OEB Filing Requirements Mapping
Exhibit 1

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2.1.2 Executive Summary

InnPower Corporation is a licensed distributor with approximately 16,000 customers servicing the Town of Innisfil and the lands located in South Barrie. InnPower Corporation's service territory encompasses 292 square kilometres (approximately the size of Mississauga) located north of the Oak Ridge Moraine within the Greater Golden Horseshoe. InnPower Corporation has approximately 292 kilometres of 44kV circuits, 401 kilometres three-phase distribution, 432 kilometres of single-phase circuits, 173 kilometres of primary underground cable, nine (9) distribution stations, two (2) shared distribution stations with Hydro One and four (4) private stations with distribution voltages of 16/27.6kV and 4.8/8.32kV.

The Town of Innisfil's economy is evolving. Looking forward to the 2031 planning horizon, the Town's employment base is anticipated to continue to diversify with continued economic growth in goods producing sectors related to transportation and warehousing, logistics, advanced manufacturing and construction, combined with strong employment growth in traditional and emerging service sectors. For the Town of Innisfil, this includes the retail and tourism sector as well as knowledge-based sectors such as professional and scientific services, information technology, health and social services, research and development, education and the broader public sector. In planning for growth over the long term, these sectors are anticipated to be amongst the key growth areas of the Town's local economy.

The Town of Innisfil is located within one of the fastest growing City/Regions in North America – the Greater Golden Horseshoe. Strong population and labour force growth within the regional market area is a key driver of local employment growth in the Town of Innisfil. Firstly, population growth within the Town and surrounding area drives demand for population-related services. Secondly, access to a diverse and growing labour force pool within the local and surrounding market area is typically cited by businesses and real estate brokers as one of the key factors considered with respect to business attraction and investment in the industrial and office sector.

The Town of Innisfil, the County of Simcoe and the Ministry of Transportation all have road improvements planned in the vicinity of the Innisfil Heights Secondary Plan Area. These expansion/upgrade works, in particular the planned widening of Innisfil Beach Road (County

Road 21), 5th Sideroad (County Road 53) and 10th Sideroad (County Road 54), will provide additional capacity to serve future development in the area. Metrolinx and the Province of Ontario recently announced its intentions to add a GO Train station in Innisfil which is one of three potential new stations to be included in the GO Regional Express Rail 10-Year Program. . The proposed site of the GO Transit station in Innisfil is situated at 6th Line, east of Sideroad 20 which was recommended by the Town of Innisfil. The station would be located in the South Alcona Beach Secondary Plan area where significant future growth is anticipated. The proposed new GO Train station is anticipated to be a major driver for residential growth and, to a lesser extent, employment growth. A key driver of Innisfil's future economic potential is its geographic location within Ontario. As noted, the Town of Innisfil is located within one of the fastest growing regions in North America, known as the Greater Golden Horseshoe. Collectively, the population of the Greater Golden Horseshoe is forecast to increase from 9.0 million in 2011 to 13.5 million in 2041, while the employment base is forecast to increase from 4.5 million in 2011 to 6.3 million in 2041. This represents a population increase of 4.4 million people (148,000 annually) and an employment increase of 1.8 million (60,000 annually). This represents a substantial increase in population and employment relative to other North American metropolitan regions of comparable population. For the Town of Innisfil, from 2016-2031, both population and employment are projected to increase by more than 100%. The following Table 1-1: summarizes these projections:

Table 1-1: Population and Employment Projections

Source	Population	Employment
Innisfil, 2011 Census and 2006 employment estimate	33,080	5,700
Innisfil Official Plan, 2031	56,000	13,100
Simcoe Official Plan, 2031	65,000	13,100
Provincial Growth Plan, 2031	56,000	13,100
Provincial Growth Plan, 2031 plus Friday Harbour and Sleeping Lion	65,240	13,100

The impending high growth rate within the Town of Innisfil brings challenges to both InnPower Corporation and our customers in terms of the following:

- balancing our obligation to connect,
- maintaining our distribution system within acceptable reliability standards,
- meeting customer demands while maintaining acceptable performance indicators

- "Just in Time" capital expense to meet our obligations under the Distribution System Code
- increasing internal efficiencies to mitigate overall expense increases directly impacting rates
- maintain flexibility to implement broader public policies as they occur, example, OESP effective January 2016 and in January 2017 the new tax rebate
- effectively increasing our customers energy literacy to increase their ability to manage invoices and understand costs
- ultimately mitigate rate shock

InnPower Corporation has undertaken this Cost of Service Application utilizing the following guiding principles:

1. Where feasible, minimize impacts on existing customers
2. Growth will pay for Growth as per the Economic Evaluation
3. Resources will be added when customer growth, demand and/or market changes dictate
4. Maintain InnPower Corporation's Performance ranking

InnPower Corporation believes our balanced approach, in conjunction with the guiding principles support the outcomes and objectives of the Renewed Regulatory Framework for Electricity (RRFE):

- Shift the focus from utility cost to value for customers
- Better align utility reliability and quality of service levels with customer expectations
- Institutionalize continuous improvement and innovation
- Provide for a comprehensive approach to network investments to achieve optimum results
- Better align timing and pattern of expenditures with cost recovery
- Provide a sustainable, predictable, efficient and effective regulatory framework

The following key examples support these principles in the day to day activities of InnPower Corporation and the preparation of this COS Application:

1. Removal of additional FTE's requested by departments in 2016 and 2017 reduced the OM&A expenses by $676,897.
2. Reduction in Discretionary and Material Projects reduced the Capital amount by $3,811,161.
3. Customer forecasts (growth and demand) have been adjusted to reflect realistic connection rates additions.
4. Year over year improvement in InnPower Corporation's Performance metrics.

As InnPower Corporation's capital spending needs to remain high to support our growth, it is more essential than ever to execute effective prioritization to meet the needs of growing our distribution system, maintaining acceptable reliability and power quality levels and demonstrate rate competiveness. As a result, InnPower will need to rely on effective cost management and increasing efficiencies. As an organization, our strategies will focus on the following:

Customer Satisfaction: Provide reliable, responsive, and affordable services in line with explicit, customer-accepted service levels. Receive timely customer feedback to maintain responsiveness to customer needs and emergencies.

Employee and Leadership Development: Recruits and retains a workforce that is competent, motivated, adaptive, and safe-working. Establish a participatory, collaborative organization dedicated to continual learning and improvement. Ensure employee institutional knowledge is retained and improved upon over time. Provides a focus on and emphasizes opportunities for professional and leadership development and strives to create an integrated and well-coordinated senior leadership team.

Operational Optimization: Ensures ongoing, timely, cost-effective, reliable, and sustainable performance improvements in all facets of its operations. Minimizes resource use, loss, and impacts from day-to-day operations. Maintains awareness of information and operational technology developments to anticipate and support timely adoption of improvements.

Financial Viability: Understands the full life-cycle cost of the utility and establishes and maintains an effective balance between debt, asset values, operations and maintenance expenditures, and operating revenues. Establishes predictable rates—consistent with community expectations and acceptability—adequate to recover costs and plan and invest for future needs.

Infrastructure Stability: Understands the condition of and costs associated with critical infrastructure assets. Maintains and enhances the condition of all assets over the long-term at the lowest possible life-cycle cost and acceptable risk consistent with customer, community, and regulator-supported service levels, and consistent with anticipated growth and system reliability goals. Assures asset repair, rehabilitation, and replacement efforts are coordinated within the community to minimize disruptions and other negative consequences.

Operational Resiliency: Ensures utility leadership and staff work together to anticipate and avoid problems. Proactively identifies, assesses, establishes tolerance levels for, and effectively manages a full range of business risks (including legal, regulatory, financial, environmental, safety, security, and natural disaster-related) in a proactive way consistent with industry trends and system reliability goals.

Stakeholder Understanding and Support: Bring about understanding and support from oversight bodies, community interests, and regulatory bodies for service levels, rate structures, operating budgets, capital improvement programs, and risk management decisions. Actively involves stakeholders in the decisions that will affect them.

Certification

As President and Chief Executive Officer, and Chief Financial Officer of InnPower Corporation, we certify that the evidence filed in this application is accurate, consistent and complete to the best of our knowledge or belief.

The filing is consistent with the requirements from Chapter 2 of the *Filing Requirements for Transmission and Distribution Rate Applications* revised on July 14, 2016.

All is which respectfully submitted,

Walter J. Malcolm
President and CEO

Laurie Ann Cooledge
Chief Financial Officer/Treasurer

InnPower Corporation 5 Year Business Plan

InnPower Corporation's Five Year Business Plan is attached as Exhibit K.

2.1.3 Administration

2.1.3. A: 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.

Title of Proceeding: An application by InnPower Corporation for an Order or Orders approving for fixing just and reasonable distribution rates and other charges, effective January 1, 2017.

2.1.3. B: Contact Information

Primary Contact for InnPower Corporation:

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President and CEO
InnPower Corporation
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Innisfil, ON, L9S 0J3
wallym@innpower.ca
Phone: 705-431-6870 x 235
Fax: 705-431-5901

Primary Contacts for the Application:

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Manager Regulatory & Conservation
InnPower Corporation
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Innisfil, ON, L9S 0J3
brendap@innpower.ca

Phone: 705-431-6870 x 262
Fax: 705-431-5901

Laurie Ann Cooledge
CFO and Treasurer
InnPower Corporation
7251 Yonge Street
Innisfil, ON, L9S 0J3
lauriec@innpower.ca
Phone: 705-431-6870 x 236
Fax: 705-431-5901

Primary Contact for Applicant's Counsel:

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Toronto ON
M5H 3Y4
John A.D. Vellone
jvellone@blg.com
Phone: 416-367-6730
Fax: 416-361-2758

2.1.3. C: Confirmation of Internet Address and Publication of Notice of Hearing

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.

In addition to the company's website InnPower Corporation utilizes the following social media accounts for additional communications to our customers:

Facebook - https://www.facebook.com/hydroinnisfil/

Twitter - https://twitter.com/innpower

InnPower Corporation recommends that the Notice of Hearing be published in the "Innisfil Examiner" as the newspaper has the highest distribution to Innisfil residents and online postings.

2.1.3. D: Bill Impacts at the Distribution Level

The following table summarizes the changes in distribution rates for InnPower Corporation with the outputs of this application for pour major rate classes.

Table 1-1: Distribution Bill Impacts

Customer Class	Item Description	Unit	2016 Rate ($)*	2017 Rate ($)
Residential				
750 kWH	Monthly Service Charge	per month	27.06	36.64
	Distribution Volumetric Rate	per kWh	0.0159	0.0139
	Total Distribution Charge		$38.99	$47.07
				20.7%
GS < 50 kW				
2000 kWH	Monthly Service Charge	per month	37.98	46.11
	Distribution Volumetric Rate	per kWh	0.0092	0.0111
	Total Distribution Charge		$56.38	$68.31
				21.2%
GS >50 to 4999 kW				
100 kW	Monthly Service Charge	per month	167.72	455.47
	Distribution Volumetric Rate	per kW	3.444	2.6458
	Total Distribution Charge		$512.15	$720.05
				40.6%
Street Lighting				
1 kW	Monthly Service Charge	per month	6.33	6.06
4 Connections	Distribution Volumetric Rate	per kW	43.7607	41.8970
	Total Distribution Charge		$3,001.05	$2,873.23
				-4.3%
*2016 Distribution rate includes ICM amount for new building				

Note: the increase on the fixed rate for the residential rate class reflects the 2nd year of transition to a fully fixed rate. Additional details are provided in Exhibit 8 of this application.

The following table provides a summary of overall Bill impacts;

Table 1-2: Overall Bill Impacts

Rate Class	2016 Invoice	2017 Invoice	$ Variance	% from 2016
Residential	$ 162.23	$ 174.80	$ 12.57	7.75%
GS < 50 kW	$ 391.50	$ 414.05	$ 22.55	5.76%
GS 50 to 4,999 kW	$ 4,827.99	$ 5,371.45	$ 543.46	11.26%
Street Lighting	$ 21,965.10	$ 20,946.96	-$ 1,018.14	-4.64%

Full details of rate design have been provided in Exhibit 8 of this application.

2.1.3. E: 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 a written/oral hearing.

2.1.3. F: 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 14, 2016 (the "Filing Requirements") in order to prepare this Application. The excel version of the complete 2017 Cost of Service Checklist is being filed in conjunction with this Application as a separate component.

2.1.3. G: Changes in Methodologies

InnPower Corporation has not presented any change in methodologies with the filing of this application.

2.1.3. H: Monthly Billing for Customers

Pursuant to the OEB's April 15, 2015 DSC amendment, InnPower Corporation confirms that it has always billed its customers on a monthly basis. Furthermore, with the implementation of TOU, pricing InnPower Corporation transitioned from monthly billing to full calendar month billing in 2013.

2.1.3. I: Board Directive from Previous Decisions

InnPower Corporation confirms that The Board did not issue specific directives in previous decisions to be addressed in this application.

2.1.3. J: Conditions of Service

InnPower Corporation's Conditions of Service are posted on Inn Power's website found at: http://www.innpower.ca/uploads/1418935928_Conditions-of-Service-2014.pdf.

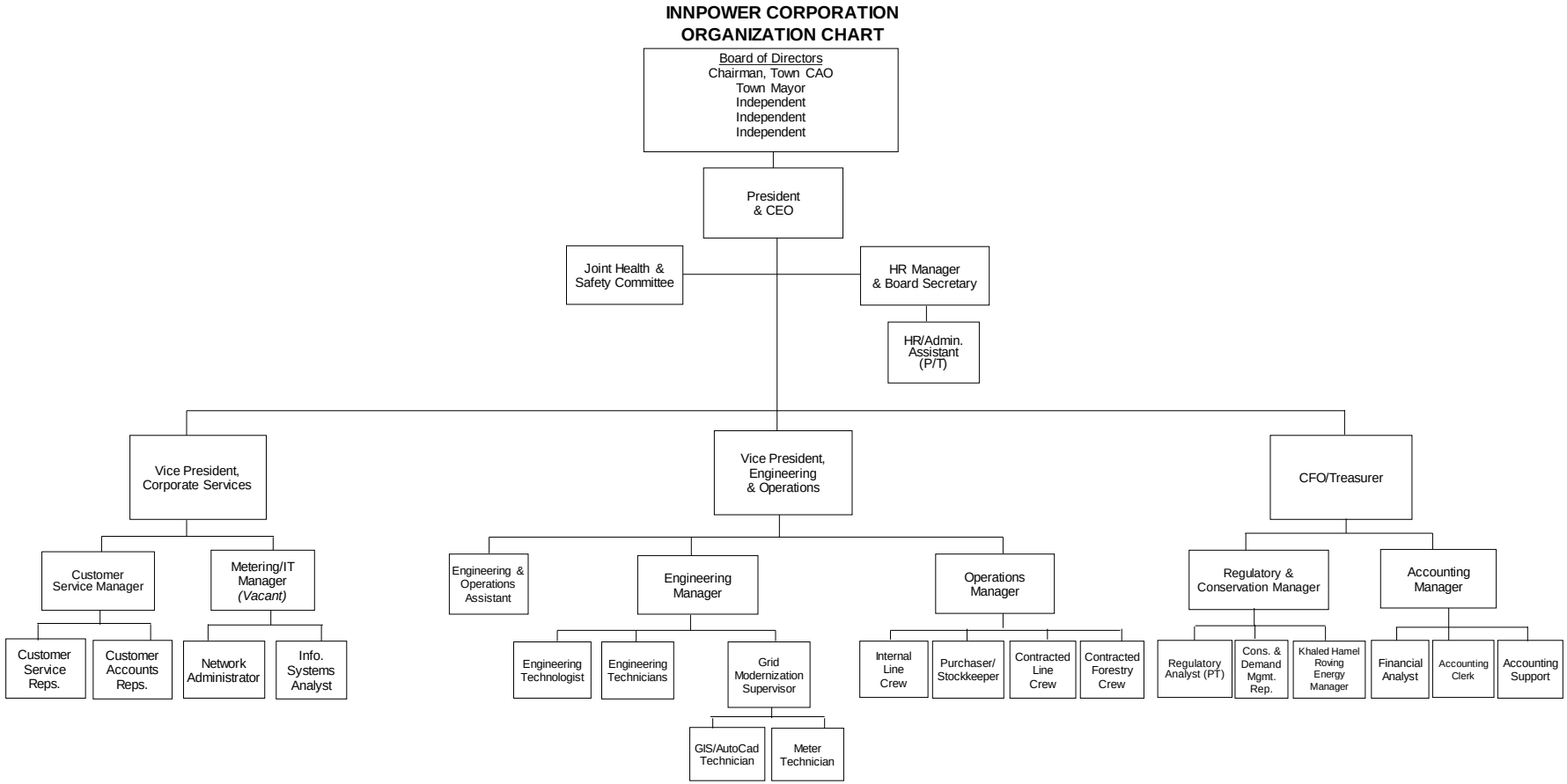
InnPower Corporation confirms that there are no rates or charges listed in the Conditions of Service that are not on InnPower Corporation's Tariff of Rates and Charges.

InnPower Corporation has provided a list of revisions in Appendix A: CHEC Revision Summary Conditions of Service Version 8.

2.1.3. K: Organizational Structure

The executive team at InnPower Corporation comprises of the President and CEO, Chief Financial Officer/Treasurer, Vice President Corporate Services, Vice President Engineering & Operations/Engineering and Board Secretary. The following Table 1-4: InnPower Organization sets out the structure of the organization.

Table 1-3 InnPower Corporation Organization Structure



UTILITY ORGANIZATIONAL STRUCTURE:

InnPower Corporation

InnPower Corporation is a wholly-owned corporation of the Town of Innisfil, and was incorporated October 5, 2000 under the laws of the Province of Ontario. The principal activity of the Company is to provide electrical power distribution throughout the Town of Innisfil and south Barrie.

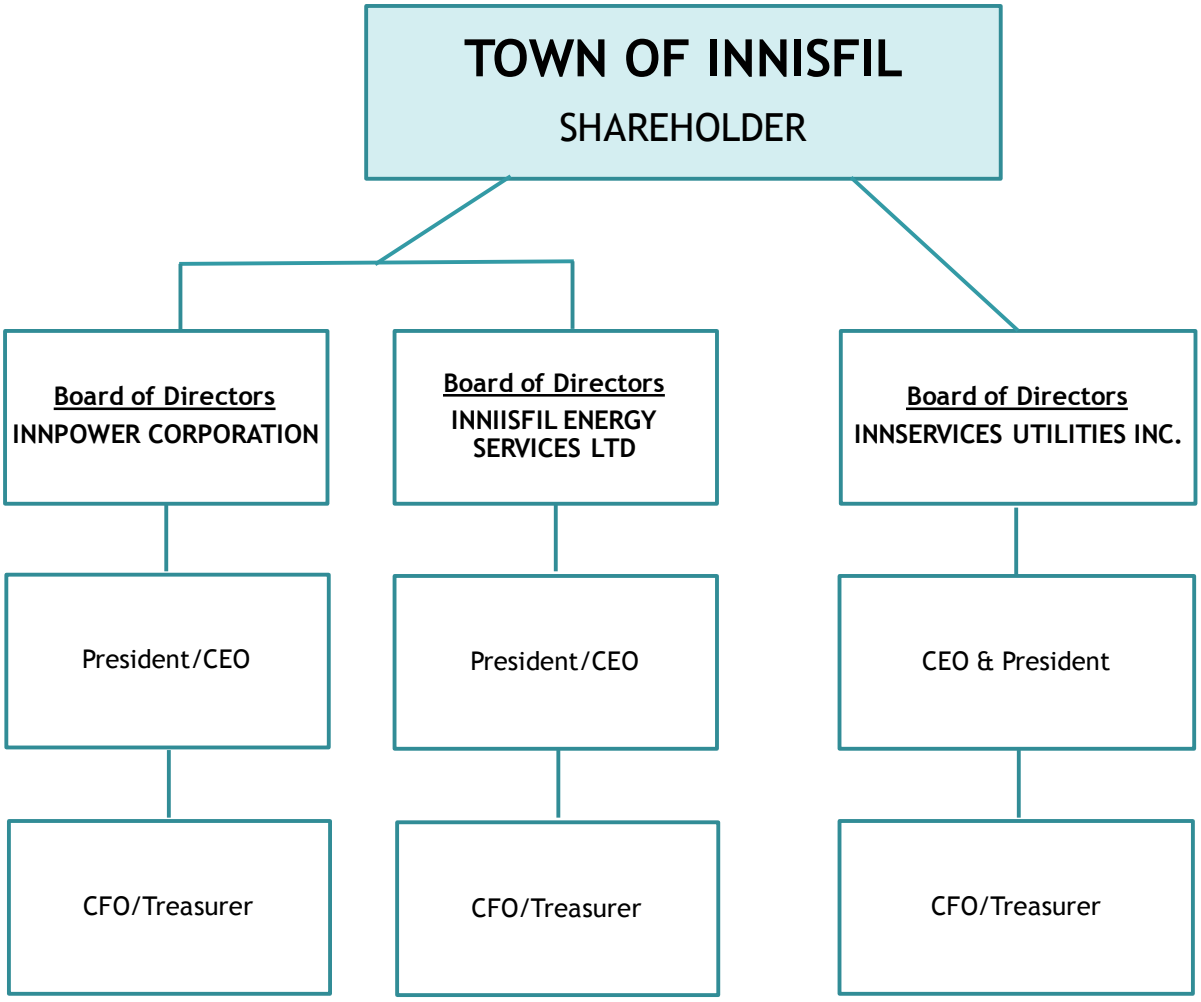
Innisfil Energy Services Limited

Innisfil Energy Services Ltd. (IESL) is a wholly-owned corporation of the Town of Innisfil and was incorporated on October 5, 2000 under the laws of the Province of Ontario. The principal activities of the Company were to provide hot water tank and sentinel light rentals. Currently IESL manages the sentinel light rental, owns and operates the Communication Towers and has provided loans for the Town of Innisfil LED Street Light Conversion. InnPower Corporation provides services under a Services Agreement to IESL.

At the time of submission of this Application, InnPower Corporation confirms that there are no planned changes in corporate or operational structure, or in legal organization and control.

The following Table 1-4: InnPower Utility Organization sets out the structure of the Utility.

Table 1-4 Utility Organization Structure



2.1.3. L: Specific Approvals Requested

InnPower Corporation hereby applies to the Ontario Energy Board (the Board) for approval of 2017 Distribution Rate Adjustments, based on Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications last revised on July 14, 2016.

InnPower Corporation is applying for annual rate adjustments under the parameters set out in the Board's 4th Generation IRM.

