselves moderately to extremely knowledgeable about the electric industry.

While it is evident that the SMART grid is still not a much talked about concept, only 34% have a basic or good understanding of what it is, oddly enough, 60% still think that it is important to pursue SMART grid implementation. It is also clear that the majority of respondents are very + somewhat supportive of the utility working with neighbouring utilities on SMART grid initiatives.

Level of knowledge about the SMART Grid

	Ontario
I have a fairly good understanding of what it is and how it might benefit homes and businesses	9%
I have a basic understanding of what it is and how it might work	25%
I've heard of the term, but don't know much about it	36%
I have not heard of the term	29%
Don't know	1%

Base: total respondents in the Ontario Benchmark survey

Efforts to reduce energy consumption

Do customers believe there is a real pay-off for trying to reduce their energy consumption? Does this impact overall efforts to reduce consumption? Respondents were asked *"How active have you been in trying to reduce your electricity consumption?"* (Base: total respondents in the Ontario Benchmark survey)

- 94% feel they are "very + somewhat active" in trying to reduce electricity consumption, and
- 81% of those do believe their efforts have resulted in reduced energy consumption, of which
- 44% estimate that they were able to offset an energy consumption reduction of more than 10%, and
- 72% believe that these efforts translated to savings on their electricity bills.

Level of Activity in trying to reduce electricity consumption	
	Ontario
Very active	52%
Somewhat active	42%
Neither proactive or inactive	0%
Not active	2%
Not very active	3%

Base: total respondents in the Ontario Benchmark survey

Active efforts have reduced energy consumption

81%

16%

Base: total respondents in the Ontario Benchmark survey who have been active in trying to reduce energy consumption

Estimate of percentage reduction in consumption	
	Ontario
1 – 2 %	5%
3 – 5 %	10%
6 – 8 %	4%
9 – 10 %	15%
More than 10%	44%
Don't know	21%

Base: total respondents in the Ontario Benchmark survey whose active efforts have reduced consumption

Efforts to conserve have translated into savings on your electricity bill

72%

24%

Base: total respondents in the Ontario Benchmark survey whose active efforts have reduced consumption

Energy Conservation & Efficiency

Energy efficiency can be broken down into two areas: *better use of energy through improved energy-efficient technologies;* and *energy saving through changes in customer awareness and behaviour.*

Efforts to conserve energy

Ontario LDCs	Yes	No	Already Done	Don't Know
Install energy-efficient light bulbs or lighting equipment	19%	9%	70%	1%
Install timers on lights or equipment	12%	50%	35%	2%
Shift use of electricity to lower cost periods	22%	17%	58%	3%
Install window blinds or awnings	12%	27%	60%	2%
Install a programmable thermostat	13%	25%	60%	2%
Have an energy expert conduct an energy audit	9%	71%	16%	4%
Removing old refrigerator or freezer for free	14%	44%	38%	4%
Join the peaksaverPLUS™ program	15%	49%	21%	16%
Replacing furnace with a high efficiency model	12%	33%	52%	4%
Replacing air-conditioner with a high efficiency model	14%	38%	44%	4%
Use a coupon to purchase qualified energy saving products	35%	39%	22%	5%

Base: An aggregate of respondents from 2014 participating LDCs

E-care and E-billing

Technology – specifically the internet—has allowed people access to far more information than ever before and the ability to do more than ever before.

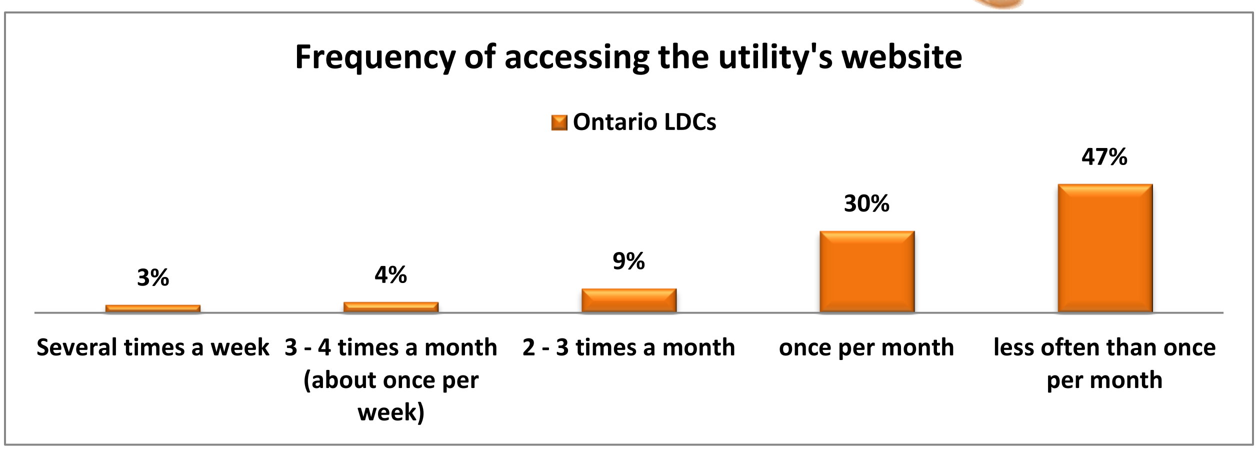
Do you have access to the internet?	
	Ontario LDCs
Yes	87%
No	13%

Base: An aggregate of respondents from 2014 participating LDCs

Over the past six months have you accessed your local utility website?

29% **70%**

Base: An aggregate of respondents from 2014 participating LDCs



Base: An aggregate of respondents from 2014 participating LDCs

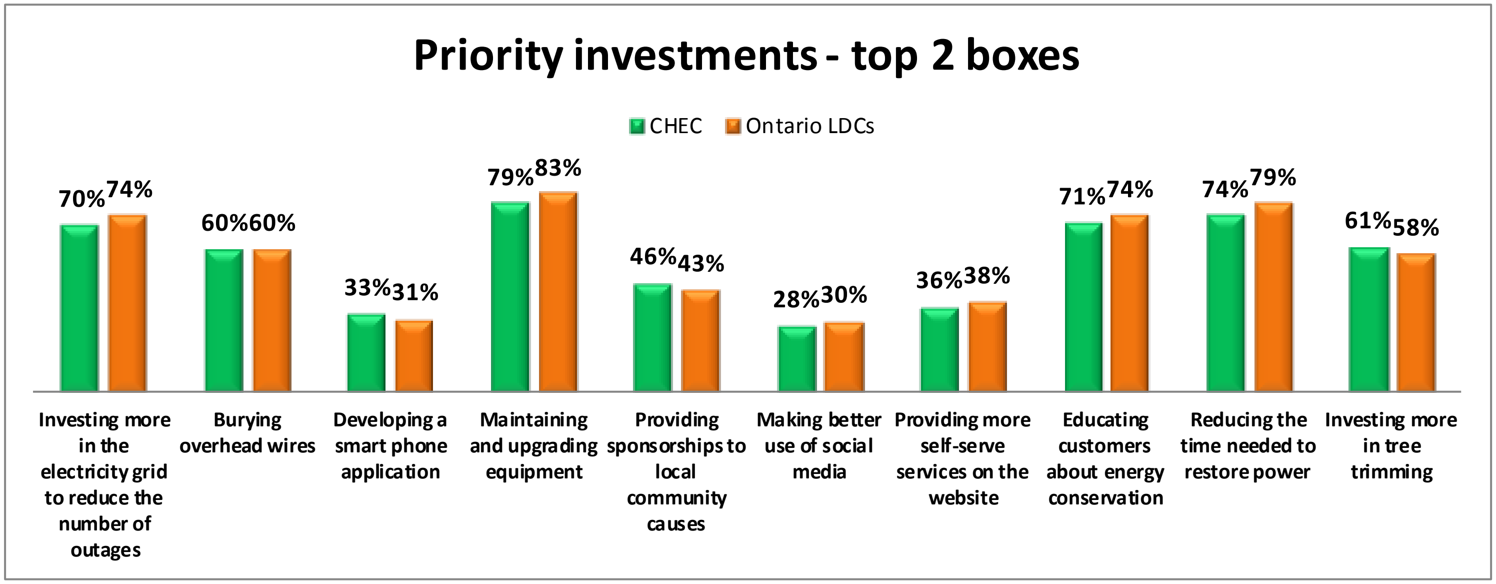
Likelihood of using the internet for future customer care needs for things such as:	
Top 2 Boxes: 'very + somewhat likely'	**Ontario LDCs**
Setting up a new account	31%
Arranging a move	38%
Accessing information about your bill	55%
Accessing information about your electricity usage	54%
Accessing energy saving tips and advice	45%
Accessing information about Time Of Use rates	51%
Maintaining information about your account or preferences	51%
Paying your bill through the utility's website	32%
Getting information about power outages	47%
Arranging for service	40%

Base: An aggregate of respondents from 2014 participating LDCs

As society becomes increasingly more familiar with technology it will become a more popular medium for giving and receiving information. One could also say, demographics will also put more pressure on the technology channels. Unfortunately, customers adopt technology on their own timetable. This causes the utility to continue to improve existing channels while building the technological channels wanted by some today, but by the year 2020, demanded by many. Will your utility be ready?

Priority Investments

While regulation and reliability are top concerns in the utility industry, aging infrastructure is now a top operational concern. Customers agree with industry insiders that infrastructure renewal is a high priority. This year, respondents were asked for their views about prioritizing investments.



Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local

Some findings shown above correlate with some of the suggestions made by respondents on things the utility could do to improve. Percentage of comments received from all Ontario respondents were:

- 14% improve reliability (10% in 2010)
- 11% better maintenance (3% in 2010)

- 10% better communication (7% in 2010)

Are CHEC customers willing to foot the bill for further improvements? 46% of CHEC respondents expressed a willingness to pay at least something to better their electricity system. 46% of respondents were not willing to incur any additional costs while 9% were not sure of their position. Where respondents varied was on how much they were actually willing to pay.

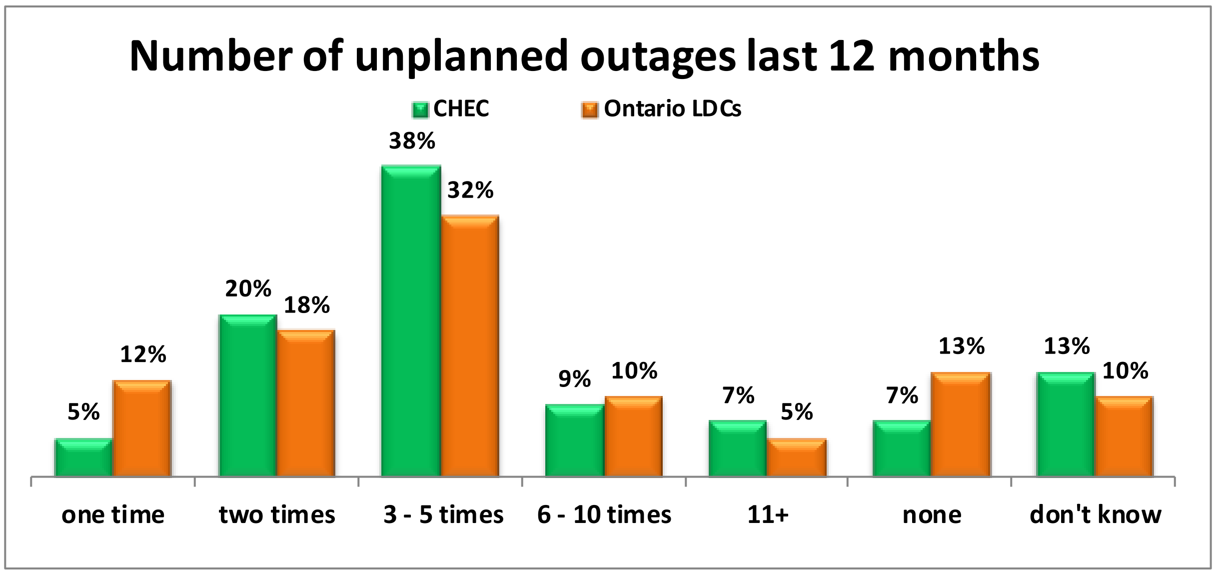
Willingness to pay for further improvements	
Using the scale of $0 to $10 per month	**CHEC**
$0	46%
$1 - 2	7%
$3 - 4	5%
$5 - 6	21%
$7 - 8	1%
$9 - 10	11%
$11+	1%
Don't know	9%

Base: total respondents

Outage Management

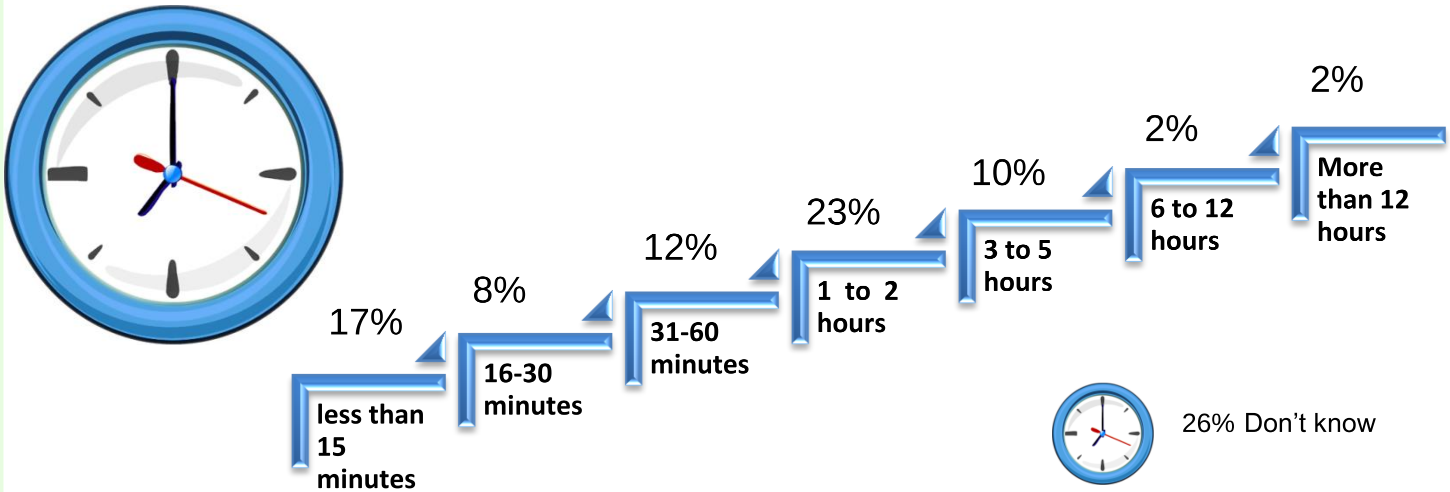
Whether an outage is planned or unplanned, the reality is that it is going to cause disruption and inconvenience under best case scenario and under worst case scenarios there could be safety and financial consequences.

However, one thing for certain, no matter what the scenario happens to be, customers are expecting their utility to keep them continually updated on the status of outages. Most importantly, and top priority, is to know the estimated restoration time. They also want to know the cause of the outage because they do not want to be a frequent outage customer.



Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local utility

When an unplanned outage occurs, how long, on average, is the outage?



Base: 90% of total respondents from the local utility

How a utility chooses to handle, manage and communicate with customers during an outage situation does affect customers' satisfaction with their utility. Customers want timely, accurate and relevant information about an outage and customers expect a utility to use various communication channels to ensure their message is getting out there. This means not only obtaining information via the call centre and IVR but customers have increasing expectations for proactive two-way communication through social media, utility websites and modern communication devices (e.g. tablets, smartphones) and apps.

Inability to provide the above information accurately and in a timely manner will result in customer complaints, increased call volumes to your call centres, create unwanted public and media attention, and negatively impact customer satisfaction.

Utility's effectiveness during an unplanned outage		
Top 2 Boxes: 'very + somewhat effective'	**Ontario LDCs**	**CHEC**
Responding to questions	61%	71%
Providing a reason for the outage	61%	63%
Providing an estimate when power will be restored	60%	60%
Responding to the power outage	81%	84%
Restoring power quickly	85%	86%
Communicating updates periodically	64%	66%
Posting information to the website	35%	30%
Using media channels for providing updates	53%	45%

Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local utility

On December 20, 2013, a severe ice storm struck the central and eastern portions of Canada and the northeastern United States. The storm's devastation caused major damage to utility distribution lines, towers, transformers, poles and entire substations and resulted in large scale outages and blackouts for long periods of time. The data suggests that customers are both tolerant and understanding when major outages take place.

Did you have a power outage during the ice storm in December 2013?

33%

48%

Base: total respondents

Percentage of Respondents who contacted their utility about the ice storm power outage

	CHEC
Yes	17%
No	82%

Base: total respondents affected by the ice storm

CHEC
Length of outage (during Ice Storm 2013)

Less than 2 hours	2 – 4 hours	4+ hours or ½ day	12-18 hours or ½ - ¾ day	19-24 hours or 1 day	1 to 1.5 days	1.6 to 2 days	More than 2 days
21%	26%	14%	7%	6%	3%	1%	2%

Base: total respondents affected by the ice storm

Using social media and multi-channel communication modes still appear to be the exception when it comes to customers contacting their utilities. Results from this year's survey indicate that the telephone is still the most used and the preferred method of contact. Overall, 87% of all Ontario respondents affected by the ice storm who informed their local utility they were experiencing a power outage did so via telephone; 93% of CHEC customers used the telephone to contact their utility.

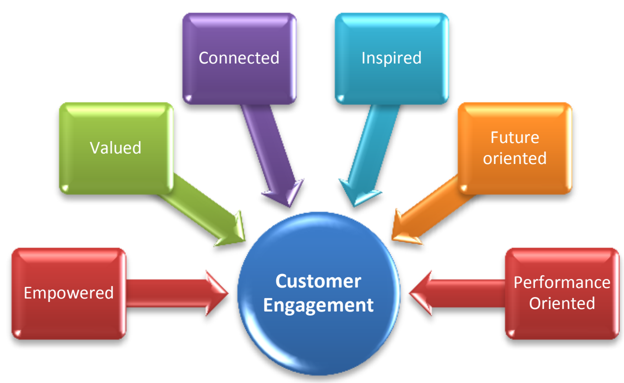
In your view, what is an acceptable period of time to go without electricity in situations like the ice storm?

Base: total respondents affected by the ice storm

None (the power shouldn't be going out)	8%
Less than 2 hours	8%
2 - 4 hours	18%
4+ hours or 1/2 day	17%
12 - 18 hours or 1/2 day to 3/4 day	7%
19 - 24 hours or 1 day	13%
1 to 1.5 days	6%
1 .6 to 2 days	4%
More than 2 days	6%

Customer Centric Engagement Index (CCEI)

The EB-2010-0379 ROB-SA report includes the following: "better engage with their customers to better understand and respond to their needs…" Conducting surveys (like this one), holding town hall meetings, focus groups, etc. are examples of engaging your customers. We call this an activity based definition of engagement. Asking 100 people to complete a survey is an engagement activity. This survey also provides you with an emotional look at engagement.



The CCEI index is a gauge of the amount of goodwill that has been generated. High numbers in CCEI suggests that there is a high level of goodwill amongst your customers – this is important for two reasons. First when something goes awry for the utility, goodwill helps the utility to be resilient. Second, goodwill encourages active participation in requests to participate in engagement activities or program offerings from the utility.

Utility Customer Centric Engagement Index (CCEI)			
	CHEC	**National**	**Ontario**
CCEI	83%	79%	76%

Base: total respondents

In a world of chaos and confusion what will a customer do? Find someone to help. In the electricity industry, the vast majority of customers turn to, and rely on, their local utility. Knowing that customers will turn to their electric utility requires utilities to really know their customers. Not easy when customer expectations continue to shift.

The shift is on. 15 years ago a utility could think about their customers in terms of usage, now they have to think about them in terms of personas (i.e., customer type). Currently, customer segmentation, for most utilities, consists of a number of "personas". While this may be adequate today, in order to achieve high customer participation in programs and to optimize business processes there will be a need for granular targeting of communications.

Most utilities are quite comfortable "pushing" out communications in a one-way world. However, the shift is on because the new channels are 2-way; even without the new channels customers are expecting 2-way dialogue. The impact on a utility's marketing-communications is significant.

Value is what a customer perceives they get in exchange for what they give up. The real challenge is educating customers on the value they receive. In the absence of a value proposition the primary thing people will talk about is cost.

We recommend having meaningful two-way dialogue with employees (and others) to leverage the results from your 2014 customer satisfaction survey derived from speaking with 612 CHEC customers [April 24 - May 2, 2014]. The electric utility business has demanding customers with high expectations.

UtilityPULSE
Sid Ridgley
Simul/UtilityPULSE
Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com
June, 2014

Good things happen when work places work. You'll receive both strategic and pragmatic guidance about how to improve Customer satisfaction & Employee engagement with leaders that lead and a front-line that is inspired. We provide: training, consulting, surveys, diagnostic tools and keynotes. The electric utility industry is a market segment that we specialize in. We've done work for the Ontario Electrical League, the Ontario Energy Network, and both large and small utilities. For sixteen years we have been talking to 1000's of utility customers in Ontario and across Canada and we have expertise that is beneficial to every utility.

Culture, Leadership & Performance – Organizational Development	**Focus Groups, Surveys, Polls, Diagnostics**	**Customer Service Excellence**
Leadership development	Diagnostics ie. Change Readiness, Leadership Effectiveness, Managerial Competencies	Service Excellence Leadership
Strategic Planning	Surveys & Polls	Telephone Skills
Teambuilding	Customer Satisfaction and Loyalty Benchmarking Surveys	Customer Care
Organizational Culture Transformation	Organization Culture Surveys	Dealing with Difficult Customers

Benefit from our expertise in Customer Satisfaction, Leadership development, Strategy development or review, and Front-line & Top-line driven-change. We're experts in helping you assess and then transform your organization's culture to one where achieving goals while creating higher levels of customer satisfaction is important. Call us when creating an organization where more employees satisfy more customers more often, is important.

Your personal contact is:

Sid Ridgley, CSP, MBA

Phone: (905) 895-7900 Fax: (905) 895-7970 E-mail: sidridgley@utilitypulse.com or sridgley@simulcorp.com

APPENDIX B: Financial Statements – Year Ending December 31, 2013

Financial Statements

Innisfil Hydro Distribution Systems Limited

December 31, 2013

Contents

Grant Thornton

Independent Auditor's Report

Grant Thornton LLP
Suite 300
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Orillia, ON
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To the Directors of

Innisfil Hydro Distribution Systems Limited

We have audited the accompanying financial statements of Innisfil Hydro Distribution Systems Limited, which comprise the balance sheet as at December 31, 2013, and the statements of earnings, retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

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

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the 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 financial position of Innisfil Hydro Distribution Systems Limited as at December 31, 2013, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Grant Thornton LLP

Orillia, Canada
April 28, 2013

Chartered Accountants
Licensed Public Accountants

Innisfil Hydro Distribution Systems Limited
Statements of Earnings and Retained Earnings

Year Ended December 31	2013	2012
Revenue		
Sale of power	$ 25,531,065	$ 23,079,623
Distribution	7,610,073	8,698,722
	33,141,138	31,778,345
Cost of power		
Power purchased	25,531,065	23,079,623
Distribution revenue	7,610,073	8,698,722
Other revenue (expenses) (Note 14)	484,640	(448,570)
Expenses		
Distribution	1,787,150	1,788,580
Billing and collecting	1,054,939	983,742
Administration	2,188,358	2,093,078
Amortization (Note 21)	1,287,210	1,698,905
	6,317,657	6,564,305
Earnings from operations	1,777,056	1,685,847
Interest on long term debt	781,831	745,433
Earnings before payments in lieu of taxes	995,225	940,414
Payments in lieu of taxes (Note 16)	776,252	228,000
Net earnings	$ 218,973	$ 712,414
Retained earnings, beginning of year	$ 4,835,300	$ 4,747,886
Net earnings	218,973	712,414
Dividends (Note 4)	(625,000)	(625,000)
Retained earnings, end of year	$ 4,429,273	$ 4,835,300

See accompanying notes to the financial statements.

Innisfil Hydro Distribution Systems Limited
Balance Sheet

December 31	2013	2012
Assets		
Current		
Cash	$ -	$ 615,028
Receivables	**3,742,942**	3,711,556
Unbilled revenue	**3,532,452**	2,892,392
Inventory	**461,816**	399,403
Payments in lieu of taxes recoverable	**209,725**	266,748
Prepaids	**327,645**	329,666
Future income tax (Note 16)	**-**	145,000
	8,274,580	8,359,793
Property and equipment (Note 5)	**33,970,638**	27,996,522
Intangible assets (Note 6)	**597,034**	530,856
Long term investment (Note 7)	**21,721**	21,721
Regulatory assets (Note 8)	**1,784,792**	720,284
Future income taxes (Note 16)	**1,013,000**	1,501,000
	$ 45,661,765	$ 39,130,176
Liabilities		
Current		
Bank Indebtedness (Note 9)	**$ 564,637**	$ -
Payables and accruals	**5,283,503**	4,049,111
Short term debt (Note 10)	**3,086,936**	-
Customer credit balances and deposits	**1,183,192**	846,682
Due to related parties (Note 4)	**1,769,128**	1,122,456
Future income tax (Note 16)	**193,500**	-
Current portion of long-term debt (Note 11)	**1,477,514**	1,313,301
	13,558,410	7,331,550
Customer and retailer deposits	**177,635**	219,046
Regulatory liabilities (Note 8)	**829,898**	1,594,781
Long term debt (Note 11)	**15,258,485**	13,741,435
	29,824,428	22,886,812
Shareholder's Equity		
Capital stock (Note 12)	**10,852,444**	10,852,444
Development charges transferred to equity	**555,620**	555,620
Retained earnings	**4,429,273**	4,835,300
	15,837,337	16,243,364
	$ 45,661,765	$ 39,130,176

On Behalf of the Board

_____ Director _____ Director

See accompanying notes to the financial statements

Innisfil Hydro Distribution Systems Limited
Statement of Cash Flows

Year Ended December 31	2013	2012
(Decrease) increase in cash and cash equivalents		
Operating		
Net earnings	$ 218,973	$ 712,414
Loss on disposal	61,041	80,107
Amortization (Note 21)	1,431,568	1,843,542
Future income taxes (Note 16)	826,500	116,000
	2,538,082	2,752,063
Change in non-cash operating working capital (Note 17)	1,501,347	331,994
	4,039,429	3,084,057
Financing		
Dividends	(625,000)	(625,000)
Advance of short term debt	3,086,936	-
Repayment of short term debt	-	(4,000,000)
Advances of long term debt	3,000,000	8,000,000
Repayment of long term debt	(1,318,737)	(1,141,089)
	4,143,199	2,233,911
Investing		
Net additions to property, equipment, and intangibles assets	(7,532,902)	(6,120,552)
Net change to regulatory assets and liabilities	(1,829,391)	2,454,627
	(9,362,293)	(3,665,925)
Net (decrease) increase in cash and cash equivalents	(1,179,665)	1,652,043
Cash and cash equivalents, beginning of year	615,028	(1,037,015)
Cash and cash equivalents, end of year	$ (564,637)	$ 615,028

See accompanying notes to the financial statements.

1. Nature of operations

The Company distributes electricity under license from the Ontario Energy Board (OEB). The Electricity Act, 1998 provides for a competitive marketplace in the sale of electricity. The Ontario Energy Board Act, 1998 (Ontario) (OEBA) conferred on the Ontario Energy Board (OEB) increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity consumers, and the responsibility for ensuring that distribution companies fulfil obligations to connect and service customers. The OEB may also prescribe license requirements and conditions to electricity distributors, which may include among other things, specified accounting records, regulatory accounting principles, separation of accounts for distinct businesses and filing and process requirements for rate setting purposes.

2. Summary of significant accounting policies

Cash and cash equivalents

Cash and cash equivalents include cash, bank indebtedness, short term investments, (maturity of 3 months or less), and bank balances.

Revenue recognition

Sale of power, distribution and related revenues are based on OEB approved unbundled rates and are recognized as power is delivered to customers. The Company estimates the revenue for the period based on customer's usage since the last meter-reading date to the end of the period. Unbilled revenue is recognized for customer usage not billed at December 31, 2013.

Other revenue, including miscellaneous service revenues and miscellaneous non-operating income are recognized as services are rendered. Other revenue, relating to late payment charges, pole rentals and interest revenue are recognized as they are earned and measurable. Scientific research and development tax credits (SRED) are recognized in other revenue when they have been applied for and are measurable.

Inventory

Inventory consists of repair parts, supplies and materials held for future capital expansion and is valued at lower of average cost and estimated net realizable value. Costs include all acquisition costs incurred in bringing inventory to its present location and condition. Net realizable value is the estimated selling price in the ordinary cost of business less any applicable selling expenses. The Company classifies rebates received from vendors as a reduction to the cost of inventory. Amount of inventory expensed during the year was $246 (2012 - $9,212).

2. Summary of significant accounting policies (Continued)

Rate-setting

The electricity distribution business is subject to rate regulation by the OEB. 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. This change in timing gives rise to the recognition of regulatory assets and liabilities. These regulatory assets and liabilities reflect the fact that revenue and expenses are recognized in the financial statements in different periods consistent with their inclusion in rates, as directed by the regulator, than would be the case for an enterprise that is unregulated. Specific regulatory assets and liabilities recognized at December 31, 2013 are disclosed in Note 8.

The Company continually assesses the likelihood of recovery of each of its regulatory assets and liabilities and believes that it is probable that its regulatory assets and liabilities will be factored into the setting of future rates. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period the assessment is made.

Amortization

Property and equipment are recorded at cost less accumulated amortization. Property and equipment that is under construction in process (CIP) is not amortized until it is ready for use.

Property and equipment and intangible assets are amortized using the straight-line method over periods approximating their estimated useful lives as follows:

Land rights	50	years
Building and fixtures	50	years
Distribution station	30	years
Distribution system	15-60	years
System supervisory equipment	15	years
Other equipment	5-10	years
Computer hardware	5	years
Computer software	3	years
Contributions in aid of construction	15-60	years

When property and equipment or intangible assets are sold, the cost of the asset and the related accumulated amortization is removed from the accounts, when identifiable from the accounts, with the resulting net gain or loss being included in operations for the year. When property and equipment is scrapped, the cost of the asset and the related accumulated amortization is removed from the accounts when it is identifiable.

2. Summary of significant accounting policies (Continued)

Property and equipment retirement obligations

Canadian generally accepted accounting principles require the Company to determine the fair value of the future expenditures required to settle legal obligations to remove property and equipment on retirement. If reasonably estimable, a liability is recognized equal to the present value of the estimated future removal expenditures. An equivalent amount is capitalized as an inherent cost of the associated property and equipment.

Some of the Company's assets may have asset retirement obligations. As the Company expects to use the majority of its property and equipment for an indefinite period, no removal date can be determined and, consequently, a reasonable estimate of the fair value of any asset retirement obligations have not been made at this time.

Intangible assets

Intangible assets represent computer software and land rights. These assets are carried at cost net of accumulated amortization.

Corporate income and capital taxes

The Company uses the liability method of tax allocation for accounting for income. Under the liability method of tax allocation, temporary differences arising from the difference between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax liabilities or assets. Future income tax liabilities or assets are measured using the substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse. A valuation allowance is recognized to the extent the recoverability of future income tax assets are not considered more likely than not.

Under the Electricity Act, 1998, the Company is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998 and related regulations.

2. Summary of significant accounting policies (Continued)

Financial instruments, hedges, and comprehensive income

The Company has made the following classification for the purpose of measuring the value of the financial instruments:

- Cash and deposits at the Company have been classified as "held for trading". Cash and cash equivalents are classified as "held to maturity". They are initially measured at fair value and the gains and losses resulting from the revaluation at fair value at the end of each period are recognized in net income.

- Receivables are classified under "loans and receivables". They are recorded at cost, which, upon their initial measurement, is equal to their fair value. Subsequent measurements of receivables are recorded at amortized cost which usually corresponds to the amount initially recorded less any allowance for doubtful accounts.

- Payables and accruals, bank indebtedness and long term debt are classified as "other financial liabilities". They are initially measured at fair value and the gains and losses resulting from their subsequent measurement at amortized cost, at the end of each period, are recognized in net income.