Background:

The Applicant is InnPower Corporation (previously referred to in this Application as the "Applicant" or "InnPower Corporation" or "IPC"). 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.

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).

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 14, 2015 in preparing this application.

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 to recover a service revenue requirement of $12,385,532

- as set out in Exhibit 1, Schedule 1, Section 2.1.5.A Revenue Requirement. The schedule of proposed 2017 rates is set out in Exhibit 8, Section 2.8.9 Tariff of Rates & Charges.
- Approval to adjust the Retail Transmission Service Rates (Network and Connection) in accordance with the Board's Guideline G-2008-0001 Electricity Distribution Retail Transmission Service Rates (RTSR), Revision 4.0 issued June 28, 2012 and as set out in Exhibit 8, Section 2.8.3 Retail Transmission Service Rates.
- Approval to continue to charge Standard Supply Service, Wholesale Market, Rural Rate Protection and OESP charges approved in the OEB Decision and Order in the matter of InnPower Corporations 2016 Distribution Rates (EB-2015-0081) subject to any modifications as a result of the OEB's future decisions.
- Approval of the proposed loss factor as set out in Exhibit 8, Section 2.8.8 Loss Adjustment Factors.
- Approval of adjusted Low Voltage rates as set out in Exhibit 8, Section 2.8.7 Low Voltage Service Rates.
- Approval for a modified microFIT Service Classification action to include microFIT and Net Metering customers and a modified rate.
- Approval to continue Specific Service charges approved in the OEB Decision and Order in the matter of InnPower Corporations 2016 Distribution Rates (EB-2015-0081).
- Approval for the following new and or modified Specific Service charges. Justifications for the new and or modified Specific Service charges are set out in Exhibit 8, Section 2.8.6

Specific Service Charges:

- Approval as presented of an interim Pole Attachment rate until the findings of the Review of Miscellaneous Rates and Charges (EB-2014-0365) determines a final rate and or a standardized calculation of a Pole attachment rate.
- Approval as presented for a modified Temporary Service -Install and Remove – Underground – No Transformer rate.
- Approval as presented for a modified Temporary Service - Install and Remove – Overhead – No Transformer rate.
- Approval as presented for a modified Temporary Service – Install and Remove – Overhead – With Transformer rate.
- Approval as presented for a modified Disconnect/Reconnect Charge – at meter-during regular hours.

- Approval to dispose of the Deferral and Variance Account Balances, audited as at December 31, 2015 plus calculated interest until December 31, 2016, over a two year period using the method of recovery described in Exhibit 9, Section 2.9.5 Disposition of Deferral and Variance Accounts.
- Approval to dispose of Account 1568 – Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) for lost revenue resulting from the 2011 – 2014 IESO programs over a two year period.
- Final disposition of a debit amount of $11,926 for One Time Incremental IFRS Transition Costs recorded in Account 1508.
- Interim approval of a Z-factor Rate Rider resulting from a major event which occurred in March 2016. Calculation of the rate rider and details of the MED event are set out in Exhibit 8, Section 2.8.2 Rate Design Policy.
- Placeholder to establish a credit for customers that transition to e-billing in the IRM timeframe.

The aforementioned requested approvals have been documented in Appendix 2-A, and are presented in Appendix G.

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.

Interim Rate Order

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, 2016, pending the implementation of the OEB`s Rate Order for the 2017 rate year.

2.1.4 Distribution System Overview

The Hydro Electric Commission of the Corporation of the Town of Innisfil was created in January 1991 (as provided for in Bill 177 (1990)). It continued to serve only the former Village of Cookstown, until 1993, when the distribution assets in the remainder of the newly Incorporated Town of Innisfil were purchased from Ontario Hydro.

Innisfil Hydro Distribution Systems Limited (Innisfil Hydro) was incorporated as a for-profit local distribution company in 2000 as required by the Electricity Act 1998. Innisfil Hydro has a distribution licence from the Ontario Energy Board (Licence # ED-2002-0520 defined boundary as the Town of Innisfil as of January 1, 1994) to operate its distribution system within the licensed territory of 292 square kilometres in the Town of Innisfil and the south part of the City of Barrie with the passing of Bill 196, Barrie-Innisfil Boundary Adjustment Act, 2009.

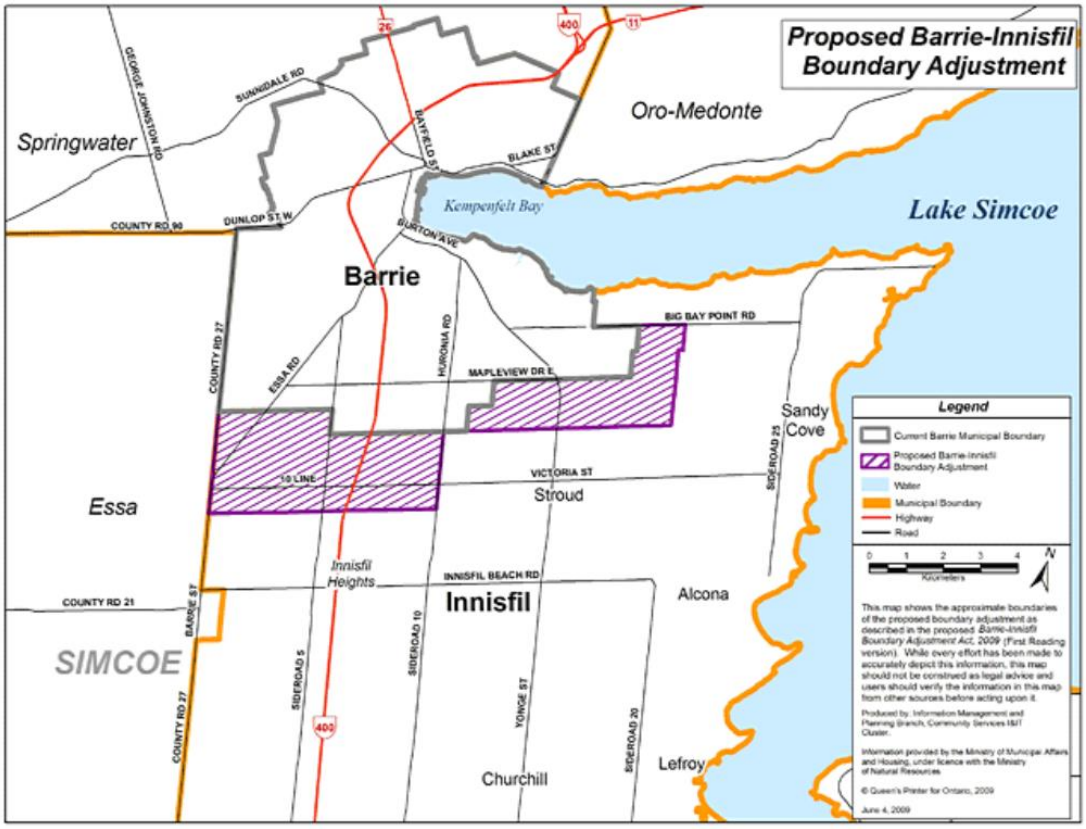
In January 2015, Innisfil Hydro changed its name to InnPower Corporation and relocated its Head Office and Operations Centre to the Innisfil Town Campus, where InnPower and the Town Roads and Parks divisions are establishing an operational hub whereby operational synergies will benefit both taxpayers and power users.

InnPower Corporation is a licensed distributor with approximately 16,000 customers servicing the lands of South Barrie and all of the Town of Innisfil which includes the communities of Alcona, Belle Ewart, Churchill, Cookstown, Guilford, Innisfil, and Lefroy.

InnPower Corporation has approximately 292 kilometres of 44KV circuits, 401 kilometres of three-phase distribution, 432 kilometres of single-phase circuits, 173 kilometres of primary underground cable, nine (9) distribution stations, two (2) shared distribution stations with Hydro One and four (4) private stations with distribution voltages of 16/27.6kV and 4.8/8.32kV.

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. Figure 1-1: Barrie Innisfil Boundary Adjustment presents InnPower Corporations service boundaries.

Figure 1-1: Barrie – Innisfil Boundary Adjustment



DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM:

Description of Distributor:

COMMUNITY SERVED:	Town of Innisfil and South Barrie
TOTAL SERVICE AREA:	292 sq. km
RURAL SERVICE AREA:	219 sq. km
DISTRIBUTION TYPE:	Electricity distribution
SERVICE AREA POPULATION:	34,000
MUNICIPAL POPULATION:	34,000
BOUNDARIES:	West: as identified in service area maps
	North: as identified in service area maps
	East: as identified in service area maps
	South: as identified in service area maps

LIST OF NEIGHBOURING UTILITIES:

InnPower Corporation neighboring utilities are PowerStream Corporation and Hydro One Inc.

PowerStream	Direct line: 1-877-963-6900
55 Patterson Road	Direct Fax: 705-722-6159
Barrie, ON L4M 4V8	Website: www.powerstream.ca
HYDRO ONE NETWORKS INC.	Direct line: 416-345-5000
483 Bay St	Direct Fax: 416-345-5870
Toronto, ON M5G 2P5	Website: www.HydroOne.com

Declaration of Host and Embedded Utilities

InnPower Corporation is fully embedded within the Hydro One Networks Inc. territory.

InnPower Corporation confirms that it has no transmission or high voltage assets deemed previously by the OEB as distribution assets.

InnPower Corporation has planned for significant densification with this 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 (APPENDIX 2-A) for this Application have been summarized below:

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.

- 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 2,400 condo resort units and or customers over the next ten (10) years.

- 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.

- The Lefroy area has development approval which will lead to approximately 2,300 new customers.

- A development named Sleeping Lion is currently being built for an estimated 5,000 residents around the existing Alcona area. Infrastructure projects commenced for this development in 2016 with the first customers connecting in 2017.

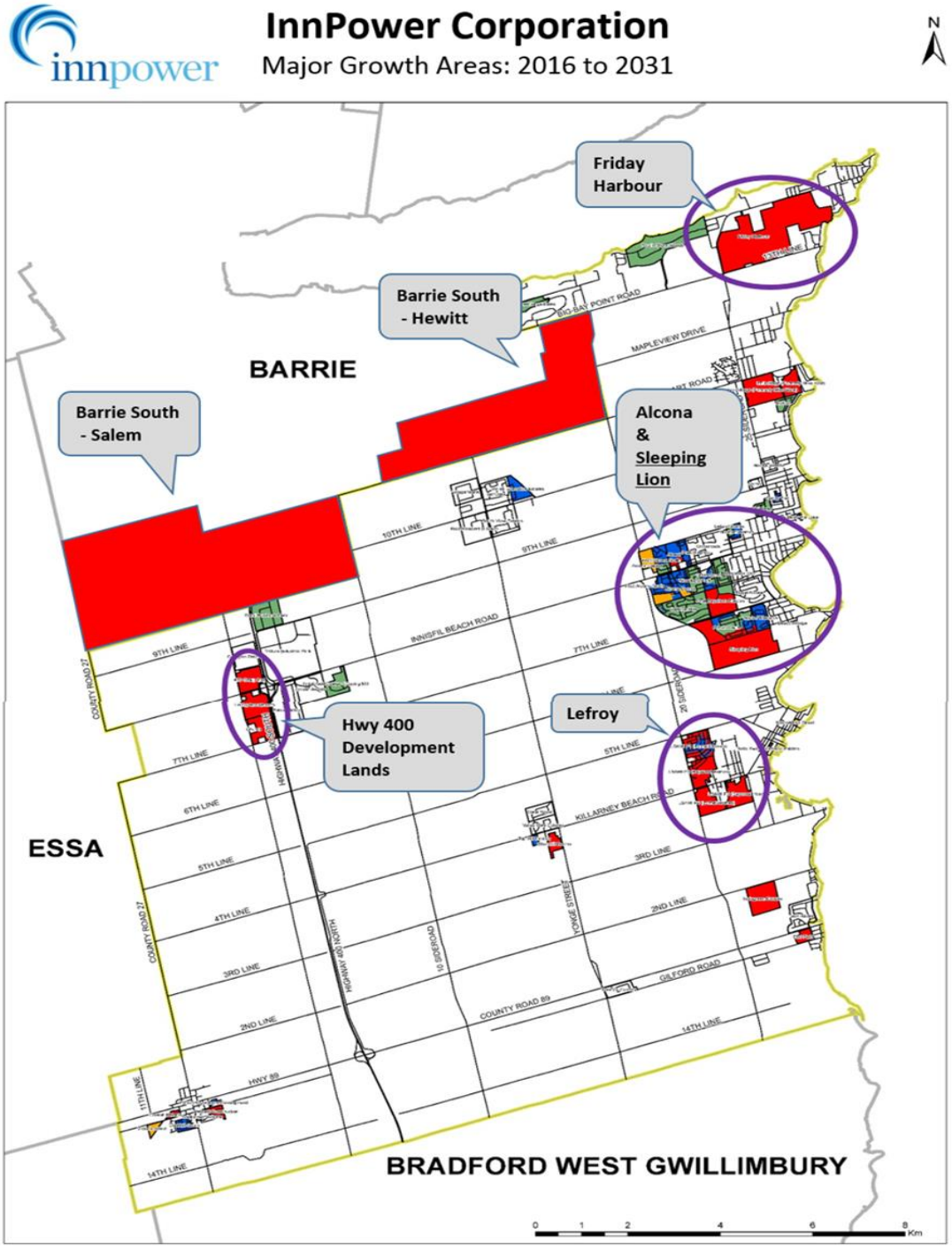
Following on the next page is a summary of the residential development that is planned for InnPower Corporation's Service Territory. This summary was the foundation for inputs to the Regional Planning, 5 Year Business Plan, Capital Planning and Operations, Maintenance and Administration forecasts.

Figure 1-3: Summary of Residential Development 2016 - 2084

			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Alcona			243	153	272	298	250	322	246	265	265	245	260	260	260	260	260	260	260	260	260
Total Alcona South (Sleeping Lion)			0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Total Churchill			0	12	12	5	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Gilford			0	5	5	5	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Cookstown			51	30	48	17	0	0	30	23	0	0	5	5	5	5	5	5	5	5	0
Total Stroud			10	10	10	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Friday Harbour			250	150	150	150	150	100	100	100	100	100	100	100	50	0	0	0	0	0	0
Total Lefroy			120	120	120	91	70	140	175	167	65	65	50	50	50	50	50	50	50	50	0
Total Growth per year			674	580	717	668	581	662	651	655	530	510	515	515	465	415	415	415	415	415	360
Alliston Total (includes Friday Harbour)			613	440	559	549	481	562	521	532	430	410	410	410	360	310	310	310	310	310	260
Alliston Total (without Friday Harbour)			363	290	409	399	331	462	421	432	330	310	310	310	310	310	310	310	310	310	260
Barrie TS Total (without Friday Harbour)			10	10	10	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Barrie TS Total (includes Friday Harbour)			613	440	559	549	481	562	521	532	430	410	410	410	360	310	310	310	310	310	260
Everett TS Total			51	30	48	17	0	0	30	23	0	0	5	5	5	5	5	5	5	5	0

Figure 1-2: InnPower Corporation Major Growth Areas sets out the major developments that will impact InnPower Corporations densification.

Figure 1-2: InnPower Corporation Major Growth Areas



2.1.5 Application Summary

2.1.5.A: Revenue Requirement

InnPower Corporation requests a Service Revenue Requirement of $12,385,532 for 2017 which provides for the recovery of the following:

- Operations, Maintenance and Administration Expenses
- Property Taxes
- Depreciation/Amortization Expense and
- Return on Rate Base (Debt Interest Expense + Return on Equity)

The 2017 Service Revenue Requirement represents an increase of $4,257,888 or 52.4% over the 2013 Board-approved amount of $8,127,644. Table 1.1 Revenue Requirement Summary presents the variances in $ and %'s from the previous Board Approved amounts to the 2017 Test Year.

Table 1.1: Revenue Requirement Summary

Revenue Requirement Summary	Board Approved 2013	2017 Test Year	2017 Variance to 2013 BA - $	2017 Variance to 2013 BA - %
OM&A Expenses	$ 4,900,000	$ 6,187,625	$ 1,287,625	26.3%
Amortization Expense	$ 1,280,461	$ 2,746,369	$ 1,465,908	114.5%
Total Distribution Expense	$ 6,180,461	$ 8,933,993	$ 2,753,532	44.6%
Regulated Return on Capital	$ 1,934,683	$ 3,188,474	$ 1,253,791	64.8%
Grossed Up PILS/Property Tax	$ 12,500	$ 263,065	$ 250,565	2004.5%
Service Revenue Requirement	$ 8,127,644	$ 12,385,532	$ 4,257,888	52.4%
Less: Revenue Offsets	$ 536,948	$ 1,207,121	$ 670,173	124.8%
Base Revenue Requirement	$ 7,590,696	$ 11,178,412	$ 3,587,716	47.3%

Based on the projected load forecast and customer growth for the 2017 Test Year, InnPower Corporation has estimated a revenue deficiency of $3,492,919 based on current rates. The computation of the revenue deficiency is set out in Exhibit 6, Section 2.6 Revenue Deficiency.

InnPower Corporation seeks approval from the OEB to revise its electricity distribution rates. The rates proposed to recover InnPower Corporation's projected revenue requirement and other relief are set out in Exhibit 8, Section 2.8.9 Tariff of Rates and Charges.

The main drivers of the revenue deficiency for the 2017 Test Year are as follows:

- An increase in OM&A expense of $1.3 M due mainly from;
  - Increased O&M to maintain the distribution system and associated reliability metrics
  - New hires brought on in 2013
  - Cost impacts resulting from the InnPower Corporation's new Administrative Headquarters
- A net increase in FTE count of 5 over the 2013 figure.
- Increase in depreciation expense resulting from net increases in rate base of $24.6M over the 2013 figure.
- Increase in PILS of $43K arising from the increase in taxable income.

2.1.5. B: Budgeting 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.

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 Corporation 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 Corporation 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 Corporation 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 Corporation 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 Corporation acknowledges that, where the priority of projects changes or factors outside of its influence change, InnPower Corporation 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; and
- Regulatory Requirements.

The Distribution System Plan presented in Exhibit 2/APPENDIX B 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 (unionized) 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. At the time of the preparation of this application InnPower Corporation and the PWU have not settled. For the purposes of this application the 2015 increase of 2.50% has been applied.

2.1.5. C: 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 same 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 1.2: 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%

Based on the output of the load forecast for the 2017 Test Year InnPower Corporation has prepared the following table to set out the load and customer growth from the 2013 Board Approved Load Forecast.

Forecasting Method for Customer Numbers and Billed Consumption

The forecast of customers by rate class was determined using a geometric mean analysis (the geometric mean was calculated over 12 years 2003 to 2014 of customers' growth rate). Based upon the geometric mean analysis, the expected number of customers/connections for the 2017 Test Year is of 20,319, or a 11% increase over the 2013 Board-approved customers/ connections.

Table 1.3: 2017 Load Forecast Growth from 2013 Board Approved Load Forecast

	Customer Connections				kWh		kW				
Class	2013 Board Approved	2017	Difference	% Change	2013 Board Approved	2017	2013 Board Approved	2017	Volumetric Difference	% Change kWh	% Change kW
Residential	14,189	15,930	1,741	12%	148,148,873	149,932,101	0	0	1,783,228	1%	
GS< 50 kW	910	1,052	142	16%	31,781,016	32,368,433	0	0	587,417	2%	
GS > 50 kW	66	72	6	8%	51,329,341	55,988,819	147,666	157,261	9,595	9%	6%
Sentinel Lighting	237	161	-76	-32%	104,942	98,320	292	273	-19	-6%	-6%
Street Lighting	2,889	3,030	141	5%	1,516,831	669,627	4,432	1,889	-2,543	-56%	-57%
Unmetered Scattered Load	78	74	-4	-5%	474,652	530,367	0	0	55,715	12%	
Total	**18,369**	**20,319**	**1,950**	11%	**233,355,655**	**239,587,667**	**152,390**	**159,423**	**2,433,393**	3%	5%

2.1.5. D: Rate Base and DSP

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 Board. 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.

Table 1-4: Rate Base Summary 2013 Board Approved to 2017 Test Year

	Last Board Approved 2013	2014	2015	2016 Bridge	2017 Test
Net Capital Assets in Service					
Opening Balance	$ 28,199,498	$ 30,850,492	$ 34,019,754	$ 49,145,092	$ 51,333,589
Ending Balance	$ 30,850,492	$ 34,019,754	$ 49,145,092	$ 51,333,589	$ 55,441,255
Average Balance	$ 29,524,995	$ 32,435,123	$ 41,582,423	$ 50,239,340	$ 53,387,422
Working Capital Allowance	$ 3,666,048	$ 3,961,443	$ 4,239,822	$ 4,565,553	$ 2,890,356
Working Capital Allowance Rate	12.0%	12.0%	12.0%	12.0%	7.5%
Total Rate Base	$ 33,191,043	$ 36,396,565	$ 45,822,245	$ 54,804,893	$ 56,277,779
Year over Year Rate Base % Increase		10%	26%	20%	3%
$ amount increase		$ 3,205,522	$ 9,425,680	$ 8,982,648	$ 1,472,886

The proposed Rate Base for the 2017 Test Year of $56,277,779 reflects an increase of $23,086,736 from the 2013 Board Approved. The increase is predominately as a result of:

- The inclusion of $13,247,546 (including land) in assets related to InnPower Corporation's new Corporate Headquarters and Administration building in 2015. These assets are related to the 2014 ICM approval (EB-2016-0085) for the new headquarters.

Details of all the 2017 additions are outlined in the InnPower Corporation' Distribution System Plan which has been filed in Exhibit 2.

The above major investments indicate the prudent, reasonable and forward-looking investment in the distribution assets necessary to meet other regulatory requirements such as "obligation to connect" new growth and the need to maintain the highest electrical safety standards.

Working Capital Allowance:

The following table sets outs the calculation of the Working Capital Allowance to support the Rate Base presented in Table 1-4:.