3. Future accounting pronouncements

International Financial Reporting Standards

The CICA has announced that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. The Canadian Accounting Standards Board (AcSB) subsequently released a ruling that qualifying entities with rate-regulated activities have the option to defer their adoption of IFRS until annual periods beginning on or after January 1, 2015. The Company has elected to adopt IFRS effective January 1, 2015.

IFRS will require increased financial statement disclosure. Although IFRS uses a conceptual framework similar to Canadian generally accepted accounting principles, there will be some differences in accounting policies that will need to be addressed. The Company is currently in the process of implementing its plan for the adoption of IFRS.

4. Related party transactions	2013	2012
The Company had the following related party transactions:		
Innisfil Energy Services Limited ("IESL") - affiliated company controlled by shareholder		
Services billed	$ 5,457	$ 7,394
The Corporation of The Town of Innisfil ("Town") - shareholder		
Interest expensed on debentures	$ 216,718	$ 299,666
Electrical services billed	2,298,935	2,073,960
Water/Wastewater billing services billed	232,169	71,812
Dividends paid	625,000	625,000
Municipal taxes	75,919	51,207
Other expenses	88,823	109,012
Building permits and fees	754,874	-
Balances outstanding at December 31:		
Due (from) to IESL	$ (3,574)	$ 7,900
Due to the Town	1,772,702	1,114,556
	$ 1,769,128	$ 1,122,456
Current portion of long term debt due to the Town	$ 960,000	$ 871,000
Long term debt due to the Town	$ 1,045,000	$ 2,005,000

During the year, the Company provided financial, management and accounting services to IESL in the amount of $5,457 (2012 - $7,394). These transactions have been recorded in these financial statements at the carrying amounts, which were equal to their fair value. Fair value represents fees for equivalent services provided to third parties in the normal course of operations as prescribed by regulation. At the end of the year, $3,574 in receivables was due from IESL.

The Company provides electricity and services to the Town. These transactions are in the normal course of operations and are measured at the exchange amount, which is equal to fair value as prescribed by regulation. During the year, the Company billed electricity and services to the Town in the amount of $2,298,935 (2012 - $2,073,960), and contributed capital of $ 72,426 (2012 - $407,485). At the end of the year, $270,560 (2012 - $446,828) was due for these services. During the year, the Company paid municipal taxes $75,919 (2012 - $51,207) and other expenses of $88,823 (2012 - $109,012) to the Town.

In 2012, the Company entered into a contract with the Town to provide water and sewer billing services for the Town. The Town was billed $232,169 (2012 - $71,812) for these services. At the end of the year $1,985,641 (2012 - $1,332,085) was owed to the Town for these collections of water and sewer billing services.

5. Property and equipment

			2013	2012
	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Land	$ 2,188,582	$ -	**$ 2,188,582**	$ 1,656,582
Building and fixtures	748,392	296,515	**451,877**	458,899
Distribution station	4,475,782	2,499,541	**1,976,241**	1,897,749
Distribution system	57,574,285	26,094,683	**31,479,602**	29,286,828
System supervisory equipment	1,895,508	1,000,000	**895,508**	805,389
Other equipment	2,150,882	1,310,479	**840,403**	951,584
Computer hardware	598,089	420,832	**177,257**	182,529
Construction in progress	3,717,179	-	**3,717,179**	327,878
Contributions in aid of construction	(9,792,874)	(2,036,863)	**(7,756,011)**	(7,570,916)
	$ 63,555,825	$ 29,585,187	**$ 33,970,638**	$ 27,996,522

The amortization for property and equipment for the year was $1,320,498 (2012 - $1,702,545).

During the year the Company capitalized $35,182 (2012 - $nil) of interest to construction in progress.

6. Intangible assets

			2013	2012
	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Land rights	$ 982,510	$ 588,047	**$ 394,463**	$ 409,589
Computer software	640,751	438,180	**202,571**	121,267
	$ 1,623,261	$ 1,026,227	**$ 597,034**	$ 530,856

The amortization for intangible assets for the year was $111,070 (2012 - $140,997).

7. Long term investment

The long term investment is recorded at cost and consists of 16,894 preferred shares of a private company that mainly provides settlement services to the electric utilities of Ontario.

8. Regulatory assets and liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process (Note 2). Innisfil Hydro has recorded the following regulatory assets and liabilities.

		2013		2012
Regulatory assets				
Stranded meters	$	**216,700**	$	334,318
Retail settlement variance accounts		**1,295,533**		(382,384)
Other		**272,559**		385,966
	$	**1,784,792**	$	337,900
Regulatory liabilities				
Regulatory assets/liabilities approved for recovery/repayment	$	**279,485**	$	551,902
Changes in useful lives of property and equipment		**550,413**		660,495
	$	**829,898**	$	1,212,397

Regulatory assets/liabilities approved for recovery/repayment

These regulatory assets/liabilities have been approved for recovery/repayment to customers by the OEB in previous IRM submissions and the 2013 COS application. Most of the balance relates to the approval received for rate changes May 1, 2013 in the COS and will be recovered/repaid over a 1 year period.

Retail settlement variance accounts

Innisfil Hydro has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's *Accounting Procedures Handbook*. To date amounts up to December 31, 2011 have been approved for recovery. The Company has accumulated a net asset since this time.

Stranded meters

Disposition of stranded meters, in the amount of $359,195 was approved in the 2013 COS by the OEB commencing May 1, 2013. The rate rider will be in effect over a two year period.

Changes in useful lives of property and equipment

In 2012, the Company changed their useful lives for some of the property and equipment categories. The OEB required these differences be recorded in regulatory accounts with the other side being recorded in other (expenses) revenue (Note 14). Disposition of the regulatory liability in the amount of $660,495 over a period of 4 years was approved by the OEB commencing May 1, 2013.

Other regulatory assets and liabilities

These accounts include certain amounts deferred as required by OEB guidelines, and include costs and partial recovery of the costs incurred to date for compliance with international financial reporting standards (IFRS) of $155,825 (2012 - $317,197).

9. Bank indebtedness

The Company has a bank letter of credit outstanding for $938,146 (2012 - $938,146), as described in Note 13. The letter of credit bears interest at the prime rate of a Canadian chartered bank less .25% per annum.

The Company has bank indebtedness of $2,225,879 (2012 - $nil), out of $4,000,000 credit limit. The facility is secured by a general security agreement conveying first fixed and floating charges over the property, assets, rights and interests of the Company and bears interest at the prime rate.

10. Short term debt

The Company has short term indebtedness with Toronto Dominion Bank of $3,086,936 (2012 – nil). The facility is secured by a general security agreement conveying first fixed and floating charges over the property, assets, rights and interests of the Company. The facility also bears interest at the prime rate, with no fixed term of repayment.

11. Long term debt

	2013	2012
Debentures payable to the Town	$ **2,005,000**	$ 2,876,000
Term loan, due October 2020	**1,887,048**	1,960,178
Term loan, due February 2022	**3,805,466**	3,909,391
Term loan, due September 2022	**3,877,255**	3,975,833
Term Loan, due November 2023	**2,994,564**	-
Infrastructure Ontario Loan	**2,166,666**	2,333,334
	16,735,999	15,054,736
Less: current portion	**1,477,514**	1,313,301
	$ **15,258,486**	$ 13,741,435

The debentures are payable to the Town and bear interest at various rates ranging from 9.5% to 9.75%. Payments are due annually on March 31 until 2015 and vary in amount each year.

The term loan, due October 2020, has a fixed interest rate of 4.53% with monthly blended payments of $13,368.

The term loan, due February 2022, has a fixed interest rate of 4.05% with monthly blended payments of $21,693.

The term loan, due September 2022, has a fixed interest rate of 3.81% with monthly blended payments of $20,695.

11. Long term debt (continued)

The term loan, due November 2023, has a fixed interest rate of 4.59% with blended monthly payments of $16,754.

All term loans above are secured by a general security agreement conveying first fixed and floating charges over the property, assets, rights and interests of the Company.

The Infrastructure Ontario Debenture was converted from a construction loan to pay for the Smart Meter Initiative. The long term debt bears interest at 3.91% with semi-annual principal repayments of $83,333 in February and August until 2026. Innisfil Hydro incurred $87,506 in interest expense to Infrastructure Ontario in 2013.

Principal payments due in each of the next five years are as follows:

2014	1,477,514
2015	1,579,201
2016	548,446
2017	566,467
2018	582,734

12. Capital stock

	2013	2012
Authorized:		
The Company is authorized to issue an unlimited number of common shares and an unlimited number of preference shares.		
Issued:		
1,000 common shares	**$ 10,852,444**	$ 10,852,444

13. Letter of credit

Security

Purchasers of electricity in Ontario, through the Independent Electricity Systems Operator (IESO) are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if the Company fails to make a payment required by default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2013, the Company provided prudential support using bank letters of credit of $938,146 (2012 - $938,146). The letter of credit bears interest at a rate of 0.75% per annum.

14. Other revenue (expenses)

	2013	2012
Late payment charges	$ 73,904	$ 74,521
Interest	26,559	(7,074)
Pole rentals	153,288	137,509
Loss on disposal	(61,041)	(80,107)
SRED revenue	-	84,575
Miscellaneous service revenues	113,245	126,126
Miscellaneous non-operating income (expenses)	68,603	(123,625)
Disposition of regulatory liability from changes in useful lives of property and equipment (Note 8)	110,082	(660,495)
	$ 484,640	$ (448,570)

15. Employee future benefits

Pension plan

The Company makes contributions to Ontario Municipal Employees Retirement System ("OMERS"), a multi-employer plan, on behalf of its staff. The plan is a contributory defined benefit plan, which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay.

Contributions were made at rates ranging from 9.0% to 14.6% of employee contributory earnings, depending upon the level of earnings. As a result, the Company made contributions in 2013 totalling $303,864 for the current service (2012 - $252,741).

Early retirement employee benefits

Effective January 1, 2009, the Company has agreed to pay 50% of the premiums for early retirees from the age of 55 to 65 who have a minimum of 15 years of service with Innisfil Hydro for specific benefit packages outlined in the conditions of employment and the collective bargaining agreement. An accrual in payables and accruals has been setup for $46,698 (2012 – $41,499).

16. Payments in lieu of taxes

The Company is required to compute and remit to the OEFC payments in lieu of income taxes (PILS). PILS are computed in accordance with rules for computing income, capital and other taxes provided for in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by The Electricity Act, 1998 and related regulations.

Future taxes

Future income taxes are provided for temporary differences. The significant components of the Company's deductible (taxable) timing differences at year end are as follows:

	2013	2012
Current future income tax (liability) asset:		
Regulatory assets	$ (193,500)	$ 145,000
Long term future income tax asset:		
Early retirement employee benefits	$ 13,000	$ 11,000
Property, equipment and intangible assets	1,000,000	1,490,000
	$ 1,013,000	$ 1,501,000
Provision for PILS:		
Current (recovery)	$ (50,248)	$ 112,000
Future (recovery)	826,500	116,000
	$ 776,252	$ 228,000

17. Supplemental cash flow information

	2013	2012
Change in non-cash operating working capital		
Receivables	$ (30,348)	$ (1,080,769)
Prepaids	2,021	(29,294)
Unbilled	(640,060)	22,580
Inventory	(62,413)	28,601
Payment in lieu of taxes	57,023	155,221
Due to related party	645,634	1,026,787
Payables and accruals	1,234,391	(3,296)
Customer credit balances and deposits	295,099	212,164
	$ 1,501,347	$ 331,994
Supplemental cash flow information		
Interest received	$ 26,559	$ 35,183
Interest paid	$ 805,526	$ 808,177
Refunds of payments in lieu of taxes	$ 106,502	$ 43,221

18. Public liability insurance

The Company is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE), which was created on January 1, 1987. A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other through the same attorney. MEARIE has provided comprehensive liability insurance to the Company of $24,000,000 per occurrence.

19. Financial instruments

Risks arising from financial instruments

Credit risk
The Company's cash is all held at The Toronto-Dominion Bank (TD Bank). The Company's credit risk associated with accounts receivable is related to payments from LDC customers. The Company collects security deposits from customers in accordance with directions provided by the Ontario Energy Board. The carrying amount of receivables is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the statement of operations. Subsequent recoveries of receivables previously provisioned are credited to the statement of operations.

Interest rate risk
The long-term debt bears fixed interest rates. Consequently, the long-term interest rate risk exposure is minimal. The bank indebtedness for any outstanding, bear interest at floating rates which gives rise to a risk that the Company's future income (loss) and cash flows may be adversely impacted by fluctuations in interest rates.

Liquidity risk
The Company manages its liquidity risk to ensure access to sufficient funds to meet operational needs. Liquidity risks are comprised of current liabilities totaling $13,558,410 (2012 - $7,331,550) which are due within one year and long-term debt as described in Note 11.

The Company carries various forms of financial instruments. Unless otherwise noted, it is management's opinion that the Company is not exposed to significant currency risk arising from these financial instruments.

20. Capital disclosures

The Company's objectives when managing capital are:

- to safeguard the entity's ability to continue as a going concern, so that it can continue to provide returns for shareholders and benefits for other stakeholders, and

- to provide an adequate return to shareholders commensurately with the level of risk.

The Company sets the amount of capital in proportion to risk. The Company manages the capital structure and makes adjustments to it in the light of changes in economic conditions and the risk characteristics of the underlying assets. In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends paid to shareholders or return capital to shareholders, issue new shares, or sell assets to reduce debt. The Company is subject to quarterly reporting and bank review of its minimum interest coverage ratio of 1.2 to 1, and maximum debt to capitalization ratio of .6 to 1, in relation to the bank indebtedness. The Company is subject to annual review from Infrastructure Ontario of its minimum debt service coverage ratio of 1 to 1, a maximum debt to capital ratio of 0.75 to 1, and a minimum current ratio of 1.1 to 1, in relation to the Infrastructure Ontario debenture.

Consistent with others in the industry, the Company monitors capital on the basis of the debt-to-equity ratio. This ratio is calculated as short and long term debt divided by equity. Short term debt is calculated as current notes and loans payable, as shown on the balance sheet. Long term debt is calculated as total long term debt, as shown on the balance sheet. Equity comprises all components of equity, share capital, development charges transferred to equity, and retained earnings.

21. Amortization of property, equipment and intangible assets

The amortization of property, equipment and intangible assets amounted to $1,431,568 (2012 - $1,843,542). The statement of earnings reflects $1,287,210 (2012 - $1,698,905) because the transportation and communication equipment amortization has been allocated to operations where the equipment was used. Amortization of $28,943 (2012 - $47,712) was mainly recorded as distribution expenses and $115,415 (2012 – $96,925) was recorded as capital expenditures and capitalized in property and equipment.

APPENDIX C: Financial Statements – Year Ending December 31, 2014

Financial Statements

InnPower Corporation

December 31, 2014

Contents

Grant Thornton

Independent Auditor's Report

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To the Directors of

InnPower Corporation

We have audited the accompanying financial statements of InnPower Corporation, which comprise the balance sheet as at December 31, 2014, and the statements of earnings, retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

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

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the 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 financial position of InnPower Corporation as at December 31, 2014, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Grant Thornton LLP

Orillia, Canada
April 20, 2015

Chartered Accountants
Licensed Public Accountants

InnPower Corporation
Statements of Earnings and Retained Earnings

Year Ended December 31	2014	2013
Revenue		
Sale of power	$ 27,773,907	$ 25,531,065
Distribution	7,727,563	7,610,073
	35,501,470	33,141,138
Cost of power		
Power purchased	27,773,907	25,531,065
Distribution revenue	7,727,563	7,610,073
Other (expenses) revenue (Note 14)	697,889	484,640
Expenses		
Distribution	1,814,455	1,787,150
Billing and collecting	1,169,535	1,054,939
Administration	2,285,340	2,188,358
Amortization (Note 21)	1,417,235	1,287,210
	6,686,565	6,317,657
Earnings from operations	1,738,887	1,777,056
Interest on long term debt	858,048	781,831
Earnings before payments in lieu of taxes	880,839	995,225
Payments in lieu of taxes (Note 16)	492,542	776,252
Net earnings	$ 388,297	$ 218,973

Retained earnings, beginning of year	$ 4,429,273	$ 4,835,300
Net earnings	388,297	218,973
Dividends (Note 4)	(468,750)	(625,000)
Retained earnings, end of year	$ 4,348,820	$ 4,429,273

See accompanying notes to the financial statements.

InnPower Corporation
Balance Sheet

December 31		2014		2013
Assets				
Current				
Cash and cash equivalents	$	**1,521,585**	$	-
Receivables		**4,677,079**		3,742,942
Unbilled revenue		**3,493,913**		3,532,452
Inventory		**439,097**		461,816
Payments in lieu of taxes recoverable		**26,806**		209,725
Prepaids		**337,601**		327,645
		10,496,081		8,274,580
Property and equipment (Note 5)		**45,755,095**		33,970,638
Intangible assets (Note 6)		**646,512**		597,034
Long term investment (Note 7)		**21,721**		21,721
Regulatory assets (Note 8)		**2,050,937**		1,784,792
Future income taxes (Note 16)		**733,500**		1,013,000
	$	**59,703,846**	$	45,661,765
Liabilities				
Current				
Bank Indebtedness (Note 9)	$	**-**	$	564,637
Payables and accruals		**6,484,003**		5,283,503
Short term debt (Note 10)		**10,894,753**		3,086,936
Customer credit balances and deposits		**1,561,351**		1,183,192
Due to related parties (Note 4)		**2,784,885**		1,769,128
Future income tax (Note 16)		**433,000**		193,500
Current portion of long-term debt (Note 11)		**1,685,539**		1,477,514
		23,843,531		13,558,410
Customer and retailer deposits		**162,841**		177,635
Regulatory liabilities (Note 8)		**385,288**		829,898
Long term debt (Note 11)		**19,555,302**		15,258,485
		43,946,962		29,824,428
Shareholder's Equity				
Capital stock (Note 12)		**10,852,444**		10,852,444
Development charges transferred to equity		**555,620**		555,620
Retained earnings		**4,348,820**		4,429,273
		15,756,884		15,837,337
	$	**59,703,846**	$	45,661,765

On Behalf of the Board

_________________ Director _________________ Director

See accompanying notes to the financial statements

InnPower Corporation
Statement of Cash Flows

Year Ended December 31		2014		2013
Increase (decrease) in cash and cash equivalents				
Operating				
Net earnings	$	**388,297**	$	218,973
Loss on disposal		**26,113**		61,041
Amortization (Note 21)		**1,557,167**		1,431,568
Future income taxes (Note 16)		**519,000**		826,500
		2,490,577		2,538,082
Change in non-cash operating working capital (Note 17)		**1,879,705**		1,501,347
		4,370,282		4,039,429
Financing				
Dividends		**(468,750)**		(625,000)
Advance of short term debt		**7,807,817**		3,086,936
Advances of long term debt		**6,000,000**		3,000,000
Repayment of long term debt		**(1,495,157)**		(1,318,737)
		11,843,910		4,143,199
Investing				
Net additions to property, equipment, and intangibles assets		**(13,417,215)**		(7,532,902)
Net change to regulatory assets and liabilities		**(710,755)**		(1,829,391)
		(14,127,970)		(9,362,293)
Net increase (decrease) in cash and cash equivalents		**2,086,222**		(1,179,665)
Bank indebtedness, beginning of year		**(564,637)**		615,028
Cash and cash equivalents, end of year	$	**1,521,585**	$	(564,637)

Cash and cash equivalents				
Cash	$	**2,300**	$	2,150
Bank balances		**1,596,633**		1,659,092
Bank indebtedness (Note 9)		**(77,348)**		(2,225,879)
Cash and cash equivalents, end of year	$	**1,521,585**	$	(564,637)

See accompanying notes to the financial statements.

1. Nature of operations

The Company distributes electricity under license from the Ontario Energy Board (OEB). The Electricity Act, 1998 provides for a competitive marketplace in the sale of electricity. The Ontario Energy Board Act, 1998 (Ontario) (OEBA) conferred on the Ontario Energy Board (OEB) increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity consumers, and the responsibility for ensuring that distribution companies fulfil obligations to connect and service customers. The OEB may also prescribe license requirements and conditions to electricity distributors, which may include among other things, specified accounting records, regulatory accounting principles, separation of accounts for distinct businesses and filing and process requirements for rate setting purposes.

2. Summary of significant accounting policies

Cash and cash equivalents

Cash and cash equivalents include cash, bank indebtedness, and bank balances.

Use of estimates

Management reviews the carrying amount of items in the financial statements at each balance sheet date to assess the need for revision or any possibility of impairment. Items subject to management estimates include: allowance for doubtful accounts and amortization periods for property, plant and equipment. Management determines these estimates based on assumptions that reflect the most probable set of economic conditions and planned courses of action.

These estimates are reviewed periodically and adjustments are made to net income as appropriate in the year they become known.

Revenue recognition

Sale of power, distribution and related revenues are based on OEB approved unbundled rates and are recognized as power is delivered to customers. The Company estimates the revenue for the period based on customer's usage since the last meter-reading date to the end of the period. Unbilled revenue is recognized for customer usage not billed at December 31, 2014.

Other revenue, including miscellaneous service revenues and miscellaneous non-operating income are recognized as services are rendered. Other revenue, relating to late payment charges, pole rentals and interest revenue are recognized as they are earned and measurable. Scientific research and development tax credits (SRED) are recognized in other revenue when they have been applied for and are measurable.

2. Summary of significant accounting policies (Continued)

Inventory

Inventory consists of repair parts, supplies and materials held for future capital expansion and is valued at lower of average cost and estimated net realizable value. Costs include all acquisition costs incurred in bringing inventory to its present location and condition. Net realizable value is the estimated selling price in the ordinary cost of business less any applicable selling expenses. The Company classifies rebates received from vendors as a reduction to the cost of inventory. Amount of inventory expensed during the year was $13,489 (2013 - $15,552).

Rate-setting

The electricity distribution business is subject to rate regulation by the OEB. 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. This change in timing gives rise to the recognition of regulatory assets and liabilities. These regulatory assets and liabilities reflect the fact that revenue and expenses are recognized in the financial statements in different periods consistent with their inclusion in rates, as directed by the regulator, than would be the case for an enterprise that is unregulated. Specific regulatory assets and liabilities recognized at December 31, 2014 are disclosed in Note 8.

The Company continually assesses the likelihood of recovery of each of its regulatory assets and liabilities and believes that it is probable that its regulatory assets and liabilities will be factored into the setting of future rates. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period the assessment is made.

Property and equipment retirement obligations

Canadian generally accepted accounting principles require the Company to determine the fair value of the future expenditures required to settle legal obligations to remove property and equipment on retirement. If reasonably estimable, a liability is recognized equal to the present value of the estimated future removal expenditures. An equivalent amount is capitalized as an inherent cost of the associated property and equipment.

Some of the Company's assets may have asset retirement obligations. As the Company expects to use the majority of its property and equipment for an indefinite period, no removal date can be determined and, consequently, a reasonable estimate of the fair value of any asset retirement obligations have not been made at this time.

Intangible assets

Intangible assets represent computer software and land rights. These assets are carried at cost net of accumulated amortization.

2. Summary of significant accounting policies (Continued)

Amortization

Property and equipment are recorded at cost less accumulated amortization. Property and equipment that is under construction in process (CIP) is not amortized until it is ready for use.

Property and equipment and intangible assets are amortized using the straight-line method over periods approximating their estimated useful lives as follows:

Land rights	50	years
Building and fixtures	50	years
Distribution station	30	years
Distribution system	15-60	years
System supervisory equipment	15	years
Other equipment	5-10	years
Computer hardware	5	years
Computer software	3	years
Contributions in aid of construction	15-60	years

When property and equipment or intangible assets are sold, the cost of the asset and the related accumulated amortization is removed from the accounts, when identifiable from the accounts, with the resulting net gain or loss being included in operations for the year. When property and equipment is scrapped, the cost of the asset and the related accumulated amortization is removed from the accounts when it is identifiable.

Corporate income and capital taxes

The Company uses the liability method of tax allocation for accounting for income. Under the liability method of tax allocation, temporary differences arising from the difference between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax liabilities or assets. Future income tax liabilities or assets are measured using the substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse. A valuation allowance is recognized to the extent the recoverability of future income tax assets are not considered more likely than not.

Under the Electricity Act, 1998, the Company is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998 and related regulations.

2. Summary of significant accounting policies (Continued)

Financial instruments, hedges, and comprehensive income

The Company has made the following classification for the purpose of measuring the value of the financial instruments:

- Cash and deposits at the Company have been classified as "held for trading". Cash and cash equivalents are classified as "held to maturity". They are initially measured at fair value and the gains and losses resulting from the revaluation at fair value at the end of each period are recognized in net income.

- Receivables are classified under "loans and receivables". They are recorded at cost, which, upon their initial measurement, is equal to their fair value. Subsequent measurements of receivables are recorded at amortized cost which usually corresponds to the amount initially recorded less any allowance for doubtful accounts.

- Payables and accruals, bank indebtedness, short term debt and long term debt are classified as "other financial liabilities". They are initially measured at fair value and the gains and losses resulting from their subsequent measurement at amortized cost, at the end of each period, are recognized in net income.

3. Future accounting pronouncements

International Financial Reporting Standards

The CICA has announced that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. The Canadian Accounting Standards Board (AcSB) subsequently released a ruling that qualifying entities with rate-regulated activities have the option to defer their adoption of IFRS until annual periods beginning on or after January 1, 2015. The Company has elected to adopt IFRS effective January 1, 2015.

IFRS will require increased financial statement disclosure. Although IFRS uses a conceptual framework similar to Canadian generally accepted accounting principles, there will be some differences in accounting policies that will need to be addressed. The Company is currently in the process of implementing its plan for the adoption of IFRS.

4. Related party transactions

The Company had the following related party transactions:

	2014	2013
Innisfil Energy Services Limited ("IESL") - affiliated company controlled by shareholder		
Services billed	**$ 10,164**	$ 5,457
The Corporation of The Town of Innisfil ("Town") - shareholder		
Interest expensed on debentures	**$ 125,288**	$ 216,718
Electrical services billed	**2,392,349**	2,298,935
Water/Wastewater billing services billed	**191,511**	232,169
Dividends paid	**468,750**	625,000
Municipal taxes	**68,734**	75,919
Other expenses	**75,789**	88,823
Building permits and fees	**-**	754,874
Balances outstanding at December 31:		
Due to IESL	**$ (21,832)**	$ (3,574)
Due to the Town	**2,806,717**	1,772,702
	$ 2,784,885	$ 1,769,128
Current portion of long term debt due to the Town (Note 11)	**$ 1,045,000**	$ 960,000
Long term debt due to the Town (Note 11)	**$ -**	$ 1,045,000

During the year, the Company provided financial, management and accounting services to IESL in the amount of $10,164 (2013 - $5,457). These transactions have been recorded in these financial statements at the carrying amounts, which were equal to their fair value. Fair value represents fees for equivalent services provided to third parties in the normal course of operations as prescribed by regulation. At the end of the year, $21,832 (2013 - $3,574) in receivables was due from IESL.

The Company provides electricity and services to the Town. These transactions are in the normal course of operations and are measured at the exchange amount, which is equal to fair value as prescribed by regulation. During the year, the Company billed electricity and services to the Town in the amount of $2,392,349 (2013 - $2,298,935), and contributed capital of $104,274 (2013 - $72,426). At the end of the year, $29,210 (2013 - $270,560) was due for these services. During the year, the Company paid municipal taxes $68,734 (2013 - $75,919), amounts relating to capital projects $1,222,936 and other expenses of $75,789 (2013 - $88,823) to the Town.

In 2012, the Company entered into a contract with the Town to provide water and sewer billing services for the Town. The Town was billed $191,511 (2013 - $232,169) for these services. At the end of the year $2,777,046 (2013 - $1,985,641) was owed to the Town for these collections of water and sewer billing services.

InnPower Corporation
Notes to the Financial Statements
December 31, 2014

5. Property and equipment

	Cost	Accumulated Amortization	2014 Net Book Value	2013 Net Book Value
Land	$ 2,188,582	$ -	**$ 2,188,582**	$ 2,188,582
Building and fixtures	748,392	307,882	**440,510**	451,877
Distribution station	6,979,368	2,404,240	**4,575,128**	1,976,241
Distribution system	60,425,457	27,125,809	**33,299,648**	31,479,602
System supervisory equipment	2,020,970	1,118,907	**902,063**	895,508
Other equipment	2,189,849	1,509,498	**680,351**	840,403
Computer hardware	547,540	360,891	**186,649**	177,257
Construction in progress	12,381,850	-	**12,381,850**	3,717,179
Contributions in aid of construction	(11,205,471)	(2,305,785)	**(8,899,686)**	(7,756,011)
	$ 76,276,537	$ 30,521,442	**$ 45,755,095**	$ 33,970,638

The amortization for property and equipment for the year was $1,408,061 (2013 - $1,320,498).

During the year the Company capitalized $172,517 (2013 - $35,182) of interest to construction in progress.

6. Intangible assets

	Cost	Accumulated Amortization	2014 Net Book Value	2013 Net Book Value
Land rights	$ 982,510	$ 603,173	**$ 379,337**	$ 394,463
Computer software	828,817	561,642	**267,175**	202,571
	$ 1,811,327	$ 1,164,815	**$ 646,512**	$ 597,034

The amortization for intangible assets for the year was $149,106 (2013 - $111,070).

7. Long term investment

The long term investment is recorded at cost and consists of 16,894 preferred shares of a private company that mainly provides settlement services to the electric utilities of Ontario.

8. Regulatory assets and liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process (Note 2). Innisfil Hydro has recorded the following regulatory assets and liabilities.

		2014		2013
Regulatory assets				
Stranded meters	$	33,458	$	216,700
Retail settlement variance accounts		1,793,951		1,295,533
Regulatory assets/liabilities approved for recovery/repayment		107,999		-
Other		115,529		272,559
	$	2,050,937	$	1,784,792
Regulatory liabilities				
Regulatory assets/liabilities approved for recovery/repayment	$	-	$	279,485
Changes in useful lives of property and equipment		385,288		550,413
	$	385,288	$	829,898

Regulatory assets/liabilities approved for recovery/repayment

These regulatory assets/liabilities have been approved for recovery/repayment to customers by the OEB in previous IRM submissions and the 2013 COS application. Most of the balance relates to the approval received for rate changes May 1, 2013 in the COS and will be recovered/repaid over a 1 year period.

Retail settlement variance accounts

Innisfil Hydro has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's *Accounting Procedures Handbook*. To date amounts up to December 31, 2011 have been approved for recovery. The Company has accumulated a net asset since this time.

Stranded meters

Disposition of stranded meters, in the amount of $359,195 was approved in the 2013 COS by the OEB commencing May 1, 2013. The rate rider will be in effect over a two year period.

Changes in useful lives of property and equipment

In 2012, the Company changed their useful lives for some of the property and equipment categories. The OEB required these differences to be recorded in regulatory accounts with the other side being recorded in other revenue (expenses) (Note 14). Disposition of the regulatory liability in the amount of $660,495 over a period of 4 years was approved by the OEB commencing May 1, 2013.

Remaining disposition due to be taken into income is as follows:

2015	165,124
2016	165,124
2017	55,041

8. Regulatory assets and liabilities (continued)

Other regulatory assets and liabilities

These accounts include certain amounts deferred as required by OEB guidelines, and include costs and partial recovery incurred to date for compliance with international financial reporting standards (IFRS) of $11,896 (2013 - $155,825).

9. Bank indebtedness

The Company has a bank letter of credit outstanding for $938,146 (2013 - $938,146), as described in Note 13. The letter of credit bears interest at the prime rate of a Canadian chartered bank less .25% per annum.

The Company has bank indebtedness of $77,348 (2013 - $2,225,879), out of $4,000,000 credit limit. The facility is secured by a general security agreement conveying first fixed and floating charges over the property, assets, rights and interests of the Company and bears interest at the prime rate.

10. Short term debt

The Company has short term indebtedness with Toronto Dominion Bank of $10,894,753 (2013 - $3,086,936). The facility is secured by a general security agreement conveying first fixed and floating charges over the property, assets, rights and interests of the Company. The facility also bears interest at the prime rate, with no fixed term of repayment.

11. Long term debt

	2014	2013
Debentures payable to the Town	**$ 1,045,000**	$ 2,005,000
Term loan, due October 2020	**1,810,535**	1,887,048
Term loan, due February 2022	**3,698,493**	3,805,466
Term loan, due September 2022	**3,774,855**	3,877,255
Term Loan, due November 2023	**2,929,602**	2,994,564
Term loan, due July 2024	**1,985,371**	-
Term Loan, due November 2024	**1,996,985**	-
Term loan, due December 2024	**2,000,000**	-
Infrastructure Ontario Loan	**2,000,000**	2,166,666
	21,240,841	16,735,999
Less: current portion	**1,685,539**	1,477,514
	$ 19,555,302	$ 15,258,486

11. **Long term debt** (continued)

The debentures are payable to the Town and bear interest at various rates ranging from 9.5% to 9.75%. Payments are due annually on March 31 until 2015 and vary in amount each year.

The term loan, due October 2020, has a fixed interest rate of 4.53% with monthly blended payments of $13,368.

The term loan, due February 2022, has a fixed interest rate of 4.05% with monthly blended payments of $21,693.

The term loan, due September 2022, has a fixed interest rate of 3.81% with monthly blended payments of $20,695.

The term loan, due November 2023, has a fixed interest rate of 4.59% with blended monthly payments of $16,754.

The term loan, due July 2024, has a fixed interest rate of 3.96% with monthly blended payments of $9,503.

The term loan, due November 2024, has a fixed interest rate of 3.914% with blended monthly payments of $9,449.

The term loan, due December 2024, has a fixed interest rate of 3.68% with monthly blended payments of $9,184.

All term loans above are secured by a general security agreement conveying first fixed and floating charges over the property, assets, rights and interests of the Company.

The Infrastructure Ontario Debenture was converted from a construction loan to pay for the Smart Meter Initiative. The long term debt bears interest at 3.91% with semi-annual principal repayments of $83,333 in February and August until 2026. Innisfil Hydro incurred $83,119 in interest expense to Infrastructure Ontario in 2014.

Principal payments due in each of the next five years are as follows:

2015	1,685,539
2016	661,144
2017	684,217
2018	705,099
2019	727,660

12. Capital stock

	2014	2013
Authorized:		
The Company is authorized to issue an unlimited number of common shares and an unlimited number of preference shares.		
Issued:		
1,000 common shares	**$ 10,852,444**	$ 10,852,444

13. Letter of credit

Security

Purchasers of electricity in Ontario, through the Independent Electricity Systems Operator (IESO) are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if the Company fails to make a payment required by default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2014, the Company provided prudential support using bank letters of credit of $938,146 (2013 - $938,146). The letter of credit bears interest at a rate of 0.75% per annum.

14. Other revenue (expenses)

	2014	2013
Late payment charges	**$ 84,703**	$ 73,904
Interest	**39,974**	26,559
Pole rentals	**169,619**	153,288
Loss on disposal	**4,450**	(61,041)
Miscellaneous service revenues	**127,272**	113,245
Miscellaneous non-operating (expenses) income	**106,747**	68,603
Regulatory liability from changes in useful life's of property and equipment (Note 8)	**165,124**	110,082
	$ 697,889	$ 484,640

15. Employee future benefits

Pension plan

The Company makes contributions to Ontario Municipal Employees Retirement System ("OMERS"), a multi-employer plan, on behalf of its staff. The plan is a contributory defined benefit plan, which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay.

Contributions were made at rates ranging from 9.0% to 14.6% of employee contributory earnings, depending upon the level of earnings. As a result, the Company made contributions in 2014 totalling $328,448 for the current service (2013 - $303,864).

Early retirement employee benefits

Effective January 1, 2009, the Company has agreed to pay 50% of the premiums for early retirees from the age of 55 to 65 who have a minimum of 15 years of service with Innisfil Hydro for specific benefit packages outlined in the conditions of employment and the collective bargaining agreement. An accrual in payables and accruals has been setup for $75,073 (2013 – $46,698).

16. Payments in lieu of taxes

The Company is required to compute and remit to the OEFC payments in lieu of income taxes (PILS). PILS are computed in accordance with rules for computing income, capital and other taxes provided for in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by The Electricity Act, 1998 and related regulations.

Future taxes

Future income taxes are provided for temporary differences. The significant components of the Company's deductible (taxable) timing differences at year end are as follows:

	2014	2013
Long term future income tax asset:		
Early retirement employee benefits	**$ 20,000**	$ 13,000
Property, equipment and intangible assets	**713,500**	1,000,000
	$ 733,500	$ 1,013,000
Current future income tax liability:		
Regulatory assets	**$ 433,000**	$ 193,500
Provision for PILS:		
Current (recovery)	**$ (26,458)**	$ (50,248)
Future	**519,000**	826,500
	$ 492,542	$ 776,252

17. Supplemental cash flow information

	2014	2013
Change in non-cash operating working capital		
Receivables	**$ (934,137)**	$ (30,348)
Prepaids	**(9,956)**	2,021
Unbilled	**38,539**	(640,060)
Inventory	**22,719**	(62,413)
Payment in lieu of taxes	**182,919**	57,023
Due to related party	**1,015,757**	645,634
Payables and accruals	**1,200,499**	1,234,391
Customer credit balances and deposits	**363,365**	295,099
	$ 1,879,705	$ 1,501,347
Supplemental cash flow information		
Interest received	**$ 39,974**	$ 26,559
Interest paid	**$ 869,568**	$ 805,526
(Refunds) payments in lieu of taxes	**$ (209,394)**	$ 106,502

18. Public liability insurance

The Company is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE), which was created on January 1, 1987. A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other through the same attorney. MEARIE has provided comprehensive liability insurance to the Company of $24,000,000 per occurrence.

19. Financial instruments

Risks arising from financial instruments

Credit risk
The Company's cash is all held at The Toronto-Dominion Bank (TD Bank). The Company's credit risk associated with accounts receivable is related to payments from LDC customers. The Company collects security deposits from customers in accordance with directions provided by the Ontario Energy Board. The carrying amount of receivables is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the statement of operations. Subsequent recoveries of receivables previously provisioned are credited to the statement of operations.

19. Financial instruments (Continued)

Interest rate risk
The long-term debt bears fixed interest rates. Consequently, the long-term interest rate risk exposure is minimal. The bank indebtedness for any outstanding, bear interest at floating rates which gives rise to a risk that the Company's future income (loss) and cash flows may be adversely impacted by fluctuations in interest rates.

Liquidity risk
The Company manages its liquidity risk to ensure access to sufficient funds to meet operational needs. Liquidity risks are comprised of liabilities totaling $23,843,030 (2013 - $13,558,410) which are due within one year and long-term debt as described in Note 11.

The Company carries various forms of financial instruments. Unless otherwise noted, it is management`s opinion that the Company is not exposed to significant currency risk arising from these financial instruments.

20. Capital disclosures

The Company's objectives when managing capital are:

- to safeguard the entity's ability to continue as a going concern, so that it can continue to provide returns for shareholders and benefits for other stakeholders, and
- to provide an adequate return to shareholders commensurately with the level of risk.

The Company sets the amount of capital in proportion to risk. The Company manages the capital structure and makes adjustments to it in the light of changes in economic conditions and the risk characteristics of the underlying assets. In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends paid to shareholders or return capital to shareholders, issue new shares, or sell assets to reduce debt. The Company is subject to quarterly reporting and bank review of its minimum interest coverage ratio of 1 to 1, and maximum debt to capitalization ratio of .65 to 1, in relation to the bank indebtedness. The Company is subject to annual review from Infrastructure Ontario of its minimum debt service coverage ratio of 1 to 1, a maximum debt to capital ratio of 0.75 to 1, and a minimum current ratio of 1.1 to 1, in relation to the Infrastructure Ontario debenture.

Consistent with others in the industry, the Company monitors capital on the basis of the debt-to-equity ratio. This ratio is calculated as short and long term debt divided by equity. Short term debt is calculated as current notes and loans payable, as shown on the balance sheet. Long term debt is calculated as total long term debt, as shown on the balance sheet. Equity comprises all components of equity, share capital, development charges transferred to equity, and retained earnings.

21. Amortization of property, equipment and intangible assets

The amortization of property, equipment and intangible assets amounted to $1,557,167 (2013 - $1,431,568). The statement of earnings reflects $1,417,235 (2013 - $1,287,210) because the transportation and communication equipment amortization has been allocated to operations where the equipment was used. Amortization of $50,479 (2013 - $28,943) was mainly recorded as distribution expenses and $89,453 (2013 - $115,415) was recorded as capital expenditures and capitalized in property and equipment.

APPENDIX D: Financial Statements – Year Ending December 31, 2015

IFRS Financial Statements

InnPower Corporation

December 31, 2015

Contents

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Independent Auditor's Report

To the Directors of InnPower Corporation,

We have audited the accompanying financial statements of InnPower Corporation, which comprise the statements of financial position as at December 31, 2015, December 31, 2014 and January 1, 2014, and the statements of comprehensive income, statements of changes in equity and statements of cash flows for the years ended December 31, 2015 and December 31, 2014, 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 International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of the financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the 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 financial position of InnPower Corporation as at December 31, 2015, December 31, 2014, and January 1, 2014, and its financial performance and its cash flows for the years ended December 31, 2015 and December 31, 2014 in accordance with International Financial Reporting Standards.

Grant Thornton LLP

Orillia, Canada
April 15, 2016

Chartered Professional Accountants
Licensed Public Accountants

InnPower Corporation
Statements of Comprehensive Income

(Expressed in 000's Canadian Dollars)

Year Ended		2015		2014
Revenue				
Electricity sales	$	30,705	$	28,034
Distribution revenue		8,785		7,566
Gain on disposal of property, plant and equipment		410		-
Other		877		790
Total Revenue		40,777		36,390
Expenses				
Purchased power		30,606		28,509
Operating expenses (Note 21)		5,580		5,293
Depreciation and amortization		2,044		1,686
Loss on disposal of property, plant and equipment		-		26
Total Expenses		38,230		35,514
Income from operating activities		2,547		876
Other Income				
Finance income		4		3
Finance cost		(1,073)		(852)
Income before provision for payments (recovery of) in lieu of taxes		1,478		27
Payments (recovery) in lieu of taxes				
Current (Note 10)		(2)		(266)
Deferred (Note 10)		348		448
Total payments (recovery) in lieu of taxes		346		182
Profit for the year before net movements in regulatory deferral account balances		1,132		(155)
Net movements in regulatory deferral account balances related to profit or loss and the related deferred tax movement (Note 11)		86		833
Profit for the year and net movements in regulatory deferral account balances		1,218		678
Other comprehensive income: items that will not be reclassified to profit or loss, net of income tax				
Remeasurements of defined benefit plan (Note 15), net of tax of $Nil (2014 - $3)		-		(7)
Other comprehensive income for the year, net of tax		-		(7)
Total comprehensive income for the year	$	1,218	$	671

See accompanying notes to the financial statements.

InnPower Corporation
Statements of Financial Position

(Expressed in 000's Canadian Dollars)

As at	December 31 2015	December 31 2014	January 1 2014
Assets			
Current Assets			
Cash and cash equivalents	$ -	$ 1,522	$ -
Receivables (Note 5)	**5,500**	4,700	3,966
Unbilled service revenue	**3,647**	3,494	3,535
Inventory (Note 6)	**452**	439	462
Prepaid expenses	**400**	338	328
Payments in lieu of taxes recoverable (Note 27)	**255**	280	224
Total Current Assets	**10,254**	10,773	8,515
Non-Current Assets			
Property, plant and equipment (Note 7)	**60,069**	54,655	41,727
Intangible assets (Note 8)	**649**	646	597
Investment (Note 9)	**22**	22	22
Deferred taxes (Note 10)	**489**	837	1,282
Total Non-Current Assets	**61,229**	56,160	43,628
Total Assets	**71,483**	66,933	52,143
Regulatory Deferral Account Debit Balances and Related Deferred Taxes (Note 11)	**895**	2,113	1,594
Total Assets and Regulatory Deferral Account Balances	**$ 72,378**	$ 69,046	$ 53,737

See accompanying notes to the financial statements.

InnPower Corporation
Statements of Financial Position

(Expressed in 000's Canadian Dollars)

As at	December 31 2015	December 31 2014	January 1 2014
Liabilities			
Current Liabilities			
Bank indebtedness (Note 16)	$ 1,472	$ -	$ 565
Accounts payable and accrued liabilities (Note 12)	7,767	9,409	7,425
Contributions in aid of construction (Note 13)	357	289	269
Customer deposits (Note 14)	1,210	1,369	991
Short term debt (Note 17)	1,602	10,895	3,087
Current portion of long term debt (Note 18)	2,596	1,685	1,477
Total Current Liabilities	15,004	23,647	13,814
Non-Current Liabilities			
Contributions in aid of construction (Note 13)	10,419	8,611	7,487
Customer deposits (Note 14)	244	163	178
Employee future benefits (Note 15)	163	148	116
Long term debt (Note 18)	29,153	19,556	15,259
Total Non-Current Liabilites	39,979	28,478	23,040
Total Liabilities	54,983	52,125	36,854
Shareholder's Equity			
Share capital (Note 19)	10,852	10,852	10,852
Retained earnings	6,284	5,691	5,481
Accumulated other comprehensive income	(7)	(7)	-
Total Shareholder's Equity	17,129	16,536	16,333
Total Liabilities and Shareholder's Equity	72,112	68,661	53,187
Regulatory Deferral Account Credit Balances and Related Deferred Tax (Note 11)	266	385	550
Total Liabilities, Shareholder's Equity and Regulatory Deferral Account Credit Balances	$ 72,378	$ 69,046	$ 53,737

Contingency and subsequent event (Notes 24 and 26)

On Behalf of the Board

_______________ Director _______________ Director

See accompanying notes to the financial statements

InnPower Corporation
Statements of Changes in Equity

(Expressed in 000's Canadian Dollars)
Year Ended December 31, 2015

	Share capital	Retained earnings	Accumulated other comprehensive income	Total
January 1, 2014	$ 10,852	$ 5,481	$ -	**$ 16,333**
Profit for the year and net movements in regulatory deferral account balances	-	678	-	**678**
Other comprehensive income, net of tax	-	-	(7)	**(7)**
Dividends	-	(468)	-	**(468)**
December 31, 2014	10,852	5,691	(7)	**16,536**
Profit for the year and net movements in regulatory deferral account balances	-	1,218	-	**1,218**
Other comprehensive income, net of tax	-	-	-	**-**
Dividends	-	(625)	-	**(625)**
December 31, 2015	$ 10,852	$ 6,284	$ (7)	**$ 17,129**

See accompanying notes to the financial statements

InnPower Corporation
Statements of Cash Flows

(Expressed in 000's Canadian Dollars)

Year Ended December 31	2015	2014
Cash flows from operating activities		
Net income for the year	$ 1,218	$ 671
Adjustments		
Depreciation and amortization of property, plant and equipment and intangible assets	2,164	1,826
(Gain) loss on disposal of property, plant and equipment and intangible assets	(410)	26
Employee future benefits	15	32
Provision for payments in lieu of taxes	346	179
Finance costs	1,073	852
Change in non-cash operating working capital		
Receivables	(800)	(734)
Unbilled service revenue	(153)	41
Inventory	(13)	23
Prepaid expenses	(62)	(10)
Accounts payable and accrued liabilities	(2,267)	1,984
Customer deposits	(78)	363
Contributions in aid of construction	1,876	1,144
Regulatory deferral account balances	1,099	(684)
	4,008	5,713
Income taxes recovered	27	210
Net cash flows from operating activities	4,035	5,923
Cash flows from investing activities		
Proceeds on disposal of property, plant and equipment	1,008	185
Purchase of property, plant and equipment and intangible assets	(8,179)	(15,014)
Net cash used in investing activities	(7,171)	(14,829)
Cash flows from financing activities		
Bank indebtedness	1,472	(565)
Advances short term debt	1,602	7,808
Advances long term debt	1,430	6,000
Repayment of long term debt	(1,817)	(1,495)
Interest paid	(1,073)	(852)
Dividends paid	-	(468)
Net cash provided by financing activities	1,614	10,428
Net (decrease) increase in cash during the year	(1,522)	1,522
Cash and cash equivalents, beginning of year	1,522	-
Cash and cash equivalents, end of year	$ -	$ 1,522

See accompanying notes to the financial statements.

1. Corporate information

InnPower Corporation's (the "Company") main business activity is the distribution of electricity. The Company owns and operates an electricity distribution system. The address of the Company's corporate office and principal place of business is 7251 Yonge Street, Innisfil, Ontario, Canada, L9S 0J3.

The sole shareholder of the Company is the Town of Innisfil.

The Company was incorporated under the Canada Business Corporations Act on October 5, 2000, and has continued as a Company under the Business Corporations Act of Ontario. The Company distributes electricity to residents and businesses in Innisfil and South Barrie under a license issued by the Ontario Energy Board ("OEB"). The Company is regulated by the OEB and adjustments to the Company's distribution and power rates require OEB approval.

2. Basis of preparation

a) Statement of compliance

The financial statements of the Company have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and interpretations as issued by the International Financial Reporting Interpretations Committee ("IFRIC") of the IASB.

These are the Company's first financial statements prepared in accordance with IFRS and IFRS 1 *First-time Adoption of International Financial Reporting Standards* has been applied. In this context, the term "Canadian GAAP" refers to generally accepted accounting principles before the adoption of IFRS. An explanation of how the transition to IFRS has affected the reported financial position, financial performance and cash flows of the Company is provided in Note 27.

The financial statements were authorized for issue by the Board of Directors on April 15, 2016.

b) Basis of measurement

The financial statements have been prepared on a historical cost basis. The financial statements are presented in Canadian dollars (CDN$), which is also the Company's functional currency, and all values are rounded to the nearest thousand, unless when otherwise indicated.

The preparation of financial statements in compliance with IFRS requires management to make certain critical accounting estimates. It is also requires management to exercise judgment in applying the Company's accounting policies. The areas involving a higher degree of judgment, complexity, or areas where assumptions and estimates are significant to the financial statements are disclosed in Note 4.

2. Basis of preparation (continued)

c) Explanation of Activities subject to Rate Regulation

The Company, as an electricity distributor, is both licensed and regulated by the Ontario Energy Board "OEB" which has a legislative mandate to oversee various aspects of the electricity industry. The OEB exercises statutory authority through setting or approving all rates charged by the Company and establishing standards of service for the Company's customers.

The OEB has broad powers relating to licensing, standards of conduct and service and the regulation of rates charged by the Company and other electricity distributors in Ontario. The Ontario government enacted the Energy Competition Act, 1998, to introduce competition to the Ontario energy market. Rates are set by the OEB on an annual basis for January 1 to December 31.

Regulatory risk

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.

Recovery risk

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future. The Company is subject to a cost of service regulatory mechanism under which the OEB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and payments in lieu of taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

3. Summary of significant accounting policies

The accounting policies set out below have been applied consistently to all periods presented in these financial statements and in preparing the opening IFRS Statement of Financial Position at January 1, 2014 for the purposes of the transition to IFRS, unless otherwise indicated.

a) Regulatory Deferral Accounts

The Company has early adopted IFRS 14 Regulatory Deferral Accounts. In accordance with IFRS 14, the Company has continued to apply the accounting policies it applied in accordance the pre-changeover Canadian GAAP for the recognition, measurement and impairment of assets and liabilities arising from rate regulation. These are referred to as regulatory deferral account balances.

3. Summary of significant accounting policies (continued)

Regulatory deferral account debit balances represent future revenues associated with certain costs incurred in the current period or in prior period(s) that are expected to be recovered from consumers in future periods through the rate-setting process. Regulatory deferral account credit balances are associated with the collection of certain revenues earned in the current period or in prior period(s) that are expected to be returned to consumers in future periods through the rate-setting process. Regulatory deferral account balances can arise from differences in amounts collected from customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by the Company in the wholesale market administered by the Independent Electricity System Operator (the "IESO") after May 1, 2002. These amounts have been accumulated pursuant to regulation underlying the Electricity Act (the "EA") and deferred in anticipation of their future recovery or expense in electricity distribution service charges.

Explanation of recognized amounts

Regulatory deferral account balances are recognized and measured initially and subsequently at cost. They are assessed for impairment on the same basis as other non-financial assets as described below.

Management continually assesses the likelihood of recovery of regulatory assets. If recovery through future rates is no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment is made.

b) Revenue

Revenue is recognized to the extent that it is probable those economic benefits will flow to the Company and that the revenue can be reliably measured. Revenue comprises of sales and distribution of energy, pole use rental, collection charges, amortization of contributions in aid of construction and other miscellaneous revenues.

Sale and distribution of energy

The Company is licensed by the OEB to distribute electricity. As a licensed distributor, the Company 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 Company is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Company ultimately collects these amounts from customers. The Company has determined that they are acting as a principal for the electricity distribution and, therefore, have presented the electricity revenues on a gross basis.

Revenues from the sale and distribution of electricity are recognized upon delivery and provision of services over the period in which the delivery and service is performed and collectability is reasonably assured and includes unbilled revenues accrued in respect of electricity delivered but not yet billed in the reporting period. Sale and distribution of energy revenue is comprised of customer billings for distribution service charges. Customer billings for distribution service charges are recorded based on meter readings.

3. Summary of significant accounting policies (continued)

Other

Other revenues, which include revenues from pole use rental, collection charges and other miscellaneous revenues are recognized at the time services are provided.

Where the Company has an ongoing obligation to provide services, revenues are recognized as the service is performed and amounts billed in advance are recognized as contributions in aid of construction.

Certain assets may be acquired or constructed with financial assistance in the form of contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. Since the contributions will provide customers with ongoing access to the supply of electricity, these contributions are classified as contributions in aid of construction and are recorded as revenue on a straight-line basis over the useful life of the constructed or contributed asset.

c) Cash and cash equivalents

Cash and cash equivalents include cash on hand, deposits held at call with financial institutions, other short-term, highly liquid investments with original maturities of three months or less that are readily convertible to known amounts of cash and subject to an insignificant risk of change in value.

d) Financial instruments

Recognition, initial measurement and derecognition

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the financial instrument and are measured initially at fair value adjusted for transaction costs, except for those carried at fair value through profit or loss which are measured initially at fair value. Subsequent measurement of financial assets and financial liabilities is described below.

Financial assets are derecognized when the contractual rights to the cash flows from the financial asset expire, or when the financial asset and substantially all the risks and rewards are transferred. A financial liability is derecognized when it is extinguished, discharged, cancelled or expires.

Classification and subsequent measurement of financial assets

For the purpose of subsequent measurement financial assets, they are classified into the following categories upon initial recognition, loans and receivables and available-for-sale (AFS) financial assets.

3. Summary of significant accounting policies (continued)

Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. After initial recognition, these are measured at amortized cost using the effective interest method, less provision for impairment. Discounting is omitted where the effect of discounting is immaterial. The Company's cash and cash equivalents, receivables and unbilled service revenue fall into this category of financial instruments.

Individually significant receivables are considered for impairment when they are past due or when other objective evidence is received that a specific counterparty will default. Receivables that are not considered to be individually impaired are reviewed for impairment in groups, which are determined by reference to the industry and region of the counterparty and other shared credit risk characteristics. The impairment loss estimate is then based on recent historical counterparty default rates for each identified group.

AFS financial assets

AFS financial assets are non-derivative financial assets that are either designated to this category or do not qualify for inclusion in any of the other categories of financial assets. The Company's AFS financial assets include investments in preferred shares of a private company. They are carried at fair value, with gains and losses recognized in other comprehensive income and reported within the AFS reserve within equity, except for dividend income and impairment losses, which are recognized in profit or loss. When the asset is disposed of or is determined to be impaired, the cumulative gain or loss recognized in other comprehensive income is reclassified from the equity reserve to profit or loss. For AFS equity investments, impairment reversals are not recognized in profit loss and any subsequent increase in fair value is recognized in other comprehensive income.

Where there is a significant or prolonged decline in the fair value of an available for sale financial asset (which constitutes objective evidence of impairment), the full amount of the impairment, including any amount previously recognized in other comprehensive income, is recognized in profit or loss.

Classification and subsequent measurement of financial liabilities

All of the Company's financial liabilities are classified as other financial liabilities, and include bank indebtedness, accounts payables and accrued liabilities, customer deposits, short term debt, debentures, term loans and Infrastructure Ontario Loans. Other financial liabilities are measured subsequently at amortized cost using the effective interest method. All interest-related charges are reported in profit or loss is included within finance costs or finance income.

Debentures, term loans and Infrastructure Ontario Loans and are initially measured at fair value. The carrying amounts of the debentures are carried at amortized cost. Debt issuance costs incurred are capitalized as part of the carrying value and amortized over the term of the related financial liability, using the effective interest method, and are included in finance cost.

3. Summary of significant accounting policies (continued)

e) Fair value measurements

The level in the fair value hierarchy within which the financial asset or financial liability is categorized is determined on the basis of the lowest level input that is significant to the fair value measurement.

Financial assets and financial liabilities are classified in their entirety into only one of the three levels.

The fair value hierarchy has the following levels:

- Level 1 - quoted prices (unadjusted) in active markets for identical assets or liabilities;
- Level 2 - inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices); and
- Level 3 - inputs for the asset or liability that are not based on observable market data (unobservable inputs).

f) Property, plant and equipment

Recognition and measurement

Property, plant and equipment (PP&E) are recognized at cost or deemed cost, being the purchase price and directly attributable cost of acquisition or construction required to bring the asset to the location and condition necessary to be capable of operating in the manner intended by the Company, including eligible borrowing costs.

Depreciation of PP&E is recorded in the Statements of Comprehensive Income on a straight-line basis over the estimated useful life of the related asset. The estimated useful lives, residual values and depreciation methods are reviewed at the end of each annual reporting period, with the effect of any changes in estimate being accounted for on a prospective basis.

The estimated useful lives are as follows:

Buildings and fixtures	50 years
Substations	30 years
Distribution lines	15 - 60 years
Distribution transformers	40 - 50 years
Meters	15 - 25 years
Office equipment	10 years
Computer equipment	5 years
Transportation equipment	10 years
Small tools and miscellaneous equipment	10 years
System supervisory	15 years

Land is not depreciated.

3. Summary of significant accounting policies (continued)

Major spare parts

Major spare parts such as spare transformers and other items kept as standby/back up equipment are accounted for as PP&E since they support the Company's distribution system reliability.

Contributions in aid of construction

When an asset is received as a capital contribution, the asset is initially recognized at its fair value, with the corresponding amount recognized as contributions in aid of construction.

Gains and losses on disposal

Gains and losses on disposal of an item of property, plant and equipment are determined by comparing the net proceeds from disposal with the carrying amount of the asset, and are included in the Statement of Comprehensive Income when the asset is disposed of. When an item of property, plant and equipment with related contributions in aid of construction is disposed, the remaining amount is recognized in full in the Statement of Comprehensive Income.

g) Borrowing costs

The Company capitalizes interest expenses and other finance charges directly relating to the acquisition, construction or production of assets that take a substantial period of time to get ready to get ready for its intended use. Capitalization commences when expenditures are being incurred, borrowing costs are being incurred and activities that are necessary to prepare the asset for its intended use or sale are in progress. Capitalization will be suspended during periods in which active development is interrupted. Capitalization should cease when substantially all of the activities necessary to prepare the asset for its intended use or sale are complete.

h) Intangible assets

Computer software

Computer software that is acquired or developed by the Company, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization and accumulated impairment losses.

Land rights

Land rights include payments made for easements, right of access and right of use over land for which the Company does not hold title and are measured at cost less accumulated amortization and accumulated impairment losses.

3. Summary of significant accounting policies (continued)

Amortization

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, other than goodwill, from the date that they are available for use. Amortization methods and useful lives of all intangible assets are reviewed at each reporting date. The estimated useful lives for the current and comparative years are:

Land rights	50 years
Computer software	3 years

i) Impairment of non-financial assets

Non-financial assets are tested for impairment when facts and circumstances indicate that the carrying amount of non-financial assets may not be recoverable. Where the carrying value exceeds its recoverable amount, which is the higher of value in use and fair value less costs of disposal, the asset is written down accordingly. Where it is not possible to estimate the recoverable amount of an individual asset, the impairment test is carried out on the asset's cash-generating unit ('CGU'), which is the lowest group of assets to which the asset belongs for which there are separately identifiable cash inflows that are largely independent of the cash inflows from other assets. The Company has one cash-generating unit for which impairment testing is performed. An impairment loss is charged to the Statement of Comprehensive Income, except to the extent it reverses gains previously recognized in other comprehensive income.

j) Employee future benefits

Defined contribution plan

The employees of the Company participate in the Ontario Municipal Employees Retirement System ("OMERS"). The Company also makes contributions to the OMERS plan on behalf of its employees. The plan has a defined benefit option at retirement available to some employees, which specifies the amount of the retirement benefit plan to be received by the employees based on length of service and rates of pay. The Company is only one of a number of employers that participates in the plan and the financial information provided to the Company on the basis of the contractual agreements is usually insufficient to measure the Company's proportionate share in the plan assets and liabilities on defined benefit accounting requirements. Therefore, the plan is accounted for as a defined contribution plan as insufficient information is available to account for the plan as a defined benefit plan. The contribution payable in exchange for services rendered during a period is recognized as an expense during that period.

Defined benefit plans

A defined benefit plan is a post-employment benefit plan other than a defined contribution plan. The Company's net obligation on behalf of its retired employees unfunded extended medical and dental benefits is calculated by estimating the amount of future benefits that are expected to be paid out discounted to determine its present value. Any unrecognized past service costs are deducted.

3. Summary of significant accounting policies (continued)

The calculation is performed by a qualified actuary using the projected unit credit method every three years or when there are significant changes to workforce. When the calculation results in a benefit to the Company, the recognized asset is limited to the total of any unrecognized past service costs and the present value of economic benefits available in the form of any future refunds from the plan or reductions in future contributions to the plan. An economic benefit is available to the Company if it is realizable during the life of the plan, or on settlement of the plan liabilities.

Defined benefit obligations are measured using the projected unit credit method discounted to its present value using yields available on high quality corporate bonds that have maturity dates approximating to the terms of the liabilities.

Remeasurements of the defined benefit obligation are recognized directly within equity in other comprehensive income. The remeasurements include actuarial gains and losses.

Service costs are recognized in the Statement of Comprehensive Income in operating expenses, and include current and past service costs as well as gains and losses on curtailments.

Net interest expense is recognized the Statement of Comprehensive Income in finance expense, and is calculated by applying the discount rate used to measure the defined benefit obligation at the beginning of the annual period to the balance of the net defined benefit obligation, considering the effects of benefit payments during the period. Gains or losses arising from changes to defined benefits or plan curtailment are recognized immediately in the Statement of Comprehensive Income. Settlements of defined benefit plans are recognized in the period in which the settlement occurs.

k) Payment in lieu of taxes payable

Tax status

The Company is a Municipal Electricity Utility ("MEU") for purposes of the payments in lieu of taxes ("PILs") regime contained in the Electricity Act, 1998. As an MEU, the Company is exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario).

Under the Electricity Act, 1998, the Company is required to make, for each taxation year, payments in lieu of taxes to the Ontario Electricity Financial Corporation ("OEFC"), commencing October 1, 2001. These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

3. Summary of significant accounting policies (continued)

Current and deferred tax

Provision for payments in lieu of taxes comprises of current and deferred tax. Current tax and deferred tax are recognized in net income except to the extent that it relates to items recognized directly in equity or regulatory deferral account balances (See Note 10). Current income taxes are recognized for the estimated income taxes payable or receivable on taxable income or loss for the current year and any adjustment to income taxes payable in respect of previous years. Current income taxes are determined using tax rates and tax laws that have been enacted or substantively enacted by the year-end date.

Deferred tax assets and liabilities are recognized where the carrying amount of an asset or liability differs from its tax base. The amount of the deferred tax asset or liability is measured at the amount expected to be recovered from or paid to the taxation authorities. This amount is determined using tax rates and tax laws that have been enacted or substantively enacted by the year-end date and are expected to apply when the liabilities/(assets) are settled/(recovered). The Company recognized deferred tax arising from temporary difference on regulatory deferral account balances.

Recognition of deferred tax assets for unused tax losses, tax credits and deductible temporary differences is restricted to those instances where it is probable that future taxable profit will be available against which the deferred tax asset can be utilized.

At the end of each reporting period, the Company reassesses both recognized and unrecognized deferred tax assets. The Company recognizes a previously unrecognized deferred tax asset to the extent that it has become probable that future taxable profit will allow the deferred tax asset to be recovered.

l) Inventories

Cost of inventories comprise of direct materials, which typically consists of distribution assets not deemed as major spares, unless purchased for specific capital projects in process or as spare units. Costs, after deducting rebates and discounts, are assigned to individual items of inventory on the basis of weighted average cost. Decommissioned assets that are transferred to inventory are tested for impairment once they are removed from service and placed in inventory. Inventory is recognized at the lower of cost and net realizable value.