Table 1-5: **Working Capital Allowance Summary 2013 Board Approved to 2017 Test Year**

Expenses for Working Capital	2013 Actuals	2014	2015	2016 Bridge	2017 Test
Eligible Distribution Expenses					
3500 Distribution - Operations	$ 1,323,999	$ 1,342,978	$ 1,377,569	$ 1,455,280	$ 1,578,483
3550 Distribution - Maintenance	$ 463,151	$ 471,477	$ 427,525	$ 530,250	$ 667,795
3650 Billing & Collecting	$ 1,054,939	$ 1,169,535	$ 1,096,116	$ 1,203,967	$ 1,184,825
3700 Community Relations	$ 5,419	$ 5,663	$ 8,066	$ 10,250	$ 12,000
3800 Admin & General	$ 2,147,695	$ 2,234,998	$ 2,648,314	$ 2,638,335	$ 2,744,522
6105 Taxes other than Income tax	$ 24,132	$ 13,463	$ 117,714	$ 88,912	$ 122,500
Total Eligible Distribution Expense	$ 5,019,335	$ 5,238,114	$ 5,675,305	$ 5,926,994	$ 6,310,125
3350 Power Supply Expenses	$ 25,531,064	$ 27,773,907	$ 29,656,547	$ 32,119,278	$ 32,227,960
Total Expenses for Working Capital	$ 30,550,399	$ 33,012,021	$ 35,331,852	$ 38,046,272	$ 38,538,084
Working Capital Factor	12%	12%	12%	12%	7.50%
Total Working Capital Allowance	$ 3,666,048	$ 3,961,443	$ 4,239,822	$ 4,565,553	$ 2,890,356

InnPower Corporation is not proposing to recover any costs in this Application for renewable energy connections/expansions, smart grid, and regional planning initiatives.

InnPower Corporation Distribution System Plan (DSP)

InnPower Corporation is submitting its first Distribution System Plan with this application for approval.

For the years 2017 and 2018, the focus of the capital spending is on system service projects to accommodate load growth, while for the years 2019 to 2021 the focus is on system renewal projects to replace assets which have reached end-of-life.

InnPower Corporation's complete DSP can be located in Exhibit 2 in Appendix B.

Capital Expenditures for the 2017 Test Year

The following table identifies the planned capital spend for the 2017 Test Year.

Investment Category	2017 Plan
System Access	$ 1,185,698
System Renewal	$ 1,215,739
System Service	$ 3,100,374
General Plant	$ 1,187,135
Total Capital (NET)	**$ 6,688,946**

Appendix 2-AB is provided to outline the change in capital expenditures from the last OEB approved capital spend by $ and %.

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2017*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2012			2013			2014			2015			2016			2017	2018	2019	2020	2021
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access		1,751	--		1,039	--		1,263	--		896	--		1,084	--	1,186	1,984	1,595	1,598	2,013
System Renewal		654	--		987	--		697	--		487	--		999	--	1,216	1,140	2,919	2,400	2,109
System Service		586	--		1,377	--		2,819	--		2,944	--		1,743	--	3,100	2,829	1,276	1,556	1,402
General Plant		828	--		1,348	--		253	--		13,250	--		661	--	1,187	1,423	897	680	706
TOTAL EXPENDITURE	6,084	3,818	-37.2%	9,021	4,751	-47.3%	13,038	5,031	-61.4%	5,674	17,578	209.8%	4,487	4,487	0.0%	6,689	7,376	6,687	6,234	6,230
System O&M		$ 1,761	--		$ 1,787	--		$ 1,814	--		$ 1,805	--		$ 1,986	--	$ 2,246	$ 2,245	$ 2,246	$ 2,246	$ 2,246

2.1.5. E: Operations, Maintenance and Administration (OM&A) Expense

InnPower Corporation's 2017 Test Year Operating Costs are $6,187,625 including Operating, Maintenance and Administration (OM&A) and excluding LEAP and property taxes as summarized in Table 1-6: below. The 2017 Test Year requested recovery is $1,297,433 greater than InnPower Corporations 2013 COS Application EB-2012-0139 and a 6% increase from the Bridge Year.

Table 1-6: Summary of OM&A Increases 2013 Board Approved to 2017 Test Year

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
Operations	$ 1,234,230	$ 1,323,999	$ 1,342,978	$ 1,377,569	$ 1,455,280	$ 1,578,483
Maintenance	$ 506,161	$ 463,151	$ 471,477	$ 427,525	$ 530,250	$ 667,795
Billing and Collecting	$ 997,953	$ 1,054,939	$ 1,169,535	$ 1,096,116	$ 1,203,967	$ 1,184,825
Community Relations	$ 8,586	$ 5,419	$ 5,663	$ 8,066	$ 10,250	$ 12,000
Administrative and General	$ 2,143,263	$ 2,147,695	$ 2,234,998	$ 2,648,314	$ 2,638,335	$ 2,744,522
Total	**$ 4,890,192**	**$ 4,995,203**	**$ 5,224,651**	**$ 5,557,591**	**$ 5,838,082**	**$ 6,187,625**
%Change (year over year)			4.6%	6.4%	5.0%	6.0%

The OM&A costs in the 2017 Test Year reflect the resourcing mix and investments to meet customer and broader public policy requirements.

As supported by future growth projections and Regional Planning, InnPower Corporation is facing a period of planning, designing, and implementation of infrastructure expansion, preventative maintenance in conjunction with increased volumes of services to meet our customer requirements resulting from year over year growth. As explained further in Section 2.4.3.1 Workforce Planning and Employee Compensation, InnPower Corporation is not requesting any additional FTE headcount costs for this application nor did it fully acquire planned FTE from our last rebasing application. This decision has been based on the following guiding principles in preparing this application:

- Minimize impacts on existing customers to the extent possible while supporting infrastructure expansion.
- Load will pay for load.
- Resources will be added when new customers are added and or market changes dictate while maintaining performance indices.
- Maintain InnPower Corporation's current PEG Benchmarking ranking of 3.

InnPower Corporation will closely monitor performance indices throughout the IRM timeframe to ensure that targets are maintained. Continued process improvements/efficiencies (as documented in Exhibit 1 Section 2.1.10 InnPower Corporation Operational Efficiencies) and expansion of shared service opportunities throughout the IRM timeframe will be prioritized to mitigate additional FTE requirements.

Further detailed analysis of OM&A Expenses by program is provided in Exhibit 4.

Overview of OM&A Expenses 2013 Board Approved to 2017 Test Year

Locates/ON1CALL

In 2013, Bill 8 legislation for ON1CALL came into effect. The impact of the legislation resulted in higher than normal cable-locate volumes, 2012 – 1,917, 2013 – 3,075 and 2014 – 4,449. In order to address the increased volumes and 5 day completion timeframes, InnPower Corporation found it necessary to look for external contracted assistance. The costs associated with software for locate management, locate completion, internal process changes and reporting are also reflected.

With InnPower Corporation's current and forecasted growth (due to densification), cable locate volumes are forecasted to increase throughout the 2016 Bridge and 2017 Test Year.

Operations Impacts

Cost Drivers for Operations total $242,474 for the 2015 – 2017 timeframe. The key drivers are threefold:

1. Increased Meter Expense due to customer growth and exchange pricing;
    - $25,987 in 2015: and
    - $26,211 in 2017
2. Increased Miscellaneous Distribution Expense
    - $78,033 in 2016:and
    - $81,130 in 2017

InnPower Corporation has invested in advance technology and smart grid capability which includes the implementation of a fully operational SCADA system. The Operations Technology/SCADA team is responsible for the design, installation and support of technology required to effectively manage distribution system field operations. This

includes wireless and data communication systems, SCADA Network Management System ("NMS") hardware and software.

The costs incurred in the operation of the SCADA system, including switching, battery checks and reporting are included in the above budget.

3. Line Supervision

- $30,413 in 2017

The Engineering Department is responsible for system planning, load growth forecasting, and new connections. This includes capital project planning and design, load and generation connections, distribution asset replacement programs, introducing new distribution assets, load flow studies, system upgrades, overhead and underground feeder construction designs. The increase in Line Supervision costs is reflective of these increased activities.

Maintenance Impacts

The following table sets out the increased Maintenance cost drivers in 2016 and 2017. The costs are associated with planned maintenance activities which are required for InnPower Corporation's distribution system.

Maintenance Cost Drivers	2014	2015	2016	2017
Maintenance Underground Feeders				
Overhead Lines & Feeders				$ 11,661
Maintenance of Underground Services			$ 40,436	
Maintenance of Overhead lines - Right of Way			$ 33,999	
Overhead Conductors and Devices				$ 65,875
Maintenance Line Transformers				$ 50,855
Maintenance Poles/Towers/Fixtures				$ 13,913
Total	**$ -**	**$**	**74,435**	**$ 142,304**

Outside Services Employed

With increased Engineering and Operations activity underway since 2013, InnPower Corporation has seen an incremental cost of legal review for service agreements, economic evaluations, etc. Additional one- time costs of $18,000 in 2015 were incurred for the final transition to IFRS Financial Statements.

Inflation

InnPower Corporation has assumed a 1.80% inflation factor for this Application.

2.1.5. F: Cost of Capital

InnPower Corporation has followed the Report of the Board on Cost of Capital Parameters for Ontario's Regulated Utilities, issued October 27, 2016, 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 27, 2015, for the allowed return on equity and where appropriate for debt.

InnPower Corporation's cost of capital for 2017 has been calculated as 5.67%, as set out in the following table.

2017		
Description	**Deemed Portion**	**Effective Rate**
Long-Term Debt	56.00%	3.72%
Short-Tern Debt	4.00%	1.76%
Return On Equity	40.00%	8.78%
Weighted Debt Rate		3.59%
Regulated Rate of Return		5.67%

InnPower Corporation has updated the appropriate models and calculations in accordance with the letter issued on October 27, 2016.

2.1.5. G: 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 in November of 2006 and all subsequent updates.

InnPower Corporation has prepared a Cost Allocation Study for the 2017 Test Year based on an allocation of the 2017 Test Year costs (i.e. the 2016 forecast revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh), by class and by customer counts.

The Cost Allocation model output identified that the Street Lighting Rate Class revenue to cost ratios were beyond the Board range at 197.80%. For the Street Lighting Rate Class InnPower Corporation is proposing a 3 year phasing during the IRM timeframe to bring the cost ratio into the acceptable Board Range.

2017 – 160%

2018 – 140%

2019 – 120%

For all other Rate Classes InnPower Corporation has applied the same methodology as used in the Applicant's 2013 Cost of Service rate application (EB-2012-1-0139) for adjusting revenue-to-cost ratio to be within the Board's expected tolerance. Table 1-7: Outlines the proposed Revenue to Cost Ratios:

Table 1-7: 2017 Proposed Revenue to Cost Ratios

Cost Allocation Based Calculations 2017												
Class	Revenue Requirement - 2017 Cost Allocation Model - Line 40 from O1 in CA	2017 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2017 Cost Allocation Model - Line 19 from O1 in CA	Total Revenue	Revenue Cost Ratio	Check Revenue Cost Ratios from 2017 Cost Allocation Model - Line 75 from O1 in CA	Proposed Revenue to Cost Ratio	Proposed Revenue	Miscellaneous Revenue	Proposed Base Revenue	Board Target Low	Board Target High
Residential	10,125,216	9,018,215	1,010,349	10,028,563	99.0%	98.99%	99.40%	10,063,999	1,010,349	9,053,651	85%	115%
GS < 50 kW	982,084	926,367	92,359	1,018,726	103.7%	103.74%	105.27%	1,033,830	92,359	941,471	80%	120%
GS >50 to 4999 kW	1,001,471	789,097	78,308	867,405	86.6%	86.50%	89.00%	891,310	78,308	813,002	80%	120%
Sentinel Lights	51,943	46,931	5,484	52,415	100.9%	100.94%	101.08%	52,504	5,484	47,019	80%	120%
Street Lighting	197,610	373,030	17,823	390,853	197.8%	197.80%	160.04%	316,258	17,823	298,435	80%	120%
Unmetered and Scattered	27,207	24,773	2,798	27,570	101.3%	101.34%	101.56%	27,631	2,798	24,833	80%	120%
TOTAL	12,385,532	11,178,412	1,207,121	12,385,532				12,385,532	1,207,121	11,178,411		

Rate Design

InnPower Corporation commenced the implementation to the new Rate Design Policy for Residential Customers in 2016 with an approved 4 year transition. In calculating the 2nd year for the transition to fully fixed rates the change in the fixed rate calculated to $4.81.

Due to this increase InnPower Corporation is proposing to add an additional year for the full transition to fixed rates. In calculating the fixed transition with the proposed additional transition year the change in the fixed rate is calculated at $3.61.

Rate Design Tab – RRWF Model

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	4

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 6,292,857.43	32.92	$ 6,292,987.20
Variable	$ 2,760,793.38	0.0184	$ 2,758,750.66
TOTAL	$ 9,053,650.81	-	$ 9,051,737.86

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	77.13%	$ 6,983,055.77	$ 36.53	$ 6,983,074.80
Variable	22.87%	$ 2,070,595.03	$ 0.0138	$ 2,069,062.99
TOTAL	-	$ 9,053,650.81	-	$ 9,052,137.79

Checks[3]	
Change in Fixed Rate	$ 3.61
Difference Between Revenues @ Proposed Rates and Class Specific	($1,513.01) -0.02%

2.1.5. H: Deferral and Variance Accounts

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.

InnPower Corporation is requesting disposal of the Group 1 and Group 2 DVA balances over a 2 year period.

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.

Table 1.8: DVA Group 1 and Group 2 Balances

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**

InnPower Corporation is not requesting any new Deferral and Variance Accounts (DVA's) with this application.

2.1.5. I: Bill Impacts

In preparing this Application, InnPower Corporation has considered the impacts on its customers in conjunction to managing the requirements of the distribution system and preparing for system expansion.

Monthly customer impacts including the average percentage Total Bill Impact and Average Dollar Impact are presented in the following tables.

Table 1-9: Summary of Overall Average Invoice Rate Impacts

Rate Class	2016 Invoice	2017 Invoice	$ Variance	% from 2016
Residential	$ 162.23	$ 174.80	$ 12.57	7.75%
GS < 50 kW	$ 391.50	$ 414.05	$ 22.55	5.76%
GS 50 to 4,999 kW	$ 4,827.99	$ 5,371.45	$ 543.46	11.26%
Street Lighting	$ 21,965.10	$ 20,946.96	-$ 1,018.14	-4.64%

In Exhibit 8, Section 2.8.11 Bill Impact Information, InnPower Corporation has provided a summary of the distribution bill impact that InnPower Corporation's customers would experience as of January 1, 2017 if the rate increase proposed in this application was approved by the OEB.

Table 1-9A: Summary of Distribution Rate Impacts

Customer Class	Item Description	Unit	2016 Rate ($)*	2017 Rate ($)
Residential				
750 kWH	Monthly Service Charge	per month	27.06	36.53
	Distribution Volumetric Rate	per kWh	0.0159	0.0138
	Total Distribution Charge		$38.99	$46.88
				20.3%
GS < 50 kW				
2000 kWH	Monthly Service Charge	per month	37.98	46.04
	Distribution Volumetric Rate	per kWh	0.0092	0.0111
	Total Distribution Charge		$56.38	$68.24
				21.0%
GS >50 to 4999 kW				
100 kW	Monthly Service Charge	per month	167.72	470.49
	Distribution Volumetric Rate	per kW	3.444	2.7283
	Total Distribution Charge		$512.15	$743.32
				45.1%
Street Lighting				
1 kW	Monthly Service Charge	per month	6.33	6.04
4 Connections	Distribution Volumetric Rate	per kW	43.7607	41.7563
	Total Distribution Charge		$3,001.05	$2,863.58
				-4.6%

*2016 Distribution rate includes ICM amount for new building

2.1.6 Customer Engagement

The RRFE Report contemplates enhanced engagement between distributors and their customers to provide better alignment between operational plans and customer needs and expectations.

In this section, InnPower Corporation has provided an overview of customer engagement activities that it has undertaken and illustrates how customer feedback has been used to continually improve the customer experience.

InnPower Corporation has completed Appendix 2-AC Customer Engagement Activities which is included in this Exhibit as an Appendix B.

InnPower Corporation strongly believes that utilizing daily touch points with customers is an opportunity to obtain feedback. To this end the following methods and platforms are utilized to engage with our customers:

- Telephone Call Centre
  - Inbound calls
  - Outbound calls
  - Interactive voice response
  - On hold messaging
- Emails
  - Inbound
  - Outbound
- Letters
  - Including hand-delivered letters to customers who will be impacted by planned outages and capital improvement projects
- Website
- Bills
  - Paper/electronic bills
  - Bill messaging/envelope messaging
  - Bill inserts

- Social Media
    - Facebook
    - Twitter
- Surveys
    - Bi-annual Customer Satisfaction survey
    - Bi-annual ESA survey
- Face to Face
    - Interactions with staff – one on one or group settings
    - Customer meetings with key staff
    - Information sessions
- Community outreach activities
    - Booths at community events
    - Displays at local retail stores
    - Presentations to community groups
- Advertising
    - Newspaper advertising , conservation and demand management programs, regulatory notices

Via the daily touchpoints with our customers' information requirements, questions and issues are communicated back to the Management Team. Based on the specific issue departmental primes will improve communication, training and future community involvement to address customer needs.

InnPower Corporation recognized that CDM Outreach was a perfect medium to engage and obtain feedback from our customers in addition to increasing energy and conservation knowledge.

In the 2011 – 2014 Conservation Framework, InnPower achieved 84.4% of its 9 GWH energy target. Considering that InnPower Corporation's customer base is approximately 90% residential this was quite the achievement. InnPower is confident that this achievement was influenced by the community outreach activities in promoting the save on energy programs. The following save on energy program uptake was accomplished:

Residential Programs

- Heating and cooling – 792
- Appliance Retirement/Exchange – 487
- Coupons – 38,466
- Peaksaver/Peaksaver plus – 263
- Home Assistance Program – 167

Business Programs

- Small Business Lighting – 410
- RetroFit – 45
- Demand Response – 2
- Audit Funding - 2

This outreach approach has been carried over with the transition to the Conservation First Framework (CFF) for the 2015 – 2020 timeframe. The following tables identify the CDM outreach activities undertaken by InnPower Corporation. To date InnPower has achieved a total of 102 days out in the Innisfil and South Barrie community interacting with our customers.

The following Tables set out the CDM Engagement and Educational Activities:

2011

2011 InnPower Customer Engagement Activities

Event/Promotion	Location	Target (RES, C&I, IND, HAP, ALL)	Event Date or Timeframe	Outreach Potential	Notes/Programs Promoted
Christmas Light Exchange	IHDSL Office	RES	11/12/11	200	All SOE Programs promoted, benefits of LEDs, light exchange (incandescent for LED).
Cookstown Chamber of Commerce Golf Tournament - Sponsorship	Sponsorship	ALL	9/8/11	500	SOE Hole Sponsorship and prize donation.
Innisfil Family Day - SOE Booth	Innisfil Rec Centre	ALL	2011	750-1,000	Promotion of all SOE programs.
Ladies of the Lake Celebration - SOE Booth	Innisfil Beach Park	ALL	2011	50-100	Promotion of all SOE programs.
Sandycove Acres Home Show - SOE Booth	Sandycove Acres	RES, HAP	2011	400	Promotion of all SOE programs.
Small Business Week	Town of Innisifl	C&I	2011	200	Promotion of SOE for Business Programs.
Summerfest - SOE Booth	Innisfil Beach Park	ALL	2011	10,000	Promotion of all SOE programs.
Weekly Farmers Market - SOE Booth (X4)	Innisfil	ALL	2011	200	Promotion of all SOE programs.
Wing Ding Fest - SOE Booth	Cookstown	ALL	2011	15,000	Promotion of all SOE programs.

2011 InnPower Customer Educational Activities					
Event/Promotion	**Location**	**Target (RES, C&I, IND, HAP, ALL)**	**Event Date or Timeframe**	**Outreach Potential**	**Notes/Programs Promoted**
Bill Messaging	Bills	ALL	2011	15,000	Updates to TOU Rates, billing changes, general promotion of SOE, Customer Connect, community events, other relevant information.
Conservation Sessions (4) - Learn to Conserve	Innisfil Public Libraries	ALL	2011	500	Educational sessions around TOU Rates, SOE Programs and energy saving tips.
Customer Connect	Online	RES	2011	2,000	Customer Connect data available for customer review/download through Customer Connect.
Customer Service TV	InnPower Office	ALL	2011	6,000	Promotion of CDM Community Events, Coupon Events, SOE Programs, energy saving tips, etc.
Innisfil Hydro Website	Online	ALL	2011	20,815	Promotion of all CDM Programs, Community Events, energy saving tips, CFL disposal, TOU info, etc.
Quarterly Conservation eNewsletter	Online	ALL	2011	15,000	Promotion of SOE Programs, energy saving tips, upcoming events, new technologies, etc.

2012

2012 InnPower Customer Engagement Activities					
Event/Promotion	**Location**	**Target (RES, C&I, IND, HAP, ALL)**	**Event Date or Timeframe**	**Outreach Potential**	**Notes/Programs Promoted**
Contractor Breakfast Session (with PowerStream)	Barrie	C&I, IND	2012	50	Promotion of SOE for Business.
Cookstown Chamber of Commerce Golf Tournament - Sponsorship	Sponsorship	ALL	9/13/12	500	Hole Sponsorship and prize donation.
Earth Hour Event 2012	Innisfil Rec Centre	ALL	3/31/12	500	Energy Conservation Pledges, promotion of SOE.
Innisfil Celtic Festival - SOE Booth	Innisfil	ALL	2012	500	SOE Booth, promotion of SOE programs, plinko and draw prizes.
Innisfil Family Day - SOE Booth	Innisfil Rec Centre	ALL	6/23/12	750-1,000	SOE Booth, promotion of SOE programs, plinko and draw prizes.
Innisfil Farmers Market - SOE Booth	Innisfil Rec Centre	ALL	2012		Promotion of all SOE Programs
Ladies of the Lake Celebration - SOE Booth	Innisfil Beach Park	ALL	2012	50-100	Promotion of all SOE programs.
Mayor's Golf Tournament - Sponsorship	Innisfil	ALL	2012		Tournament Sponsorship.
OACETT Annual Georgian Bay Chapter Golf Tournament - Sponsorship	Sponsorship	RES, C&I	2012	120	Draw Prize.
OMAFRA Session	Utopia	All	2012	80	
Retialer Co-ops (Canadian Tire, Home Depot, Home Hardware) - SOE Booth	Canadian Tire, Home Depot, Home Hardware, Canadian Tire	RES	2012		Promotion of SOE Coupon Event.
Sandycove Acres - HAP Session	Sandycove Acres	RES, HAP	2012	100	HAP Presentation.
Sandycove Acres Home Show - SOE Booth	Sandycove Acres	RES, HAP	2012	400	Promotion of all SOE programs, with focus on HAP. SOE Draw Prize.
Simcoe County District School Board - Cheque Presentation	Cheque Presentation	C&I	1/18/12		Retrofit Cheque Presentation and News Release.
Summerfest - SOE Booth	Innisfil Beach Park	ALL	6/16/12 6/17/12	10,000	SOE Booth, promotion of SOE programs, plinko and draw prizes.
Wing Ding Fest - SOE Booth	Cookstown	ALL	6/8/12 6/9/12	15,000	SOE Booth, promotion of SOE programs, plinko and draw prizes.