Net realizable value is the estimated selling price in the ordinary course of business less the estimated costs of completion and the estimated costs necessary to make the sale.

3. Summary of significant accounting policies (continued)

m) Standards, amendments and interpretations not yet effective

At the date of authorization of these financial statements, certain new standards, amendments and interpretations to existing standards have been published by the IASB but are not yet effective, and have not been adopted early by the Company.

Management anticipates that all of the relevant pronouncements will be adopted in the Company's accounting policies for the first period beginning after the effective date of the pronouncement. Information on new standards, amendments and interpretations that are expected to be relevant to the Company's financial statements is provided below. Certain other new standards and interpretations have been issued but are not expected to have a material impact on the Company's financial statements.

IFRS 9 Financial Instruments replaces IAS 39 Financial Instruments: Recognition and Measurement

IFRS 9 amends the requirements for classification and measurement of financial assets, impairment, and hedge accounting. IFRS 9 retains but simplifies the mixed measurement model and establishes three primary measurement categories for financial assets: amortized cost, fair value through profit or loss, and fair value through other comprehensive income. The basis of classification depends on the entity's business model and the contractual cash flow characteristics of the financial asset. The effective date for IFRS 9 is January 1, 2018. The Company is in the process of evaluating the impact of the new standard.

IFRS 15, Revenue from Contracts with Customers

IFRS 15 is based on the core principle to recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. IFRS 15 focuses on the transfer of control. IFRS 15 replaces all of the revenue guidance that previously existed in IFRSs. The effective date for IFRS 15 is January 1, 2018. The Company is in the process of evaluating the impact of the new standard.

IFRS 16, Leases

In January 2016, the IASB issued IFRS 16 Leases, which replaces IAS 17 Leases. IFRS 16 provides a single lessee accounting model, requiring the recognition of assets and liabilities for all leases, unless the lease term is twelve months or less or the underlying asset has a low value. Lessor accounting remains largely unchanged from IAS 17 and the distinction between operating and finance leases is retained. In addition, lessees will recognize a front-loaded pattern of expense for most leases, even when they pay constant annual rentals. The standard is effective for annual periods beginning on or after January 1, 2019, and will be applied retrospectively with some exceptions. Early adoption is permitted if IFRS 15 has been adopted. The Company is in the process of evaluating the impact of the new standard.

4. Use of estimates and judgements

The Company makes certain estimates and assumptions regarding the future. Estimates and judgments are continually evaluated based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. In the future, actual experience may differ from these estimates and assumptions. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

Property, plant and equipment
The Company relies on a third party independent study to componentize and determine the estimated useful lives of its distribution system assets. The useful life values from the study were derived from industrial statistics, research studies, reports and past utility experience. Actual lives of assets may vary from estimated useful lives.

Employee future benefits
The costs of post-employment medical and insurance benefits are determined using actuarial valuations. An actuarial valuation involves making various assumptions. Due to the complexity of the valuation, the underlying assumptions and its long term nature, post-employment medical and insurance benefits are highly sensitive to changes in these assumptions. All assumptions are reviewed at each reporting date.

Payments in lieu of taxes
The Company is required to make payments in lieu of taxes calculated on the same basis as income taxes on taxable income earned and capital taxes. Significant judgment is required in determining the provision for income taxes. There are many transactions and calculations undertaken during the ordinary course of business for which the ultimate tax determination is uncertain. The Company recognizes liabilities for anticipated tax audit issues based on the Company's current understanding of the tax law. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the current and deferred tax provisions in the period in which such determination is made.

Receivables impairment
In determining the allowance for doubtful accounts, the Company considers historical loss experience of account balances based on the aging and arrears status of receivable balances.

5. Receivables

	December 31 2015	December 31 2014	January 1 2014
Accounts receivables	**$ 5,309**	$ 4,678	$ 3,949
Related party receivables	**191**	22	17
	$ 5,500	$ 4,700	$ 3,966

The amounts due from related parties are unsecured and have no specific interest or repayment terms.

6. Inventory

The amount of spare parts inventory consumed by the Company and recognized as an expense during 2015 was $15 (2014 - $13).

7. Property, plant and equipment

Property, plant and equipment consist of the following:

	Land and Buildings	Distribution equipment	Other fixed assets	Construction in progress	Total
Cost					
Balance at January 1, 2014	$ 2,641	$ 33,457	$ 1,913	$ 3,716	$ 41,727
Additions	-	6,005	244	8,665	14,914
Disposals	-	(309)	-	-	(309)
Balance at December 31, 2014	2,641	39,153	2,157	12,381	56,332
Balance at January 1, 2015	2,641	39,153	2,157	12,381	56,332
Additions	12,430	6,103	1,065	-	19,598
Disposals	(575)	(69)	(22)	(11,584)	(12,250)
Balance at December 31, 2015	$ 14,496	$ 45,187	$ 3,200	$ 797	$ 63,680
Depreciation and impairment losses					
Balance at January 1, 2014	$ -	$ -	$ -	$ -	$ -
Depreciation for the year	11	1,277	389	-	1,677
Impairment loss	-	-	-	-	-
Disposals	-	-	-	-	-
Balance at December 31, 2014	11	1,277	389	-	1,677
Balance at January 1, 2015	11	1,277	389	-	1,677
Depreciation for the year	145	1,427	410	-	1,982
Impairment loss	-	-	-	-	-
Disposals	(16)	(14)	(18)	-	(48)
Balance at December 31, 2015	$ 140	$ 2,690	$ 781	$ -	$ 3,611
Carrying amounts					
At January 1, 2014	**$ 2,641**	**$ 33,457**	**$ 1,913**	**$ 3,716**	$ 41,727
At December 31, 2014	**$ 2,630**	**$ 37,876**	**$ 1,768**	**$ 12,381**	$ 54,655
At December 31, 2015	**$ 14,356**	**$ 42,497**	**$ 2,419**	**$ 797**	$ 60,069

During the year ended December 31, 2015, the Company capitalized borrowing costs related to the construction of the new operations building amounting to $136 (2014 - $173).

8. Intangible assets

Intangible assets consist of the following:

	Computer software	Land rights	Total
Cost			
Balance at January 1, 2014	$ 203	$ 394	$ 597
Additions	199	-	199
Disposals	(1)	-	(1)
Balance at December 31, 2014	401	394	795
Balance at January 1, 2015	401	394	795
Additions	185	-	185
Disposals	(16)	-	(16)
Balance at December 31, 2015	$ 570	$ 394	$ 964
Depreciation and impairment losses			
Balance at January 1, 2014	$ -	$ -	$ -
Depreciation for the year	134	15	149
Impairment loss	-	-	-
Disposals	-	-	-
Balance at December 31, 2014	$ 134	$ 15	$ 149
Balance at January 1, 2015	$ 134	$ 15	$ 149
Depreciation for the year	169	13	182
Impairment loss	-	-	-
Disposals	(16)	-	(16)
Balance at December 31, 2015	$ 287	$ 28	$ 315
Carrying amounts			
At January 1, 2014	**$ 203**	**$ 394**	**$ 597**
At December 31, 2014	**$ 267**	**$ 379**	**$ 646**
At December 31, 2015	**$ 283**	**$ 366**	**$ 649**

9. Investment

The investment in preferred shares is of a private company that mainly provides settlement services to the electric utilitiles of Ontario.

	December 31 2015	December 31 2014	January 1 2014
16,894 preferred shares	$ 22	$ 22	$ 22

10. Payments in lieu of taxes

The significant components of the provision for payments in lieu of taxes are as follows:

	2015	2014
Current tax		
Based on current year taxable income	$ (2)	$ -
Tax refund based on application of losses carried back	-	(266)
Total current tax	$ (2)	$ (266)
Deferred tax		
Origination and reversal of temporary differences	$ 348	$ 448
Losses available for carry forward	-	-
Total deferred tax	$ 348	$ 448
Total provision for payments of lieu of taxes	$ 346	$ 182

The payments in lieu of taxes varies from amounts which would be computed by applying the Company's combined statutory federal and provincial income tax rate. Reconciliation of the payments in lieu of taxes at the statutory income tax rate to the provision for payment in lieu of taxes is as follows:

Rate reconciliation before net movements in regulatory balances and OCI

	2015	2014
Profit for the year before net movements in regulatory deferral account balances and OCI	$ 1,478	$ 27
Statutory tax rate	26.5%	26.5%
Expected payments in lieu of taxes	392	7
Increase (decrease) resulting from:		
Timing differences between accounting and tax net income	-	185
Items not deductible for tax purposes	3	2
Rate variances	44	-
Other	(93)	(12)
Provision for payments in lieu of taxes	$ 346	182

10. Payments in lieu of taxes (continued)

Rate reconciliation after net movements in regulatory balances

	2015	2014
Profit for the year and net movements in regulatory deferral account balances	**$ 1,568**	$ 888
Statutory tax rate	**26.5%**	26.5%
Expected payments in lieu of taxes	**415**	235
Increase (decrease) resulting from:		
Timing differences between accounting and tax net income	**-**	(16)
Items not deductible for tax purposes	**3**	2
Rate variances	**44**	-
Other	**(112)**	(12)
Provision for payments in lieu of taxes	**$ 350**	$ 209

	2015	2014
Provision for payments in lieu of taxes before net movements in regulatory deferral account balances and OCI	**$ 246**	$ 182
Provision for payments in lieu of taxes recorded in net movement in regulatory balances	**4**	27
Provision for payment in lieu of taxes after net movement in regulatory balances	**350**	209
Provision for recovery in lieu of taxes recorded in OCI	**-**	(3)
Provision for payments in lieu of taxes	**$ 350**	$ 206

The movement in the 2015 deferred tax assets are:

	Balance January 1 2015	**Recognized in net Income**	**Recognized in OCI**	**Balance December 31 2015**
Deferred tax assets				
Property, plant and equipment	**$ 798**	**$ (352)**	**$ -**	**$ 486**
Employee future benefits	**39**	**4**	**-**	**43**
Loss carried forward	**-**	**-**	**-**	**-**
Deferred tax assets	**$ 837**	**$ (348)**	**$ -**	**$ 489**

	Balance January 1 2014	Recognized in net income	Recognized in OCI	Balance December 31 2014
Deferred tax assets				
Property, plant and equipment	$ 1,085	$ (287)	$ -	$ 798
Employee future benefits	31	5	3	39
Loss carried forward	166	(166)	-	-
Deferred tax assets	$ 1,282	$ (448)	$ 3	$ 837

10. Payments in lieu of taxes (continued)

At December 31, 2015, a deferred tax asset of $489 (December 31, 2014 - $837; January 1, 2014 - $1,282) has been recorded. The utilization of this tax asset is dependent on future taxable profits in excess of profits arising from the reversal of existing taxable temporary differences. The Company believes that this asset should be recognized as it will be recovered through future rates.

11. Regulatory deferral account balances

All amounts deferred as regulatory deferral account debit balances are subject to approval by the OEB. As such, amounts subject to deferral could be altered by the regulators and the actual recovery or settlement periods could differ based on OEB approval. Due to previous, existing or expected future regulatory articles or decisions, the Company has the following amounts expected to be recovered by customers (returned to customers) in future periods and as such regulatory deferral account balances are comprised of:

	Note	Remaining recovery reversal period	Balance Dec. 31 2014	Balances arising in period	Recovery/ reversal	**Balance Dec. 31 2015**
Regulatory Deferral Account Debit						
Deferred tax	*v)*	-	$ 62	$ (4)	$ -	**$ 58**
Settlement variances	*i)*	various	1,977	(92)	(1,093)	**792**
IFRS transition costs	*ii)*	-	12	-	-	**12**
Other costs	*iii)*	1	29	4	-	**33**
Stranded meters	*iv)*	-	33	-	(33)	**-**
			$ 2,113	$ (92)	$ (1,126)	**$ 895**

	Note	Remaining recovery reversal period	Balance Jan. 1 2014	Balances arising in period	Recovery/ reversal	Balance Dec. 31 2014
Regulatory Deferral Account Debit						
Deferred tax	*v)*	-	$ 90	$ (28)	$ -	$ 62
Settlement variances	*i)*	various	920	530	527	1,977
IFRS transition costs	*ii)*	1	157	-	(145)	12
Other costs	*iii)*	1	211	(172)	(10)	29
Stranded meters	*iv)*	1	216	2	(185)	33
			$ 1,594	$ 332	$ 187	$ 2,113

11. Regulatory deferral account balances (continued)

	Note	Remaining recovery reversal period	Balance Dec. 31 2014	Balances arising in period	Recovery/ reversal	**Balance Dec. 31 2015**
Regulatory Deferral Account Credit						
Changes in useful lives	*vi)*	2	$ 385	$ -	$ (165)	**$ 220**
Stranded meters	*vii)*	-	-	-	46	**46**
			$ 385	$ -	$ (119)	**$ 266**

	Note	Remaining recovery reversal period	Balance Jan. 1 2014	Balances arising in period	Recovery/ reversal	Balance Dec. 31 2014
Regulatory Deferral Account Credit						
Changes in useful lives	*vi)*	3	$ 550	$ -	$ (165)	$ 385
			$ 550	$ -	$ (165)	$ 385

	Jan. 1 2014	Dec. 31 2014	**Dec. 31 2015**
Net Regulatory Assets	$ 1,045	$ 1,728	**$ 629**

i. *Settlement variances*

This account is comprised of the variances between amounts charged by the Company to customers, based on regulated rates, and the corresponding cost of non-competitive electricity service incurred by the Company. The settlement variances relate primarily to service charges, non-competitive electricity charges, imported power charges and the global adjustment.

The Company has recognized a settlement variance asset of $792 (December 31, 2014 – $1,977; January 1, 2014 – $920) arising from the recognition of regulatory deferral account balances. The settlement variance asset balance is presented within the total regulatory deferral account debit balances presented in the statement of financial position.

11. Regulatory deferral account balances (continued)

ii. IFRS transition costs

During 2009, the OEB consultation process was set up to determine the effect of IFRS on local distribution companies. The consultation concluded that prudently incurred administrative costs directly related to IFRS transition would be recoverable from ratepayers on the same basis as other administrative costs. The OEB has approved the collection from customers to cover the expected one-time costs of implementing IFRS. Collections of $413 over a 2 year period (May 1, 2013 to April 30, 2015) are off-set by OEB approved expenses in this variance account.

The Company has recognized an IFRS transition cost asset of $12 (December 31, 2014 – $12; January 1, 2014 – $157) arising from the recognition of regulatory deferral account balances. The IFRS transition cost asset balance is presented within the total regulatory deferral account debit balances presented in the statement of financial position.

iii. Other costs

The Company has recognized a cost asset of $33 (December 31, 2014 – $29; January 1, 2014 – $211) mainly for lost revenue as a result of CDM programs and a corporate tax true up from 2001 to 2006. The other cost asset balance is presented within the total regulatory deferral account debit balances presented in the statement of financial position.

iv. Stranded meters

In April 2013 the Company obtained approval from the OEB to recover the remaining cost of the stranded meters related to the deployment of smart meters which were formerly included in capital assets over a 2 year period effective May 2013. The stranded meters were transferred from capital assets to regulatory assets in fiscal 2010. In the absence of rate regulation, these stranded meters would have previously been expensed.

v. Deferred tax

The recovery from, or refund to, customers of future income taxes through future rates is recognized as a regulatory deferral account balance. The Company has recognized a deferred tax asset of $58 (December 31, 2014 – $62; January 1, 2014 – $90) arising from the recognition of regulatory deferral account balances. The deferred tax asset balance is presented within the total regulatory deferral account balances presented in the statements of financial position.

vi. Change in asset useful lives

In 2012, the Company changed their useful lives for some of the property, plant and equipment assets. These differences are recorded in regulatory accounts with the other side being recorded in other (expenses) revenue. Disposition of the regulatory liability over a period of 4 years was approved by the OEB commencing May 1, 2013. The change in asset useful lives liability balance is presented within the total regulatory deferral account credit balances presented in the statement of financial position.

12. Accounts payable and accrued liabilities

Major components of accounts payable and accrued liabilities consist of the following:

	December 31 2015	December 31 2014	January 1 2014
Purchased power	$ **2,412**	$ 3,115	$ 2,589
Accounts payable and accruals	**3,321**	3,320	2,906
Due to related parties	**1,858**	2,781	1,738
Customer credit balances	**176**	193	192
	$ **7,767**	$ 9,409	$ 7,425

The amounts due to related parties are unsecured and have no specific interest or repayment terms.

13. Contributions in aid of construction

Contributions in aid of construction consists of capital contributions received from electricity customers to construct or acquire property, plant and equipment which has not yet been recognized as revenue, and also includes revenue not yet recognized from demand billable activities.

	December 31 2015	December 31 2014
Deferred contributions, net, beginning of year	$ **8,900**	$ 7,756
Contributions in aid of construction received	**2,190**	1,413
Contributions in aid of construction recognized as other revenue	**(314)**	(269)
Deferred contributions, net, end of year	$ **10,776**	$ 8,900
Current portion	$ **357**	$ 289
Non-current portion	$ **10,419**	$ 8,611

14. Customer deposits

Customer deposits represent cash deposits from electricity distribution customers and retailers, as well as construction deposits.

Deposits from electricity distribution customers are refundable to customers demonstrating an acceptable level of credit risk as determined by the Company in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

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 contributions in aid of construction.

	December 31 2015	December 31 2014	January 1 2014
Customer deposits	**$ 264**	$ 194	$ 209
Construction deposits	**1,190**	1,338	960
Total customer deposits	**$ 1,454**	$ 1,532	$ 1,169
Current portion	**$ 1,210**	$ 1,369	$ 991
Non-current portion	**$ 244**	$ 163	$ 178

15. Employee future benefits

a) Defined contribution plan

The employees of the Company participate in the Ontario Municipal Employees Retirement System ("OMERS"). Although the plan has a defined retirement benefit plan for employees, the related obligation of the corporation cannot be identified. The OMERS plan has several unrelated participating municipalities and costs are not specifically attributed to each participant. The employer portion of amounts paid to OMERS during the year was $340 (2014 - $328). The contributions were made for current service and these have been recognized in net income.

b) Defined benefit plan

The Company provides certain unfunded health, dental and life insurance benefits on behalf of its retired employees from age 55-65 with 15 years of services. These benefits are provided through a group defined benefit plan. The Company has reported its share of the defined benefit costs and related liabilities, as calculated by an actuary, in these financial statements. The accrued benefit liability and the expense for the years ended December 31, 2015 and 2014 were based on results and assumptions determined by actuarial valuation as at January 15, 2015.

The plan is exposed to a number of risks, including:

Interest rate risk: decreases/increases in the discount rate used (high quality corporate bonds) will increase/decrease the defined benefit obligation.

Longevity risk: changes in the estimation of mortality rates of current and former employees.

15. Employee future benefits (continued)

Information about the group unfunded defined benefit plan as a whole and changes in the present value of the unfunded defined benefit obligation and the accrued benefit liability are as follows:

	Defined benefit liability 2015	2014
Balance, January 1	$ **148**	$ 116
Current service cost	**16**	16
Interest cost	**5**	6
Included in profit or loss	**21**	22
Remeasurement loss (gain)		
Actuarial (gain) losses from financial assumptions	**-**	10
Included in other comprehensive income	**-**	10
Benefits paid during the year	**(6)**	-
Balance, December 31	$ **163**	$ 148

The main actuarial assumptions underlying the valuation are as follows:

Assumption	2015	2014	Reasonable Possible Change	Defined Benefit Obligation Increase	Defined Benefit Obligation Decrease
Discount rate	**4.1%**	4.1%	1%	10%	9%
Retirement age – males	**60**	60	-	-	-
Retirement age – females	**60**	60	-	-	-

16. Bank indebtedness

The Company has bank indebtedness of $2,784 (December 31, 2014 – $77; January 1, 2014 – $2,226), out of $4,000 credit limit. The facility is secured by a general security agreement conveying first fixed and floating charges over the property, assets, rights and interests of the Company and bears interest at the prime rate.

17. Short term debt

The Company has short term indebtedness with Toronto Dominion Bank of $1,602 (December 31, 2014 – $10,895; January 1, 2014 – $3,087). The facility is secured by a general security agreement conveying first fixed and floating charges over the property, assets, rights and interests of the Company. The facility also bears interest at the prime rate, with no fixed term of repayment.

18. Long term debt

		December 31 2015		December 31 2014		January 1 2014
Debentures, 9.50% due March 2015	$	-	$	1,045	$	2,005
Term loan, 4.53% due October 2020		**1,730**		1,810		1,887
Term loan, 4.05% due February 2022		**3,585**		3,698		3,805
Term loan, 3.81% due September 2022		**3,668**		3,775		3,877
Term loan, 4.59% due November 2023		**2,862**		2,929		2,996
Term loan, 3.96% due July 2024		**1,950**		1,987		-
Term loan, 3.914 due November 2024		**1,961**		1,997		-
Term loan, 3.68% due January 2025		**1,966**		2,000		-
Term loan, 2.814% due June 2020		**12,194**		-		-
Infrastructure Ontario loan		**1,833**		2,000		2,166
		31,749		21,241		16,736
Less: current portion		**2,596**		1,685		1,477
	$	**29,153**	$	19,556	$	15,259

All term loans above are secured by a general security agreement conveying first fixed and floating charges over the property, assets, rights and interests of the Company.

The Infrastructure Ontario Debenture was converted from a construction loan to pay for the Smart Meter Initiative. The long term debt bears interest at 3.91% with semi-annual principal repayments of $83 in February and August until 2026. The Company incurred $75 (2014 – $81) in interest expense to Infrastructure Ontario in 2015. The Company is in breach of a financial covenant which allows Infrastructure Ontario the ability to demand repayment of the debenture in full. The breach was not remedied by the time the financial statements were authorized for issue.

Principal payments due in each of the next five years are as follows:

2016	$2,596
2017	794
2018	823
2019	853
2020	885

19. Share capital

a) Ordinary shares

An unlimited number of common shares are authorized for issue. An unlimited number of preference shares are authorized for issue.

As of December 31, 2015, the Company has issued and fully paid 1,000 (December 31, 2014 – 1,000; January 1, 2014 – 1,000) common shares. The shares have no par value.

All shares are ranked equally with regards to the Company's residual assets.

19. Share capital (continued)

b) Movement in ordinary share capital

No movement in ordinary share capital has occurred during 2015 and 2014.

20. Related party transactions

The ultimate parent

The common shares of InnPower Corporation are owned by the Town of Innisfil, the ultimate parent, which constitutes a local government. Consequently, the Company is exempt from some of the general disclosure requirements of IAS 24 with relation to transactions with government-related parties, and has applied the government-related disclosure requirements.

Transactions with related parties

The Company provides electricity and services to the Town of Innisfil. The following are the related transactions:

		2015		2014
Debenture interest	$	25	$	125
Electrical services billed		3,026		2,392
Water/wastewater billing services billed		221		192
Dividends paid		-		469
Municipal taxes		185		69
Other expenses		75		76

The Company provides billing services to its affiliate Innisfil Energy Services Limited. None of these transactions would constitute an individually significant transaction.

Key management personnel compensation comprised:

The key management personnel of the Company have been defined as members of its board of directors and executive management team members.

		2015		2014
Executive management compensation	$	817	$	649
Director fees		197		43
	$	1,014	$	692

21. Expenses by nature

		2015		2014
Repairs and maintenance	$	900	$	823
Staff costs		3,178		3,056
General administration and overhead		1,445		1,294
Bad debts		59		120
	$	5,580	$	5,293

22. Staff costs

		2015		2014
Wages, salaries and short-term employee benefits	$	4,397	$	4,162
Less capitalized wages, salaries and short-term employee benefits		(681)		(589)
Less recoverable wages, salaries and short-term employee benefits		(540)		(517)
	$	3,178	$	3,056

23. Financial instruments and risk management

Fair value disclosure

The carrying values of cash and cash equivalents, receivables, unbilled service revenue, bank indebtedness, accounts payable and accrued liabilities and customer deposits approximate their respective fair values because of the short maturity of these instruments.

The fair value of the investment (Level 2) is calculated based on the present value of the expected future cash flows from the investment in preferred shares, discounted using a credit adjusted risk free rate of interest.

The fair value of the debentures (Level 2) is $Nil (2014 - $1,054). The fair value is calculated based on the present value of future principal and interest cash flows, discounted at the current rate of interest at the reporting date.

The fair value of the term loans (Level 2) is $29,866 (2014 - $18,915). The fair value is calculated based on the present value of future principal and interest cash flows, discounted at the current rate of interest at the reporting date.

The fair value of the Infrastructure Ontario Loan (Level 2) is $1,833 (2014 - $2,021). The fair value is calculated based on the present value of future principal and interest cash flows, discounted at the current rate of interest at the reporting date.

Risk Management

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

23. Financial instruments and risk management (continued)

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 Company, such as cash and receivables, expose it to credit risk. The Company earns its revenue from a broad base of customers located in Innisfil and South Barrie. No single customer accounts for revenue in excess of 10% of total revenue.

The carrying amount of receivables is reduced through the use of an allowance for impairment 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 impairment at December 31, 2015 is $76 (December 31, 2014 - $193, January 1, 2014 - $184). An impairment loss of $59 was recognized during the year. The Company's credit risk associated with receivables $176 primarily related to payments from distribution customers. At December 31, 2015, approximately $127 (December 31, 2014 - $195, January 1, 2014 - $216) is considered 60 days past due. The Company has approximately 15,000 customers, the majority of which are residential. Credit risk is managed through the Company maintaining bank accounts at a reputable bank and the collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2015, the Company holds security deposits in the amount of $264 (December 31, 2014 - $193, January 1, 2014 - $208).

ii) Market risk:

The Company is not exposed to significant market risk.

iii) Interest rate risk:

The Company's policy is to minimize interest rate cash flow risk exposures on long-term financing. Longer-term borrowings are therefore usually at fixed rates. At December 31, 2015, the Company is not exposed to any material changes in market interest rates on its longer-term borrowing.

vi) Liquidity risk:

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they come due. The Company monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Company's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Company has access to a $4,000 line of credit and monitors cash balances to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

23. Financial instruments and risk management (continued)

The following table sets out the contractual maturities (representing undiscounted contractual cash-flows) of financial liabilities:

	Due within 1 year	Due between 1-2 years	Due past 2 years
At December 31, 2015			
Bank indebtedness	1,472	-	-
Accounts payables and accrued liabilities	7,767	-	-
Customer deposits	1,210	244	-
Short term debt	1,602	-	-
Long term debt	2,596	794	28,359
At December 31, 2014			
Bank indebtedness	-	-	-
Accounts payables and accrued liabilities	9,409	-	-
Customer deposits	1,369	163	-
Short term debt	10,895		
Long term debt	1,685	661	18,895

24. Contingency

The Company has a bank letter of credit outstanding for $938 (December 31, 2014 – $938; January 1, 2014 – $938). The letter of credit bears interest at the prime rate of a Canadian chartered bank less .25% per annum). Purchasers of electricity in Ontario, through the Independent Electricity Systems Operator (IESO) are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if the Company fails to make a payment required by default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2015, the Company provided prudential support using bank letters of credit of $938 (December 31, 2014 – $938; January 1, 2014 – $938). The letter of credit bears interest at a rate of 0.75% per annum.

25. Capital management

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

The Company's definition of capital is shareholder's equity. As at December 31, 2015, shareholder's equity amounts to $17,067 (December 31, 2014 - $16,586; January 1, 2014 - $16,352).

26. Subsequent event

Subsequent to December 31, 2015, the Company received additional advances of short term debt in the amount of $1,355 from TD Canada Trust. This amount, combined with the $1,602 included in short term debt at December 31, 2015 (Note 17), was converted into a $2,957 term loan in February 2016. The term loan bears interest at 3.48%, is due March 2026 and has principal repayments in each of the next five years as follows:

Principal payments due in each of the next five years are as follows:

2016	$48
2017	59
2018	61
2019	63
2020	65

27. First time adoption of international financial reporting standards and correction of error

IFRS 1, *First Time Adoption of International Financial Reporting Standards*, requires that comparative financial information be provided. As a result, the first date at which the Company has applied IFRS was January 1, 2014 (the "Transition Date"). IFRS 1 requires first-time adopters to retrospectively apply all effective IFRS standards as of the reporting date, which for the Company will be December 31, 2015. However, it also provides for certain optional exemptions and certain mandatory exceptions for first-time IFRS adoption. Prior to transition to IFRS, the Company prepared its financial statement in accordance with Canadian generally accepted accounting principles ("pre-changeover Canadian GAAP").

The IFRS 1 applicable exemptions and exceptions applied in the conversion from pre-changeover Canadian GAAP to IFRS are as follows:

Mandatory exceptions:

Derecognition of financial assets and liabilities

The Company has applied the derecognition requirements in IAS 39 prospectively for transactions occurring on or after January 1, 2014. As a result any non-derivative financial assets or non-derivative financial liabilities derecognized in accordance with pre-changeover Canadian GAAP as a result of a transaction that occurred before January 1, 2014, have not been recognized in accordance with IFRS unless they qualify for recognition as a result of a later transaction or event.

Estimates

The estimates previously made by the Company under pre-changeover Canadian GAAP were not revised for the application of IFRS, except where necessary to reflect any difference in accounting policy or where there was objective evidence that those estimates were in error. As a result, the Company has not used hindsight to revise estimates.

27. First time adoption of international financial reporting standards and correction of error (continued)

Optional elections:

Deemed cost for operations subject to rate regulation

The Company has elected the deemed cost exemption applicable to entities subject to rate regulation as described under IFRS 1. The election permits the Company, at the date of transition to IFRS, to use the previous Canadian GAAP carrying amount of items of PP&E and intangible assets as deemed cost (thereby eliminating any accumulated depreciation balances existing at the date of transition); hence there will be no impact on retaining earnings for opening balances of PP&E and intangible assets at the date of transition. In accordance with the election, the Company has tested these items of property, plant and equipment and intangible assets at the date of transition to IFRS for impairment and no such losses were identified.

Transfers of assets from customers

The Company has elected to apply the IFRS 1 election to only apply IFRIC 18 prospectively from the date of transition to non-repayable supply contribution made by customers.

Regulatory deferral account balances

The Company has elected to early adopt IFRS 14, which permits an entity to continue to apply its previous Canadian GAAP accounting policies for the recognition, measurement and impairment of regulatory deferral account balances.

Reconciliations of pre-changeover Canadian GAAP equity and comprehensive income to IFRS

IFRS 1 requires an entity to reconcile cash flows, equity, and comprehensive income for prior periods as shown below.

In the statement of changes in cash flows, there is a reclassification from the movement in regulatory assets and regulatory liabilities to a movement in the regulatory deferral account balance. These are both shown as movements within investing activities and as such do not results in material adjustments to the net cash flow balance.

The explanations for the impact of the transition to IFRS on the specific accounts are described below. Reconciliation of retained earnings and comprehensive income as previously reported under Canadian GAAP to IFRS are provided below. Other than the employee future benefits and the related deferred taxes, all other items have no impact on Retained Earnings or Comprehensive Income as they are reclassifications within the relevant statements.

27. First time adoption of international financial reporting standards and correction of error (continued)

Retained Earnings		December 31 2014		January 1 2014
Retained earnings as previously reported under Canadian GAAP	$	4,348	$	4,429
Correction of error:				
Payments in lieu of taxes (Note v)		832		547
Revised retained earnings as reported under Canadian GAAP		5,180		4,976
Adjustments to retained earnings:				
Employee future benefits (Note ii)		(72)		(70)
Contributions in aid of construction (Note iii)		556		556
Deferred taxes (Note iv)		27		19
Retained earnings under IFRS	$	5,691	$	5,481

Comprehensive income		December 31 2014
Comprehensive income as reported under Canadian GAAP		-
Adjustments for transition:		
Employee future benefits (Note ii)		(10)
Deferred taxes (Note iv)		3
	$	(7)

i) Regulatory assets and liabilities

Regulatory assets and liabilities that were recognized under pre-changeover Canadian GAAP have been reclassified to the regulatory deferral account balance as either a debit balance or a credit balance. The amount recorded as a regulatory asset and liability respectively, under pre-changeover Canadian GAAP was $1,785 and $830 at January 1, 2014. This adjustment is a reclassification on the Statements of Financial Position and has no impact on the Statements of Equity or the Statements of Comprehensive Income.

ii) Employee future benefits

Under IFRS, the Company recognizes remeasurements in Other Comprehensive Income. These amounts are not reclassified in subsequent periods. Employee benefits expected to be settled wholly within 12 months after the end of the reporting period are short-term benefits, and are not discounted. Under previous pre-changeover Canadian GAAP, the Company amortized the excess of the net actuarial gains or losses over 10% of the accrued benefit into the Statement of Comprehensive Income on a straight line basis over the average remaining service period of active employees to full eligibility. At the date of transition, all previously unamortized actuarial gains or losses were recognized in retained earnings.