2012 InnPower Customer Educational Activities					
Event/Promotion	**Location**	**Target (RES, C&I, IND, HAP, ALL)**	**Event Date or Timeframe**	**Outreach Potential**	**Notes/Programs Promoted**
Bill Messaging	Bills	ALL	2012	15,000	Updates to TOU Rates, billing changes, general promotion of SOE, Customer Connect, community events, other relevant information.
CFL Recycling Program	IHDSL Office, Innisfil Town Hall	RES	2012		CFL disposal program for InnPower customers. Cross promotion of LED Coupons.
Conservation Sessions (4) - TOU Implementation	Innisfil Public Libraries	ALL	2012	500	Educational sessions around TOU Rates, SOE Programs and energy saving tips.
Kill-a-Watt Appliance Monitor Loan Program	Innisfil Public Libraries	RES	2012		Appliance monitors available to be loaned out at Innisfil Public Library branches.
Customer Connect	Online	RES	2012	2,000	Customer Connect data available for customer review/download through Customer Connect.
Customer Service TV	InnPower Office	ALL	2012	6,000	Promotion of CDM Community Events, Coupon Events, SOE Programs, energy saving tips, etc.
Innisfil Hydro Website	Online	ALL	2012	19,795	Promotion of all CDM Programs, Community Events, energy saving tips, CFL disposal, TOU info, etc.
Quarterly Conservation eNewsletter	Online	ALL	2012	300	Promotion of SOE Programs, energy saving tips, upcoming events, new technologies, etc.

2013

2013 InnPower Customer Engagement Activities

Event/Promotion	Location	Target (RES, C&I, IND, HAP, ALL)	Event Date or Timeframe	Outreach Potential	Notes/Programs Promoted
2013 Innisfil Hydro Kids Conservation Calendar Contest	Innisfil Schools	ALL	2013	1000	All SOE Programs promoted in calendar. Contest theme around energy conservation.
Barrie Minor Hockey Association - Sponsorship	Sponsorship	ALL	2013		Team Sponsorship.
Ladies of the Lake Celebration - SOE Booth	Innisfil Beach Park	ALL	2013	50-100	Promotion of all SOE programs, with focus on Coupons, draw prize and plinko.
Cookstown and District Chamber of Commerce Golf Tournament - Sponsorship	Sponsorship	ALL	9/12/13	500	SOE Hole Sponsorship.
Innisfil Family Day – SOE Booth	Innisfil Rec Centre	ALL	6/22/13	750-1,000	SOE Booth, promotion of SOE programs, plinko and draw prizes.
Innisfil Farmers Market - Soe Booth	Innisfil Rec Centre	ALL	2013	200	Promotion of SOE Programs.
Innisfil Pitch-in Day – SOE Booth	Centennial Park	ALL	2013	200	SOE Booth, promotion of SOE programs, SOE giveaways for volunteers.
Innisfil Summerfest – SOE Booth	Innisfil Beach Park	ALL	6/15/2013 6/16/13	10,000	SOE Booth, promotion of SOE programs, plinko and draw prizes.
Kids Scoop Bus Window Sponsorship	Kids Scoop Bus	RES	2013	200	SOE Window Ad on Kids Scoop Bus.
Mayor's Golf Tournament - Sponsorship	Sponsorship	ALL	September, 2013	500	SOE Hole Sponsorship.
OACETT Annual Georgian Bay Chapter Golf Tournament - Sponsorship	Sponsorship	RES, C&I	2013	120	Draw Prize.
Sandy Cove Acres Home Show – SOE Booth	Sandycove Acres	RES, HAP	2013	400	Promotion of all SOE programs, with focus on HAP. SOE Draw Prize.
Sandy Cove Farmers Market – SOE Booth	Sandycove Acres	ALL	2013	100	Promotion of SOE Programs.
Sandycove Acres - HAP Session	Sandycove Acres	RES, HAP	2013	100	HAP Presentation.
Wing Ding Festival – SOE Booth	Cookstown	ALL	6/8/13 6/9/13	15,000	SOE Booth, promotion of SOE programs, plinko and draw prizes.

2013 InnPower Customer Educational Activities

Event/Promotion	Location	Target (RES, C&I, IND, HAP, ALL)	Event Date or Timeframe	Outreach Potential	Notes/Programs Promoted
Bill Messaging	Bills	ALL	2013	15,000	Updates to TOU Rates, billing changes, general promotion of SOE, Customer Connect, community events, other relevant information.
CFL Recycling Program	IHDSL Office, Innisfil Town Hall	RES	2013		CFL disposal program for InnPower customers. Cross promotion of LED Coupons.
Customer Connect	Online	RES	2013	2,200	Customer Connect data available for customer review/download through Customer Connect.
Customer Service TV	InnPower Office	ALL	2013	6,000	Promotion of CDM Community Events, Coupon Events, SOE Programs, energy saving tips, etc.
Innisfil Hydro Website	Online	ALL	2013	17,913	Promotion of all CDM Programs, Community Events, energy saving tips, CFL disposal, TOU info, etc.
Kill-a-Watt Appliance Monitor Loan Program	Innisfil Public Libraries	RES	2013		Appliance monitors available to be loaned out at Innisfil Public Library branches.
Quarterly Conservation eNewsletter	Online	ALL	2013	500	Promotion of SOE Programs, energy saving tips, upcoming events, new technologies, etc.

2014

2014 InnPower Customer Engagement Activities

Event/Promotion	Location	Target (RES, C&I, IND, HAP, ALL)	Event Date or Timeframe	Outreach Potential	Notes/Programs Promoted
2014 Innisfil Hydro Kids Conservation Calendar Contest	Innisfil Schools	ALL	2014	600	All SOE Programs promoted in calendar. Contest theme around renewable energy.
Barrie Minor Hockey Association - Sponsorship	Sponsorship	ALL	2014		Team Sponsorship.
Celebrate Lake Simcoe – SOE Booth	Innisfil Beach Park	ALL	7/26/14	50-100	Promotion of all SOE programs, with focus on Coupons, draw prize and SOE plinko.
Cookstown and District Chamber of Commerce Golf Tournament - Sponsorship	Gilford	ALL	9/11/14	500	SOE Hole Sponsorship.
Cookstown Splish Splash Event – SOE Booth	Cookstown	ALL	5/31/14	250	Promotion of all SOE programs, with focus on Coupons, draw prize and SOE plinko.
ICECorp New Year's Skate - Sponsorship	Innisfil Rec Centre	RES	12/31/13	200-400	Draw Prize.
Innisfil Family Day – SOE Booth	Innisfil Rec Centre	ALL	6/21/14	750-1,000	Promotion of all SOE programs, with focus on Coupons, draw prize and SOE plinko.
Innisfil Pitch In Day – SOE Booth	Centennial Park	ALL	5/10/14	200	Promotion of all SOE programs, with focus on Coupons. Draw prize including LED bulbs and smart power bar.
Innisfil Summerfest – SOE Booth	Innisfil Beach Park	ALL	6-14-14 6-15-14	10,000	Promotion of all SOE programs, with focus on Coupons, draw prize and SOE plinko.
Kids Scoop Bus Window Sponsorship	Kids Scoop Bus	RES	1/1/14		SOE Window Ad on Kids Scoop Bus.
Local Builder/Developer Session	IHDSL Office	RES, C&I	12/11/14	50	Promotion of new construction SOE programs.
Mayors Annual Golf Tournament - Sponsorship	Sponsorship	ALL	September, 2014	500	SOE Hole Sponsorship.
OACETT Annual Georgian Bay Chapter Golf Tournament - Sponsorship	Sponsorship	RES, C&I	September, 2014	120	SOE Draw Prize.
Red Velvet Gala Enviornmental Leadership Award - Sponsorship	Sponsorship	C&I	10/10/14	100-150	SOE Sponsorship of Enviornmental Leadership Award.
Sandycove Acres Home Show - SOE Booth	Sandycove Acres	RES, HAP	4/12/14	400	Promotion of all SOE programs, with focus on HAP. SOE Draw Prize including LED bulbs and smart power bar.
Sandycove Acres Farmers Market - SOE Booth	Sandycove Acres	ALL	2014	100	Promotion of SOE Programs.
Save on Energy Regional Symposium Barrie - SOE Booth	Barrie Golf and Country Club	C&I, IND	2/25/14	125	Collaborative regional event with LDCs, OPA/IESO. Promotion of all SOE Business programs and case studies.
Wing Ding Fest - SOE Booth	Cookstown	ALL	6/7/14 6/8/14	15,000	Promotion of all SOE programs, with focus on Coupons, draw prize and SOE plinko.

2014 InnPower Customer Educational Activities

Event/Promotion	Location	Target (RES, C&I, IND, HAP, ALL)	Event Date or Timeframe	Outreach Potential	Notes/Programs Promoted
Bill Messaging	Bills	ALL	2014	15,000	Updates to TOU Rates, billing changes, general promotion of SOE, Customer Connect, community events, other relevant information.
CFL Recycling Program	IHDSL Office, Innisfil Town Hall	RES	2014		CFL disposal program for InnPower customers. Cross promotion of LED Coupons.
Customer Connect	Online	RES	2014	2,400	Customer Connect data available for customer review/download through Customer Connect.
Customer Service TV	InnPower Office	ALL	2014	6,000	Promotion of CDM Community Events, Coupon Events, SOE Programs, energy saving tips, etc.
Facebook Posts	Online	ALL	2014	825	Promotion of CDM Community Events, Coupon Event, SOE Programs, energy saving tips, etc.
Innisfil Hydro Website	Online	ALL	2014	25,237	Promotion of all CDM Programs, Community Events, energy saving tips, CFL disposal, TOU info, etc.
Keeps Kids Safe Workshop	Church's Farm Supply	RES	4/12/14	75	Electrical Safety Presentation.
Kill-a-Watt Appliance Monitor Loan Program	Innisfil Public Libraries	RES	2014		Appliance monitors available to be loaned out at Innisfil Public Library branches.
Twitter Posts	Online	ALL	2014	3,000	Promotion of CDM Community Events, Coupon Event, SOE Programs, energy saving tips, etc.

2015

2015 InnPower Customer Engagement Activities

Event/Promotion	Location	Target (RES, C&I, IND, HAP, ALL)	Event Date or Timeframe	Outreach Potential	Notes/Programs Promoted
Celebrate Lake Simcoe (Sailabration) - Sponsorship	Innisfil Beach Park	ALL	7/25/15	60	SOE Giveaways provided.
ICECorp New Year's Skate - Sponsorship	Innisfil Rec Centre	RES	12/31/15	200-400	Draw Prize including LED light bulbs
Innisfil Family Day - SOE Booth	Innisfil Rec Centre	ALL	6/20/15	750-1,000	Promotion of all SOE programs, with focus on Coupons. Draw prize including LED bulbs and smart power bar.
Innisfil Pitch in Day - Sponsorship	Centennial Park	RES	5/9/15	200	SOE Draw Prize provided for volunteers.
Innisfil Rotary Club Train - Sponsorship	Sponsorship	ALL	2015		SOE Sponsorship of Rotary Club Train upgrades. Plaque promoting SOE for recognition.
Innisfil Summerfest - SOE Booth	Innisfil Beach Park	ALL	6/13/15 6/14/15	10,000	Promotion of all SOE programs, with focus on Coupons. Draw prize including LED bulbs and smart power bar.
Innisfil Winterhawks Major Peewee "A" - Sponsorship	Sponsorship	RES	5/2016 Season		SOE Banner Sponsorship, to be displayed at all 2015-2016 home and away games.
InnPower Open House	InnPower Host	ALL	4/11/15	600	Open House at InnPower's new Head Office. Promotion of all SOE Programs, with a focus on Coupons. Customer Connect demos.
Kids Scoop Bus Window Sponsorship	Kids Scoop Bus	RES	2015		SOE Window Ad on Kids Scoop Bus.
Ladies of the Lake Celebration - SOE Booth	Innisfil Beach Park	ALL	7/25/15	60	Promotion of all SOE programs, with focus on Coupons. Draw prize including LED bulbs and smart power bar.
Mayor's Annual Golf Tournament - Sponsorship	Sponsorship	ALL	ptember, 2015	150	Hole Sponsorship and SOE prize donation.
OACETT Annual Georgian Bay Chapter Golf Tournament - Sponsorship	Sponsorship	RES, C&I	ptember, 2015	120	SOE Prize donation.
Red Velvet Gala Enviornmental Leadership Award - Sponsorship	Sponsorship	C&I	10/23/15	100-150	SOE Sponsorship of Enviornmental Leadership Award.
Sandycove Acres Home Show - Sponsorship	Sandycove Acres	RES, HAP	4/11/15	400	Donated SOE Draw Prize including LED bulbs and smart power bar.
Simcoe County Carriage Driving Golf Tournament - Sponsorship	Sponsorship	RES	6/6/15	75-100	Donation of SOE yo-yos for prize bags.
Skills for the Green Economy - SOE Info Session	Innisfil Town Hall	ALL	10/21/15	25-50	InnPower presentation on SOE Programs.
Wing Ding Fest - SOE Booth	Cookstown	ALL	6/6/15 6/7/15	15,000	Promotion of all SOE programs, with focus on Coupons. Draw prize including LED bulbs and smart power bar.

2015 InnPower Customer Educational Activities

Event/Promotion	Location	Target (RES, C&I, IND, HAP, ALL)	Event Date or Timeframe	Outreach Potential	Notes/Programs Promoted
Bill Messaging	Bills	ALL	2015	15,000	Updates to TOU Rates, billing changes, general promotion of SOE, Customer Connect, community events, other relevant information.
CFL Recycling Program	InnPower Office, Innisfil Town Hall	RES	2015		CFL disposal program for InnPower customers. Cross promotion of LED Coupons.
Customer Connect	Online	RES	2015	2,400	Customer Connect data available for customer review/download through Customer Connect.
Customer Service TV	InnPower Office	ALL	2015	6,000	Promotion of CDM Community Events, Coupon Events, SOE Programs, energy saving tips, etc.
Facebook Posts	Online	ALL	2015	1,134	Promotion of CDM Community Events, Coupon Event, SOE Programs, energy saving tips, etc.
Green Button	Online	RES, C&I	2015	2,400	Green Button data available for customer download through InnPower Website/Customer Connect.
InnPower Website	Online	ALL	2015	22,530	Promotion of all CDM Programs, Community Events, energy saving tips, CFL disposal, TOU info, etc.
Kill-a-Watt Appliance Monitor Loan Program	Innisfil Public Libraries	RES	2015		Appliance monitors available to be loaned out at Innisfil Public Library branches.
OESP Program Info Sessions/Application Assistance	InnPower Office, Sandycove Acres	RES, HAP	11/19/15 11/23/15 12/1/15 12/3/15 12/7/15	1,200	InnPower presentation on OESP Program, eligibility criteria, app. process, etc. InnPower staff available to assist with OESP Application submission, cross promotion of HAP.
Twitter Posts	Online	ALL	2015	7,000	Promotion of CDM Community Events, Coupon Event, SOE Programs, energy saving tips, etc.

2016

2016 InnPower Customer Engagement Activities

Event/Promotion	Location	Target (RES, C&I, IND, HAP, ALL)	Event Date or Timeframe	Outreach Potential	Notes/Programs Promoted
ICECorp New Year's Skate - Sponsorship	Innisfil Rec Centre	RES	12/31/15	200-400	Draw Prize including LED light bulbs
Innisfil Family Day - SOE Booth	Innisfil Rec Centre	ALL	6/18/16	750-1,000	Promotion of all SOE programs, with focus on Coupons. Draw prize including LED bulbs and smart power bar.
Innisfil Farmers Market - SOE Booth	Innisfil Rec Centre	ALL	7/21/16 8/11/16 9/8/16 10/6/16	300	Promotion of all SOE programs, with focus on Coupons. Draw prize including LED bulbs and smart power bar.
Innisfil Pitch-in Day - SOE Booth	Centennial Park	ALL	5/14/16	200	Promotion of all SOE programs, with focus on Coupons. Draw prize including LED bulbs and smart power bar.
Innisfil Summerfest - SOE Booth	Innisfil Beach Park	ALL	6/11/16 6/12/16	10,000	Promotion of all SOE programs, with focus on Coupons. Draw prize including LED bulbs and smart power bar.
Innisfil Winterhawks Minor Bantam "AA" - Sponsorship	Sponsorship	RES	2016/2017 Season		SOE Banner Sponsorship, to be displayed at all 2016-2017 home and away games.
OACETT Annual Georgian Bay Chapter Golf Tournament - Sponsorship	Sponsorship	RES, C&I	9/16/16	150	Donated SOE prizes, packaged with SOE LED bulb coupons.
Retailer Co-op Events (Canadian Tire) - SOE Booth	Alcona Canadian Tire	ALL	10/1/16 10/15/16 10/30/16	3,000	Promotion of all SOE programs with a focus on Coupon Event. Educating customers on LED bulbs (Kelvin, Lumens, benefits, etc.).
Sandycove Acres Home Show - SOE Booth	Sandycove Acres	RES, HAP	4/9/16	400	Promotion of all SOE programs, with focus on HAP. SOE Draw Prize including LED bulbs and smart power bar.
Sick Kids Hospital Fundraiser - Sponsorship	Sponsorship	RES	4/15/16	100	Donated SOE Prize Basket.
Simcoe County Carriage Driving Golf Tournament - Sponsorship	Sponsorship	RES	6/4/16	75-100	Donated IPC/SOE Golf Balls. Provided LED Bulb Coupons for giveaway. SOE poster displayed @ event
Stroud First Beavers - Sponsorship	Sponsorship	RES	4/18/16	40	Donated 15 SOE first aid kits, LED Bulb Coupons for giveaway. SOE Poster displayed @ event.
Town of Innisfil Cheque Presentation	InnPower Office	C&I, IND			SOE Incentive Cheque Presentation and News Release
Town of Innisfil Permit Palooza - SOE Booth	Town Hall	ALL	5/5/16	75	Promotion of all SOE programs, with focus on Coupons. Draw prize including LED bulbs and smart power bar
Wing Ding Festival - SOE Booth	Cookstown	ALL	6/4/16 6/5/16	15,000	Promotion of all SOE programs, with focus on Coupons. Draw prize including LED bulbs and smart power bar.

2016 InnPower Customer Educational Activities

Event/Promotion	Location	Target (RES, C&I, IND, HAP, ALL)	Event Date or Timeframe	Outreach Potential	Notes/Programs Promoted
Bill Messaging	Bills	ALL	2016	15,000	Updates to TOU Rates, billing changes, general promotion of SOE, Customer Connect, community events, other relevant information.
CFL Recycling Program	InnPower Office, Innisfil Town Hall	RES	2016		CFL disposal program for InnPower customers. Cross promotion of LED Coupons.
Customer Connect	Online	RES	2016	2,400	Customer Connect data available for customer review/download through Customer Connect.
Customer Service TV	InnPower Office	ALL	2016	6,000	Promotion of CDM Community Events, Coupon Events, SOE Programs, energy saving tips, etc.
Facebook Posts	Online	ALL	2016	12,199	Promotion of CDM Community Events, Coupon Event, SOE Programs, energy saving tips, etc.
Green Button	Online	RES, C&I	2016	2,400	Green Button data available for customer download through InnPower Website/Customer Connect.
InnPower 2017-2021 Rate Application Info Session	InnPower Office	ALL	3/9/16	30	InnPower 2017-2021 Rate Application and Distribution System Plan Presentation, session covered process for rate applications, forecasted local growth and cost pressures.
InnPower Website	Online	ALL	2016	22,593	Promotion of all CDM Programs, Community Events, energy saving tips, CFL disposal, TOU info, etc.
Keeps Kids Safe Workshop	Church's Farm Supply	RES	4/16/16	75	Electrical Safety Presentation.
Kill-a-Watt Appliance Monitor Loan Program	Innisfil Public Libraries	RES	2016		Appliance monitors available to be loaned out at Innisfil Public Library branches.
OESP Program Application Assistance	Sandycove Acres, InnPower Office	HAP	2016		InnPower CDM Staff available to assist with OESP Application process, cross promotion of HAP
Twitter Posts	Online	ALL	2016	11,595	Promotion of CDM Community Events, Coupon Events, SOE Programs, energy saving tips, etc.

Home Assistance Program Session – Sandy Cove Acres



Cheque Presentation to Simcoe County District School Board



Bi – Annual Customer Satisfaction Survey

InnPower Corporation conducted a customer satisfaction survey with its residential and GS<50 classes. InnPower Corporation engaged UtilityPULSE to conduct an independent customer satisfaction survey for 2014. The survey asks customers questions on a wide range of topics, including:

- power quality and reliability;
- price;
- billing and payment;
- communications; and
- the customer service experience.

UtilityPULSE conducted the 2014 survey in April of 2014, with final results available in June 2014. Overall InnPower Corporation received an overall rating of A, which is higher than the National and Ontario comparators. However this is a drop from InnPower Corporations previous bi-annual customer survey in 2012 in which InnPower achieved an A+. The change in the overall rating is a customers' perception of Price and Value relating to the introduction of TOU pricing.

2014 Survey Results

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

This change aligns with feedback obtained from InnPower Corporation's outreach activities and daily customer touchpoints.

- Customers are very concerned about increasing electricity rates
- Energy knowledge of understanding key drivers on a bill is very low, majority of customers feel that InnPower is responsible for setting commodity rates

InnPower has enclosed a copy of the complete UtilyPULSE survey report in Appendix C.

Looking forward InnPower Corporation will be developing a more holistic customer engagement strategy which will include transactional feedback on the multiple touchpoints with our customers. The feedback will provide information to InnPower to implement changes for our customers that specifically meet their needs.

2.1.7 Performance Measurement

In its Application, InnPower Corporation has presented its performance for each of the Board's performance outcomes over the last five years, its current performance, and its projections for continuous improvements over the term of the Application.

2.1.7.1 – Renewed Regulatory Framework for Electricity Distributors (RRFE)

The Board introduced a new approach to rate setting at the end of 2012 with the Renewed Regulatory Framework. The Renewed Regulatory Framework is a performance based approach to regulation that focuses on the achievement of outcomes such as efficiency, reliability, sustainability, and financial viability.