The adjustment for employee future benefits results in a decrease in operating and increase in finance expenses and an increase in Other Comprehensive Income on the Statement of Comprehensive Income.

27. First time adoption of international financial reporting standards and correction of error (continued)

iii) Contributions in aid of construction

In accordance with the Electricity Act, 1998, development charges collected prior to January 1, 2000 and expended on qualifying growth-related capital assets were to be transferred and reported as a separate line to equity. Under IFRS, such contributions represent transfers of assets and should be recognized as revenue on a straight line basis over the useful life of the constructed asset in the Statement of Comprehensive Income. As at January 1, 2014, it was determined that these contributions would have been fully recognized as income on a retroactive basis and, accordingly, a reclassification of $556 was made from development charges in equity to retained earnings.

Under IFRS, contributions in aid of construction are recorded as deferred revenue and are recognized as revenue on a straight-line basis over the useful life of the constructed or contributed asset in the Statement of Comprehensive Income. As a result, an adjustment was made to reallocate contributions in aid of construction and increase assets and increase liabilities on the Statement of Financial Position. On transition, $7,756 was reclassified as contributions in aid of construction from property, plant and equipment.

iv) Deferred taxes

The above changes have increased (decreased) the deferred tax asset as follows based on a tax rate of 26.5% (January 1, 2014 – 26.5%):

	December 31 2014	January 1 2014
Employee future benefits (Note ii)	$ (27)	$ (19)

v) Correction of error

In 2013 and 2014, the Company's provisions for payments in lieu of current and deferred taxes related to non-capital losses and regulatory account retail settlement variances was calculated incorrectly. As this error is not related to the Company's transition to IFRS, the comparative figures presented have been restated.

The correction of this error results in a decrease in the provision for current taxes of $61 and $130 and deferred taxes of $224 and $417 at December 31, 2014 and January 1, 2014, respectively, and corresponding increases in the current and deferred payments in lieu of tax asset accounts and retained earnings.

APPENDIX E: Conditions of Service

Conditions of Service

For

a member of
Cornerstone Hydro Electric Concepts Association

Prepared August 2014

CONDITIONS OF SERVICE

Table of Contents

SECTION 1 INTRODUCTION

1.1 Identification of Distributor and Territory

The Distributor is a corporation, incorporated under the laws of the Province of Ontario to distribute electricity.

The Distributor is licensed by the Ontario Energy Board "OEB" to supply electricity to Customers as described in the Distribution Licence issued to the Distributor by the OEB. Additionally there are requirements imposed on the Distributor by the various codes referred to in the Licence and by the Electricity Act, the Ontario Energy Board Act and other provincial legislation.

The Distributor is limited to operate distribution facilities within their Licensed Territory as defined in the Distribution Licence.

1.1.1 General

Nothing contained in this document or in any contract for the supply of electricity by the Distributor shall prejudice or affect any rights, privileges, or powers vested in the Distributor by law under any Act of the Legislature of Ontario or the Parliament of Canada, or any regulations thereunder.

All operations performed by the distributor and its agents shall be performed within the rules and regulations set out by the appropriate authorities including but not limited to: Electrical Safety Authority (ESA), Ministry of Labour, Ministry of Transportation, etc.

The Distributor will normally provide one electrical service to each customer location at a nominal service voltage.

Modifications to an existing service must comply with the requirements of the standards in effect at the time of the modifications.

The customer or their authorized representative must make application for new or upgraded electric services, temporary power services and generation connections.

The customer or their representative shall consult with the Distributor concerning the availability of supply, the voltage of supply, service location, metering and any other details. These requirements are separate from and in addition to those of the Electrical Safety Authority. The Distributor will confirm, in writing, the Characteristics of Electric Supply available at a specific site.

The customer is required to provide the Distributor sufficient lead-time in order to ensure:

(a) *the timely provision of supply to new and upgraded premises or*
(b) *the availability of adequate capacity for additional loads to be connected in existing premises or*
(c) *the availability of adequate capacity for generation to be connected to the specific location.*

If special equipment is required or equipment delivery problems occur then longer lead times may be necessary. The customer will be notified of any extended lead times.

Customers will be required to pay the cost of repair or replacement of the Distributors' plant that has been damaged through the customers' action or neglect.

The supply of electricity or a service connection is conditional upon the Distributor being permitted and able to provide such a supply, obtaining the necessary apparatus and material, and constructing works to provide the service. Should the Distributor not be permitted to supply or not be able to do so, it is under no responsibility to the customer whatsoever.

The customer shall not build, plant or maintain or cause to be built, planted or maintained any structure, tree, shrub or landscaping that would or could obstruct the running of distribution lines, endanger the equipment of the Distributor, interfere with the proper and safe operation of the Distributor's facilities or adversely affect compliance with any applicable legislation in the sole opinion of the Distributor.

Prior to commencing any service work, the customer must consult with the Distributor to ensure compliance with current requirements.

The customer is responsible for selecting a qualified/competent contractor. Careful selection of a contractor can significantly affect the cost of a project. The Distributor shall be consulted prior to the selection of a mutually acceptable contractor.

The customer maintains the responsibility to ensure that all work is done in accordance with the distributor's design and technical standards and specifications.

The Distributor, at the expense of the customer, reserves the right to inspect the work throughout the duration of the project, and the Contractor shall supply him such accommodations as he may require. The Inspector shall request that the Contractor stop work at any time he feels the Contractor is not proceeding in accordance with these "conditions of service". The customer shall confer with the Distributor before work recommences to mitigate undue cost and construction delays for the project.

Customers may be required to pay Capital Contributions for the addition of new and upgraded electrical services. In some instances an Economic Evaluation as defined in the Distribution System Code (DSC) may be required. Customers installing distributed generation may be required to pay for additions of new or upgraded Distributor electrical plant associated with the connection of the generation and the associated engineering studies.

1.2 Related Codes and Governing Laws

The Distributor is limited in its scope of operation by the:

1. *Electricity Act, 1998*
2. *Ontario Energy Board Act, 1998*
3. *Green Energy Act*
4. *Energy Consumer Protection Act, 2010*
5. *Distribution Licence - Licence Numbers*
6. *Affiliate Relationships Code*
7. *Distribution System Code*
8. *Retail Settlement Code*
9. *Standard Service Supply Code*
10. *Conservation and Demand Management Code*
11. *Transmission System Code*
12. *Ontario Regulation 22/04 - Electrical Safety Authority (ESA)*
13. *Measurement Canada*
14. *Electricity and Gas Inspection Act*
15. *Freedom of Information and Protection of Privacy Act, R.S.O. 1990*
16. *Personal Information Protection and Electronic Documents Act (S.C. 2000, c. 5)*

In the event of a conflict between this document and the Distribution Licence or regulatory Codes issued by the OEB, or the Electricity Act, the provisions of the Act, the Distribution Licence and associated regulatory Codes shall prevail.

When planning and designing for electricity service, Customers and their agents must refer to all applicable Provincial and Canadian electrical codes, and all other applicable federal, provincial, and municipal laws, regulations, codes and by-laws to also ensure compliance with their requirements. The work shall be conducted in accordance with the Ontario Occupational Health and Safety Act, the Regulations for Construction Projects and the Electrical Utility Safety Rules (IHSA formally EUS&A) (or the OHSC Safety) rulebook.

1.3 Interpretations

In these Conditions, unless the context otherwise requires:

- Headings and underlining are for convenience only and do not affect the interpretation of these Rules.
- Words referring to the singular include the plural and vice versa.
- Words referring to a gender include any gender.

1.4 Amendments and Changes

The provisions of these Conditions of Service and any amendments made from time to time form part of any Contract made between the Distributor and any connected Customer, Generator or their agents.

In the event of changes to this Conditions of Service a notice shall be provided to customers as required in the Distribution System Code and copies made available at the Distributor's office or on the Distributors' Website.

The Customer is responsible for contacting the Distributor to ensure that the Customer has, or to obtain the current version of the Conditions of Service. The Distributor may charge a reasonable fee to recover costs for providing the Customer with more than one copy of this document.

1.5 Contact Information

The Distributor and its agents can be contacted during normal working hours. Please refer to the Contact Listing in the Appendices for phone number of the Local Distribution Company servicing your area.

1.6 Customer Rights

In those instances where the Customer will own their secondary or primary service, the Customer has the right to hire a Contractor to supply and install the service.

The customer has the right to demand identification from any person purporting to be an authorized agent or employee of the distributor.

A customer, who believes that he has suffered damages to his property or equipment as a result of negligence on the part of the Distributor, may submit a written claim for damages to the Distributor. The Distributor will investigate the claim and respond in writing within 10 business days of the receipt of the claim.

1.7 Distributor Rights

In those instances where the Customer has the authority to hire a Contractor to construct plant which will become part of the Distributors' system, the Distributor shall have the right to require the Contractor to submit proof of previous experience and satisfactory performance, and, the Distributor shall have the right to investigate such proof and approve the Contractor prior to the Owner awarding a contract for the work to the Contractor.

The Distributor shall have access to Customer property in accordance with section 40 of the *Electricity Act, 1998*.

1.8 Disputes

If, following good faith negotiations between a customer or other market participant and the Distributor, a resolution cannot be reached, the dispute may be submitted to a dispute resolution process.

Any dispute which shall arise between the Distributor and a customer(s) and other market participants subject to the terms of these Conditions of Service concerning the rights, duties or obligations of the Distributor or others subject to these Conditions of Service, shall be subject to the following dispute resolution procedure:

Mediation

- Either party (the "Initiating Party") may invoke the dispute resolution procedure by sending a written notice to the other party (the "Respondent Party") describing the nature of the dispute and designating a representative of the Initiating Party with appropriate authority to be its representative in negotiations relating to the dispute. The responding Party shall, within five business days of the receipt of such notice, send a written notice to the Initiating Party, designating a representative of the Responding party with the appropriate authority to be its representative in negotiations relating to the dispute.

- Within ten business days of the receipt by the Initiating Party of the written notice of the Responding Party the designated representatives shall enter into good faith negotiations with a view to resolving the dispute. If the dispute is not resolved in thirty days of the commencement of such negotiations, or such longer period as may be agreed upon, either party may, by written notice to the other party, require that the parties be assisted in their negotiations by the Ontario Energy Board. In accordance with the OEB dispute resolution process, The Ontario Energy Board will complete its review of the dispute within 150 days.

1.9 Service Quality Requirements

The level of service provided by the Distributor is defined in specific terms within Section 7 of the DSC, or as the DSC may be amended from time to time. The Distributor recognizes the requirements and will strive to meet or exceed these requirements and the associated reporting to the OEB. The reporting of these requirements forms public record available to the Distributor's customers.

1.10 Liability

A distributor shall only be liable to a customer and a customer shall only be liable to a distributor for any damages which arise directly out of the willful misconduct or negligence:

1.0 Of the distributor in providing distribution services to the customer;
2.0 Of the customer in being connected to the distributor's distribution system; or
3.0 Of the distributor or customer in meeting their respective obligations under the Distribution System Code, their licences and any other applicable law.

Despite the above; neither the distributor nor the customer shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise.

1.11 Force Majeure

Neither party shall be held to have committed an event of default in respect of any obligation under the Distribution System Code if prevented from performing that obligation, in whole or in part, because of a force majeure event.

Notwithstanding any of the foregoing, settlement of any strike, lockout, or labor dispute constituting a force majeure event shall be within the sole discretion of the party to the agreement involved in the strike, lockout, or labour dispute. The requirement that a party must use its best efforts to remedy the cause of the force majeure event, mitigate its effects, and resume full performance under the Distribution System Code shall not apply to strikes, lockouts, or labour disputes.

SECTION 2 DISTRIBUTION ACTIVITIES (GENERAL)

2.1 Connections

This section includes information that is applicable to all customer classes of the distributor. Items that are applicable to only a specific customer class are covered in Section 3.

2.1.1 Obligations to Connect

As provided in Section 28 of the Electricity Act 1998 the Distributor has the Obligation to Connect any Building that 'lies along" its distribution system subject to conditions outlined in section 2.1.3. A building 'lies along" a distribution line if it can be connected to the distributor distribution system without an expansion or enhancement.

A Building that appears to 'lie along' a distribution line may be refused connection to that line should the distribution line not have sufficient capacity for the requested connection. In such instances, the distributor shall make an offer to connect which will include the cost of the enhancement.

As provided in Section 25.36 of the Electricity Act 1998 the Distributor shall connect a renewable energy generation facility to its distribution system in accordance to regulations, the market rules and any licence issued by the Board if requested and all regulations, market rules, orders or code have been met in respect to the connection.

Connection fees as noted within the Conditions of Service shall apply. (See sections 3.1.3, 3.1.4, 3.2.3, 3.2.4, 3.3.3, 3.3.4 3.4.3, 3.4.4, 3.5.1 & 3.8.1)

2.1.2 Offer to Connect

The Distributor will make an Offer to Connect to any customer requesting a connection within the Distributors licensed territory. As required by the Distribution System Code, the Offer to Connect must be fair and reasonable and be based on the distributors' design standard. The Offer to Connect must also be made within a reasonable time from the request for connection and the receipt of all required information from the Customer.

The Distributor may require a customer to pay all or a part of the costs of electrical plant installed to supply only that customer. Such capital contributions will be calculated using the guidelines set out by the OEB in the Distribution System Code. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

The Distributor may require a customer proposing to install generation to pay the costs of electrical plant installed to facilitate the connection of the generation. Such capital contributions will be calculated using the guidelines set by the OEB in the Distribution System Code. The Customer proposing a generation project should review the CHEC Generation Guide and Appendix E and Appendix F of the Distribution System Code for further information and direction on the technical and administrative requirements.

2.1.3 Connection Denial

The Distribution System Code in section 3.1 sets outs the conditions for a Distributor to deny connections. A Distributor is not obligated to connect a customer within its service territory if the connection would result in any of the following:

- Contravention of existing Canadian Laws, and those of the Province of Ontario including the Ontario Electrical Safety Code.
- Violations of conditions in a Distributors' Licence.
- Use of a distribution system line for a purpose that it does not serve and that the Distributor does not intend to serve.
- Adverse effect on the reliability and safety of the distribution system.
- Imposition of an unsafe work situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of the distributors' distribution system.
- A material adverse effect on the quality of distribution services received by an existing connection.
- Discriminatory access to distribution services.
- Potential increases in monetary amounts that already are in arrears with the distributor

The distributor shall inform the person requesting the connection of the reason(s) for not connecting and, where the distributor is able to provide a remedy, make an offer to connect. If the distributor is unable to provide a remedy to resolve the issue, it is the responsibility of the customer to do so before a connection may be made.

2.1.4 Inspections before Connections

The Distributor has the right to request an inspection prior to any connection.

All customer electrical installations shall be inspected and approved by the Electrical Safety Authority, referred to herein as the ESA.

The Distributor requires notification from the ESA of this approval prior to the connection of a customer's service.

Services that have been disconnected for a period of six months or longer shall also be inspected and approved by the ESA prior to reconnection.

Temporary services, for construction purposes, are approved by the ESA for a period of twelve months and must be re-inspected should the period of use exceed twelve months.

The Distributor reserves the right to inspect and approve Transformer rooms, Vaults and Pads prior to, during, and following the installation of equipment.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

Customer owned substations must be inspected by both the Electrical Safety Authority and the Distributor, prior to connection to the Distribution system.

Duct banks and road crossings shall be inspected and approved by the Distributor prior to the pouring of concrete and again before backfilling.

The Distributor reserves the right to inspect any underground trenches prior to backfilling.

The Distributor reserves the right to approve the installation and location of all submarine cable. All documentation and permits required for laying of submarine cable must be provided to the Distributor. The installation of submarine cable must meet the requirements of all governing legislation.

All work done on existing Distributor plant must be authorized by the Distributor and carried out in accordance with all applicable safety acts and regulations.

In accordance with the Distribution System Code, if the Distributor refuses to connect a building in its service territory that lies along one of its distribution lines, the distributor shall inform the person requesting the connection of the reasons for not connecting, and where the distributor is able to provide a remedy, make an offer to connect. If the Distributor is unable to provide a remedy to resolve the issue, it is the responsibility of the customer to do so before a connection can be made.

2.1.5 Relocation of Plant

The Distributor will, where feasible, accommodate requests to relocate electrical plant such as poles and metal enclosed equipment.

The customer will be required to pay all of the costs incurred by the relocation.

Requests by civic authorities to relocate distribution facilities will be done so in accordance with the appropriate regulations. See *Public Service Works on Highways Act*.

2.1.6 Easements

To maintain the reliability, integrity and efficiency of the distribution system, the Distributor has the right to have supply facilities on private property registered against title to the property. Easements may be required when the Distributors' underground or overhead plant is to be located on private property or crosses over an adjacent private property to service a Customer.

The Customer shall acquire and grant in the distributors name, at no cost to the Distributor, where required, an easement to permit installation and maintenance of service. The width and extent of this easement shall be determined by the Distributor. The easement shall be granted prior to connection of the service.

The Owner shall furnish to the Distributor, free and clear of all encumbrances, sufficient easements to enable the servicing of all existing or proposed developments or subdivisions from plants located on the Owners' property.

Sufficient property at suitable locations shall be made available for the purpose of the installation of distributors' assets.

The Customer will prepare at its own costs a reference plan and associated easement documents to the satisfaction of the Distributors' solicitor prior to its registration and register the easement plan. Details will be provided upon application for service.

Where surface restoration by the Distributor is required following any repairs or maintenance to a service, the Distributor will in so far as is practicable, restore the property to its original condition; and provide compensation for any damages caused by the entry that cannot be repaired.

2.1.7 Contracts

Standard Form of Contract - All customers will be requested to complete and sign the standard form of contract to apply for a connection. A Standard Contract for service shall be considered as being in force from the date it is signed by the Customer and the Distributor and shall remain in force until terminated by either party.

Implied Contract - In all cases, notwithstanding the absence of a formal contract, the taking and using of electrical energy from the Distributor by any Person or Persons constitutes the acceptance of the terms and conditions of all regulations, conditions and rates as established by the Distributor. Such acceptance and use of energy shall be deemed to be the acceptance of a binding contract with the Distributor and the Person so accepting shall be liable for payment for such energy and the contract shall be binding upon the Person's heirs, administrators, executors, successors or assigns.

Special Contracts - Special contracts that are customized in accordance with the service requested by the Customer normally include, but are not necessarily limited to, the following examples:

- *construction sites*
- *mobile facilities*
- *non-permanent structures*
- *special occasions, etc.*
- *Generation*

In all cases of special contracts the terms and conditions of all regulations, conditions and charges as established by the Distributor shall apply to the customer connection unless specifically noted in the special contract.

2.2 Disconnection

The Distributor has the right and/or obligation to disconnect the supply of electrical energy or service to a Customer for causes including but not limited to:

(a) contravention of the laws of Canada or the Province of Ontario including the Ontario Electrical Safety Code;

(b) violation of conditions in a distributor's licence;

(c) materially adverse effect on the reliability or safety of the distribution system;

(d) imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system;

(e) a material decrease in the efficiency of the distributor's distribution system;

(f) inability of the distributor to perform planned inspections and maintenance;

(g) a materially adverse effect on the quality of distribution services received by an existing connection; and

(h) if the person requesting the connection owes the distributor money for distribution services, or for non-payment of a security deposit.

Disconnection of service shall follow the Distributor's Disconnection/Reconnection Policy.

2.3 Conveyance of Electricity

2.3.1 Guaranty of Supply

The Distributor agrees to use reasonable diligence in providing a regular and uninterrupted supply but does not guarantee a constant supply or the maintenance of unvaried frequency or voltage and will not be liable in damages to the Customer by reason of any failure in respect thereof.

Customers requiring a high degree of security of supply or power quality are responsible to provide their own back-up or standby facilities.

Customers requiring power for human life support equipment must provide their own equipment to ensure an uninterrupted supply of power. Customers on life support equipment are encouraged to contact the Distributor to inform them of their medical needs and the backup equipment which is in place.

When power is interrupted, or the Customer is experiencing power quality problems the Customer or their electrical contractor shall first ensure that interruption is not due to problems within the customer owned installation. If after verifying that the cause of the problem does not reside on the customers' installation, the customer shall contact the Distributor. The Distributor will respond to and take reasonable steps to restore power. The Distributor reserves the right to recover costs from the customer for making false claims of interruptions.

Although it is the Distributors' policy to minimize inconvenience to Customers, it is necessary to occasionally interrupt a Customers' supply to maintain or improve the Distributors' system, or to provide new or upgraded services to other Customers. Whenever practical and cost effective, as determined by the Distributor, arrangements suitable to the Customer and the Distributor may be made to minimize any inconvenience. The Distributor will endeavor to provide the Customer with reasonable advance notice, except in cases of emergency, involving danger to life and limb, or impending severe equipment damage.

The Distributor will endeavor to notify Customers prior to interrupting the supply to any individual service. However, if an unsafe or hazardous condition is found to exist, or if the use of electricity by apparatus, appliances, or other equipment is found to be unsafe or damaging to the Distributor or the public, service may be discontinued without notice.

Depending on the outage duration and the number of Customers affected, the Distributor may issue a news release to advise the general public of the outage.

2.3.2 Power Quality

The distributor will respond to and take reasonable steps to investigate consumer power quality complaints and report to the consumer on the results of the investigation. The method and level of investigation will be at the discretion of the Distributor.

If the source of a power quality problem is caused by the consumer making the complaint, the distributor may seek reimbursement for the time and cost spent to investigate the complaint.

If the source of a power quality problem is caused by a consumer, the Distributor may direct the consumer to take corrective action. If the Consumer does not take such action within a reasonable time, the Distributor may disconnect the supply of power to the Customer. (*see section 2.2*)

2.3.3 Electrical Disturbances

There are levels of voltage fluctuation and other disturbances that can cause flickering lights and more serious difficulties for Customers connected to the Distributor distribution system.

Some types of electronic equipment, such as video display terminals, can be affected by the close proximity of high electrical currents that may be present in transformer rooms.

No electrical equipment, which may produce an undesirable system disturbance, shall be connected by a customer to a customer's service without prior approval of the Distributor.
Examples of equipment, which may cause disturbance, are large motors, welders, generators and variable speed drives. In planning the installation of such equipment, the customer is required to consult with the Distributor.

The Distributor will endeavour to maintain voltage variation limits, under normal operating conditions, at the Customers' Delivery Points, as specified by the latest edition of the Canadian Standards Association, C235. However, more sensitive electronic equipment such as computers can be seriously affected by variations in quality of supply voltage. Customers who need electrical power of high quality and with rigid voltage tolerances are responsible for providing their own power conditioning equipment.

Customers requiring a three-phase supply should install protective apparatus to avoid damage to their equipment, which may be caused by the interruption of one phase, or non-simultaneous switching of phases of the Distributors' supply.

The customer shall provide such protective devices as may be necessary to protect his property or equipment from any disturbance beyond the control of the distributor.

The customer installing generation will install a Distributor approved system configuration and voltage level. In general where the connection of generation will be to the service supply the generation will be required to be the same voltage and number of phases.

2.3.4 Standard Voltage Offerings

2.3.4.1 For Secondary Voltage

The Supply Voltage governs the limit of supply capacity for any Customer. General guidelines for supply from overhead street circuits are as follows:

- *at 120/240 Volts single phase, or*
- *120/208 Volts three phase, four wire, or*
- *347/600 Volts three phase, four wire,*

OR

Where street circuits are buried, the Supply Voltage and limits will be determined upon application to the Distributor.

OR

Where the Customer or Developer provides a pad on private property;

- *at 120/240 Volts single phase, or*
- *at 120/208 Volts three phase, four wire, or*
- *at 347/600 Volts three-phase, four-wire*

2.3.4.2 For Primary Voltage

Primary supplies to transformers or customer-owned substations will be one of the following as determined by the Distributor:

- *2,400/4,160 Volts 3 phase 4 wire*
- *4,800/8,320 Volts 3 phase 4 wire*
- *7,200/12,400 Volts 3 phase 4 wire*
- *8,000/13,800 Volts 3 phase 4 wire*
- *16,000/27,600 Volts 3 phase 4 wire*
- *44,000 Volts 3 phase 3 wire*

The customer shall contact the Distributor when planning their service to verify standard transformer availability and supply capacity.

2.3.5 Voltage Guidelines

The Distributor maintains service voltage at the Customers' service entrance within the guidelines of C.S.A. Standard CAN3-C235 (latest edition) which specifies maximum variations from "normal operating conditions" and for "extreme operating conditions".

Where voltages lie outside the indicated limits for Normal Operating Conditions but within the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on a planned and programmed basis, but not necessarily on an emergency basis.

Where voltages lie outside the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on an emergency basis. The urgency for such action will depend on many factors such as the location and nature of load or circuit involved, the extent to which limits are exceeded with respect to voltage levels and duration, etc.

Where concern exists with the service voltage level customers are encouraged to contact the Distributor to confirm the allowed variations and to determine whether corrective action is required.

2.3.6 Back-up Generators

Customers with portable or permanently connected emergency generation capability shall comply with all applicable criteria of the Ontario Electrical Safety Code and in particular, shall ensure that customer emergency generation does not back-feed on the Distributors' system.

To access the Ontario Electrical Code which specifies the requirements for the connection of generators and to further review the Standby Generator Safety Checklist review Generator Safety Info.

Customers with permanently connected emergency generation equipment shall notify the Distributor regarding the presence of such equipment.

The Distributor reserves the right to have the connection of this equipment inspected.

Generation systems found to be feeding into the Distribution system without proper approval of the Distributor shall be subject to immediate disconnection.

2.3.7 Metering

2.3.7.1 General

2.3.7.1.1 Access

The Distributor or its agents shall have the right to access, read and safely maintain any of the Distributors' electricity meters on the Customer's premises.

All metering installations shall be accessible from a public area.

2.3.7.1.2 Costs

All the Distributor metering equipment located on the Customer's premises are in the care and at the risk of the Customer and if destroyed or damaged, other than by normal usage, the Customer will pay for the cost of repair or replacement.

Regardless of any charges for metering installations, all meters and meter instrumentation equipment shall remain the property of the Distributor and maintenance of this equipment shall be the Distributors' responsibility. Where primary metering is utilized the customer may own the current and potential transformers.

2.3.7.1.3 Voltage

Generally, metering will be at utilization voltage. Where the Distributor provides primary transformation, primary voltage metering will be allowed only in special circumstances following full discussion with the Distributor.

Customer-owned substations may require primary metering. The provisions required for these installations shall be specified and approved by the Distributor for each application.

2.3.7.1.4 Primary Metering

Primary metering units may be installed outdoors or within an electrical vault as outlined in the current Electrical Safety Code. Where the customer prefers not to provide an approved electrical vault, the Distributor at additional cost can provide a metering unit with non-flammable coolant.

2.3.7.1.5 Bulk Metering

Non-residential or mixed-use buildings will normally be bulk metered by a single meter. However, where specific areas are clearly and permanently defined and in other respects as a separate entity, individual metering of the loads may be required.

Individual residential condominium or apartment units should be metered individually to empower the residents with control over their individual costs. In such instances, one or more bulk meters may still be required at the facility for the purpose of calculating house loads and/or transformer allowances (on customer owned transformers) where applicable.

Individual suite metering can be installed and operated by the Distributor or private unit sub-metering providers. The installation and operations of systems will comply with the requirements as outlined in the Energy Consumer Protection Act, 2010 S.O. 2010, Chapter 8.

In all installations where the Customer requests revenue metering remote from the secondary entrance equipment or downstream from a Customer-owned dry-core transformer, provisions are required for a bulk meter directly after the main switch. This bulk metering is required in addition to any public metering provisions. The Customer will be required to contribute to the cost of the metering installation.

Where more than one meter is required, the meters shall be grouped where practical.

The customer shall permanently and legibly identify all metered services with respect to correct municipal 911 address and unit #. The identification shall be applied to all service switches and breakers and to all meter cabinets and meter mounting devices that are not immediately adjacent to the service switch. The customer shall insure that all service identifications are accurate and by not doing so will be held responsible. The Distributor shall issue a Meter Verification Sheet for this purpose to the owner or contractor.

In any case, a copy of the metering layout plan shall be forwarded to the Distributor for review and approval.

If the distribution of the metered load circuit is in dispute, (ie: circuits from one premise is found to supply a second premise) the Distributor reserves the right to transfer all accounts into the Property Owners' name until such time as the problem has been resolved, and the individual metering can be clearly identified with the individual units.

2.3.7.1.6 Locks

All devices on the line side of the Distributor metering shall have provisions for padlocking.

For commercial and industrial services the Customer's main switch shall have provisions for padlocking the switch handle in the open position, and the switch cover (or door) in the closed position.

When a disconnect device has been locked in the "OFF" position by the Distributor, under no circumstances shall anyone other than the Distributor or its authorized agent remove the lock.

At the discretion of the Distributor, a dual locking arrangement, a Distributor master key arrangement, a key box arrangement, or a copy of the access key will be required for access.

2.3.7.1.7 Meter Seals

All devices used by the Distributor for metering are sealed. Only the Distributor or its authorized agents have the authority to break this seal. Tampering with the seal will require the Distributor to investigate the cause of the tampering. Following the investigation, the proper authorities will be contacted as required (*ESA, Police, Fire*). The customer shall be responsible for all reasonable costs associated with the investigation.

2.3.7.1.8 Maintenance of Metering Equipment

The customer is responsible for maintaining the integrity of the meter base and cabinets, unless owned by the LDC, to meet the required mechanical and electrical standards.

For residential meters the meter base is considered customer owned and is to be maintained by the property owner. Any requirement for maintenance should be coordinated with the Distributor and completed in accordance to all applicable standards.

Commercial/Industrial installations result in varying ownership of cabinets and equipment. The property owner is to maintain any metering equipment under their control. Any requirement for maintenance should be coordinated with the Distributor and completed in accordance to all applicable standards.

2.3.7.2 Current Transformer Boxes

Where a current transformer box is required, it shall be CSA approved, of a size and type as stipulated by the Distributor, and include a provision for padlocks. A removable plate shall be provided in the box for mounting the equipment.

As an alternative to a separate CT box and meter, a single enclosure combining both functions may be feasible. Contact the Distributor for details.

In cases where the CTs only meter a portion of the metal clad switchgear (such as house loads), a separate disconnect switch must be installed ahead of the metering compartment so that the service can be de-energized without any interruption to the main service supply.

Generally, one house load meter only will be allowed. Additional house load meters will require authorization from the Distributor.

Conductors should enter the current transformer box at the top and leave at the bottom, or vice versa. If this cannot be arranged, the next largest CT box must be used to enable conductors to be trained in place. Where parallel conductors are used, the sum of the conductors will determine the size of the CT box to use. In all cases the Customer shall supply suitable cable termination lugs.

On all electrical services that require current transformers and the neutral for metering, an isolated neutral block shall be provided in the current transformer box.

Customer/ Contractor must receive distributor authorization regarding size, type and location of meter cabinets before installation of apparatus

2.3.7.3 Interval Metering

The Distribution System Code, as amended from time to time, requires the Distributor to meter Customers of specific load levels with pulse-recording meters, or interval meters, which are interrogated remotely. The Distributor, at its' sole discretion, may also require such metering on any customer whose load characteristics may have a significant impact on the Net System Load Shape, or where reasonable access to the meter for the purpose of acquiring metering data may be limited due to location.

A customer that requests interval metering shall compensate a distributor for all incremental costs associated with that meter, including the capital cost of the interval meter, installation costs associated with the interval meter, ongoing maintenance (including allowance for meter failure), verification and re-verification of the meter, installation and ongoing provision of communication line or communication link with the customer' s meter, and cost of metering made redundant by the customer requesting interval metering. The communication system utilized for interval meters shall be in accordance with the distributors' requirements.

Where such metering exists the Distributor will consider customer requests to provide a secondary pulse for load control or customer-owned metering at the customers' expense.

In keeping with the intent of the Legislation and accompanying amendments, once an interval meter installation is processed as part of the distributors' settlement process, and has affected the relevant changes to the distributors net system load, the installation must not be changed back to a non-interval meter installation.

Where a customer submits a request to read their own interval meter, the Distributor shall make this access available given the following conditions are met:

- The meter has the capability of read-only password protection
- The customer provides a signed copy of the "*Interval Metering Access Agreement*" to the Distributor.

2.3.7.3.1 Interval Metering Communications

Solid-state recorders and/or Electronic Interval Meters installed by the Distributor have provision for remote interrogation. When a phone line is required for this purpose, the Owner will facilitate the provision of a telephone line in the metering cabinet for the Distributors' metering purposes.

At its' sole discretion, for metering installations where loss of metering data would cause a substantial impact on the Distributors Settlement System and other customers, the Distributor may require the phone line to be dedicated for metering purposes only. When such dedicated phone lines are required, phone lines must be installed and functioning prior to the new service being energized.

A dedicated phone line is a voice quality telephone line, which is active 24 hours a day to the metering location extension jack, which is mounted on the metering board.

When the communication system relies on radio frequency the Owner will facilitate the provision of a location of an external antenna. The distributor will install the antenna and the associated wiring.

2.3.7.3.2 Smart Meters

The Ontario Government has mandated the installation of Smart Meters as a replacement to current metering technology. The LDC will install smart meters in accordance with regulations and policies set out by Government authorities.

Residential and small General Service customers, who are billed on an energy-only basis, will be provided with a smart meter. Metering requirements for Large General Service customers will be reviewed in concert with any new Regulations.

Where the customer installation requires by-directional metering (example for generation connections) the additional cost of the metering may be charged as an additional fee.

2.3.7.4 Meter Reading

The Distributor will read all meters on a regularly scheduled basis whenever possible. If an actual meter reading is not obtained, the Customer shall pay a sum based on an estimated demand and/or energy for electricity used since the last meter reading.

2.3.7.5 Final Meter Reading

When a service is no longer required, or the Customer is switching Energy Providers, the Customer shall provide the Distributor sufficient notice of the date so that a final meter reading can be obtained. The Customer shall provide access to the Distributor or its agents for this purpose.

If a final meter reading is not obtained, the Customer shall pay a sum based on an estimated demand and/or energy for electricity used since the last meter reading. Estimates will be based on available historical consumption.

Where Smart Meters are installed the final reading can be accommodated through remote interrogation. If at the time of final read remote access to the meter is not available an estimate of consumption will be made based on meter reading system data calculated to estimate the final billing.

2.3.7.6 Faulty Registration of Meters

Metering electricity usage for the purpose of billing is governed by the Federal Electricity and Gas Inspection Act and associated regulations, under the jurisdiction of Measurement Canada, Industry Canada. The Distributors' revenue meters are required to comply with the accuracy specifications established by the regulations under the above Act.

In the event of incorrect electricity usage registration, the Distributor will determine the correction factors based on the specific cause of the metering error and the Customer's electricity usage history. The Customer shall pay for all the energy supplied, a reasonable sum based on the reading of any meter formerly or subsequently installed on the premises by the Distributor, due regard being given to any change in the character of the installation and/or the demand.

If the incorrect measurement is due to reasons other than the accuracy of the meter, such as incorrect meter connection, incorrect connection of auxiliary metering equipment, or incorrect meter multiplier used in the bill calculation, the billing correction will apply for the duration of the error. The Distributor will correct the bills for that period in accordance with the regulations under the Act.

Where the distributor has under billed a customer or retailer, the maximum period of under billing for which the distributor is entitled to be paid will be as specified in the latest revision of the Acts and Codes. Where the distributor has over billed a customer or retailer, the maximum period of over billing for which the customer or retailer is entitled to be repaid will be as specified in the latest revision of the Acts and Codes.

2.3.7.7 Meter Dispute Testing

The Distributor will attempt to resolve billing enquiries. However, to give Customers confidence in the accuracy of electricity meters, the Distributor will conduct an internal investigation to verify the accuracy of any meter the Customer believes to be recording incorrectly. If the internal investigation does not resolve the matter, the Customer or the Distributor may request Measurement Canada to test the meter as per the Federal Electricity and Gas Inspection Act.

If the test indicates that the meter is not accurate, the Customer's historic billing will be adjusted, and the Distributor shall pay the full costs of the meter dispute testing.

2.3.7.8 Location

The location of the indoor or outdoor meter shall be readily accessible at all times and acceptable to the Distributor. If a meter is recessed or enclosed after installation, without the prior approval of the Distributor, the service may be subject to disconnection.

The location of the service entrance, routing of duct banks, metering, and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

In all locations where Commercial/Industrial revenue metering is accessible to the general public, a lockable enclosure or a room for service equipment and meters, shall be provided by the Owner at the discretion of the Distributor, as follows:

- *An electrical room reserved solely for metering equipment or*
- *Metal enclosed switchgear approved by the Distributor or*
- *A suitable metal metering cabinet or*
- *A vandal proof cage.*

2.3.7.9 Meter Mounting Heights

Provision for metering shall facilitate a practical mounting height for revenue meters in compliance with the Distributor's standard specifications and all applicable codes and regulations.

2.3.7.10 Environment

The following requirements apply to the areas allocated for revenue metering.

The customer to the satisfaction of the Distributor shall provide where there is the possibility of danger to workmen, or damage to equipment from moving machinery, dust, fumes, or moisture, protective arrangements.

A clear safe working space of not less than 1.2 m (48") in front of the installation from the floor to ceiling with a minimum ceiling height of 2.1 m (84") provided to insure the safety of the Distributor or other authorized employee(s) who may be required to work on the installation.

Where excessive vibration may affect or damage metering equipment, adequate shock-absorbing mounting shall be provided and installed by the customer.

2.3.7.11 Meter Sockets

The owner will supply and install a meter socket as specified by the Distributor. Meter sockets will be directly accessible to the Distributors' staff and remain in a safe and maintainable status.

A listing of approved revenue metering sockets is available from the Distributor.

2.3.7.12 Cabinets

Where required by these Conditions of Service the Owner shall supply and install a meter cabinet to the Distributors' requirements.

Meter cabinets shall be installed indoors, except where special permission is granted by the Distributor to install the meter cabinet outside. In such cases, an approved weather proof, lockable, C.S.A. approved meter cabinet shall be provided by the Customer.

2.3.7.13 Metering Loops

Three-phase, four-wire services will require a loop for metering, within the meter cabinet, for all three phases.

Mineral insulated, solid, or hard drawn wire conductors are not acceptable as metering loops.

2.3.7.14 Metal Enclosed Switchgear

The following regulations apply to the installation of instrument transformers and metering equipment within metal enclosed switchgear.

The Distributor will provide the following revenue metering equipment as required:

- Colour coded secondary wiring
- Revenue meters

The Owner shall:

- Consult with The Distributor regarding the installation of metering equipment, which may include:
    - Potential transformers
    - Potential transformer fuse holders and fuses
    - Current transformers
    - Phone line for remote interrogation of meters
    - Duplicate Pulse Initiators
    - Provide complete shipping instructions for instrument transformers for those projects where these are to be provided by the Distributor for installation by the switchboard manufacturer.
    - Install instrument transformers, metering cabinet and conduit.
    - Each main bus bar to be drilled and tapped (10-32) or (10-24) on the line side of the removable current transformer link.
    - Receive Distributor's approval for access / location

- Submit two copies of the manufacturer's switchboard drawings, for approval, dimensioned to show provision for and arrangement of the Distributors' metering equipment.

Meters shall be installed by the Distributor in a customer-owned metal cabinet of a size and type pre-approved by the Distributor, mounted at an approved location separate from the switchgear.

Tamper proof or sealable rigid conduit or any equally approved conduit of a size and type specified by the Distributor shall be installed between the CT compartment of the switchgear and the meter cabinet.

For conduit installations greater than 30 m (100'), in length or where several bends are necessary, larger conduits or other special provision may be required, at the discretion of the Distributor.

2.3.7.15 Switchgear Connected to Wye Source

Where a Wye source neutral connection is to be used or grounded, the Owner shall provide a conductor sized to the requirements of the Ontario Electrical Safety Code from the instrument transformer compartment to the neutral connection.

2.3.7.16 Four Quadrant Metering (Generation)

All Ontario Energy Board-licensed generators connected to the distribution system that sell energy and settle through the distributor's retail settlement process shall be required to install metering that meets the requirements of the Distribution System Code as approved by the Ontario Energy Board, and/or the Market Rules as approved by the Independent Electricity System Operator.

2.3.7.17 Net Metering for Embedded Generation

Customers with specific generation facilities may reduce their net energy costs by exporting surplus generated energy back onto the utility distribution system. Surplus energy exported onto the utility distributions system will be calculated as a credit against the energy the customer consumes from the distribution system.

All customers wishing to become a Net Metering participant must meet all of the following conditions:

1. The electricity is generated primarily for the customer's own use;
2. The electricity is solely generated from a renewable energy source (such as wind, drop in water elevation, solar radiation, agricultural bio-mass, or any combination thereof;
3. The maximum cumulative output capacity of the equipment used to generate the electricity that the generator intends to return to the distributor for net metering purposes is no greater than 500 kilowatts based on the maximum output capacity of the equipment; and
4. The generator conveys the electricity that is generated directly from the point of generation to another point for the generator's own consumption without reliance on the Distributor's distribution system before conveying any electricity that is in excess of the generator's own needs at the time of generation into the Distributor's distribution system.
    a. (Reference – Ontario Regulation 541/05 – Net Metering, Section 7)

In order to participate in the Net Metering program, the customer will be required to meet all the parallel generation requirements for Connecting Micro-Generation Facilities (10 kW or less) or Other Generation Facilities (greater than 10 kW and less than 500 kW), as applicable to the generator size, as found in Section 3.5 - Embedded Generation Facilities

The customer must have a bi-directional revenue meter that records energy flow in both directions.

Customers considering generation should review feed in tariff (FIT) programs which may be operating at the time. Reference to the CHEC Generation Guide and Appendix E and Appendix F of the Distribution System Code may prove instructive.

2.3.7.18 Metering for Embedded Generation

Generating facilities will connect directly to the distribution system at a voltage of 44kV or less. Output from the generating facility shall be metered in a manner to ensure proper collection of required information for settlements. Such metering may include:

a. for generators of 10 kW or less and connected to the line side of the load meter
    (i) a bi-directional kWh meter to measure energy consumed and energy exported; or
    (ii) a bi-directional interval meter to measure hourly energy consumed and energy exported

b. for all other generators, an interval meter must be installed.

In some instances, the load meter may also have to be changed in order to accommodate proper settlement calculations. The generator will be responsible for costs associated with the connection to the distribution system and any required metering installation as defined by the relevant Codes and Acts.

2.4 Tariffs and Charges

2.4.1 Service Connection

Charges for Service Connections are set out in the Distributors approved rates, (Miscellaneous Rates and Charges) and may be obtained by request from the Distributor. Notice of Rate revisions may be published in the local newspapers and or mailed out to all customers with the first billing issued at revised rates.

2.4.2 Energy Supply

The Distributor shall provide Customers connected to the Distribution System with access to electricity through Standard Supply Service as defined in the Retail Settlement Code published by the OEB or as mandated though Legislation or Regulations issued by the Ministry of Energy.

Disputes arising from charges relating to Standard Supply Service shall be directed to the Distributor.

Customers will be switched to a licensed Retailer of choice only if the retailer has a Service Agreement with the Distributor. The Customer's authorized Retailer through the Electronic Business Transaction system (EBT) must make the Service Transfer Request (STR) in accordance with the rules established and amended from time to time by the Ontario Energy Board.

Disputes arising from charges relating to Retailer Service shall be directed to the Retailer.

The Distributor may, at its discretion, refuse to process a Service Transfer Request for a Customer to switch to a Retailer if that Customer owes money to the Distributor for Distribution Services and or Standard Supply Service.

2.4.2.1 Wheeling of Power

Customers considering delivery of electricity through the Distributors' Distribution System shall contact the Distributor for technical requirements and current applicable Rates.

2.4.3 Supply Deposits & Agreements

Whenever required by the Distributor, the Customer shall provide and maintain security as specified in the Distribution System Code. The Distributor shall require security amounts based on the existing security and deposit policies.

Where a customer proposes the development of premises that requires the Distributor to place equipment orders for special projects, the customer is required to sign the necessary Supply Agreements and furnish a suitable deposit before such equipment is ordered by the Distributor. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

2.4.4 Billing

The Distributor may, at its option, render bills to its Customers on either a monthly, bi-monthly, quarterly or annual basis. The option applicable to the customer shall be identified to the customer at the time of application for service. Under special circumstances the Distributor may require more frequent payment.

Prorating of Service and Demand charges will be performed at the discretion of the Distributor.

2.4.4.1 Competitive Charges:

Are based on rates as determined by:

i. the Hourly Ontario Spot Market Price (HOEP); or
ii. the utilities Weighted Average Price (WAP) as determined by net system load; or
iii. the customers retailer contract rate; or
iv. the rates published by the OEB; or
v. Legislation or Regulations issued by the Ministry of Energy.

These charges are typically the commodity charges related to energy however do not need to be limited to same.

2.4.4.2 Non-competitive Charges:

Non-competitive Charges are based on rates approved by the Ontario Energy Board, and fall outside the scope of this document as they are adjusted on an annual basis. Approved rates as they relate to the transmission, distribution and other non-competitive elements may be attained through the utilities rate documents. These documents will be provided by the utility at the customer’s request.

These charges can include but are not limited to; distribution charges, transmission charges, global adjustments.

2.4.4.3 Billable Engineering Units:

Customers will be billed on:

i. actual or estimated meter reading data; or
ii. derived consumption data (Streetlights, sentinel lights and other scattered loads); or
iii. a flat rate, depending on the type of load being billed.

2.4.4.4 Use of Estimates:

In months where a bill is issued, but no reading is obtained, the Distributor estimates usage in order to determine billing quantities. The estimate is based on historical usage for the premise, or a pre-determined quantity if there is no historical usage information available.

2.4.5 Payments and Late Payment Charges

Bills are rendered for distribution services and electrical energy used by the Customer.

Bills are due when rendered by the utility and are payable in full by the due date. A customer may pay the bill without the application of a late payment charge up to a due date as specified in the Distribution System Code. This due date shall be identified clearly on the customer's bill.

Where payment is made by mail or at a financial institution, payment will be deemed to be made consistent with the requirements in the Distribution System Code.
A partial payment will be applied to any outstanding arrears before being applied to the current billing, unless special considerations have been made by the utility or the conditions of the Distribution System Code outlines an alternate process.

Outstanding bills are subject to the collection process and may ultimately lead to the service being discontinued or limited. Service will be restored once satisfactory payment has been made. Discontinuance of service does not relieve the Customer of the liability for arrears.

The Distributor shall not be liable for any damage on the Customer's premises resulting from such discontinuance of service. A reconnection charge may apply where the service has been disconnected due to non-payment.

The Customer will be required to pay additional charges for the processing of non-sufficient fund (N.S.F.) cheques.

2.4.6 Unauthorized Energy Use

The Distributor shall use its discretion in taking action to mitigate unauthorized energy use. Upon identification of possible unauthorized energy use, the Distributor shall notify, if appropriate, Measurement Canada, The Electrical Safety Authority, Police Officials, Retailers that service customers affected by an authorized energy use, or other entities.

The Distributor may recover from the parties responsible for the unauthorized energy use all costs incurred by the Distributor arising from unauthorized energy use, including an estimate of the energy used, inspection and repair costs.

A service disconnected due to unauthorized use of energy shall not be reconnected until such time as all arrears resulting from the unauthorized use has been resolved to the satisfaction of the Distributor.

Prior to reconnection, the Distributor shall require proper authorization from applicable authorities.

2.5 Customer Information

The Distributor reserves the right to request specific information from the customer in order to facilitate the normal operation of its business. Failure of a customer to supply such information may prevent the normal continuation of service.

The Retail Settlement Code as amended from time to time specifies the rights of customers and their retailers to access current and historical usage information and related data and the obligations of distributors in providing access to such information.

Under these requirements, the Distributor shall upon authorization by a customer make the following information available to the Customer or the Retailer that provides electricity to a customer connected to the Distributors' distribution system:

- The Distributors' account number for the customer,
- The Distributors' meter number for the meter or meters located at the customer's service address
- The customer's service address,
- The date of the most recent meter reading,
- The date of the previous meter reading,
- Multiplied kilowatt-hours recorded at the time of the most recent meter reading,
- Multiplied kilowatt-hours recorded at the time of the previous meter reading,
- Multiplied kW for the billing period (if demand metered),
- Multiplied kVA for the billing period (if available),
- Usage (kWh's) for each hour during the billing period for interval-metered customers
- An indicator of the read type (e.g., distributor read, consumer read, distributor estimate, etc.)
- Average distribution loss factor for the billing period

This information will be provided to the Customer / Retailer upon request twice per year at no charge. The Distributor may request a fee to recover costs for additional requests. A request is considered to be data delivered to a single address. Thus, a single request to send information to three locations is considered three requests.

The Distributor acknowledges that no confidential information regarding its' customers shall be released to a third party without the expressed prior written consent of the customer unless the request is rightfully received from the third party requesting the information, or the Distributor is legally required to disclose such information under the terms and in accordance with the Freedom of Information and Protection of Privacy Act, R.S.O. 1990, c. F.31.

SECTION 3 CUSTOMER SPECIFIC

3.1 Residential

This section refers to the supply of electrical energy to Customers residing in residential dwelling units.

3.1.1 General

Energy is generally supplied as single phase, 3-wire, 60-Hertz, having a nominal voltage of 120/240 Volts.

There shall be only one Demarcation Point to a dwelling.

In circumstances where two existing services are installed to a dwelling, and one service is to be upgraded, the upgraded service will replace both of the existing services.

All new single-family homes will be required to install their primary and secondary service wires to the specifications contained within the Distributors' technical specification document.

Whether the method of supply will be overhead or underground will be at the discretion of the distributor. The Distributor will adhere to any existing regulations subject to requirements of authorities.

Unless specifically documented otherwise to the Customer, where the distributor has taken ownership of such plant all services installed by the Distributor or by an approved contractor using approved materials, will be maintained by the Distributor.

3.1.2 Early Consultation

The Customer shall supply a completed Site Planning document and related information to the Distributor well in advance of installation commencement. (see appendix) The information shall be supplied in a manner requested by the Distributor at the time of the application.

3.1.3 Standard Connection Allowance

For the purposes of calculating customer connection fees, the Basic Connection for Residential consumers is defined as 100 amp 120/240 volt overhead service.

The basic connection for each customer shall include;

i. supply and installation of overhead distribution transformation capacity or an equivalent credit for transformation equipment; and
ii. up to 30 meters of overhead conductor or an equivalent credit for underground services.

In the case of an upgrade to an existing service, where the existing service is below the basic connection, the credit up to the basic connection will apply.

Secondary services exceeding the basic 30 meter length may require specific design approved by the Distributor to ensure power quality.

3.1.4 Variable Connection Fees

Any requirements above the defined basic connection shall be subject to a variable connection charge to be calculated as the costs associated with the installation of connection assets above and beyond the basic connection. The distributor may recover this amount from a customer through a connection charge or equivalent payment.

3.1.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by the Distributor includes repair and like-for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

3.1.5.1 Secondary Service Connections

The Point of Demarcation for residential services up to and including 400 amps is at the line side of the Meter Base for Underground services, and at the top of the stack for Overhead services, beyond which the customer bears full responsibility for installation and maintenance.

The Point of Demarcation for residential services over 400 amps is at the secondary side of the transformer.

For Secondary Services wholly owned and maintained by the Customer, the Demarcation Point is the secondary connection at the transformer or the service bus.

The Customer shall install, own, and maintain the secondary conductor under any of the following conditions:

(a) conductor terminations are inside the Customer's building;
(b) conductor is installed beyond the service entrance;
(c) conductor is connected to a Primary Service; or
(d) conductor is a non-standard installation.

3.1.5.2 Primary Service Connections

For Primary Service, the Demarcation Point is the primary connection at the Distributor's Distribution system.

3.1.6 Supply Voltage

(a) A Residential building is supplied at one service voltage per land parcel.

(b) Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

(c) The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.1.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission" from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution plant.

3.1.8 Metering:

The owner will supply and install a meter socket complete with collar acceptable to the Distributor and which meets the Ontario Electrical Safety Code. Meter sockets will be directly accessible to the Local Distribution Company and:

- Mounted 1.7 meters from the finished grade to the center of the meter and, either on the exterior of the front of the building or, within 3 meters of the front of the building on the driveway side.

- Installed ahead of (on the line side of) the main disconnect switch.
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.
- Remain accessible, safe, and maintainable

For more details refer to section 2.3.7 in these Conditions of Service.

3.1.9 Overhead Service

The Owner will provide service equipment to both the Distributors' and ESA requirements, and be of sufficient height to maintain proper minimum clearances. The Owner's main switch and the overhead service conductors will be of compatible capacity.

3.1.10 Underground Service

Underground secondary services will be installed at the Owners' expense, to the Distributor's specifications. The Owner's main switch and the underground service conductors will be of compatible capacity.

3.1.11 Street Townhouses and Condominiums:

NOTE: Street Townhouses and Condominiums requiring centralized or bulk metering will be covered under section 3.2 of these Conditions of Service. Also 3.1.11.2

3.1.11.1 Service Information:

The Owner will enter into a Servicing Agreement with the Distributor, governing the terms and conditions under which the electrical distribution system and services will be designed and installed.

The Owner will provide all of the civil works to accommodate the Distributor and will pay the complete cost of the electrical distribution system, design and services.

- The distribution system and services shall be underground unless otherwise approved.
- One service will be provided for each unit.
- The nominal service voltage will be 120/240 volts, 1 phase, 3 wire.
- The Distributor will approve the location of duct banks, service routings and meter bases.
- Distribution plant shall not be installed until grade is at +/- 150 mm of final grade unless otherwise approved by the Distributor.
- Street lighting will be to Municipal standards and installed at the Owner's expense.

3.1.11.2 Metering:

The Owner will supply and install meter sockets specified by the Distributor.

Multiple or grouped meter bases will be accepted only when prior approval has been given by the Distributor both as to type and proposed location. A completed meter verification form shall be provided to the distributor prior to energization, and shall remain accessible, safe, and maintainable.

Meter sockets will be located on the exterior front wall of the units and will be directly accessible to the Distributor.

- Mounted on the front wall 1.7 meters above finished grade to the center of the meter
- Installed ahead of (on the line side of) the main disconnect switch
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.

Normally the service will not be energized until the outside finish in the area of the revenue meter has been completed. If exceptions are made to this, then the general contractor will be responsible for ensuring that the meter is suitably protected while work is being done on the exterior wall adjacent to the meter. The general contractor will be entirely responsible for all costs for materials and labour for repairing or replacing a damaged meter. Meters must always remain fully accessible for reading, replacement, repair, and general maintenance. Customers and/or their contractors should contact the Distributor prior to enclosing meters and/or meter bases to ensure that safety and access are not compromised or the Distributor may disconnect the service until remedial action, as determined by the Distributor, are undertaken

3.1.12 Seasonal and Remote Dwellings:

Due to the varied nature of Seasonal and Remote Dwellings some special arrangements may be required to service these locations. Arrangements will be made in such a manner to provide services such as restoring power, maintenance of equipment or new construction requests to water access or remote customers, without endangering personnel or the public.

3.1.12.1 Service Information:

The Owner will enter into a Servicing Agreement with the Distributor, governing the terms and conditions under which the electrical distribution system services will be provided.

In the event of a power interruption, the Distributor will respond to and take reasonable steps to restore power. The Distributor reserves the right to recover costs from the customer for making false claims of interruptions.

3.1.12.2 Access:

All operations performed by the distributor and its agents shall be performed within the rules and regulations set out by the appropriate authorities including but not limited to: ESA, Ministry of Labour, Ministry of Transportation, etc.

- **Night crossings**

  The Distributors' transportation equipment will not be used to cross any water ½ hour before sunset and ½ hour after sunrise due to safety concerns. It will be at the discretion of the Distributor whether they will board customer owned transportation equipment in these circumstances.

- **Ice conditions**

  Recognizing seasonal ice hazards, the Distributor reserves the right to suspend water passage during freeze up and spring thaw, as well as any such time deemed unsafe by the Distributor.

- **Severe weather conditions**

  Recognizing that severe weather conditions may pose undue safety hazards, the Distributor reserves the right to postpone attempts to restore power until restoration can be performed in a safe manner.

3.1.13 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section 2.1.4 for further inspection details)

3.2 General Service (Below 50 kW)

3.2.1 General

This section refers to the supply of electrical energy to General Service Buildings requiring a connection with a connected load less than 50 kW, and Town Houses and Condominiums described in section 3.1.8 that require centralized bulk metering.

General Service buildings are defined as buildings that are used for purposes other than single-family dwellings.

3.2.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Owner shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc.

3.2.3 Basic Connection Charge

All costs attributed to the connection of a new General Service customer (Below 50 kW) shall be recovered either as part of the Distributor's revenue requirements or through a basic connection charge to the customer.

3.2.4 Variable Connection Charge

All costs associated with the installation of connection assets shall be subject to a variable connection charge. The distributor may recover this amount from a customer through a connection charge or equivalent payment. If an expansion of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

3.2.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

3.2.5.1 Secondary Service Demarcations

A General Service Customer Demarcation Point is at the secondary side of the transformer, or as otherwise set by the distributor, beyond which the customer bears full responsibility for installation and maintenance.

In some instances, where it is in the best interest of the operation of the distribution system, the Distributor may establish the Demarcation Point at the top of stack for overhead services or at the meter base for underground services.

The Demarcation Point might be located on an adjacent property. In such cases, a registered easement must exist.

3.2.5.2 Primary Service Demarcations

For Primary Service, the Demarcation Point is the primary connection at the Distributor's Distribution system.

3.2.6 Supply Voltage

(a) A General Service building is supplied at one service voltage per land parcel.

(b) Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

(c) The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.2.7 Access:

At the Distributor's discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.2.8 Metering:

The owner will supply and install a meter socket complete with collar acceptable to the Distributor. Meter sockets will be directly accessible to the Distributor and unless otherwise specified during the early consultation process:

- Mounted 1.7 meters from the finished grade to the center of the meter and, either on the exterior of the front of the building or, within 3 meters of the front of the building on the driveway side.
- Installed ahead of (on the line side of) the main disconnect switch.
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.
- Remain accessible, safe, and maintainable

For more details refer to section 2.3.7 in these Conditions of Service.

3.2.9 Overhead Service:

In circumstances where Commercial buildings cannot reasonably be supplied electrical energy by an underground service, the Distributor shall use its' sole discretion based on acceptable industry practices in establishing the specific requirements for the service installation.

3.2.10 Underground Service:

Under normal circumstances, Commercial buildings are supplied electrical energy by an underground service through a single point of entry for each land parcel, at a location specified by the Distributor.

3.2.11 Supply of Equipment:

The Distributor supplies, installs and maintains subject to the variable connection fee:

- Primary switchgear.
- Primary transformation equipment.
- Meter and secondary metering transformers.

The Owner shall supply, install and maintain any additional equipment required for the connection beyond the point of Demarcation.

3.2.12 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section 2.1.4 for further inspection details)

3.3 General Service (Above 50 kW)

3.3.1 General

This section refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load greater than 50 kW.

3.3.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Owner shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc.

3.3.3 Basic Connection Charge

All costs attributed to the connection of a new General Service customer (Above 50 kW) shall be recovered either as part of the Distributor's revenue requirements or through a basic connection charge to the customer.

3.3.4 Variable Connection Charge

All costs associated with the installation of connection assets shall be subject to a "variable connection charge". The distributor may recover this amount from a customer through a connection charge or equivalent payment. If an expansion of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

3.3.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Primary Service or Secondary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

The Distributor reserves the right to direct the operations of any customer owned switchgear connected to the distribution system including those located beyond the point of demarcation.

3.3.5.1 Secondary Service Connections

A General Service Customer Demarcation Point for customers above 50 kW is at the secondary side of the transformer, or as otherwise set by the distributor, beyond which the customer bears full responsibility for installation and maintenance.

In some instances, where it is in the best interest of the operation of the distribution system, the Distributor may establish the Delivery point at the top of stack for overhead services or at the meter base for underground services.

The location of the service entrance, routing of duct banks and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

The Demarcation Point might be located on an adjacent property. In such cases, a registered easement must exist.

3.3.5.2 Primary Service Connections

For GS > 50 kW class customers, an electrical requirement in excess of 300 kVA may require a customer owned substation. In some instances primary metering may be required. (Note: 300 kVA is the threshold for a GS > 50 kW customer class).

In General, the Demarcation Point for a General Service Customer with a primary connection is on the primary side of the transformer at the first available distributor owned point of isolation, or as otherwise set by the distributor. This delivery point might be located on an adjacent property from which the

Distributor has an authorized easement. In all cases the final Demarcation Point will be the decision of the Distributor.

The location of the service entrance, termination poles, routing of duct banks, metering facilities, and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

In some circumstances the owner may be required to construct a private pole line. Primary conductors will be terminated complete with cut-out(s) at the Demarcation Point by the Distributor at the owners' expense.

Where a private pole line is to be constructed by the Owner with an approved contractor, this shall be constructed to the ESA and the Distributors' requirements.

Where the customer wishes an underground supply, the customer shall supply and install the underground cables and termination pole complete with primary switch, fuses and lightning arresters. The installation shall be subject to ESA inspection and specific approval of the Distributor. The customer owned termination pole must comply with items as prescribed by the Distributor.

At the Distributors' discretion, the customers' underground service may be connected to a termination pole owned by the distributor. In such cases, the Distributor shall supply and install at the customers expense, any required primary switch, fuses, and lightning arrestors.

3.3.6 Supply Voltage

A General Service building is supplied at one service voltage per land parcel.
Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

Depending upon the location of the building Primary supplies to transformers and Customer owned Sub-Stations will be one of the following as determined by the Distributor:

- *2,400/4,160 Volts 3 phase 4 wire*
- *4,800/8,320 Volts 3 phase 4 wire*
- *7,200/12,400 Volts 3 phase 4 wire*
- *8,000/13,800 Volts 3 phase 4 wire*
- *16,000/27,600 Volts 3 phase 4 wire*
- *44,000 Volts – 3 Phase 3 Wire*

The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.3.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution plant.

3.3.8 Metering:

Meter installations will be directly accessible to the Distributor. The owner will consult with the Distributor well in advance of installation commencement to allow the Distributor time for proper planning and ordering of equipment.

For more details refer to section 2.3.7 in these Conditions of Service.

3.3.9 Overhead Service:

In circumstances where Commercial buildings cannot reasonably be supplied electrical energy by an underground service, the Distributor shall use its' sole discretion based on acceptable industry practices in establishing the specific requirements for the service installation.

3.3.10 Underground Service:

Under normal circumstances, Commercial buildings are supplied electrical energy by an underground service through a single point of entry for each land parcel, at a location specified by the Distributor.

3.3.11 Sub-transmission Service:

The Owner will pay for the full cost of sub-transmission services and may in some circumstances be required to construct a private pole line. The Distributor will terminate sub-transmission conductors complete with live line loops and hardware at the Demarcation Point.

3.3.12 Supply of Equipment:

The Distributor supplies, installs and maintains subject to the variable connection fee:

- Primary switchgear.
- Primary transformation equipment.
- Meter and secondary metering transformers.

The Owner shall supply, install and maintain any additional equipment required for the connection beyond the point of Demarcation.

3.3.13 Short Circuit Capacity:

The Owner shall ensure that the service entrance equipment has an adequate short-circuit interrupting capability.

3.3.14 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.
The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section 2.1.4 for further inspection details)

3.4 General Service (Above 500 kW)

3.4.1 General

This section refers to the supply of electrical energy to General Service Services requiring a connection at a connected load greater than 500 kW.

3.4.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Customer shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment, and coordination with ESA requirements etc.

Note: Larger services may require approval by the ESA to ensure compliance with their design requirements. The customer should contact the ESA early in the planning stages.