The Report of the Board, *Renewed*26 *Regulatory Framework for Electricity Distributors: A Performance Based Approach* ("RRFE Report") issued on October 18, 2012, outlines the following four (4) performance outcomes 2 the Board expects distributors to achieve:

- **Customer Focus**: services are provided in a manner that responds to identified customer preferences;
- **Operational Effectiveness:** continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
- **Public Policy Responsiveness:** utilities deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
- **Financial Performance:** financial viability is maintained; and savings from operational effectiveness are sustainable.

Scorecard

On March 5, 2014, the Board issued a report for the *Performance Measurement for Electricity Distributors: A Scorecard Approach* (EB-2010-0379). The report details the scorecard measures approach which the Board expects to use in order to monitor and assess a distributor's effectiveness and improvement in achieving the four performance outcomes mentioned above, and to eventually facilitate distributor benchmarking.

InnPower Corporation has published its most recent scorecard for public viewing on its website at:

http://www.innpower.ca/news-article.php?id=56

InnPower Corporations scorecard for 2011 - 2015 is presented below in Table 1-28.

2.1.7.2 Customer Focus

Service Quality

New Residential/Small Business Connected On Time

In 2011 InnPower Corporation achieved 81.20% not meeting the industry target of 90% for connecting New Residential/Small Services on time. The miss of the target was primarily based on InnPower not calculating new connections correctly, nor providing appropriate documentation to confirm that the connection was completed on time.

From Since 2012 this metric has been trending upwards with the exception of 2013 in which 89.90% was achieved. This slight dip was due to an increase of 20% in new connections from 2012. InnPower Corporation plans to maintain this performance metric above the industry target.

Scheduled Appointments Met On Time

In line with the New Residential /Small Business metric for 2011, InnPower Corporation achieved 60.40% for Scheduled Appointments Met On Time, not meeting the industry target of 90%. Although improvements were realized in 2012 and 2013, InnPower did not start meeting and exceeding the Scheduled Appointments Met on Time metric until 2014. InnPower Corporation plans to maintain this performance metric above the industry target.

Table 1-28: InnPower Corporation 20156 Scorecard

Scorecard - Innpower Corporation 9/22/2016

Performance Outcomes	Performance Categories	Measures		2011	2012	2013	2014	2015	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		81.20%	95.30%	89.90%	96.40%	97.90%	up	90.00%	
		Scheduled Appointments Met On Time		60.40%	64.30%	83.00%	94.40%	91.80%	up	90.00%	
		Telephone Calls Answered On Time		95.80%	74.60%	67.10%	70.60%	80.40%	down	65.00%	
	Customer Satisfaction	First Contact Resolution					99.006%	98.99			
		Billing Accuracy					99.95%	99.94%	down	98.00%	
		Customer Satisfaction Survey Results					A	A			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness						86.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	flat		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	flat		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	flat		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		0.98	1.34	2.10	4.70	1.47	up		2.09
		Average Number of Times that Power to a Customer is Interrupted [2]		1.12	0.71	0.92	3.14	0.75	down		1.41
	Asset Management	Distribution System Plan Implementation Progress					In Progress	In Progress			
	Cost Control	Efficiency Assessment			3	3	3	3			
		Total Cost per Customer [3]		$695	$720	$732	$761	$883			
		Total Cost per Km of Line [3]		$13,782	$13,842	$14,168	$14,693	$17,126			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]						14.22%			13.01 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	100.00%		100.00%				
		New Micro-embedded Generation Facilities Connected On Time				100.00%	100.00%	100.00%	flat	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.61	1.10	0.63	0.41	0.78			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.84	0.93	1.30	2.04	2.03			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.01%	8.01%	8.98%	8.98%	8.98%			
			Achieved	8.58%	1.96%	5.70%	5.82%	7.61%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework. This measure is under review and subject to change in the future.

Legend: 5-year trend: up, down, flat. Current year: target met, target not met

InnPower Corporation was advised of a Compliance Audit on November 13, 2013 for the aforementioned metrics. As a result of the audit InnPower Corporation was found non-compliant in the calculation and reporting of the two metrics. As a result a process review of the reporting metrics was undertaken by the internal departments in InnPower. An action plan was developed and implemented within a 6 month period. The OEB Performance and Audit team conducted a follow up audit and InnPower Corporation was found to be fully compliant.

All SQI's and measures are now reported monthly and certified by the departmental prime. The monthly reporting allows staff members to proactively adjust the process to ensure that our customers' service needs are met.

Telephone Calls Answered on Time

InnPower Corporation has met and or exceeded the industry target of 65% answering a qualified call in 30 seconds or less since 2011. In 2015 Customer Service agents answered 80.40% of 21,000 inbound calls in 30 seconds or less. InnPower Corporation plans to maintain this performance metric above the industry target.

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, not resulting in the enquiry being escalated to 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.

Reporting of this metric commenced in 2015 and InnPower achieved 98.99%. InnPower plans to monitor and maintain this metric above the industry target of 98%.

Billing Accuracy

For the period from January 1, 2015 – December 31, 2015 InnPower issued 190,770 bills and achieved a billing accuracy of 99.94%. This compares favorably to the prescribed OEB target of 98%. Accuracy levels remained consistent regardless of the many staff changes endured for maternity coverages, accomplished through continued training, analysis, streamlining and procedures maintained by InnPower.

InnPower continues to monitor its billing accuracy results and processes monthly to maintain high accuracy.

2.1.7.3 Operational Effectiveness

In the Board's Scorecard Report (EB-2010-0379), Board staff recommended seven measures to assess a distributor's operational effectiveness: one safety measure, two system reliability measures, one asset management measure, and three overall cost performance measures

Safety

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.

In March of 2015, InnPower engaged a third-party organization to undertake InnPower Corporation's "Public Awareness of Electrical Safety" survey. Results were based on a telephone survey (Random Digit Dialing) among 400 members of the general public, 18 years of age or older, residing in InnPower Corporation's geographic service territory.

The result of the first year of surveying the public about electrical safety shows that many customers do have good knowledge and or have received information pertaining to the 6 core measurement questions. InnPower Corporation's Public Awareness Index Score is 86%.

At this time there is no set performance target by the OEB for the public awareness of electrical safety. The OEB will establish a performance target once three years of data has been gathered.

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 2015, 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.

InnPower Corporation plans to maintain these outstanding safety results.

System Reliability

In 2014, InnPower Corporation's reliability statistics for both System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) fell outside InnPower Corporation's target of 0.98 – 2.10 and 0.71 – 1.19 respectively. The root cause of the outages was severe weather which occurred on February 5, 2014 and June 3, 2014.

In 2015 InnPower Corporation is back on track has stayed within the target ranges for SAIDI (1.47) and SAIFI (0.75).
InnPower Corporation plans to maintain the SAIDI, SAIFI targets within the target ranges.

Distribution System Maintenance

The reliable performance of InnPower Corporation's electricity distribution network during normal operation as well as in the face of severe weather is the direct result of continual investments in new electricity distribution infrastructure including smart grid technologies:

- Use of high quality engineering design standards;
- Proactive upgrading of equipment;
- Preventative maintenance;
- Smart grid technologies that automate elements of the network; and;
- Diligent tree-trimming program.

Asset Management

Distribution System Plan Implementation Progress

InnPower Corporation has not historically tracked DSP cost efficiency and effectiveness as InnPower is submitting its first DSP with this application. In conjunction with approval of the DSP, InnPower will be developing processes to monitor and report in these areas. Metrics will include:

- Physical project progress vs. plan:
- Financial progress vs. plan: and
- Actual vs. planned cost of work completed.

InnPower Corporation's Distribution Plan is completed and filed with this Application in Exhibit 2, Appendix A.

Cost Control

Total Cost Per Customer

Total cost per customer is calculated as the sum of InnPower Corporation's capital and operating costs and dividing this cost figure by the total number of customers that InnPower serves. InnPower has experienced increases in its total costs required to deliver quality and reliable services to customers.

The total cost performance result for 2015 is $883/customer, or a 16% increase over its 2014 result. InnPower Corporation's results reflect the capital investment for future growth of the new Operations/Corporate Centre. InnPower is estimating steady customer growth in the territory for the next 25 years. InnPower will manage on going infrastructure investment and maintenance to ensure customer growth exceeds costs growth resulting in a decline of the cost per customer.

Total Cost per Km of Line

This measure uses the same total cost that is used in the Cost per Customer calculation above. InnPower Corporation's cost per km of line is $17,126. This is a 17% increase over the 2014 rate. The increase is directly related to the capital investment of the new Operations/Corporate Centre. InnPower is anticipating built out growth for its territory for the next 25 years. As this

intensification occurs, InnPower will continue to seek solutions to optimize resources and ensure the cost per km of line is competitive within the market.

2.1.7.4 Public Policy Responsiveness

In the Board's Scorecard Report, Board staff recommended four measures to assess a distributor's public policy responsiveness: two CDM measures and Two measures for connection of renewable generation.

Conservation and Demand Management:

Since 2006, through two previous generations of CDM programming, InnPower Corporation ro has consistently demonstrated a strong commitment to serving its customers. For 2011- 2014, InnPower was allocated 4-year targets of 2.5 MW of Net Summer Peak Demand Savings and 9.2 GWh of Net Cumulative Energy Savings.

InnPower Corporation utilizes the community outreach aspect of CDM for customer engagement, education, and promotion of the "*saveonenergy*" programs. At the end of the 2011-2014 Conservation Timeframe InnPower Corporation has achieved 84.4% of its energy target of 9.2 GWh.

2015 was a transition year for the Conservation First Framework with a new target of 13.01 GWh for the CFF Timeframe of 2015- 2020. InnPower has just received the 2015 results and we are pleased to report that we exceeded our 2015 forecast and achieved 14.2% towards the target!

<u>Renewable Generation Connection Impact Assessments Completed on Time</u>

InnPower Corporation supports the efficient processing of requests by embedded renewable and non-renewable generation. As of December 31, 2015 InnPower Corporation has connected a total of 94 microFIT and 7 FIT generation customers with a connected capacity of 2.317 MW.

Government Obligations

In addition to the obligations above, the table below presents a brief list of government obligations has integrated into its business operations.

Government Obligation	Description	Compliance
Smart Meter Deployment	Directive of the Minister of Energy, Smart Meters provide accurate energy consumption and allow utilities to respond quickly to power interruptions	100% achieved
Conservation and Demand Management	On March 31, 2010 the Minister of Energy issued a directive to the Board to amend licences of all electricity distributors to include a condition to meet electricity consumption reduction targets through CDM programs.	Forecast: Energy (GWh) = 9.2
Adoption of IFRS	Required by the Canadian Accounting Standards Board (AcSB), publicly accountable enterprises must transition from CGAPP to IFRS by January 1, 2012.	100% achieved
Low-Income Energy Assistance Program (LEAP)	The Board determined that the funds to be distributed by distributors to LEAP should be the greater of $2,000 or 0.12% of a distributor's Board-approved distribution revenue requirement.	100% achieved
Ontario Clean Energy Benefit (OCEB)	Effective January 1, 2011, a credit of 10% of the base invoice amount applies to the electric charges on each residential or GS<50 customer bill. Effective September 1, 2012, OCEB was limited to the first 3000 kWh consumption per month. InnPower submits monthly online OCEB reports to the Ministry of Energy.	100% achieved
Bill Print changes to include Line Losses	O.Reg 275/04 "INFORMATION ON INVOICES TO LOW-VOLUME CONSUMERS OF ELECTRICITY" specifies how electricity costs are to be presented on bills. Until June 30, 3012, line losses were reflected in the "Electricity" subheading on low-volume customer bills. O.Reg 405/12 amends O.Reg 275/04 and requires that charges related to losses as of July 1, 2013 are to be included under the "Delivery" subheading for non-retailer customers. Retailer bills will be required to make this change for July 1, 2015.	100% achieved
Distribution System Code Amendments	Amendments impact billing issuance and payment revisions, disconnections and payment procedures, disconnections for non-payments and arrears payment agreements	100% achieved
Revised Electricity Reporting and Record Keeping	On March 7, 2014 the Board issued a notice amending the Electricity RRR to implement an electricity distributor scorecard to support the Board's continued benchmarking of electricity distributor total costs, and to facilitate the Board-s continued monitoring of electricity distributor financial viability.	100% achieved

Requirements	New financial viability reporting on large customers (new Sections RRR 2.1.17 and 2.1.18) as well as five new performance measures were established to new Section RRR 2.1.19.	
Ontario Electricity Support Program (OESP)	New electricity support program, monthly credit to assist consumers eligible for the program.	100% achieved
Debt Retirement Charge	Removal of the DRC charge on the invoice however bill modifications required to advise the consumer that the DRC saved them $nn.nn	100% achieved
Electricity Rebate	Rebate to customers that will credit the GST portion of the HST on a customers' electricity invoice.	Effective January 1, 2017

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2.1.7.5 InnPower Corporation Operational Efficiencies/Process Improvements

InnPower Corporation has been working diligently to improve its performance, reduce costs thus being more efficient.

InnPower Corporation's overall strategy is to continuously seek areas of improvement in its processes and services which will ultimately meet our customers' needs, reduce costs and align with the objectives of the RRFE.

The improvements achieved have contributed to maintaining and improving performance indicators throughout the IRM period while managing increased workload increases driven by year over year growth.

The following set outs the areas of improvement that InnPower Corporation has implemented and or is in the planning stages for future implementation.

Human Resources

Wellness Policy

In November 2012, InnPower introduced a Wellness Policy. The short-term disability plan currently allows for four occurrences of three days each without a doctor note. By the fourth and subsequent days, a doctor's note is required. By analyzing sick time, it was discovered that many staff were taking their four occurrences of three days every year. It even showed that the occurrences were occurring regularly once per quarter. The new policy did not change the short-term disability plan, but it now requires employees who are absent for more than two days in an occurrence, or who have more than one occurrence in a three-month period, to have an interview with their supervisor.

Implementation of the Wellness policy has resulted in a decrease of incidental absences thus allowing for adequate coverage of work functions as scheduled and improved work force morale.

Electronic Pay Stubs

Electronic Pay Stubs was implemented for InnPower (2012) and InnServices (2016). The implementation reduced staff time and mileage costs in delivery of pay stubs.

Electronic Board Packages

Prior to 2012, Board meeting packages were copied and couriered to Board members. IPC no longer provides hard copies. Board packages are sent via emails and the Board was provided with iPads. Implementation reduced associated staff time, courier charges and office supplies (paper, toner).

Paid Lunches for Outside Staff

During recent union negotiations, Management and union agreed to a letter of understanding permitting outside staff to receive 20-minute paid lunch break at the job site during the "summer" months. Savings will be realized by not having to tear down work site and return to the office. There will also be savings of gas and wear and tear of vehicles. This item is currently on hold due to upcoming conciliation.

There are nine outside staff. The savings that will be realized in their time in not having to return to the office from a job site and then returning to it during the months of April through September is approximately $65,000. The savings realized by not having to breakdown a job site and then set it up again is approximately $23,000 for a total of approximately $88,000. The cost of providing outside staff a paid 20-minute lunch taken at the job site is approximately $17,600. The approximate savings realized would be $70,400.

Manulife Generic Drug Plan

IPC currently offers to employees' prescription reimbursement through Manulife ManuScript Generic Drug Plan 2. The plan requires the use of generic drugs, except where the doctor or dentist gives written direction that the prescribed drug is not to be substituted with a generic brand.

During recent union negotiations, Management has proposed the use of a Mandatory Generic Drug Plan, whereby a doctor must provide medical evidence why a patient cannot use a generic substitution.

Efficiency Committee

IPC will be establishing an Efficiency Committee (members from Management and Union), to meet and discuss potential efficiencies that can be found in day-to-day work. Ideas are to be presented to the President/CEO. This will begin once the new collective agreement has been settled.

The committee provides a forum for open communication and trust between and to investigate and implement future efficiencies.

Customer Service

New Phone System

In 2015, IPC purchased a new phone system as our prior system was not adequate for our growth. The new phone system provides the tools which aid in meeting the needs of our customers:

- Enhanced recording option, valuable for customer service training and auditing customer calls.
- Main and backup queue which contributes to improving calls answered in 30 seconds.
- Monitoring feature which allows management to manage staff levels in the queue.
- Enhanced reporting functions

Customer Self-Service Portal

IPC recently upgraded the "Customer Connect" self-serve portal that we have provided since 2011 with the introduction of Time of Use Billing. The portal provides tools for both customers and staff in explaining usage patterns which can contribute to increasing energy literacy. Once customers have access they have the option to investigate questions without having to call the IPC office.

The portal allows customers to view their account data including, TOU data, billing and payment history, meter reading history, billing analysis, green button data, paperless eBilling and conservation ideas and other information.

InnPower Website

IPC released a new website in January 2015, to coincide with the date of our new administrative centre and company name. The re-designed website provides links to:

- InnPower Corporation's outage management system (OMS), which includes a map providing outage information to customers for planned or unplanned outages.
- Twitter feeds fed to the outage section of the website real time, providing updates to customers on outage restoral.

IPC Customer Service CIS Utilization Review

IPC initiated a utilization review (UR) in 2015 by our Customer Information System (CIS) vendor. The purpose of the review was to understand IPC's current CIS processes and identify areas where staff may be experiencing difficulties or performing redundant or unnecessary tasks.

The UR document outlined IPC's processes along with a number of suggested improvements or alternatives. It identified processes that could be improved through alternative use of the software through process re-engineering, automation, report modification/development or further resource training and task-re-assignment.

IPC has implemented Phase 1 of the software suite. The cost of the software was $40,000 plus annual maintenance. Since implemented in 2016, InnPower is still compiling metrics to identify additional annual savings. To-date staff time saved due to automation is approximately $10,000 annually with further processes to be implemented. Cost avoidance is also realized with automation as the margin of error is reduced with less manual intervention. Training costs are also reduced.

Interactive Voice Response (IVR)

IPC has maintained an IVR system since 2011. The IVR system provides two areas of efficiencies:

- Customers can check account balances and make payments using the telephone or online. This enables customers to retrieve information re their account without having to call customer service to get account balances.
- The IVR provides technology to notify customers by phone of:
    - Overdue notices

- Tree trimming activity
- Planned outages

Mobile Workforce Management

IPC utilizes a workforce management that provides service orders electronically since 2009 with the implementation of smart meters.

The mobile workforce module allows the creation of work orders by both inside and outside staff members. Distribution of the work orders is also electronic which allows real time processing allowing prioritization of workloads, reduction of truck rolls and on site completion of the work order including the arrival time of the Technician.

With all work orders being warehoused in IPC's CIS system, reporting has been streamlined and provides auditable data to support Appointment Met and Appointments Scheduled metrics.

Information Technology

Virtualized Network

IPC implemented a Virtualized Network in 2011. The benefit to virtualizing networks assists to reduce costs (labour and maintenance) and:

- Less physical services required
- Reduction in power and cooling requirements to operate servers
- Reduced footprint as server numbers are reduced
- Minimal planning and lead time to implement and replace new servers for applications
- Test servers can be created very quickly

Streamlined Backup Strategy

IPC continues to strengthen backup processes which allow recovery times to be reduced, minimizing productivity downtime in the event of failure.

The Customer Information System is backed up to a hot site using transaction logs that are sent every 30 minutes.

IPC currently shares IT space with the Town of Innisfil. This provides a no cost benefit to each party and allows offsite storage for disaster recovery.

AMI Security Audit

IPC has joined a consortium of 22 utilities that all utilize the same Advanced Metering Infrastructure (AMI) vendor to conduct an audit of the AMI systems to ensure the systems are secure. An RFP has been issued with a vendor to be selected.

The costs are not known yet as the vendor has not been selected; however, as part of the consortium, the costs are shared among participants saving over 95% if we were to have an audit of this magnitude done individually. A similar audit was done in 2011/2012 and the total cost of that audit was approximately $379,000. This was a consortium of 32 utilities with a savings of over $367,000 from cost sharing.

AMI Testing Facility

Advanced Metering Infrastructure (AMI) Testing Facility. InnPower has been a member of the PowerStream AMI testing facility which is designed to test upgraded versions of the Census Regional Network Interface (RNI). This is a vital service so that testing can be completed and any issues identified prior to upgrading the software.

Membership costs are $5,000/year. and include the entire infrastructure of the AMI system including Tower Gateway Base station (TGB), Regional network interface, all computing hardware and all testing resources required. TGB costs alone for InnPower in 2009 were over $100,000 each. Staffing resources alone would cost more than $5,000 annually to test the new versions of the software.

Regulatory

InnPower Scorecard

With the issuance of the RRFE Report of the Ontario Energy Board and noted future scorecard requirements, IPC developed an annual performance scorecard for RRR and internal metrics. The scorecard is produced on a monthly basis and provides both historical (5 years) and annual data year to date.

The IPC scorecard allows review by each respective department on a monthly basis to Identify successes and potential issues by RRR/SQI metric. IPC has calculated that the scorecard saves each Manager a total of 2 hours per month as all metrics are warehoused within one document.

IPC Dashboard

In 2017 IPC plans on purchasing dashboard software that will allow the IPC Scorecard and KPI metrics to be posted on all staff's desktop. Postings will be timely and associated with the end users work discipline. IPC anticipates the following benefits with this implementation:

- Supports a culture of measurement by metric supporting the RRFE outcome of Operational Efficiencies and Customer Focus
- Provides a feedback mechanism in which staff can discuss specific metrics and identify areas of improvement

Conservation and Demand Management

Roving Energy Manager

In 2015, IPC in conjunction with 14 CHEC LDC's applied to IESO under the Collaboration Fund to secure a Roving Energy Manager resource. As the lead LDC the Roving Energy Manager reports to IPC and is accountable to provide all reporting to IESO and the collaborative CHEC LDC's. Under the Collaboration Agreement the CHEC LDC's contribute 25% of the cost of the resource including expenses and training.

Collectively, the CHEC LDC's do not have the volume of business customers to justify the hiring of an Energy Manager independently. The shared utilization of the Energy Manager provides our business customers a resource to assist with identifying energy saving changes that impact their bottom-line costs and benefits the CHEC LDC's with energy measures contributing to their respective energy saving targets.

Finance

Budgeting Software (Prophix)

Commencing in 2014 IPC's Finance team began the implementation of Prophix budgeting software.

2014 – Purchase of software and development of workflows, processes, financial reports under CGAAP and expense templates with trending budgets for import into ERP system.
2015 – Development and implementation of templates for capital projects, debt and Interest schedules, payroll and labour schedules.

2016 – Development of 5 year budget, revisions of reporting due to IFRS and improvements
The phased implementation of the Prophix business intelligence budget software has provided the following benefits to IPC:

- Improved controls associated with the budget process
- Increased automation and reduced manager time spent on budgeting
- Reduced requirement for finance department support
- Decreased time required to produce the budget
- Ability to involve and engage more staff in the budget process

Paperless Processes Software

InnPower is currently engaging support providers to assist with the implementation of document management software and features of current software to reduce costs of employee process time, paper, postage and increase efficiency and control. The following efficiencies are anticipated:

- Provide a more efficient way of processing purchases, receiving, invoicing and approvals;
- Provide a platform to manage enterprise wide documentation, retention, and destruction;
- Utilize electronic transfer of funds to provide efficiency from reduced time printing, handling and filing paper, and reduce costs of associated supplies;

Shared Services Agreement with InnServices

In August of 2015 IPC enter into a shared services agreement with InnServices for the provision of financial services which includes payroll, monthly reconciliations and reporting, miscellaneous invoicing, accounts payable and managing the year-end audit. Payment for these services is at cost plus 1%. This provides an additional revenue stream to IPC which benefits our customers with regards to rates. The Financial Services Agreement is attached as Appendix L.

Additional benefits include:

- More efficient way to implement growth
- Increases size and knowledge of respective departments
- Promotes cross functional teams which drives efficiencies

Engineering and Operations

Efficiencies resulting from Smart Meters

Smart Meters have played an important role in providing real-time operational data to internal and external stakeholders. This data has served the following purposes:

Educating customers: Historical and real-time meter usage data has been made available to customers to view through our customer connect portal. Registered customers can view their usage history and make informed decisions on how to best use electrical power. “Green button data” has also been available to customers, so that customers can provide usage data to third party energy providers for data analytics and integration with third party tools and applications.

- Outage Management: InnPower has integrated real-time AMI data with its Outage Management System (OMS). The OMS system incorporates meter event data i.e. last gasp outage alarms, restoration alarms, and voltage alarms into the call handling system. This data is then used in conjunction with customer calls and SCADA data to predict the location of an outage. As the OMS system does not solely rely on customer calls, outages can be restored prior to a customer report of a power outage.
- Meter ping functionality is also used by customer service and dispatchers to determine if a customer trouble call is not related to InnPower Corporation’s distribution system; e.g. tripped breaker. This reduces the overhead cost and expenses associated with a truck rollout.
- System Analysis: Historical AMI data is used by InnPower engineering to determine the actual loading on a distribution transformer. This information is used for asset management and condition analysis of infrastructure within the distribution system.
- Voltage flags are used by engineering and meter technicians to determine if high/low voltage event occurs in the distribution system. Other information, such as tampers, are also used by InnPower to determine if a meter has been tampered by external forces.

Upgrading of Supervisory Control & Data Acquisition (SCADA) System

In 2014, IPC upgraded its SCADA system. The upgraded SCADA system provides visibility to our grid and offers remote switching capability. This allows InnPower to reduce truck-rolls to specific switch sites to operate them; thereby reducing O&M costs.

Outage Management System (OMS)

In 2015 InnPower implemented an OMS system. The OMS system provides a means of logging and tracking outage records. It helps InnPower to perform data-analytics of its outage history and identify high risk areas and ensure prudent investments are made to address failure and failure risk.

The OMS system is linked to InnPower Corporation's website so customers can report an outage and/or see areas that are impacted by an outage.

Geospatial Information System Upgrade

InnPower Corporation's new and improved GIS system (upgraded in 2015) houses information pertaining to all grid connected assets. It provides the backend database for storing asset installation data, performance data, and other information required for financial reporting.

The GIS system also provides accurate grid connectivity data that is used by the SCADA and OMS systems, and by designers who work on grid design for circuit expansion and renewal. InnPower is continuing to leverage the capabilities of its GIS software to verify asset information, add new or missing asset data, and further expand its capabilities to perform data harvesting for better asset performance analysis.

SPIDA Calc and CYME Engineering Software

In 2014 InnPower implemented SPIDA Calc and CYME software. Automation of heavy engineering computational processes has been streamlined to improve efficiency and reduce turnaround time.

Both SPIDA Calc and CYME help with running engineering calculations.

InnPower Engineering Construction Standards

InnPower has developed internal expertise to prepare and approve internal engineering design standards to reduce turnaround time and cost.

Upgrading Radio System

InnPower Corporation's new and improved radio system provided enhanced RF communication with its entire "connected" grid. It makes the SCADA system work smoothly and as intended.

Collaboration with the Town during the design and construction phases has enabled cost containment. On-going maintenance costs will also be reduced.

Cable Locate Processing System

In 2014 InnPower implemented a new Locate processing system (TelDig) to streamline the entire locating process from beginning to end.

Completed tickets are then synchronized with the Ontario-1-Call servers to upload tickets on a daily basis and provide completion notification to ON1Call. In order to provide Completion notification to ON1Call InnPower had two options, develop and build an interface or invest in software with the completion functionality.

In addition to managing the cable locates process from beginning to end, TelDig has a "mobile" unit that is used by field techs to complete tickets. Monthly reporting is also simplified for cable locates as all locates are warehoused and timestamped for each process phase.

Cost Savings/Synergies with the Town of Innisfil

InnPower Corporation's Corporate Headquarters/Administrative Centre is located on the "Town of Innisfil Campus". The Town Campus area consists of the Innisfil Town Hall, Innisfil Operations Centre, Innisfil Recreational Centre, South Simcoe Police and service yards for InnPower and the Town of Innisfil. With the colocation of the buildings the opportunity to explore service contracts via RFP's in the following areas to reduce costs;

- Janitorial Services
- Building maintenance
- HVAC maintenance
- Locate services

- GIS services for field data collection
- Work Management & Asset Management System Implementation
- Emergency Management – resource sharing to improve storm/MED outage restoration efforts

Shared Services with the Town of Innisfil

Water/Waste Water Billing

In 2013 InnPower Corporation incorporated water and waste water billing services with the InnPower invoice on a monthly basis. This provides an additional revenue stream to IPC which benefits our customers with regards to rates. Additional information re this revenue offset is detailed in Exhibit 3, Section 2.3.3 Other Revenue.

The following table set outs incurred and projected future savings which have been incorporated into InnPower Corporation's cost structure and flow directly to the benefit of ratepayers.

Efficiency Initiative	2013	2014	2015	2016	2017	2018	2019	2020	2021
Wellness Policy	$ 3,480	$ 4,350	$ 5,075	$ 6,141	$ 7,430	$ 8,991	$ 10,879	$ 13,163	$ 15,928
Electronic Pay Stubs	$ 2,400	$ 2,400	$ 2,400	$ 2,700	$ 2,749	$ 2,798	$ 2,848	$ 2,900	$ 2,952
Electronic Board Packages	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,036	$ 2,073	$ 2,110	$ 2,148	$ 2,187
Paid Lunches Outside Staff					$ 70,400	$ 70,400	$ 70,400	$ 70,400	$ 70,400
Generic Drug Plan				$ 1,500	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000
CIS Utilization Review				$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Streamlined Back up				$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000
IPC Monthly Scorecard	$ 11,520	$ 11,520	$ 11,520	$ 11,520	$ 11,727	$ 11,938	$ 12,153	$ 12,372	$12,595
IPC Dashbord & Intregration						$ 10,230	$ 10,230	$ 10,230	$10,230
Phophix Budget Software (net of implementation costs)					$ 15,942	$ 16,229	$ 16,251	$ 16,818	$17,121
Paperless Process Software (net of implementation costs)				$ 15,000	$ 30,950	$ 41,918	$ 57,903	$ 58,905	$59,926
Total	**$ 19,400**	**$ 20,270**	**$ 20,995**	**$ 60,861**	**$ 166,234**	**$ 189,577**	**$ 207,774**	**$ 211,936**	**$216,338**

2.1.7.6 Benchmarking

InnPower Corporation utilizes the outcome of the annual PEG report and the OEB Yearbook to undertake benchmarking analysis. The intent of the analysis is to identify potential areas of improvement and or areas that will improve with greater densification to remain and or improve our current PEG Ranking/Performance. InnPower Corporation has been ranked in the Group 3 utilities since the implementation of the annual PEG report in 2013.

InnPower Corporation also undertakes benchmarking comparisons with members of the CHEC Association. This analysis is presented in Appendix J.

Benchmarking Forecast for InnPower Corporation

InnPower Corporation has completed the OEB's Benchmarking_Forecast_Model with the data presented in this application and the results indicate an annual result in the Stretch Factor Cohort of "3" for the 2016 Bridge and 2017 Test Year. InnPower Corporation's Benchmarking_Forecast_Model has been provided in Appendix H.

Summary of Cost Benchmarking Results

InnPower

	2015 (History)	2016 (Bridge)	2017 (Test Year)	2018	2019	2020
Cost Benchmarking Summary						
Actual Total Cost	14,265,653	14,433,911	15,667,316	na	na	na
Predicted Total Cost	13,098,824	13,297,653	14,185,462	na	na	na
Difference	1,166,829	1,136,259	1,481,854	na	na	na
Percentage Difference (Cost Performance)	**8.5%**	**8.2%**	**9.9%**	**na**	**na**	**na**
Three-Year Average Performance			8.9%	na	na	na
Stretch Factor Cohort						
Annual Result	3	3	3	na	na	na
Three Year Average			3			

2.1.8 Financial Information

Historical Financial Statements

InnPower Corporation has provided the following audited Financial Statement as attachments:

- APPENDIX D: Year ended 31 December, 2013
- APPENDIX E: Year ended 31 December, 2014
- APPENDIX F: Year ended 31 December, 2015

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 in Appendix J. 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.

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.

Prospectus and Recent Debt/Share Issuance Update

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

Other Relevant Information

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

Materiality Threshold

InnPower Corporation is seeking recovery in this application of a Service Revenue Requirement of $12,385,532. In accordance with the Filing Requirements for Electricity Distribution Rates Applications issued July 14, 2016 InnPower Corporations has calculated a materiality threshold for this application of $61,927 or 0.5% of the requested distribution revenue requirement.

2.1.9 Distributor Consolidation

InnPower Corporation confirms that it has neither acquired and or amalgamated with another distributor since its last rebasing application EB-2012-0139.

APPENDICIES

A	CHEC Revision Summary - Conditions of Service Version 8
B	Appendix 2-AC Customer Engagement Activities
C	Utility Pulse Survey Report
D	2013 IPC Financial Statements
E	2014 IPC Financial Statements
F	2015 IPC Financial Statements
G	Requested Approvals
I	InnPower Benchmarking Forecast Model
J	2.1.13 InnPower Corporation Trial Balance Mapped to Balance Sheet
K	CHEC 2014 Benchmarking Report

APPENDIX A: CHEC Revision Summary Conditions of Service

COS Revisions to Date (Version 7 to Version 8):

A summary of the changes is as follows:

- **General Changes:**
  - Copyright symbol added to bottom of Conditions of Service.
- **Section 1.2 – Revision to links:**
  - Added – Freedom of Information and Protection of Privacy Act, R.S.O. 1990
  - Added – Personal Information Protection and Electronics Documents Act, 2000
- **Section 1.9** – Revision to wording for "Service Quality Requirements":
  - Added "or as the DSC may be amended from time to time"
- **Section 2.3.7.1.1** – Revision to wording for "Meter 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.
- **Section 2.3.7.2** – Revision to wording for "Current Transformer Boxes":
  - "Customer/ Contractor must receive distributor authorization regarding size, type and location of meter cabinets before installation of apparatus"
- **Section 2.3.7.3** – Created new document – "Interval Metering Access Agreement"
- **Section 2.3.7.11** – Revision to wording for "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.
- **Section 2.3.7.14** – Added line to requirements for "Metal Enclosed Switchgear":
  - Receive Distributor's approval for access / location
- **Section 2.3.7.17** – Revised section so that Net Metering conditions match Ontario Reg. 541 / 05 and other CHEC Documents
- **Section 3.1.6** – Removed the reference to the "120/208 Volts 3 Phase 3 Wire" configuration
- **Section 3.1.8** – Added line to requirements for "Metering":
  - Remain accessible, safe, and maintainable
- **Section 3.1.11.2** – Revision to wording for "Metering":
  - 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.
- **Section 3.2.6** – Removed the reference to the "120/208 Volts 3 Phase 3 Wire" configuration
- **Section 3.2.8** – Added line to requirements for "Metering"
  - Remain accessible, safe, and maintainable
- **Section 3.3.5** – added "Primary Service or" to paragraph 3. Also added "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." to the end of the section.
- **Section 3.3.3.5.2** - Revised in several locations to include requirements for a customer owned substation. The wording was borrowed from Section 3.4.5 and 3.4.5.1 and revised to reflect the GS > 50 kW requirements.

- **Section 3.4.6** – Revised paragraph for "Supply Voltage" so it is noted that the 500 kW threshold is specific to GS > 500 customers:
    - 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).
- **Section 3.5.7** – Added section for Micro-Embedded Generation
- **Section 3.8** – The following changes have been implemented for USL
    - Section 3.8.1 to Section 3.8.4 have been added based on changes to the DSC
    - Section 3.8.5 has been revised to eliminate duplicate wording
- **Section 3.10** – Added section for Regional Planning
- **Appendices:**
    - Policies – a note has been added that allows a Distributor to substitute their own policies in place of the CHEC Standard Policies
    - Contact Information – CHEC LDC Contact Information has been updated to reflect current membership status

APPENDIX B: Customer Engagement Activities

File Number: EB-2016-0086
Exhibit: 1
Tab:
Schedule:
Page:

Date: 28-Nov-16

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.
Call Centre/Customer Service Activities		
Providing service to approximately 6,000 customer walk-ins per year	Need to explain the bill, need to make payment arrangements, account balances, billing inquiries, services such as e-Billing, TOU rates, outages, conservation programs, bill components. Enhancing customer education/knowledge	Maintain this service option including an ability to make payment in-person. Trained all front office staff to handle majority of issues, one stop service. Raised issues and concerns are discussed at customer service weekly huddle for communication and action to appropriate department.
InnPower Corporation managed over 21,000 inbound calls in 2015	Need to explain the bill, need to make payment arrangements, account balances, billing inquiries, services such as e-Billing, TOU rates, outages, conservation programs, bill components. Enhancing customer education/knowledge	Trained all front office staff to handle majority of issues, one stop service. Raised issues and concerns are discussed at customer service weekly huddle for communication and action to appropriate department.
Low Income customers and or customers having difficulty making payments	Low-income customers in need of assistance require information about low income programs available to them.	Participation in the Low Income Energy Assistance Program Continuous training for Customer Service Representatives for AMP arrangements, OESP, LEAP and HAP CDM program
Services for disabled customers	Disabled customers need to receive the same level and quality of service as non-disabled customers, regardless of any barriers there may be.	InnPower Corporation is firmly committed to providing accessible, quality service to all customers and visitors in compliance with the Accessibility for Ontarians with Disability Act (AODA). InnPower Corporate Headquarters was designed to incorporate accessible building features Customer Service staff and all other employees have been trained and re-trained annually to accommodate the needs of customers with disabilities.
Community Outreach and Consumer Education	Customers and their families need information about how to understand your bill, causes of high bills, new energy programs (TOU,OESP) and conservation programs.	Customer Service, CDM and Operational staff attend community events to provide information, answer questions and provide face to face interaction to our customers. From 2011 to 2015 InnPower has spent a total of 102 days at community events and educational sessions.
Operations Customer Engagement		
Emergency First Responders: Fire, Police, Ambulance	Emergency first responders must be made aware of electrical hazards they may encounter when responding to emergencies and taught how to keep themselves safe.	InnPower Corporation works closely with First Responders to ensure adequate knowledge of electrical hazards.
Customer Demand Work	Customer require new services, service upgrades, increased transformation, sevice new developments including subdivisions	Requests are managed via a scheduling process with appropriate priorization.
Trouble call response	Customer need for power restoration	24/7 coverage with ability to call in necessary resources to respond to most contingency situations
Customers Impacted by Capital Improvements, Reconstruction Projects or Tree-Trimming	Customers need to be informed of planned outages or tree-trimming.	Customers who will be impacted by a planned outage or tree-trimming receive a hand-delivered notice that outlines details of the project and provides a number to call for questions.
Locating electrical infrastructure, approximately 4,000 requests per year	Need to build new infrastructure requires electrical plant to be safely located so construction can proceed	Locates are all now scheduled through On1Call as mandated by the Government of Ontario. On1Call then contacts InnPower Corporation via a file transfer process to schedule the appointment.
Municipal Government Consultations - Town of Innisfil, Town of Barrie	Need for shared information on planning and development	Plans need to be communicated in order to ensure appropriate design or construction decisions and system planning, and future capital planning.
Conservation Demand Management (CDM) Activities		
102 days of participation in community events and educational sessions on conservation programs from 2011 - 2016 (year to date). Full listing of all events and potentially outreach potential is detailed in Exhibit 1 Section 2.1.6 Customer Engagement.	Customers and their families need information about how to understand your bill, causes of high bills, new energy programs (TOU,OESP) and conservation programs and household conservation tips to assist customers to reduce overall consumption.	Community events and energy educational sessions are constantly updated based on customer feedback. Feedback is also provided to all departments via Management meetings to ensure opportunities can be addressed.
Commercial and Industrial Customer Site Visits	Commercial and industrial customers need technical expertise to identify and implement complex commercial or industrial energy conservation projects.	More than 167 commerical and industrial customer visits were made between 2013 -2016 (YTD) by IPC's Roving Energy Manager and Conservation specialist. The purpose of the visits was to assist these customers in identifying and implementing complex commercial or industrial energy conservation projects as well as in submitting applications saveONenergy programs.
Customer Service TV	Customers and their families need information about how to understand your bill, causes of high bills, new energy programs (TOU,OESP) and conservation programs and household conservation tips to assist customers to reduce overall consumption.	Customer Service TV is constantly updated reflecting new rates, conservation programs, consumer alerts, etc.

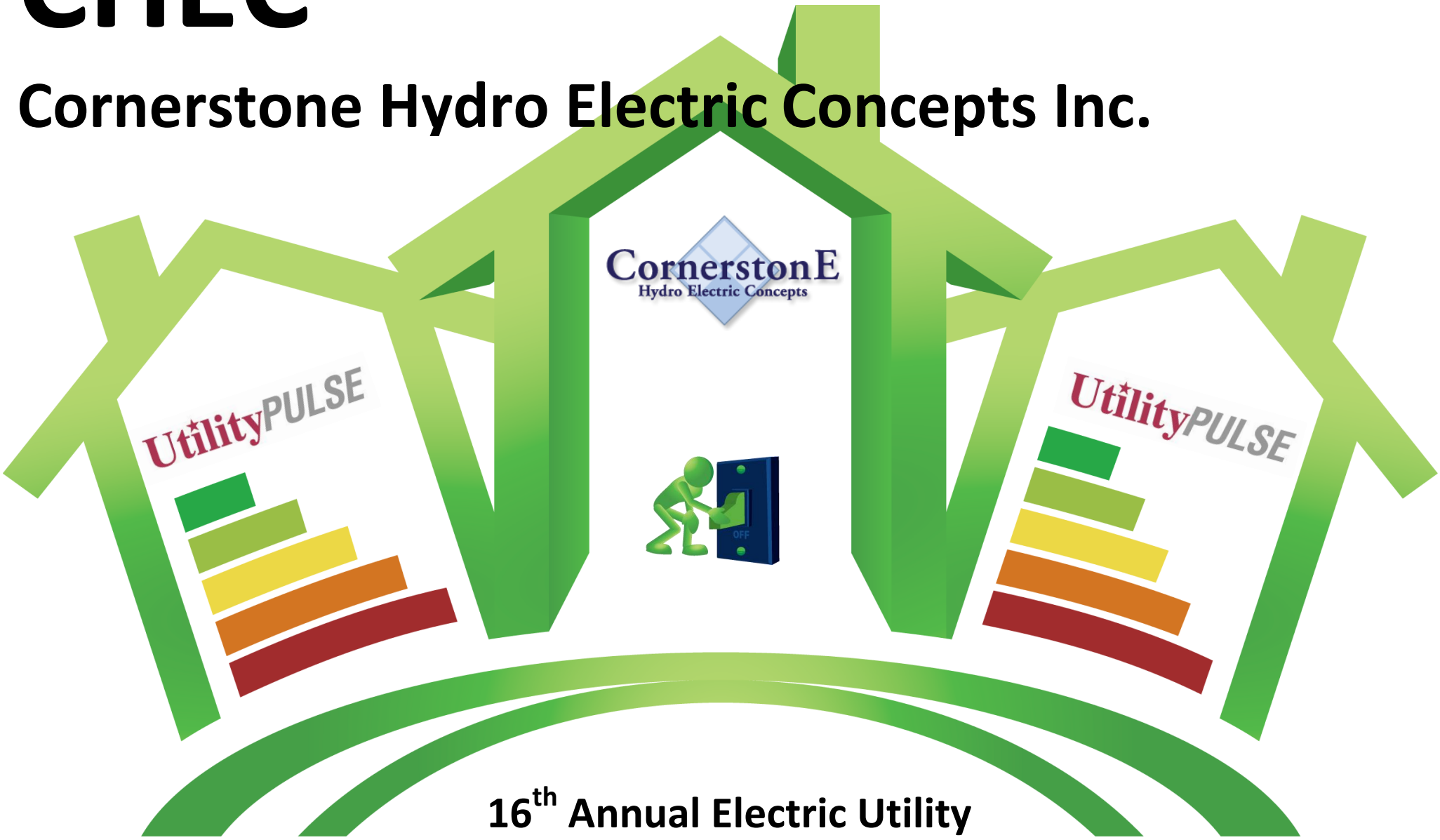
Social Media - Facebook and Twitter	Customer behaviour during power outages has indicated their strong desire for up-to-the minute outage information and an almost immediate Twitter response to outages, 24 hours a day. Safety information prior to severe weather events appears to be greatly appreciated by customers. Information about scams, energy conservation tips, safety information, etc. are retweeted by followers indicating a strong level of interest in these topics.	Community events and energy educational sessions are posted on social media. Outage updates are updated via Twitter which automatically posts to Facebooks providing customers options for updates.
InnPower Corporation Corporate Engagement		
UtilityPulse Customer Satisfaction Survey 2014	Customers want low price and high value, customer service, company leadership, the business to be a good corporate steward, operational effectiveness and power quality/reliability. Customers require various communication channels to be kept informed	InnPower Corporation is in the process of developing a formal communication plan as to how IPC can continously improve communications to our customers.
Shareholder Meetings	InnPower Corporation regulary meets with its shareholders to discuss IPC's plans, rates and the impact on customers.	IPC takes shareholder feedback and integrates into strategic planning
Bill messages, bill inserts, envelope messages, advertising	Customers require information on rate changes, conservation programs, etc. Some customers prefer to receive information in print form.	Regular bill messages, bill inserts, envelope messages and print advertising informs customers about changes in rates, conservation programs, electrical safety topics, customer surveys, holiday hours, etc.
Media Releases, Information Alerts	Customers require information on material issues such as power outages, new services and price increases as well energy conservation initiatives.	InnPower Corporation sends out media releases and information alerts to keep customers informed.