The Distributor will:

- *Advise the customer of the suitability of the in-service date*
- *Arrange with the customer for a Service Contract*
- *Review the submitted drawings; return one set to the customer with comments and/or approval. If requested by the Distributor, the customer shall resubmit the drawings where the comments are extensive and require major changes*

- *Specify the required main fuse link or relay setting for co-ordination with the system. In case of multiple transformer stations, a complete co-ordination study shall be submitted by the customer for approval.*
- *Make the final connection to the source of supply*
- *Determine metering requirements*
- *Advise the Transmitter of the particulars of the customer owned substation*

3.4.3 Basic Connection

All costs attributed to the connection of a new General Service customer (Above 500 kW) shall be recovered either as part of the Distributor's revenue requirement or a basic connection charge to the customer.

3.4.4 Variable Connection Charge

All costs associated with the installation of connection assets shall be subject to a variable connection charge. The distributor may recover this amount from a customer through a connection charge or equivalent payment. If an expansion of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

3.4.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Primary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

The Distributor reserves the right to direct the operations of any customer owned switchgear connected to the distribution system including those located beyond the point of demarcation.

3.4.5.1 Service Installation

In General, the Demarcation Point for a General Service Customer with a demand of over 500 kW is on the primary side of the transformer at the first available distributor owned point of isolation, or as otherwise set by the distributor. This delivery point might be located on an adjacent property from which the Distributor has an authorized easement. In all cases the final Demarcation Point will be the decision of the Distributor.

The location of the service entrance, routing of duct banks, metering facilities, and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

The Distributor will install overhead supply lines and required cut-outs to the first point of support on private property. The location of this support must be approved by the Distributor and shall be within 30 metres of the Distributors' existing overhead plant. All costs for materials and labour shall be at the customers' expense.

The service pole or first point of support on private property shall be considered self-supported and shall be complete with suitable hardware for attaching the suspension insulators. The Customer shall be responsible for all costs associated with equipment, installation, and inspection.

Where the customer wishes an underground supply, the customer shall supply and install the underground cables and termination pole complete with primary switch, fuses and lightning arresters. The installation shall be subject to ESA inspection and specific approval of the Distributor. The customer owned termination pole must comply with items as prescribed by the Distributor.

At the Distributors' discretion, the customers' underground service may be connected to a termination pole owned by the distributor. In such cases, the Distributor shall supply and install at the customers expense, any required primary switch, fuses, and lightning arrestors.

When requested, the customer shall make provision in the substation switchgear or transformer, for loop feeding the Distributors' supply cables via load interrupter switches.

In some instances, primary metering may be required.

3.4.6 Supply Voltage

A General Service building is supplied at one service voltage per land parcel.

General Service connections above 500 kW may require a customer owned substation (Note: 500 kW is the threshold for a GS > 500 kW customer class).

Depending upon the location of the building, primary supplies to transformers and Customer owned Sub-Stations will be one of the following as determined by the Distributor:

- *2,400/4,160 Volts 3 phase 4 wire*
- *4,800/8,320 Volts 3 phase 4 wire*
- *7,200/12,400 Volts 3 phase 4 wire*
- *8,000/13,800 Volts 3 phase 4 wire*
- *16,000/27,600 Volts 3 phase 4 wire*
- *44,000 Volts - 3 Phase 3 Wire*

The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.4.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution plant.

Where the high voltage interrupting switches are located inside a building, a direct outside entrance to the switchgear room must be provided.

The outside door providing direct access to the transformer or switchgear room must be compliant with all applicable codes and requirements, and of a quality to be approved by the Distributor.

3.4.8 Metering:

The owner will supply and install provisions for metering following the details outlined both in these Conditions of Service, and technical documents provided to the customer during the consultation process.

For more details refer to section 2.3.7 in these Conditions of Service.

3.4.9 Sub-transmission Service:

The Owner will pay for the full cost of sub-transmission services and may in some circumstances be required to construct a private pole line.

The Distributor will terminate sub-transmission conductors complete with live line loops and hardware at the Demarcation Point.

3.4.10 Short Circuit Capacity:

The Owner shall ensure that the service entrance equipment has an adequate short-circuit interrupting capability.

3.4.11 Drawings

Apart from the regular drawings submission to the ESA, the customer shall provide two sets of the following drawings and details to the Distributor.

Survey Plan: prepared by an Ontario Land Surveyor, showing the property limits, registered plan and existing buildings or easements if any.

Site Plan: showing the location of the station relative to buildings, structures and set backs from adjacent property lines. The site plan shall also include the exact location of existing Distributor owned plant and the proposed route of the incoming supply.

Schematic or Single-Line Diagram: indicating the major components of the station and their electrical ratings. Where additions or alterations are being made, these shall be clearly distinguished from unchanged portions of the installation.

Electrical Details: sufficient details shall be provided in order to enable fast processing and approval of the station drawings. The following represents the minimum data required.

- Plan, elevation and profile views of the station structure, switchgear, transformer(s), termination poles, duct banks, etc.
- Dimensions to clearly indicate the electrical, physical and working clearances as well as relative location of all equipment.
- Pole or structure for dead-ending the Distributor lines shall be complete with suitable hardware for attaching the suspension insulators that will be supplied and installed by the Distributor.
- Fencing arrangement.
- Grounding details. (In the case of indoor metal enclosed switchgear, when the Distributor has operating control of any interrupter switches, the assembly shall further incorporate ground rod parking stands and stirrups per the Distributors Specifications.)
- Details of vault construction (if indoor substation).
- Manufacturer's drawings of metal-enclosed switchgear showing internal arrangement of equipment, clearances, means of access, interlocking and provision for personal safety. Where the Distributors' cables terminate in the switchgear, the customer shall provide suitable terminators for the size and type of cable as specified by the Distributor.
- When the customer's switchgear is used for loop feeding the Distributors' supply cables, provision for padlocking the in and out load interrupter switches and the associated bay doors shall be required.

- Indoor and outdoor switchgear assemblies shall contain a space heater and protective guard in each bay, along with thermostat(s), sized to promote air circulation and to prevent condensation from forming.

- At the discretion of the distributor, the customer shall make provisions for a future system neutral connection to the customer's dead-ending pole or structures installed by the Distributor. Where the Distributors' neutral terminates in the customer's switchgear, the customer shall provide a suitable connector on the ground bus for the size and type of cable specified by the Distributor.

3.4.12 Pre-Service Inspection

The customer shall present to the Distributor a final "Pre-service Inspection Report" a minimum of 3 working days before connection can be affected.

The "Pre-Service Inspection Report" shall outline and document the results of all tests and inspection carried out on the substation components. The information contained in the report must be to the satisfaction of the Distributor before connection can be authorized.

The "Pre-Service Inspection Report" shall be required in case of:

- ***New Substation***: *in which case all components of the substation shall be reported upon.*

- ***Modified substation***: *in which case all components of the substation shall be reported upon.*

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section 2.1.4 for further inspection details)

3.5 Embedded Generation

3.5.1 General

An Embedded Generator shall provide the Distributor with proof of compliance of the regulators' registration requirements, permits and inspections as required, including ESA and Licences as appropriate.

The Distributor shall collect costs reasonably incurred with making an offer to connect a generator from the entity requesting the connection. Costs reasonably incurred include but are not limited to costs associated with:

- Preliminary review for connection requirements.(Connection Impact Assessment)
- Detailed study to determine connection requirements. (Cost of Connection)
- Final proposal to the generator.
- Connection costs for construction or make ready work for the distribution system as per the cost allocation methods in the DSC.

A Generator that is or wishes to become connected to the distributors' distribution system shall enter into a Connection Agreement with the Distributor as prescribed in Appendix E of the DSC.

A generator shall ensure that a disconnection method suitable to the Distributor is installed to provide visible isolation of the generation.

If damage or increased operating costs result from a connection with a Generator, the Generator shall reimburse the Distributor for these costs.

The Embedded Generator is responsible for providing suitable protection equipment to protect his plant and equipment for any conditions on the distributor and interconnected transmission systems such as reclosing, faults and voltage unbalance.

To incorporate the connection of embedded generator to the distribution system, the line/feeder protection including settings and breaker reclosing circuits must be reviewed and modified if necessary by the distributor or transmission authority. This process may be complex and may require significant time.

The embedded generator greater than 10 kW must submit a proposed single line diagram and protection scheme signed and sealed by a Professional Engineer in the Province of Ontario for review to the distributor contact as identified by the distributor.

Based on the transformer connection proposed by the embedded generator additional significant protection cost may be incurred (e.g. delta HV transformer winding may require 3 phase HV breaker / reclosure device). The embedded generator shall not order the protection equipment and transformer until the station line diagram is reviewed and accepted by the distributor.
The purpose of the distributor review is to establish that the embedded generator electrical interface design meets the distributor requirements.

The protection schemes shall incorporate adequate facilities for testing/maintenance.

Negative phase sequence protection shall be installed where required, to detect abnormal system condition as well as to protect the generator.

The embedded generator may be required to install utility grade relays for those protections that could affect the distributor or transmission authority system.

The embedded generator may be required to submit a Ground Potential Rise study for review by the distributor, if telecommunications circuits are specified for remote transfer trip protection.

In addition to the forgoing the CHEC Generation Guide can be referred to for further details with respect to the connection process and Appendix F of the Distribution System Code.

The generator in addition to the requirements of the host LDC may be required to meet the conditions of upstream LDCs. The additional requirements will be communicated through the host LDC.

3.5.2 Protection

The embedded generator should provide protection systems to cover the following conditions:

3.5.2.1 Internal Faults:

The Generator should provide adequate protections to detect and isolate generator and station faults.

3.5.2.2 External Faults:

The protection system should be designed to provide full feeder coverage complete with a reliable DC supply. In some cases redundancy in protection schemes may be required.

Normally the following fault detection devices are required for synchronous generator(s) installation(s).

3.5.2.3 Ground Faults:

When the HV winding of the Generator station transformer is wye connected with the neutral solidly grounded, then ground over-current protection in the neutral is required to detect ground faults.

If the Embedded generator station transformer HV winding connected to the Distributor system is ungrounded wye or delta, then ground under-voltage and ground over-voltage protections shall be required to detect ground faults.

Depending on the size, type of generator and point of connection, a distributor may require the relaying system to be duplicated, complete with separate auxiliary trip relays and separately fused DC supplies to ensure reliable protection operation and successful isolation of the embedded generator.

3.5.2.4 Phase Faults:

To detect phase faults, at least one of the following protections should be installed with acceptable redundancy where required depending on fault values:

- Distance
- Phase directional over-current
- Voltage-restrained over-current
- Over-current
- Under-voltage

3.5.2.5 Islanding/Abnormal Conditions:

Voltage and frequency protections are required to separate the embedded generator from the distribution system for an islanded condition and thus maintain the quality of supply to distribution system customers. This also will enable speedy restoration of the distribution system.

Typically, the protections required to detect islanding/abnormal conditions are:

- Over-voltage
- Under-voltage
- Over-frequency
- Under-frequency
- Voltage-balance

The above protections should be timed to allow them to ride through minor disturbances.

3.5.3 Induction Generator

Due to the operating characteristics of the induction generator the protection package required is normally less complex than the synchronous generator. An embedded generator should design the protection scheme to trip for the same conditions as stated for synchronous generators. An induction generator is an asynchronous machine that requires an external source such as a healthy distribution system to produce normal 60 Hz power. Alternatively, if there is an outage in the distribution system then there is unlikely to be 60 Hz output from the induction generator. In certain instances, an induction generator may continue to generate electric power after the source is removed. This phenomenon, known as self-excitation, can occur whenever there is sufficient capacitance in parallel with the induction generator to provide the necessary excitation and when the connected load has certain resistive characteristics.

3.5.4 DC Remote Tripping / Transfer Tripping

Remote or transfer tripping may be required between the Generator and the feeder circuit breaker if the Generator is connected at a critical location in the distribution system. This feature will provide for isolation of the embedded generator when certain faults or system disturbances are detected at the feeder circuit breaker location.

Additional Protection Features, such as Remote Trip and Generator end open signal, may be required in some applications. Remote Trip Protection will often involve the participation of a neighboring or Host LDC. Early consultation is important to ensure a timely connection to the system.

3.5.5 Maintenance

An Embedded Generator shall have a regular scheduled maintenance plan to assure the Distributor that all connection devices and protection & control systems are maintained in good working order. These provisions shall be included in the Connection Agreement. A complete copy of the inspection report shall be delivered to the Distributor within 30 days.

In developing a maintenance plan, the Generator should consider the following requirements:

- Qualified personnel should carry out all inspections and repairs.
- Prior to completing any testing or repairs on the system the Distributor shall be contacted to coordinate the work.
- Periodic tests should be performed on protection systems to verify that the system operates as designed. Testing intervals for protection systems should not exceed four (4) years for microprocessor-based systems and two (2) years for electro-mechanical based systems.
- Isolating devices at the point of connection should be operated at least once per year.
- The Generator facility should be inspected visually at least once per year to note obvious maintenance problems such as broken insulators or other damaged plant.
- Any deficiencies identified during inspections shall be noted and repairs scheduled as soon as possible, with timing dependent on the severity of the problem, due diligence concerns (of both the Distributor and the Generator) and financial and material requirements. The Distributor shall be notified of any deficiencies involving critical protective equipment.
- The Distributor shall be provided with copies of all relevant inspection and repair reports that may affect the protection and performance of the Distributors' systems. The Distributor has the right to witness any relevant test being performed by the generator.
- Testing & inspection requirements specified by the Distributor.

3.5.6 Post Connection Changes

Any changes to the system after the initial connection will be communicated to the Distributor prior to implementation.

Where any of these proposed changes alter the protection associated with the installation the Distributor will be provided with sufficient information to allow review of the protection scheme and the potential impacts on the distribution system.

Where the customer makes changes which result in the need for additional studies, protection changes or alterations to the distribution system the customer will be responsible for the costs incurred by the Distributor as allowed by the various codes and regulations.

3.5.7 Micro-Embedded Generation

The following are the minimum requirements for Micro-Embedded Generation. The Distributor may require other information.

A Distributor shall require a person that applies for the connection of a Micro-Embedded Generation facility to the Distributor's distribution system to provide, upon making the application, the following information:

a) The name-plate rated capacity of each unit of the proposed generation facility and the total name-plate rated capacity of the proposed generation facility at the connection point;
b) The fuel type of the proposed generation facility;
c) The type of technology to be used; and
d) The location of the proposed generation facility including the address and account number with the distributor, where available.

In addition to the forgoing, the CHEC Generation Guide and Appendix F of the Distribution System Code can be referred to for further details with respect to the connection process.

3.6 Embedded Market Participant

An Embedded Market Participant shall provide the Distributor with proof of compliance of IESO registration requirements, and appropriate Licences.

Where the Conditions of Service of this Distributor exceed the technical requirements of any other licence or participant obligations, these Conditions of Service shall take precedence.

The Embedded Market Participant must meet at a minimum, the standards as set out in these Conditions of Service in order to connect to the Distributors' distribution facilities.

3.7 Embedded Distributor

An Embedded Distributor shall provide the Distributor with proof of compliance of IESO and OEB registration Requirements, and appropriate Licences.

Where the Conditions of Service of this Distributor exceed the technical requirements of any other licence or participant obligations, these Conditions of Service shall take precedence.

The Embedded Distributor must meet at a minimum, the standards as set out in these Conditions of Service in order to connect to the Distributors' distribution facilities.

Metering requirements of the Embedded Distributor shall be at the discretion of the Host Distributor.

3.8 Miscellaneous Small Services

This section pertains to the supply of electrical energy for Street Lighting, Traffic Signals, Bus Shelters, Telephone Booths, Cable T.V. Amplifiers, Decorative Street Lighting, Bill Boards, and other similar small loads.

These small services may be required to be metered by the Distributor.

To facilitate these installations the Distributor may have standard designs which are to be followed by parties requesting the attachment.

In addition any attachments made to the Distributor's system will be required to conform to Ontario Regulation 22/04 and Ontario Electrical Safety Code. The Distributor will provide direction to the Owner with respect to any special requirements under Regulation 22/04.

3.8.1 Rights and Responsibilities:

Unmetered Customer Responsibilities:

- Comply with the Distributor's requirements for new connections, which may require the signing of a formal agreement for services. Unmetered customers cannot use power from the Distributor's Distribution system without written or implied consent from the Distributor.
- Comply with the requirements of the Distributor's standards for power quality and reliability and the Ontario Electrical Safety Code to ensure public safety. Where compliance is breached, the unmetered customer may be billed for subsequent restoration costs, and/or may be permanently removed from the Distributor's electrical system.
- Retain all information provided to and by the Distributor per the terms outlined in this Conditions of Service. The Distributor may not retain record details for each unmetered service and thus will not be held responsible for any incomplete records.
- Install, operate, and maintain its secondary conductor from the Distributor's designated Supply Point to the intended load.
- Provide timely and accurate electrical profile, power quality and usage data to the Distributor as outlined in these Conditions of Service. Provision of data to the Distributor constitutes consent to the Distributor to share or release load detail, plus energy and demand data, however, the customer's identity shall remain confidential.
- Accept energy consumption based on either 1) the maximum continuous calculated load, or 2) the results of a Distributor's meter analysis.
- Allow no external party to connect to its unmetered service or its unmetered secondary bus.
- Relocate, at the unmetered customer's cost, the secondary conductors of an unmetered service to another designated Supply Point at the Distributor's request.
- Submit revised unmetered data that affects energy consumption and/or billing determinants to the Distributor within 30 days, or as otherwise specified by the Distributor.
- Understand that the unmetered connection facility is not intended for an unmetered customer to generate back into the Distributor's distribution system. If an unmetered customer has generation facilities, the connection shall meet the Distributor's specification(s) for standby generation.

Distributor's Responsibilities:

- Provide a service layout for each unmetered service location that identifies the Supply Point and prescribes any applicable Distributor's standards and conditions.
- Strive to make new unmetered service connections within 10 working days of having all Distributors' connection conditions met.
- Provide reasonable notice to the unmetered customer should the Supply Point require relocation:
  - Planned Supply Point relocations - 90 day written notice.
  - Emergency Supply Point relocations – when possible.
- Ensure that unmetered service billing information accurately reflects calculated electrical consumption by unit, quantity, load profile and demand. Devices of the same class by type or load, where possible, can be grouped together and assigned the same billing determinants.

3.8.2 Process for Updating and Validating Data

A Distributor will strive to ensure that unmetered service billing information accurately reflects calculated electrical consumption by unit, quantity, load profile and demand, based on information supplied by the unmetered customer. An unmetered customer, at its cost, has the following options available for submitting data:

New Unmetered Services – Unmetered customers shall provide the Distributor with electrical profile, power quality, and usage accuracy studies prior to new unmetered equipment being introduced to a Distributors electrical system. Acceptable examples for collecting and providing such data are:

1. An in-house test plan (covering: scope, applicability, conditions, quality control, measurement devices, timing, staff competencies, control documents, error resolution process, and external references) that meets the Distributors approval. Final results and report shall be signed and sealed by a Professional Engineer of Ontario;
2. A signed and sealed certified test report from the Standards Council of Canada, an ANSI compliant laboratory, or other similarly qualified laboratory having competencies in electrical equipment testing; or
3. Having the Distributor meter specific unmetered nodes of their choice to determine accurate data. With the advent of Smart Metering the metering of actual consumption data is available and preferred by most Distributors.

Existing Unmetered Services – Throughout the lifecycle of the unmetered service, unmetered customers are required to submit updated and accurate data to the Distributor when it becomes known by the unmetered customer or requested by the Distributor.

At the very least, the unmetered customer must provide written notification to the Distributor by January 31st each year that no material changes to the technical data or number of unmetered service nodes has occurred.

3.8.3 General Billing Conditions:

An unmetered service is deemed to be “in-service” once it has been connected and energized by the Distributor. Once energized, the Distributor will bill the unmetered customer based on the billing standards outlined in these Conditions of Service and/or by the Distributors billing policies.

Where possible, the unmetered customer shall work with the Distributor to classify like energy devices such that similar devices can be consolidated to similar energy usage profiles for energy billing purposes. When requested by the Distributor, the unmetered customer shall consolidate their separate unmetered billing accounts down to at least the number of similar energy profile classifications. Security deposits, billing, and payment options are handled as specified in these Conditions of Service and/or by the Distributor’s billing policies.

Unmetered customers are responsible for ensuring their electrical consumption is accurate on an ongoing basis. The Distributor encourages voluntary data disclosure to ensure data quality and billing accuracy is maintained. Upon the Distributors receipt of updated unmetered load data, the Distributor shall have a period of up to 90-days to review and adjust its billing determinants.

To ensure the quality of unmetered data, the Distributor encourages the unmetered customer to cooperate in a joint audit, at a minimum interval of every 5 years, or earlier upon written notice from the Distributor. Unmetered customers who participate in a joint audit will be responsible for their associated audit costs.

If the unmetered customer provides the Distributor with poor unmetered data (i.e.: not to audit standards, no data, late data, etc.) a unmetered customer shall be responsible to pay the Distributor for verification, data correction and usage costs for the duration the unmetered connection has been energized on the distributor’s system.

In the event that the Distributor or the unmetered customer identify or cause a billing error, the Distributor will rectify the matter consistent with the polices outlined in these Conditions of Service and/or the Distributor’s billing policies.

Billing of the energy and fixed charges will continue until the Distributor has been duly notified and the unmetered service has been permanently removed from the Distributor’s electrical system.

Failure to comply with any of the above USL requirements could result in disconnection from the distribution system as per these Conditions of Service and/or the Distributors Disconnection/Reconnection Policy. Reconnection to the system would be subject to the reconnection requirements and costs as outlined in these Conditions of Service and/or the Distributors Disconnection / Reconnection policy.

3.8.4 Record Retention:

The unmetered customer shall retain information provided to and by the Distributor for a minimum period of seven years while the unmetered service is energized on the Distributors electrical system. Once the service has been permanently removed, the retention period shall be a minimum of two years.

The retained information shall include yet, not be limited to, the information outlined above, and any other relevant correspondence or agreements regarding the unmetered account including the associated service connections and load.

The unmetered customer who fails to retain such records shall be responsible for costs related to the Distributor researching and reconstructing such missing information.

3.8.5 General

At the discretion of the Distributor, the service voltage will be:

120/240 volts, single phase three wire or
120 volts, single phase two wire or
120/208 volts, three phase, four wire
347/600V three phase, four wire

The method and location of the supply will vary based on the conditions present on the Distributors' plant, and will be established for each application through consultation with the Distributor.

Where specified by the Distributor during the Early Consultation process, the Customer will provide underground ducts to the Distributor's specifications.

The Owner shall be responsible for all costs associated with the supply and installation of service conductors

The Distributor will install required transformation and may charge the Owner the cost.

Prior to energization of a service the Distributor will require notification from the ESA that the installation has been inspected and approved for connection.

The Owner will be required to maintain any equipment in proper and safe working order. Where the equipment is found to be in disrepair or present a hazard the Distributor may disconnect, remove and charge the costs to the owner.

3.8.6 Early Consultation

The Owner shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc. Information required includes:

- Required in-service date
- Requested Service Entrance Capacity and voltage rating of the service entrance equipment
- Locations of other services, gas, telephone, water and cable TV
- Survey plan and site plan indicating the proposed location of the service equipment with respect to public rights-of way and lot lines.

The Distributor after reviewing the information provided may require the owner to provide further information or approved drawings signed by a Professional Engineer ensuring that the installation is consistent with the requirements of Regulation 22/04.

3.8.7 Street Lighting

Where the street lighting is installed, owned and maintained by the Municipality or a third party, a Joint Use Agreement may be required for attachment to the Distribution system. Installations shall meet Ontario Regulation 22/04 and Ontario Electrical Safety Code.

The owner will be required to ensure qualified personnel are engaged to work on the streetlight system and that the system is maintained in a manner as to not represent a hazard to the distribution system and the public.

Proper records of the street light system shall be maintained by the owner to facilitate identification of equipment, appropriate record management and the ability to locate any underground plant associated with the system.

3.8.8 Traffic Signals

Traffic Signals and Crosswalk Lights are owned and maintained by the applicable road authority. Any traffic signals and crosswalk lights, if attached to the distribution system will be required to be in compliance with Regulation 22/04.

3.8.9 Bus Shelters

Bus Shelter Lighting is owned and maintained by the Customer.

3.8.10 Decorative Street Lighting

Such installations could be lighting for festive occasions or "neighbourhood character" street-scaping and will be maintained by the Customer.

Where such lighting represents a barrier to distribution system maintenance the Distributor may remove to facilitate work on the system in a safe manner. The owner will be responsible for reinstalling any equipment removed by the Distributor.

3.9 Attachments to Distribution Plant

The Distributor reserves the right to refuse any attachment to the Distribution Plant.

Customer attachments require written consent of the Distributor. Generally, consent will only be provided to licensed franchisees such as Bell Canada, Rogers Cable, and registered Telecom Companies. The Distributor reserves the right to refuse attachments to its poles.

Pole attachments will require a signed contract between the Distributor and the customer. Each pole attachment is subject to a yearly joint use charge and installation must conform to Regulation 22/04. Requesting parties will be responsible for meeting the requirements of Regulation 22/04 and the associated costs. No customer owned wires or apparatus are to be installed on the Distributor's poles prior to entering into a contract and confirming that the installation meets the requirements.

Where make ready work is required to accommodate the requested attachment the requesting party will be responsible for all costs associated with the make ready work.

Any attachments not approved will be removed by the Distributor at the owner's expense.
To meet engineering, safety, congestion and aesthetic considerations only three locations are generally allowed for the attachment of support strands and communications cables in the communication space of the Distributor's poles. Each customer requesting attachment in the communication space is allowed to install one support or communications cable only and this applies to all its associates as defined by the Ontario Business Corporation Act.

The owner of any third party plant shall be responsible to maintain their plant in a safe and proper condition compliant with Regulation 22/04 and relevant standards including any specific Distributor Standards.

The owner of any third party plant will be responsible for transfers of their plant in a timely manner as required by the Distributor.

3.9.1 Miscellaneous Attachments

Owners of miscellaneous equipment wishing to attach to the Distributor's system shall make written application for review and where appropriate approval by the Distributor.

Failure to obtain written authorization from the Distributor and or to enter into a Joint Use Agreement will result in the removal of the equipment and any associated plant by the Distributor at the owner's expense.

3.9.2 Joint Use Agreements

This section pertains to owners of plant who wish to make attachments to the Distribution System which have a direct or indirect influence on the performance, appearance and safety of the support structure or the Distributor's ability to make access and maintain it. For greater clarity this section applies to companies such as communication companies, CATV companies, and municipalities, but may be extended to others interested in making attachments.

All construction, installation and maintenance of attachments by the third party will conform to Ontario Regulation 22/04 and follow the appropriate guidelines. The requirements of Regulation 22/04 provide direction on design, material standards, construction and verification of the installations.

To facilitate good construction and project planning and compliance with Regulation 22/04 any party requesting to make an attachment shall contact the Distributor in writing well in advance of the proposed installation date.

Prior to making any attachments the owner of the plant will be required to enter into a Joint Use Agreement with the Distributor or if a Joint Use Agreement has been previously entered into, to follow the process for new attachments or modifications to existing attachments as specified in the Joint Use Agreement.

The owner of any third party plant shall be responsible to maintain their plant in a safe and proper condition compliant with Regulation 22/04 and the conditions of the Joint Use Agreement.

3.10 Regional Planning

Owners of miscellaneous equipment wishing to attach to the Distributor's system shall make written application for review and where appropriate approval by the Distributor.

SECTION 4 GLOSSARY OF TERMS

"Basic Connection" means a new residential 100A overhead, single-phase, secondary service including transformation capacity, standard metering, 30 meters of overhead conductor;

"Board" means the "Ontario Energy Board" (OEB);

"Conditions of Service" means the document developed by the distributor in accordance with subsection 2.3 of the Distribution System Code, that describes the operating practices and connection rules for the distributor;

"Condominiums" are located on common land, which is the property of a condominium corporation or is owned by the Owner of all of the units (rental property). These units usually front onto internal roads that are also privately owned;

"Condominium Development" is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit and have direct outside access at ground level;

"Connection" means the process of installing and activating connection assets in order to distribute electricity;

"Connection Agreement" means an agreement entered into between a distributor and a person connected to its distribution system that delineates the conditions of the connection and delivery of electricity to or from that connection;

"Connection assets" means that portion of the distribution system used to connect a customer to the existing main distribution system, and consists of the assets between the point of connection on a distributors' main distribution system and the ownership Demarcation Point with that customer;

"Consumer" means a person who uses, for the person's own consumption, electricity that the person did not generate;

"Customer" means a person that has contracted for or intends to contract for connection of a building or an embedded generation facility. This includes developers of residential or commercial sub-divisions;

"Demand meter" means a meter that measures a consumers' peak usage during a specified period of time;

"Demarcation Point" means the point at which the obligation of the Distributor ends and those of the Customer begin for the purposes of maintenance and repair of the distribution service;

"Disconnection" means a deactivation of connection assets, which results in cessation of distribution services to a consumer;

“Distribute”, with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less;

“Distributed Generation” means any type of electrical generator or static inverter producing alternating current that has the capability of Parallel Operation with the LDC distribution system, or is designed to operate separately from the LDC system and can supply a load that can also be fed by the LDC system.

“Distribution losses” means energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows;

“Distribution loss factor” means a factor(s) by which metered loads must be multiplied such that when summed equal the total measured load at the supply point(s) to the distribution system.;

“Distribution services” means services related to the distribution of electricity and the services the Board has required distributors to carry out.

“Distribution system / plant” means a system for distributing electricity, and includes any structures, equipment or other things used for that purpose. A distribution system is comprised of the main system capable of distributing electricity to many customers and the connection assets used to connect a customer to the main distribution system;

“Distribution System Code” means the code, approved by the Board, and in effect at the relevant time, which, among other things, establishes the obligations of a distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum technical operating standards of distribution systems;

“Distributor” means a person who owns or operates a distribution system;

“**Electricity Act**” means the *Electricity Act, 199*8, S.O. 1998, c.15, Schedule A;

“Energy Competition Act” means the *Energy Competition Act, 199*8, S.O. 1998, c. 15;

“Electrical Safety Authority” or **“ESA”** means the person or body designated under the *Electricity Act* regulations as the Electrical Safety Authority;

“Embedded Distributor” means a distributor who is not a wholesale market participant and that is provided electricity by a host distributor;

“Embedded Generation Facility” means a generator whose generation facility is not directly connected to the IESO-controlled grid but instead is connected to a distribution system;

“Embedded Load Displacement Generation Facility” means an embedded generation facility connected to the customer side of the revenue meter where the generation facility does not inject electricity into the distribution system for the purpose of sale;

"Embedded Market Participant" means a consumer who is a wholesale market participant whose facility is not directly connected to the IESO-controlled grid but is connected to a distribution system;

"Emergency" means any abnormal system condition that requires remedial action to prevent or limit loss of a distribution system or supply of electricity, or that could adversely affect the reliability of the electricity system;

"Emergency backup generation facility" means a generation facility that has a transfer switch that isolates it from a distribution system;

"Enhancement" means a modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example, from general load growth;

"Expansion" means an addition to a distribution system in response to a request for additional customer connections that otherwise could not be made; for example, by increasing the length of the distribution system;

"Feed in Tariff (FIT)" means the provincial Renewable Energy Feed-In Tariff (FIT) Program for the Province (or programs which may operate from time to time) to encourage and promote greater use of renewable energy sources including wind, waterpower, renewable biomass, bio-gas, bio-fuel, landfill gas and solar for electricity generating projects that can be connected to a host facility, a distribution system or the IESO-Controlled Grid, in Ontario. The fundamental objective of the FIT Program, in conjunction with the Green Energy Act (Ontario), is to help facilitate the increased use in the Province of Renewable Generating Facilities of varying sizes, technologies and configurations via a standardized, open and fair process.

"Four-quadrant Interval Meter" means an interval meter that records power injected into a distribution system and the amount of electricity consumed by the customer;

"Generate", with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system;

"Generation Facility" means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system, and includes any structures, equipment or other things used for that purpose;

"Generator" means a person who owns or operates a generation facility;

"Geographic Distributor" with respect to a load transfer, means the distributor that is licensed to service a load transfer customer and is responsible for connecting and billing the load transfer customer;

"Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

"Holiday" means a Saturday, Sunday, statutory holiday, or any day as defined in the Province of Ontario as a legal holiday;

"IESO" means the Independent Electricity System Operator established under the Electricity Act;

"IESO-Controlled Grid" means the transmission systems with respect to which, pursuant to agreements, the IESO has authority to direct operation;

"Interval meter" means a meter that measures and records electricity use on an hourly or sub-hourly basis;

"Large Embedded Generation Facility" means an embedded generation facility with a name-plate rated capacity of 10MW or more;

"Lies Along" means a property can be connected to the distributor distribution system without an expansion or enhancement, and meets the conditions listed in the Conditions of Service of the distributor who owns or operates the distribution line.