Note: Use "ALT-ENTER" to go to the next line within a cell

APPENDIX C: UtilityPulse Survey Report

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.

This is privileged and confidential material and no part may be used outside of CHEC without written permission from UtilityPULSE, the electric utility survey division of Simul Corporation.



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

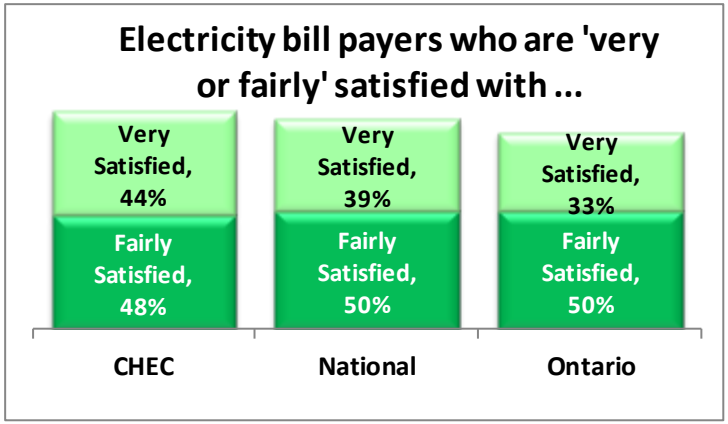
Your 2014 report contains data comparisons to:

- 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.

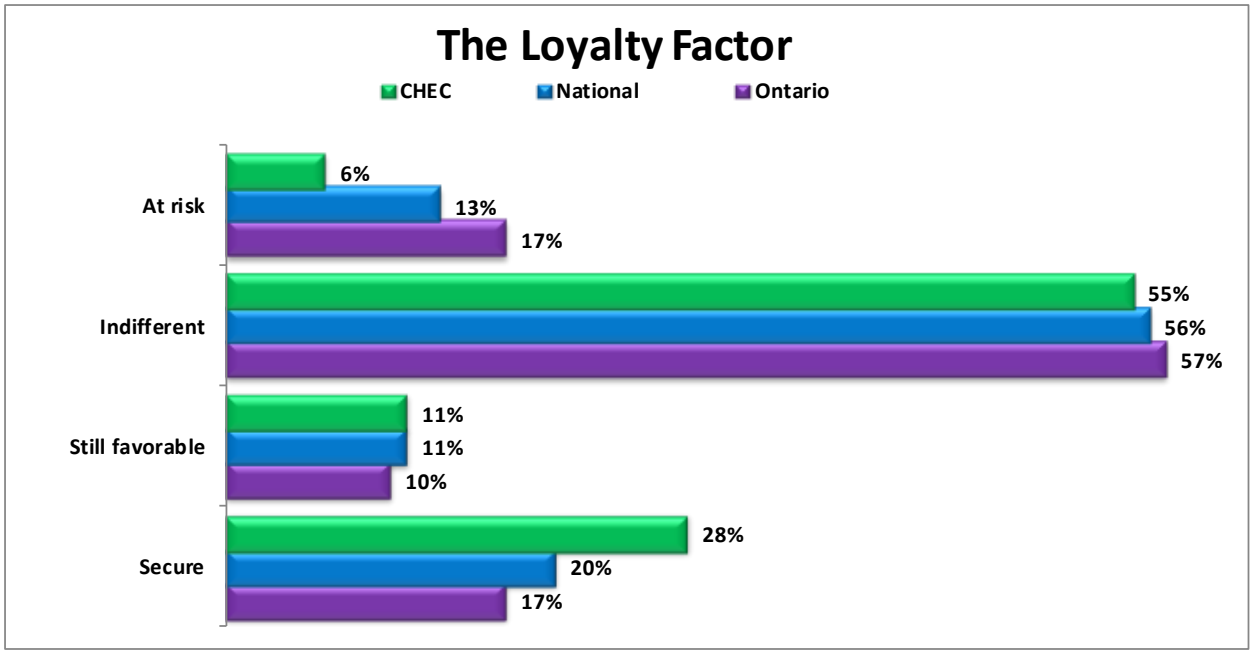
Customer Loyalty Groups				
	Secure	**Favorable**	**Indifferent**	**At Risk**
	CHEC			
2014	28%	11%	55%	6%
2013	33%	13%	49%	5%

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

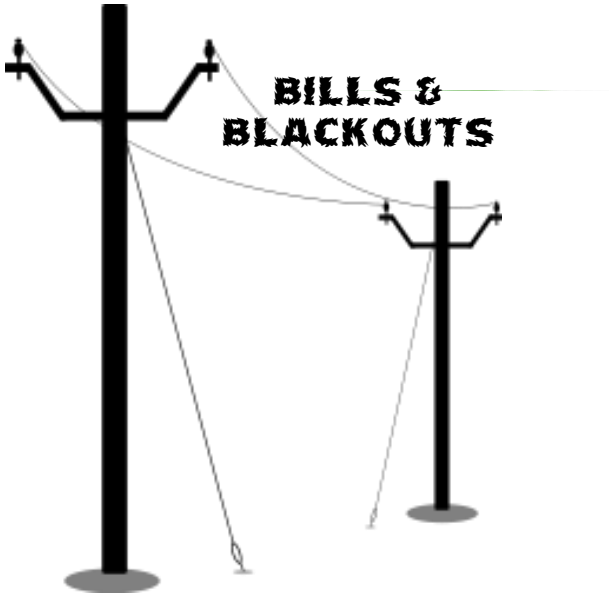
Utilities benefit from a trusted relationship with their empowered Customers. Higher levels of trust are the hallmarks of Secure customers. When people interact, either face-to-face, by telephone or on-line, if people do not trust each other, the interaction is not going to be efficient. Trust improves 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.

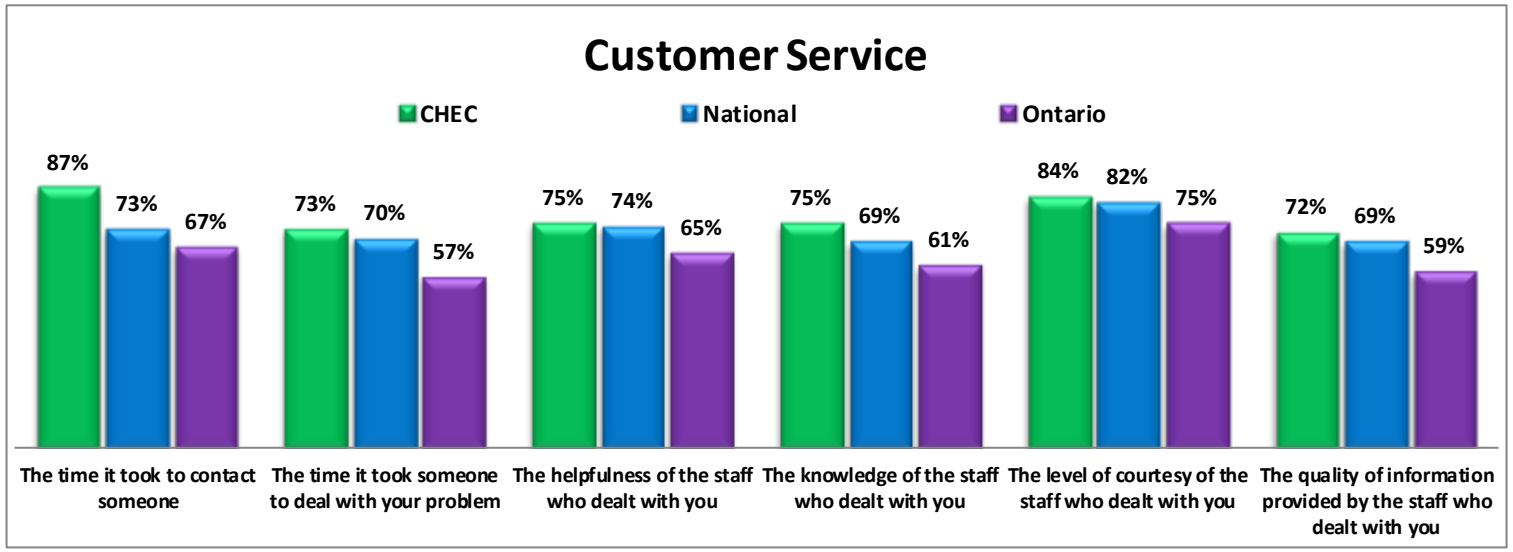
Your 2014 survey gives you the following information from respondents:

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

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

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

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

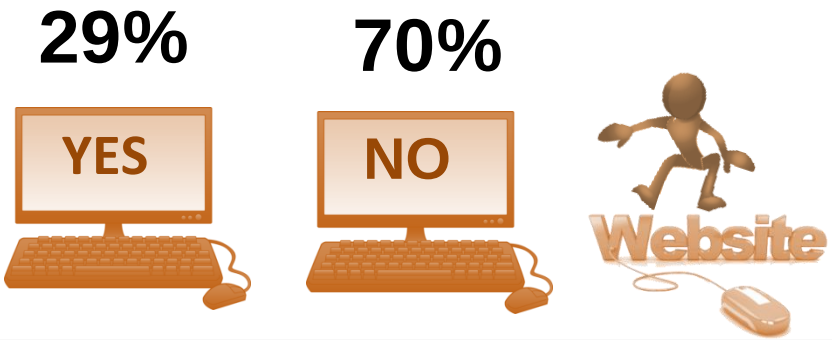
Technology – specifically the internet—has allowed people access to far more information than ever before and the ability to do more than ever before.

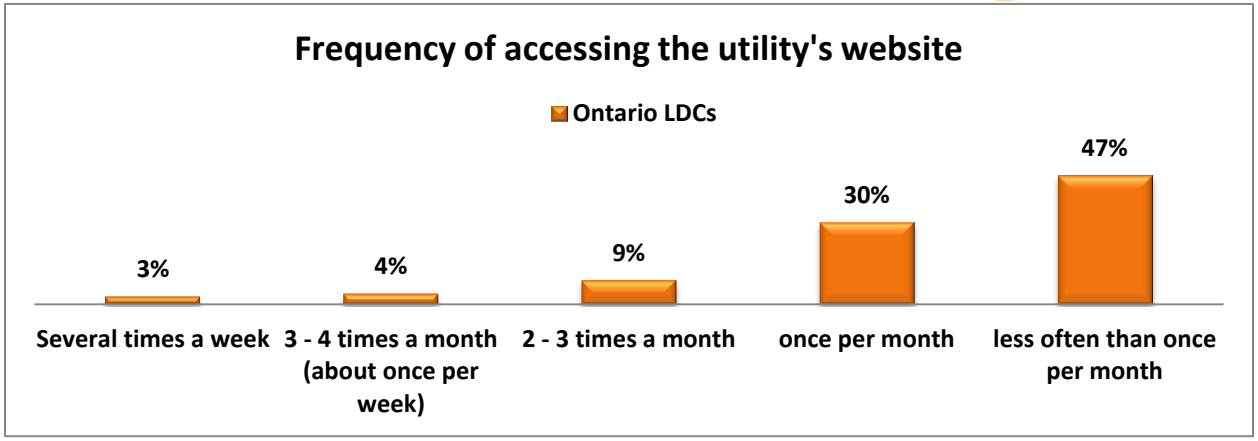
Do you have access to the internet?	
	Ontario LDCs
Yes	87%
No	13%

Base: An aggregate of respondents from 2014 participating LDCs

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

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

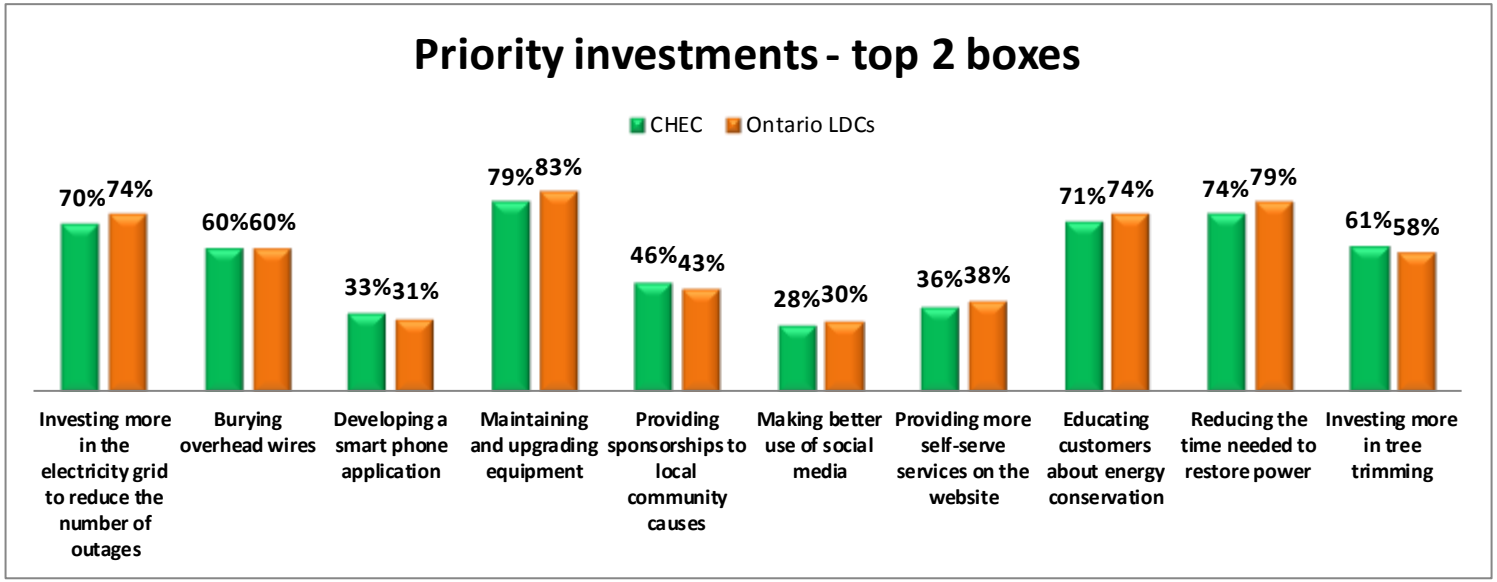


As society becomes increasingly more familiar with technology it will become a more popular medium for giving and receiving information. One could also say, demographics will also put more pressure on the technology channels. Unfortunately, customers adopt technology on their own timetable. This causes 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%

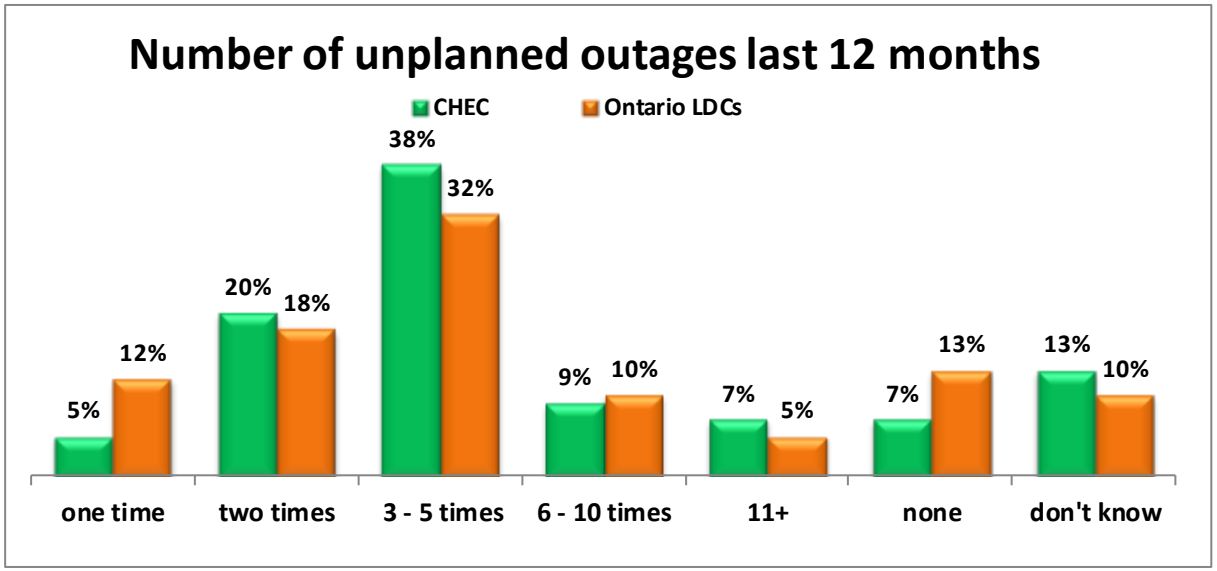
Base: total respondents



Outage Management

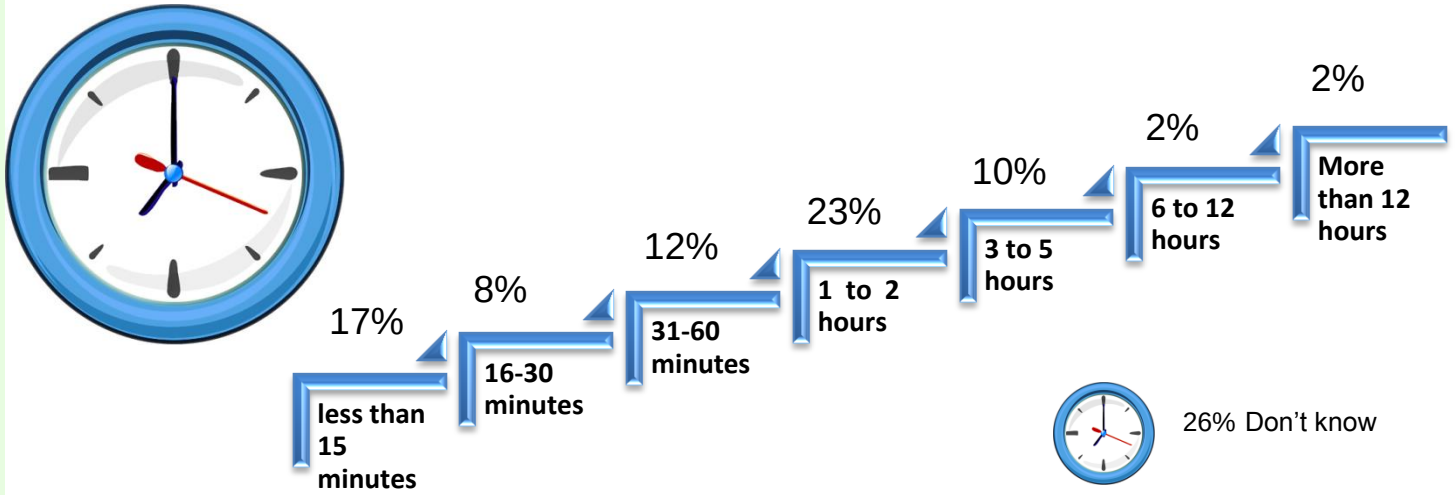
Whether an outage is planned or unplanned, the reality is that it is going to cause disruption and inconvenience under best case scenario and under worst case scenarios there could be safety and financial consequences.

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?

Base: total respondents



33%

48%

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?

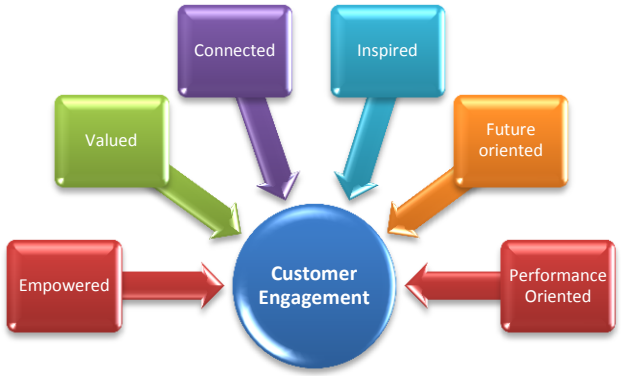


Base: total respondents affected by the ice storm

•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.



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APPENDIX D: IPC 2013 Audited Financial Statements

Financial Statements

Innisfil Hydro Distribution Systems Limited

December 31, 2013

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Grant Thornton

Independent Auditor's Report

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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

	Cost	Accumulated Amortization	2013 Net Book Value	2012 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

	Cost	Accumulated Amortization	2013 Net Book Value	2012 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 E: IPC 2014 Audited Financial Statements

Financial Statements

InnPower Corporation

December 31, 2014

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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		2014		2013
The Company had the following related party transactions:				
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.

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 F: IPC 2015 Audited Financial Statements

IFRS Financial Statements

InnPower Corporation

December 31, 2015

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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:

			Reasonable Possible	Defined Benefit Obligation	
Assumption	**2015**	2014	Change	Increase	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 G: 2-A Requested Approvals

File Number:	EB-2016-0086
Exhibit:	1
Tab:	
Schedule:	
Page:	
Date:	28-Nov-16

Appendix 2-A
List of Requested Approvals

The distributor must fill out the following sheet with the complete list of specific approvals requested and relevant section(s) of the legislation must be provided. All approvals, including accounting orders (deferral and variance accounts) new rate classes, revised specific service charges or retail service charges which the applicant is seeking, must be separately identified, as well being clearly documented in the appropriate sections of the application.

Additional requests may be added by copying and pasting blank input rows, as needed.

If additional requests arise, or requested approvals are removed, during the processing of the application, the distributor should update this list.