"Load Transfer" means a network supply point of one distributor that is supplied through the distribution network of another distributor and where this supply point is not considered a wholesale supply or bulk sale point;

"Load Transfer Customer" means a customer that is provided distribution services through a load transfer;

"Market Rules" means the rules made under section 32 of the *Electricity Act*;

"Measurement Canada" means the Special Operating Agency established in August 1996 by the *Electricity and Gas Inspection Act*, 1980-81-82-83, c. 87, and Electricity and Gas Inspection Regulations (SOR/86-131);

"Medium Sized Embedded Generation Facility" means an embedded generation facility with a name-plate rated capacity of less than 10 MW and:

a) more than 500 kW in the case of a facility connected to a less than 15kV line;
b) more than 1 MW in the case of a facility connected to a 15 kV or greater line;

"Meter Service Provider" means any entity that performs metering services on behalf of a distributor, generator, or registered market participant;

"Meter Installation" means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, meters, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment;

"Metering Services" means installation, testing, reading and maintenance of meters;

"Micro Embedded Load Displacement Generation Facility" means an embedded load displacement generation facility with a name-plate rated capacity of 10 kW or less;

"Net Metering" means a settlement process for Embedded Generation behind a Load Customer meter as defined by Ontario Regulation 541/05

"Ontario Electrical Safety Code" means the code adopted by O. Reg. 164/99 as the Electrical Safety Code;

"Ontario Energy Board Act" means the *Ontario Energy Board Act, 199*8, S.O. 1998, c.15, Schedule B;

"Operational Demarcation Point" means the physical location at which a distributors' responsibility for operational control of distribution equipment including connection assets ends at the customer;

"Ownership Demarcation Point" means the physical location at which a distributors' ownership of distribution equipment including connection assets ends at the customer;

"Physical Distributor" with respect to a load transfer, means the distributor that provides physical delivery of electricity to a load transfer customer, but is not responsible for connecting and billing the load transfer customer directly;

"Point of Supply" with respect to an embedded generation facility, means the connection point where electricity produced by the generation facility is injected into a distribution system;

"Rate" means any rate, charge or other consideration, and includes a penalty for late payment;

"Rate Handbook" means the document approved by the Board that outlines the regulatory mechanisms that will be applied in the setting of distributor rates;

"Regulations" means the regulations made under the *Act or the Electricity Act*;

"Regulation 22/04" Electrical Distribution Safety: means the regulation made under the Electricity Act establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors.

"Retail", with respect to electricity means,

a) To sell or offer to sell electricity to a consumer
b) To act as agent or broker for a retailer with respect to the sale or offering for sale of electricity, or
c) To act or offer to act as an agent or broker for a consumer with respect to the sale or offering for sale of electricity.

"Retail Settlement Code" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes a distributors' obligations and responsibilities associated with financial settlement among retailers and customers and provides for tracking and facilitating customer transfers among competitive retailers;

"Retailer" means a person who retails electricity;

"Service Area" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

"Small Embedded Generation Facility" means an embedded generation facility which is not a micro-embedded generation facility with a name-plate rated capacity of 500 kW or less in the case of a facility connected to a less than 15 kV line and 1MW or less in the case of a facility connected to a 15 kV or greater line;

"Smart Meter" means a device that measures electrical energy use (kilowatt-hours, kWh) on an hourly or sub-hourly basis and is part of an integrated data management system. The meter records, stores and transmits date and time-stamped meter readings to a utility's computer to facilitate Time-of-Use and Hourly billing. Smart meters may also include other capabilities and features to aid in load management and energy conservation.

"Standard Offer" means a settlement process for distribution connected Embedded Generation under contract for supply with the Ontario Power Authority.

"Total losses" means the sum of distribution losses and unaccounted for energy;

"Townhouses" are usually a free hold property, the land is owned by the individual Owners of each unit, fronting onto a municipal street;

"Townhouse Development" is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit, and have direct outside access at ground level;

"Transmission System" means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose;

"Transmission System Code" means the Board approved code that is in force at the relevant time, which regulates the financial and information obligations of the Transmitter with respect to its relationship with customers, as well as establishing the standards for connection of customers to, and expansion of a transmission system;

"Transmit" with respect to electricity, means to convey electricity at voltages of more than 50 kilovolts;

"Transmitter" means a person who owns or operates a transmission system;

"Unaccounted-for Energy" means all energy losses that cannot be attributed to distribution losses. These include measurement error, errors in estimates of distribution losses and un-metered loads, energy theft and non-attributable billing errors;

"Un-metered loads" means electricity consumption that is not metered and is billed based on estimated usage;

"Validating, Estimating and Editing (VEE)" means the process used to validate, estimate and edit raw metering data to produce final metering data or to replicate missing metering data for settlement purposes;

"Wholesale Market Participant" means a person that sells or purchases electricity or ancillary services through the IESO-administered markets;

SECTION 5 APPENDICIES

Contact Information

Distribution Connection Process

Request For Connection Form

Electrical Planning Requirements Document

Electric Service Meter Base/ Service Verification Form

POLICIES Relevant to Conditions of Service:

Please Contact LDC to obtain the most recent copy of the policy:

Policy 6.0 – Security Deposit*

Policy 6.2 – Billing and Payment*

Policy 8.1 – Disconnection/Reconnection*

Policy 9.3 – Environmental Policy*

***Please Note: The above policies are CHEC standard policies. Distributor policies may supersede the CHEC standard policies.**

CHEC LDC Contact Information

Local Distribution Company	Phone Number	Address
Centre Wellington Hydro Ltd. **License # ED-2002-0498**	(519) 843-2900	730 Gartshore Street, P. O. Box 217 Fergus, ON N1M 2W8
COLLUS PowerStream Corp. **Licence # ED-2002-0518**	(705) 445-1800	43 Stewart Road, P. O. Box 189 Collingwood, ON L9Y 3Z5
Innisfil Hydro Dist. Systems Ltd. **Licence # ED-2002-0520**	(705) 431-4321	2073 Commerce Park Drive Innisfil, ON L9S 4A2
Lakefront Utilities Inc. **Licence # ED-2002-0545**	(905) 372-2193	207 Division Street, P. O. Box 577 Cobourg, ON K9A 4L3
Lakeland Power Distribution Ltd. **Licence # ED-2002-0540**	(705) 789-5442	200-395 Centre St. North Huntsville, ON P1H 2M2
Midland Power Utility Corporation **Licence # ED-2002-0541**	(705) 526-9361	16984 Highway #12, P. O. Box 820 Midland, ON L4R 4P4
Orangeville Hydro Ltd. **Licence # ED-2002-0500**	(519) 942-8000	400 C Line, P. O. Box 400 Orangeville, ON L9W 2Z7
Orillia Power Distribution Corp. **License # ED-2002-0530**	(705) 326-2495	360 West St. South, P. O. Box 398 Orillia, ON L3V 6J9
Ottawa River Power Corporation **Licence # ED-2003-0033**	(613) 732-4626	283 Pembroke Street, P.O. Box 1087 Pembroke, ON K8A 6Y6
Renfrew Hydro Inc. **License #ED-2002-0577**	(613) 432-8785	29 Bridge Avenue West Renfrew, ON K7V 3K3
Rideau St. Lawrence Dist. Inc. **Licence # ED-2003-0003**	(613) 925-3851	985 Industrial Rd. P.O. Box 699 Prescott, ON K0E 1T0
Wasaga Distribution Inc. **Licence # ED-2002-0544**	(705) 429-2517	950 River Road West P.O. Box 20 Wasaga Beach, ON L9ZL 1A2
Wellington North Power Inc **Licence # ED-2002-0511**	(519) 323-1710	290 Queen Street West, P.O. Box 359 Mount Forest, ON N0G 2L0
West Coast Huron Energy Inc. **Licence # ED-2002-0510**	(519) 524-7371	57 West Street Goderich, ON N7A 2K5

Note: License Numbers published by OEB as of August 1, 2014

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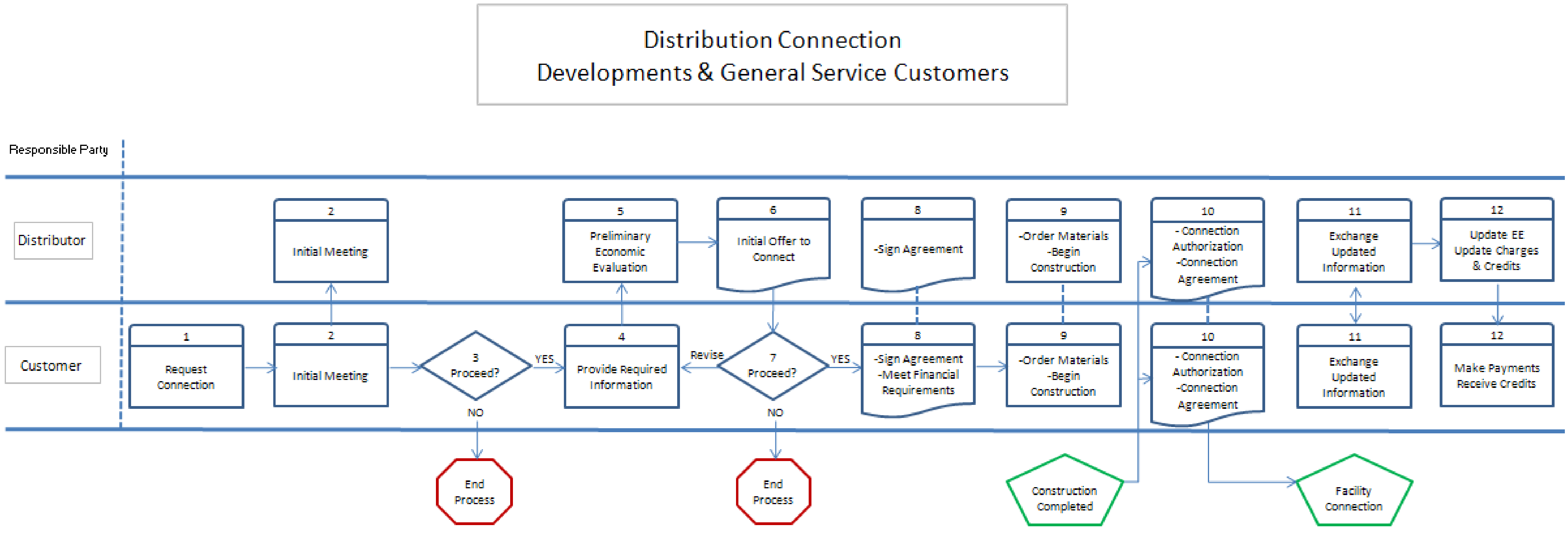
Distribution Connection

For Generation please see the CHEC Generation Guide



Distribution Connection
Developments & General Service Customers

If you are planning on building a Subdivision, Commercial Building, or an Industrial Development, the process of connecting to the Local Distribution Infrastructure will require coordination with the Distributor.

The following information in conjunction with the preceding chart is designed to assist the parties in meeting their respective obligations and facilitate the required connection. It is important to note although the steps identified in both the chart and the following descriptions need to be followed in proper order, some of the steps may be combined to help speed up the process if all the required information is provided in a timely manner.

Step 1 – Request for Connection

Customer submits a connection request to the Distributor. Initial request should at a minimum include the following information:

- Location of proposed development
- General description of development
- Proposed construction date
- Contact information for Development

Step 2 – Initial Meeting

Customer and Distributor meet to review proposed new development and connection requirements. Initial meeting will provide both parties with an opportunity to gain a better understanding of the proposed development and identify any issues related to timing and connection to the Distribution System.

Based on the information provided by the customer prior to the meeting, the Distributor will be able to provide at a high level:

- An initial concept of the type of work that may be required to facilitate a connection. ie:
    - Extension of an existing Feeder
    - Potential requirement for a new DS
    - Add a second or third phase to an existing feeder
- An understanding of the of the customer responsibilities
- An understanding of what must be managed by the Distributor
- An understanding of what may be contracted by the customer
- An estimated timeline required to provide connection facilities
- An initial estimate of required expansion costs – note: more detailed estimates on costs will be provided with the Offer to Connect should the Customer choose to continue to Step 4.

Step 3 – Customer Decision
Based on the results of the initial meeting, the Customer decides on proceeding with the process or withdrawing their Request for Connection.

Step 4 – Customer Provides Required Information

If the Customer decides to proceed with the process for acquiring a connection, the Customer notifies the Distributor and provides the relevant detailed information as noted below:

- A statement noting if the Customer intends on managing the contestable work noted during the consultation
- Number of Residential Connections
- Residential – Type, Number, and size of units
- Number of Commercial / Industrial Connections
- Estimated Average Monthly consumption (at minimum winter & summer estimates)
- Estimated annual facility connections over five years from date of LDC system connection

The following information is also required however the Distributor reserves the right to perform the work internally or through an external consultant:

- Design and engineering specifications including but not limited to stamped site service drawings
- Determination of required Transformation based on estimated building loads
- Estimated Capital costs of facilities which would be assumed by the Distributor following energization

To assist the Customer in providing the required information, a submission summary sheet is provided as an attachment to this document.

Step 5 – Preliminary Economic Evaluation

Upon receipt of the required information from the Customer, if an expansion of the distribution system is required, the Distributor will perform a preliminary Economic Evaluation following the process as required in the Distribution System Code.

The Preliminary Economic Evaluation will assist the Distributor in calculating what (if any) portion of the Capital Costs the LDC will invest and will be used in the preparation of the Offer to Connect.

Step 6 – Offer to Connect

Using the information provided by the Customer, and following the completion of the Preliminary Economic Evaluation, the Distributor will prepare an “Offer to Connect”. The Offer to Connect will contain the following information:

- A statement as to whether the offer is a firm offer or an estimate to be revised after the actual costs are known
- The amount of Capital Contribution that will be required from the Customer
- The amount of the Expansion Deposit that will be required from the Customer
- A description of the costs related to the Capital Contribution
- The costs for inspections
- A description of the deliverables required from the Customer before Connection
- An estimated Connection Date

Step 7 – Customer Decision

Customer Reviews Offer to Connect and decides if they would like to continue with the project as planned. Three options are available to the Customer:

- Customer elects to drop the project a notice of withdrawal of the Request for Connection shall be provided to the Distributor.
- Customer would like to revise their Connection request, a notice informing the Distributor of the requested changes shall be provided to the Distributor (go back to Step 4)
- Customer agrees with the Offer to Connect,

Step 8 – Construction Agreement

Once the Customer accepts the Distributor’s Offer to Connect, the parties shall enter into an agreement covering the construction and connection requirements and responsibilities.

The Customer and the Distributor sign the agreement and the Customer provides the financial deposits and/or guarantees as required.

Step 9 – Construction

Following receipt of signed Construction Agreement and required financial deposits and/or guarantees from the Customer, both parties shall begin ordering materials and begin construction.

Step 10 – Connection Authorization

Once construction is completed, both parties will ensure that inspections are completed and all required connection authorizations are in place. After receipt of a signed connection agreement and any additional financial contributions, the Distributor will authorize and connect the facility. If the customer is coordinating the work on the expansion facilities within the development, the customer is also required to provide “As-Built” drawings and a detailed material listing to ensure the Distributor has sufficient information in hand to verify system security prior to energization.

Step 11 – Exchange Updated Information

The Customer and the Distributor shall exchange any required updated information on the project including, but not limited to:

- All applicable Connection Authorizations
- All applicable Warranties
- Any new information that was provided as an estimate in Step 4

- Actual costs of any “capital works” related to the expansion facilities within the development
- Detailed site plan with appropriate Municipal Address information for individual services

Step 12 –Updated Economic Evaluation
As required, the Distributor shall recalculate the Preliminary Economic Evaluation using actual information acquired during and following the construction process.

If the development includes estimated connections that are not energized at the time of the initial Connection, the Distributor shall re-run the Economic Evaluation on an annual basis using actual customer connection information during the five (5) year connection horizon used in the initial Economic Evaluation.

Request for Connection – Sample Form

Development Name:	
Site Plan Identification	

Contact Information:

Contact Name:	
Street:	
Town:	
Postal Code:	

Requested Connection Date:	

Multi-Phase Development?	Y / N
If YES - Identify Phase	

<u>Type & Number of Connections:</u>

		Average Monthly Consumption Per Unit - Winter	Per Unit - Summer
Residential:		kWh's	kWh's
Commercial:		kWh's	kWh's
Industrial:		kWh's	kWh's

Residential Dwelling Design:	Town Homes	
	Semi-Detached	
	< 1,500 SqFt Single Dwellings	
	>1,500 <3,500 SqFt Single Dwellings	
	> 3,500 SqFt Single Dwellings	

Connection Horizon

Year 1		
Year 2	Estimated connections in 1st year	
Year 3	Estimated connections in 2nd year	
Year 4	Estimated connections in 3rd year	
Year 5	Estimated connections in 4th year	
	Estimated connections in 5th year	

Capital Costs:

Distribution Infrastructure:	
Transformers:	
Ducts & Structures:	

Date: Submitted:	
Submitted By:	
Signature:	

Electrical Planning Requirements

It is essential that the following information be provided to:

a) enable an assessment to be made on the impact of the proposed project on the Electrical Distribution System.

b) enable the Distributor to prepare pertinent information for the developer.

Please supply answers to the following questions as soon as possible as electrical planning cannot proceed until the Distributor has reviewed this information.

Preliminary electrical site plan drawings are to be submitted together with this form. Electrical drawings are to be submitted to the Distributor for approval prior to any related job tenders or the commencement of any electrical construction. The drawings shall be drawn to a scale usable by the Distributor, shall show local pole locations, proposed transformer location, proposed electrical room/metering location and show how access to the metering would be gained (i.e.: the path to the metering).

Electrical site plan drawings are to be submitted to the Distributor on one (1) Paper copy and in an electronic format as approved by the Distributor.

Project Location: **(Municipal Address)** ______

Name of Project: ______

Name of Applicant: ______

Address: ______

Contact Name: ______

Address: ______

E-Mail: ______

Telephone: (   ) ______ **Fax:** (   ) ______

Service Classification (☒ as many as apply):

☐ Residential
☐ General Service < 50kW
☐ General Service > 50kW
☐ General Service >500kW
☐ Unmetered or Miscellaneous Load
☐ Temporary Service

Service Entrance Switchboard with Utility CT and PT Compartment ☐ Yes ☐ No

Capacity of Main Service (in Amperes):
Maximum rated capacity: ______

Estimated Connected Load in kW:
Maximum initial Load: ______ kW
Maximum Future Load: ______ kW

What service voltage is required (☒ one only):

☐ 120/240 Volt Single Phase
☐ 120/208 Volt Three Phase
☐ 347/600 Volt Three Phase
☐ Primary

Metering Type (☒ one only):

☐ Single Meter
☐ Multiple Meters

Quantity of Meter installations

100A or less: ______
101A to 200A: ______
more than 200A: ______

Required In-Service Date:
Month / Day / Year ______/______/______

Comments: **Please use the back of this form for comments**

Signed: ______ **Date:** ______

(Representative of Applicant)

Name: ______ **Title:** ______

Electric Service Meter Base/Municipal Address Verification Form – Sample

LOCAL DISTRIBTUION COMPANY NAME: ____

This Form MUST be completed by the Owner and/or their Electrical Contractor if applicable prior to service connection.

Electric Service Civic Address:____

Name of Owner:____

Telephone: ________________________________ **Fax:** ____________________________

Name of Contractor:____

Telephone: **Fax:**

In area (A) provided below, carefully sketch the Front View layout of the Electric Meter Base(s).
Match the corresponding (B) BILLING ADDRESS (INCLUDE UNIT #) for each meter base(s) shown in (A).

(A) Front View of Electric Meter Base(s)	(B) Billing Address
	1)
	2)
	3)
	4)
	5)
	6)
	7)

The following terms are agreed upon by the undersigned at the time of submitting the form:

1. That all information contained on the form is accurate.
2. That if any information is determined to be inaccurate, the Utility will not be able to energize the service connection(s).
3. That if any information has to be corrected by Utility personnel there will be applicable charges to prepare the amended form.
4. That an amended form must be signed and returned along with payment of any applicable invoice, as per note 3, prior to further consideration as to the activation of the service connection.

I/We the undersigned, acknowledge the information provided above has been verified and is accurate.

Signature of Owner:____ Date:_______________________

Signature of Contractor:____Date:_______________________

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APPENDIX F: Board Governance

INNPOWER CORPORATION

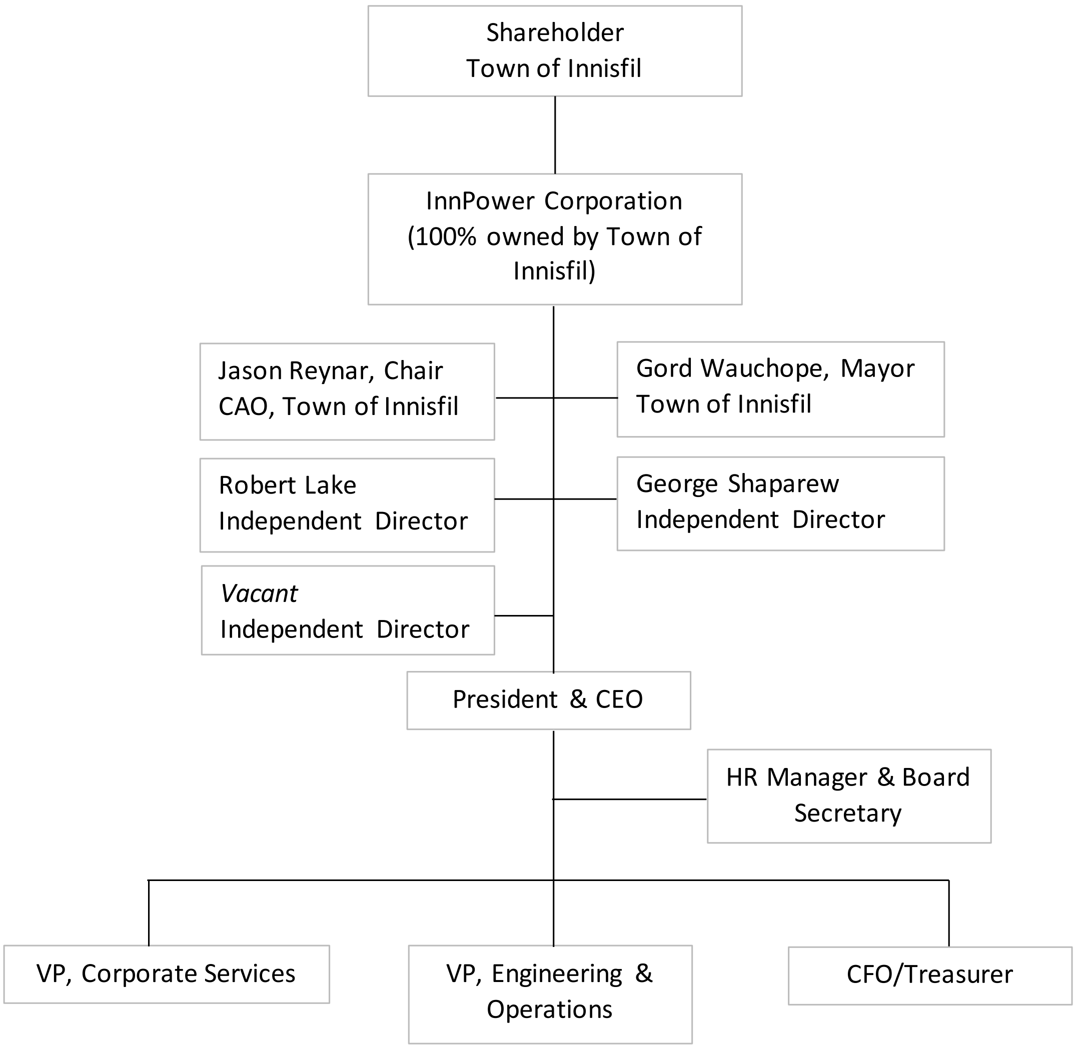
BOARD GOVERNANCE

MAY 2016

innpower

TABLE OF CONTENTS

2.1.8 Corporate Governance



InnPower Corporation is a wholly owned subsidiary of the Corporation of the Town of Innisfil. The corporation has a Board of Directors responsible to its sole shareholder. The Town of Innisfil's Chief Administrative Officer and Mayor both sit on the Board, as Chair and Director respectively.

Name	Appointment Date	End of Term Date	Replaced
Brian Jackson	October 25, 2000	November 30, 2010	
Nick Tatone	October 25, 2000	March 31, 2003	
Robert Lake	October 25, 2000		
Roy Atkinson	October 25, 2000	June 2004	
James Richardson	October 25, 2000	December 21, 2001	
Alan Wells	June 2004	September 2004	Roy Atkinson
Larry Allison	September 20, 2004	August 23, 2009	Alan Wells
Dave Weldon	August 24, 2009	January 24, 2010	Larry Allison
John Skorobohacz	January 25, 2010	April 15, 2016	Dave Weldon
Barbara Baguley	December 1, 2010	November 30, 2014	Brian Jackson
Gordon Wauchope	December 1, 2014		Barbara Baguley
George Shaparew	January 1, 2015		
Jason Reynar	August 1, 2015		

Board Composition

As stated in Article 2.04 of the Corporation's By-Law No. 1:

"2.04 Composition

2.02.01 Until changed in accordance with the Act and the Articles, the board shall consist of up to five members.

2.02.02 The Board shall include the two Municipal Representatives.

2.02.03.01 The Board may include up to three Private Sector Representatives. As the terms of each Private Sector Representative expires subsequent Private Sector Representatives shall be appointed for terms of up to three years.

2.02.04.02 Private Sector Representatives shall be elected by the Shareholders from the nominations put forward by the Board.

2.02.05 The Board shall not include the President and Chief Executive Officer."

Board Mandate

As stated in Article 2.01 of the Corporation's By-law No. 1:

"2.01 Primary Role of the Board

The Directors are responsible for the stewardship of the Corporation. The Ontario Business Corporations Act (OBCA), the statute which governs the Corporation, provides that the stewardship responsibility of the Board consists primarily of the duty to manage or supervise the management of the business and affairs of the corporation. The OBCA further authorizes the Board, subject to certain exemptions, to delegate to an officer or officers of the Corporation powers to manage the business and affairs of the Corporation. As authorized by the OBCA and for the purpose of effectively discharging the Board's stewardship responsibility,

(a) The Board has delegated to the President & CEO of the Corporation many of the Board's powers and much of the Board's authority to manage the business and affairs of the Corporation, and
(b) The Board has assumed the duty to supervise the President & CEO's management of the business and affairs of the Corporation."

Schedule of 2016 Board Meetings

January 18	July 18
February 22 *(rescheduled to March 2)*	August 15
March 21	September 19
April 18	October 17
May 16	November 21
June 20	December 12

Director Continuing Education

InnPower Corporation is committed to supporting the continuous learning needs of employees and Board members. The Education, Training and Development Policy provides clear and consistent direction for all full-time employees and Board members regarding eligibility for, and reimbursement of, tuition or other expenses related to external education, including professional development programs, legislated or mandatory training, seminars, conferences, workshops, conventions, or post-secondary courses or training.

Code of Conduct

InnPower Corporation has adopted a written code of conduct policy. The policy reflects the practice and intention of the Company in all its business endeavours, and applies to each and every one of the Company's employees. "Employee" includes employees, officers and directors of the Company and its subsidiaries and affiliates. The President & CEO and CFO/Treasurer sign off on the policy on an annual basis. The sign off is tracked electronically. The Board satisfies itself regarding compliance with the code by there being no corporate violations by any employee.

Furthermore, Section 2.03 of By-Law No. 1 states:

"2.03 Standard of Conduct

As required by the OBCA, every member of the Board must, in discharging his or her duties,

(a) Act honestly and in good faith with a view to the best interests of the Corporation, and
(b) Exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

Accordingly, the action which the Board or a Board committee must take to discharge each of its duties in any circumstances is the action which could reasonably be expected to be taken in comparable circumstances by a person (1) acting honestly and in good faith with a view to the best interests of the Corporation, and (2) exercising the care, diligence and skill that a reasonably prudent person would exercise."

Board Nominations

When there is a vacancy on the Board, prior to the Annual General Meeting, the Board passes a resolution recommending to the Shareholder the appointment of an individual to the Board. The same process occurs when re-appointing a Board member.

As outlined in By-Law No. 1, the following articles deal with Board appointments:

"2.05 Resident Canadians – A majority of the directors shall be resident Canadians.

2.06 Qualifications – No person shall be qualified for election as a director if that person is less than 18 years of age, is of unsound mind and has been so found by a court in Canada or elsewhere, is not an individual or has the status of a bankrupt.

2.07 Continuing Terms – Municipal Representatives will not sit for any longer on the Board after ceasing to hold municipal office, either as Mayor or CAO. Incumbent directors, if qualified, shall be eligible for re-appointment.

2.08 Resignation – A director who is not named in the articles may resign from office upon giving a written resignation to the Corporation and such resignation becomes effective when received by the Corporation or at the time specified in the resignation, whichever is later.

2.09 Removal – Subject to the provisions of the Act, shareholders may, by resolution, remove any Private Sector Representative from office before the expiration of their respective term and may, be resolution, appoint any qualified person in that person's place for the remainder of the term.

2.10 Vacating Office – A director ceases to hold office upon death, resignation or removal, from office by shareholders, or when that person becomes disqualified to serve as a director.

2.11 Vacancies – Subject to the provisions of the Act, where a vacancy occurs on the board, shareholders may appoint a person to fill the vacancy for the remainder of the term."

Board Committees

There are presently no Board committees.

APPENDIX A
BOARD MEMBER BIO'S

Jason Reynar was appointed Chairman of the Board for InnPower Corporation August 1, 2015. Jason is the Chief Administrative Officer of the Town of Innisfil, where he has worked in various roles since 2010.

Prior to that, he was a litigator in Toronto. Jason has a B.A. (Hons.) in Criminal Justice and Public Policy from the University of Guelph; law degree (LL.B.) and Masters in Law (LL.M.) from Osgoode Hall Law School, York University; and is a 2017 MBA candidate at Schulich School of Business, York University.

Gord Wauchope was elected as the Mayor of the Town of Innisfil on October 27, 2014. He has been a Director on the Board of InnPower Corporation since December 1, 2014.

Prior to being elected Mayor, Gord served as Councillor for the Town of Innisfil Ward 6 from 1998 to 2006 and as Deputy Mayor from 2006 to 2010.

Before entering politics, Gord was a police officer and served for 30 years in Metropolitan Toronto.

Mayor Wauchope has lived in Innisfil for 28 years.

Robert Lake is past-President of Peterborough Utilities Group of Companies. Prior to that he held various positions at Peterborough Utilities Commission and throughout the province with Ontario Hydro.

Bob holds a Professional Engineers (P.Eng) designation and was a member of the PEO's Complaints Committee and Simcoe County Executive. Other professional appointments include Vice President, President and past-President of the Electricity Distributors' Association, founding Member of Enerconnect and President of the District 1 MEA Executive.

Mr. Lake has been a Board Member of InnPower Corporation since 2000. He is also a current member of Independent Electricity System Operator's Technical Panel, Electricity Safety Authority's Member Review Panel, Board Member of Kawartha Credit Union, Member of the Source Water Protection Committee and a Board Member of Helping Hands International.

George Shaparew is past-President & CEO of InnPower Corporation and Innisfil Energy Services Limited. Prior to joining InnPower Corporation, he held various positions at Oakville Hydro, including Director of Line Operations and Director of Marketing & Customer Service. He was appointed to InnPower Corporation's Board of Directors effective January 1, 2015.

George holds several professional designations including a Masters of Engineering (M.Eng), a Masters in Law (LLM), an Executive MBA, a Certified Engineering Technologist (CET) and a Certified Municipal Manager (CMM III). He is also a certified Power Lineman. He has also held several governance appointments, including Voting Member of the CSA, Chairman of EDA's Georgian Bay District Executive, Director/Trustee of the Southlake Hospitality Cottage Association, to name a few.