Innpower Corporation is seeking the following approvals in this application:

1	○ Approval to charge distribution rates effective for January 1, 2017 to recover a service revenue requirement of $13,178,325, as set out in Exhibit 1, Schedule 1, Section 2.1.5.A Revenue Requirement. The schedule of proposed 2017 rates is set out in Exhibit 8, Section 2.8.9 Tariff of Rates & Charges.
2	○ Approval to adjust the Retail Transmission Service Rates (Network and Connection) in accordance with the Board's Guideline G-2008-0001 Electricity Distribution Retail Transmission Service Rates (RTSR), Revision 4.0 issued June 28, 2012 and as set out in Exhibit 8, Section 2.8.3 Retail Transmission Service Rates.
3	○ Approval to continue to charge Standard Supply Service, Wholesale Market, Rural Rate Protection and OESP charges approved in the OEB Decision and Order in the matter of InnPower Corporations 2016 Distribution Rates (EB-2015-0081) subject to any modifications as a result of the OEB's future decisions;
4	○ Approval of the proposed loss factor as set out in Exhibit 8, Section 2.8.8 Loss Adjustment Factors.
5	○ Approval of adjusted Low Voltage rates as set out in Exhibit 8, Section 2.8.7 Low Voltage Service Rates.
6	○ Approval to continue Specific Service charges approved in the OEB Decision and Order in the matter of InnPower Corporations 2016 Distribution Rates (EB-2015-0081).
7	○ Approval for a modified microFIT Service Classification definition to include microFIT and Net Metering customers and a modified rate.
8	○ Approval to continue Specific Service charges approved in the OEB Decision and Order in the matter of InnPower Corporations 2016 Distribution Rates (EB-2015-0081).
9	○ Approval for the following new and or modified Specific Service charges. Justifications for the new and or modified Specific Service charges are set out in Exhibit 8, Section 2.8.6 Specific Service Charges: ○ Approval as presented of an interim Pole Attachment rate ○ Approval as presented for a modified Temporary Service -Install and Remove – Underground – No Transformer rate ○ Approval as presented for a modified Temporary Service - Install and Remove – Overhead – No Transformer rate ○ Approval as presented for a modified Temporary Service – Install and Remove – Overhead – With Transformer rate ○ Approval as presented for a modified Disconnect/Reconnect Charge – at meter- during regular hours
10	○ Approval to dispose of the Deferral and Variance Account Balances, audited as at December 31, 2015 plus calculated interest until December 31, 2016, over a two year period using the method of recovery described in Exhibit 9, Section 2.9.5 Disposition of Deferral and Variance Accounts.
11	○ Approval to dispose of Account 1568 – Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) for lost revenue resulting from the 2011 – 2014 IESO programs over a two year period.
12	○ Interim approval of a Z-factor Rate Rider resulting from a Major Event which occurred in March 2016. Calculation of the rate rider and further details of the MED event are set out in Exhibit 8, Section 2.8.2 Rate Design Policy.
13	○ Placeholder to establish a customer credit for customers that transition e-billing in the IRM timeframe.

APPENDIX H: InnPower Corporation Benchmarking Forecast Model

Data Required for Cost Benchmarking

InnPower

Select LDC from Dropdown Box: InnPower

Required Item		History	Bridge Year	Test Year	Additonal Years for Custom IR Filings					
		2015	2016	2017	2018	2019	2020	2021		COMMENTS
	Gross Capital Cost Additions Data									
1	Total Gross Capital Additions	19,803,244	8,472,869	8,558,202					Enter Values	Data source Rev Requirement Model (Rebase), includes additions and
2	HV Gross Capital Additions	-	-	-					Enter Values	contributions
	Output and Other Business Conditions									
3	Number of Customers	16,157	16,517	17,054					Enter Values	Number of customers reflected for 2015 only include Res, and GS classes, load forecast
4	Delivery Volume	237,763,329	238,940,858	239,587,667					Enter Values	Load Forecast, Billed kWh
5	Annual Peak Demand	50,975	51,992	52,992					Enter Values	
6	Distribution Circuit-km	833	862	892					Enter Values	
7	Ten Year Customer Growth Percentage	17.14%	19.41%	20.75%					Enter Values	
	Inflation Measures									
8	Wage Growth	2.56%	2.56%	2.56%					Optional: Default Values Provided	Assumed the same as 2015
9	Growth in Economy-wide Inflation	1.57%	1.57%	1.57%					Optional: Default Values Provided	Assumed the same as 2015
10	Rate of Return (WACC)	6.51%	5.63%	5.71%					Enter Values	
	OM&A Expenses Included in Cost Benchmarking									
Choose a Method:	y **Use Method 1 [1A - 1B + 1C]**	5,396,319	5,650,747	6,214,285	-	-	-	-	Formula	
	n **Use Method 2 [2A - 2B + 2C]**	5,396,319	5,925,747	6,214,285					Formula	
11	**OM&A Values Transfered to Calculations Worksheet**	5,396,319	5,650,747	6,214,285	-	-	-	-	Formula	
	Method 1: Enter Values Calculated Elsewhere		Enter Values Supported by Separate Calculations							
	1A Total OM&A Consistent with accounts included in [2B]	5,283,654	5,538,082	6,101,620					Enter Values	
	1B HV Cost (Accounts 5014, 5015, and 5112) if included in total	-							Enter Values	
	1C LV Adjustment	112,665	112,665	112,665					Enter Values	
										COMMENTS
	Method 2: Enter Detailed Data									
	OM&A Data									
5005	Operation Supervision and Engineering	220,454	174,400	226,363					Enter Values	2016 & 2017 values taken from Revenue Requirement - BB
5010	Load Dispatching	14,948	19,100	19,700					Enter Values	
5012	Station Buildings and Fixtures	48,576	53,000	54,800					Enter Values	
5014	Transformer Station Equipment - Operation Labor	-							Enter Values	
5015	Transformer Station Equipment - Operation Supplies and Expenses	-							Enter Values	
5016	Distribution Station Equipment - Operation Labor	9,718	9,900	10,200					Enter Values	
5017	Distribution Station Equipment - Operation Supplies and Expenses	5,228	3,700	3,825					Enter Values	
5020	Overhead Distribution Lines and Feeders - Operation Labor	136,301	141,000	152,661					Enter Values	
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	7,484	7,700	7,950					Enter Values	
5035/5030	Overhead Distribution Transformers - Operation	246	3,075	3,225					Enter Values	
5040	Underground Distribution Lines and Feeders - Operation Labor	18,961	27,800	28,863					Enter Values	
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	98,966	107,750	112,000					Enter Values	
5055	Overhead Distribution Lines and Feeders	189	-	-					Enter Values	
5065	Meter Expense	241,353	253,245	270,856					Enter Values	
5070	Customer Premises - Operation Labor	55,089	61,400	63,463					Enter Values	
5075	Customer Premises - Operation Materials and Supplies	101,904	111,900	115,100					Enter Values	
5085	Miscellaneous Distribution Expense	405,527	470,310	478,478					Enter Values	
5090	Underground Distribution Lines and Feeders - Rental Paid	-							Enter Values	
5095	Overhead Distribution Lines and Feeders - Rental Paid	11,199	11,000	11,000					Enter Values	

	5096	Other Rent (Distribution)	-							Enter Values	
		Subtotal: Operation	**1,376,142**	**1,455,280**	**1,558,483**	**-**	**-**	**-**	**-**	Formula	
	5105	Maintenance Supervision and Engineering	8,489	14,050	14,475					Enter Values	
	5110	Maintenance of Buildings and Fixtures	-							Enter Values	
	5112	Maintenance of Transformer Station Equipment	-							Enter Values	
	5114	Maintenance of Distribution Station Equipement	33,377	49,750	51,775					Enter Values	
	5120	Maintenance of Poles, Towers and Fixtures	10,632	6,200	20,115					Enter Values	
	5125	Maintenance of Overhead Conductors and Devices	49,140	65,100	130,975					Enter Values	
	5130	Maintenance of Overhead Services	64,767	59,300	61,325					Enter Values	
	5135	Overhead Distribution Lines and Feeders - Right of Way	119,801	153,800	159,175					Enter Values	
	5145	Maintenance of Underground Conduit	-							Enter Values	
	5150	Maintenance of Underground Conductors and Devices	24,178	11,200	11,850					Enter Values	
	5155	Maintenance of Underground Services	76,614	117,050	121,200					Enter Values	
	5160	Maintenance of Line Transformers	17,208	25,050	75,905					Enter Values	
	5175	Maintenance of Meters	23,319	28,750	28,750					Enter Values	
		Subtotal: Maintenance	**427,525**	**530,250**	**675,545**					Formula	
	5305	Supervision (Billing and Collection)	-	131,059	134,664					Enter Values	Bad debt expense are not included, 5335
	5310	Meter Reading Expense	-	20,331	19,365					Enter Values	
	5315	Customer Billing	388,248	460,409	476,446					Enter Values	
	5320	Collecting	345,165	371,340	380,146					Enter Values	
	5325	Collecting - Cash Over and Short	148	-	-					Enter Values	
5335	5330	Collection Charges	-							Enter Values	
	5340	Miscellaneous Customer Account Expenses	162,718	145,828	94,204					Enter Values	
		Subtotal : Billing and Collections	**896,279**	**1,128,967**	**1,104,825**					Formula	
	5405	Supervision (Community Relations)	-							Enter Values	
	5410	Community Relations - Sundry	5,268	7,500	9,000					Enter Values	
	5420	Community Safety Program	350	750	1,000					Enter Values	
	5425	Miscellaneous Customer Service and Informational Expense	2,448	2,000	2,000					Enter Values	
		Subtotal: Community Relations	**8,066**	**10,250**	**12,000**					Formula	
	5605	Executive Salaries and Expenses	262,073	253,317	258,383					Enter Values	
	5610	Management Salaries and Expenses	329,473	356,934	364,073					Enter Values	
	5615	General Administrative Salaries and Expenses	923,300	959,276	978,462					Enter Values	
	5620	Office Supplies	216,791	195,250	207,750					Enter Values	
	5625	Administrative Expense Transferred - Credit	-	-	-					Enter Values	
	5630	Outside Services Employed	199,342	186,000	181,100					Enter Values	
	5640	Injuries and Damages	49,896	46,350	50,000					Enter Values	
	5645	OMERS Pensions and Benefits	15,753	57,680	60,000					Enter Values	
	5646	Employee Pensions and OPEB	-	17,978	18,520					Enter Values	
	5647	Employee Sick Leave	-							Enter Values	
	5650	Franchise Requirements	-							Enter Values	
	5655	Regulatory Expenses	111,126	95,800	90,000					Enter Values	
	5665	Miscellaneous General Expenses	131,055	125,800	136,000					Enter Values	
	5670	Rent (Administrative and General)	1,530	800	800					Enter Values	
	5672	Lease Payment Expense	-							Enter Values	
	5675	Maintenance of General Plant	282,148	333,500	345,679					Enter Values	
	5680	Electrical Safety Authority Fees	9,212	9,650	10,000					Enter Values	
		Sutotal: A&G Expenses	**2,531,699**	**2,638,335**	**2,700,767**					Formula	
	5635	Property Insurance	43,943	50,000	50,000					Enter Values	
	6210	Life Insurance	-							Enter Values	
		Subtotal: Insurance	**43,943**	**50,000**	**50,000**					Formula	
	5515	Advertinsing	-							Enter Values	
		Subtotal Advertising	**-**	**-**	**-**	**-**	**-**	**-**	**-**	Formula	
		2A Total of Above Accounts Used for Benchmarking	5,283,654	**5,813,082**	**6,101,620**	**-**	**-**	**-**	**-**	Formula	
Adjustments to OM&A for Benchmarking											
		5014	-	-	-	-	-	-	-	Formula	
		5015	-	-	-	-	-	-	-	Formula	
		5112	-	-	-	-	-	-	-	Formula	
		2B Subtotal: HV Adjustment (to subtract from cost)	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**Formula**	
		2C LV Adjustment	**112,665**	**112,665**	**112,665**					**Enter Values**	2015 Value *3% annually

Benchmarking Calculations for LDC Forecasting

Selected LDC: InnPower

Line Reference Number	Row Nu	Account	2014	2015	Forecasted Values 2016	2017	2018	2019	2020	2021	Data Item Number
		Section 1: Source Data and OM&A Calculations									
1		**OM&A Data (Detail may be hidden or expanded using the +/- buttons to the left of the row numbers)**									
22		**Subtotal: Operation**		**1,376,142**							
36		**Subtotal: Maintenance**		**427,525**							
44		**Subtotal : Billing and Collections**		**896,279**							
49		**Subtotal: Community Relations**		**8,066**							
67		**Sutotal: A&G Expenses**		**2,531,699**							
70		**Subtotal: Insurance**		**43,943**							
72		**Subtotal Advertising**		**-**							
73		**Total of Above Accounts Used for Benchmarking**		**5,283,654**							
74											
75		**Adjustments to OM&A for Benchmarking**									
79		Subtotal: HV Adjustment (to subtract from cost)		-							
80		LV Adjustment		112,665							
81		Total Adjusted OM&A Expense		5,396,319	5,650,747	6,214,285	-	-	-	-	11
82											
83		**Gross Capital Cost Additions Data**									
84		Total Gross Capital Additions		19,803,244	8,472,869	8,558,202	-	-	-	-	1
85		HV Gross Capital Additions		-	-	-	-	-	-	-	2
86											
87		**Output and Other Business Conditions**									
88		Number of Customers		16,157	16,517	17,054	-	-	-	-	3
89		Delivery Volume		237,763,329	238,940,858	239,587,667	-	-	-	-	4
90		Annual Peak Demand		50,975	51,992	52,992	-	-	-	-	5
91		Distribution Circuit km		833	862	892	-	-	-	-	6
92											
93											

94	**Actual Cost**									
95										
96	OM&A		5,396,319.30	5,650,747.00	6,214,284.54	-	-	-		
97										
98	Capital									
99		Rate of Return	6.51%	5.63%	5.71%	0.00%	0.00%	0.00%	0.00%	10
100		Depreciation Rate	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	
101		Construction Cost Index	163.12	165.71	168.34	168.34	168.34	168.34	168.34	9
102		Capital Price	17.93	16.79	17.19	7.73	7.73	7.73	7.73	
103		Gross Plant Additions	19,803,244	8,472,869	8,558,202	-	-	-	-	1
104		HV Capital Additions	-	-	-	-	-	-	-	2
105		Quantity of Capital Additions	121,404	51,132	50,840	-	-	-	-	
106		Quantity of Capital Removed	17,959	22,707	24,012	25,243	24,085	22,979	21,924	
107		Capital Quantity	494,710	523,134	549,962	524,719	500,634	477,655	455,731	
108		Capital Cost	8,869,333	8,783,164	9,453,031	4,054,319	3,868,225	3,690,674	3,521,272	
109										
110	Total Actual Cost		14,265,653	14,433,911	15,667,316	4,054,319	3,868,225	3,690,674	3,521,272	

Predicted Cost

	Output Quantity								
	Number of Customers		16,157	16,517	17,054	-	-	-	-
	Delivery Volume		237,763,329	238,940,858	239,587,667	0	0	0	0
	Annual Peak Demand		50,975	51,992	52,992	-	-	-	-
	Capacity Proxy		66,861	66,861	66,861	66,861	66,861	66,861	66,861
	Input Prices								
	GDP IPI [30% Weight]	113.4	115.2	117.1	118.9	118.9	118.9	118.9	118.9
	Average Hourly Earnings [70% Weight]	938.36	962.73	987.73	1,013.35	1,013.35	1,013.35	1,013.35	1,013.35
	OM&A Price Index Growth [30% GDPIPI growth + 70% AWE Growth	2.019%	2.287%	2.267%	2.264%	0.000%	0.000%	0.000%	0.000%
	OM&A Price Index Level		132.11	135.14	138.23	138.23	138.23	138.23	138.23
	Capital Price Index	17.57	17.93	16.79	17.19	7.73	7.73	7.73	7.73
	Business Conditions								
	Line km		833.00	862.00	892.00	-	-	-	-
	2002-2013 Average Line km		696.50	707.53	719.06	676.76	639.17	603.66	570.12
	Customers Ten Years Ago		13,793						
	Ten Year Customer Growth Percentage		17.14%	19.41%	20.75%	0.00%	0.00%	0.00%	0.00%

(Details of the predicted cost calculations may be hidden by using the +/- button to the left of row 248)

Company Values for Variables Used in the Prediction Equation

Constant	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Capital Price / OM&A Price (WK)	0.1357	0.1242	0.1243	0.0559	0.0559	0.0559	0.0559
Customers (Y1)	16,157	16,517	17,054	-	-	-	-
Capacity (Y2)	66,861	66,861	66,861	66,861	66,861	66,861	66,861
Deliveries (Y3)	237,763,329	238,940,858	239,587,667	0	0	0	0
Average Line Length	696.5	707.5	719.1	676.8	639.2	603.7	570.1
Customers Added in last 10 years	17.14%	19.41%	20.75%	0.00%	0.00%	0.00%	0.00%
Trend	9	10	11	12	13	14	15

Company-Specific Parameter Estimates*

91	Constant	12.8159	12.8159	12.8159	12.8159	12.8159	12.8159	12.8159
92	Capital Price / OM&A Price (WK)	0.6278	0.6278	0.6278	0.6278	0.6278	0.6278	0.6278
93	Customers (Y1)	0.4425	0.4425	0.4425	0.4425	0.4425	0.4425	0.4425
94	Capacity (Y2)	0.1609	0.1609	0.1609	0.1609	0.1609	0.1609	0.1609
95	Deliveries (Y3)	0.1031	0.1031	0.1031	0.1031	0.1031	0.1031	0.1031
96	WKWK	0.1246	0.1246	0.1246	0.1246	0.1246	0.1246	0.1246
97	Y1Y1	(0.3793)	(0.3793)	(0.3793)	(0.3793)	(0.3793)	(0.3793)	(0.3793)
98	Y2Y2	0.1806	0.1806	0.1806	0.1806	0.1806	0.1806	0.1806
99	Y3Y3	0.1678	0.1678	0.1678	0.1678	0.1678	0.1678	0.1678
100	WKY1	0.0509	0.0509	0.0509	0.0509	0.0509	0.0509	0.0509
101	WKY2	0.0108	0.0108	0.0108	0.0108	0.0108	0.0108	0.0108
102	WKY3	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020	0.0020
103	Y1Y2	0.1483	0.1483	0.1483	0.1483	0.1483	0.1483	0.1483
104	Y1Y3	0.0609	0.0609	0.0609	0.0609	0.0609	0.0609	0.0609
105	Y2Y3	(0.1955)	(0.1955)	(0.1955)	(0.1955)	(0.1955)	(0.1955)	(0.1955)
106	Average Line Length	0.2874	0.2874	0.2874	0.2874	0.2874	0.2874	0.2874
107	Customers Added in last 10 years	0.0167	0.0167	0.0167	0.0167	0.0167	0.0167	0.0167
108	Trend	0.0168	0.0168	0.0168	0.0168	0.0168	0.0168	0.0168

167	**Sample Mean Values**							
168								
169	Constant	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
170	Capital Price / OM&A Price (WK)	0.1644	0.1644	0.1644	0.1644	0.1644	0.1644	0.1644
171	Customers (Y1)	63,422.3118	63,422.3118	63,422.3118	63,422.3118	63,422.3118	63,422.3118	63,422.3118
172	Capacity (Y2)	345,129.0146	345,129.0146	345,129.0146	345,129.0146	345,129.0146	345,129.0146	345,129.0146
173	Deliveries (Y3	1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994	1,630,327,994
174	WKWK	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
175	Y1Y1	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
176	Y2Y2	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
177	Y3Y3	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
178	WKY1	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
179	WKY2	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
180	WKY3	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
181	Y1Y2	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
182	Y1Y3	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
183	Y2Y3	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
184	Average Line Length	2,723	2,723	2,723	2,723	2,723	2,723	2,723
185	Customers Added in last 10 years	0.1286	0.1286	0.1286	0.1286	0.1286	0.1286	0.1286
186								
187								
188								
189	**2013 Values Logged and Mean Scaled (where applicable)**							
190								
191	Constant	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
192	Capital Price / OM&A Price (WK)	(0.1918)	(0.2801)	(0.2793)	(1.0788)	(1.0788)	(1.0788)	(1.0788)
193	Customers (Y1)	(1.3675)	(1.3455)	(1.3135)	#NUM!	#NUM!	#NUM!	#NUM!
194	Capacity (Y2)	(1.6413)	(1.6413)	(1.6413)	(1.6413)	(1.6413)	(1.6413)	(1.6413)
195	Deliveries (Y3)	(1.9253)	(1.9203)	(1.9176)	#NUM!	#NUM!	#NUM!	#NUM!
196	WKWK	0.0184	0.0392	0.0390	0.5819	0.5819	0.5819	0.5819
197	Y1Y1	0.9350	0.9051	0.8626	#NUM!	#NUM!	#NUM!	#NUM!
198	Y2Y2	1.3469	1.3469	1.3469	1.3469	1.3469	1.3469	1.3469
199	Y3Y3	1.8533	1.8438	1.8386	#NUM!	#NUM!	#NUM!	#NUM!
200	WKY1	0.2623	0.3769	0.3668	#NUM!	#NUM!	#NUM!	#NUM!
201	WKY2	0.3148	0.4597	0.4583	1.7707	1.7707	1.7707	1.7707
202	WKY3	0.3693	0.5379	0.5355	#NUM!	#NUM!	#NUM!	#NUM!
203	Y1Y2	2.2444	2.2083	2.1558	#NUM!	#NUM!	#NUM!	#NUM!
204	Y1Y3	2.6327	2.5837	2.5187	#NUM!	#NUM!	#NUM!	#NUM!
205	Y2Y3	3.1599	3.1518	3.1474	#NUM!	#NUM!	#NUM!	#NUM!
206	Average Line Length	(1.3633)	(1.3476)	(1.3315)	(1.3921)	(1.4493)	(1.5064)	(1.5636)
207	Customers Added in last 10 years	133.27%	150.93%	161.35%	0.00%	0.00%	0.00%	0.00%
208	Trend	9.0000	10.0000	11.0000	12.0000	13.0000	14.0000	15.0000

Product of Parameter and 2013 Values

	Constant	12.816	12.816	12.816	12.816	12.816	12.816	12.816
	Capital Price / OM&A Price (WK)	(0.120)	(0.176)	(0.175)	(0.677)	(0.677)	(0.677)	(0.677)
	Customers (Y1)	(0.605)	(0.595)	(0.581)	#NUM!	#NUM!	#NUM!	#NUM!
	Capacity (Y2)	(0.264)	(0.264)	(0.264)	(0.264)	(0.264)	(0.264)	(0.264)
	Deliveries (Y3)	(0.199)	(0.198)	(0.198)	#NUM!	#NUM!	#NUM!	#NUM!
	WKWK	0.002	0.005	0.005	0.073	0.073	0.073	0.073
	Y1Y1	(0.355)	(0.343)	(0.327)	#NUM!	#NUM!	#NUM!	#NUM!
	Y2Y2	0.243	0.243	0.243	0.243	0.243	0.243	0.243
	Y3Y3	0.311	0.309	0.309	#NUM!	#NUM!	#NUM!	#NUM!
	WKY1	0.013	0.019	0.019	#NUM!	#NUM!	#NUM!	#NUM!
	WKY2	0.003	0.005	0.005	0.019	0.019	0.019	0.019
	WKY3	0.001	0.001	0.001	#NUM!	#NUM!	#NUM!	#NUM!
	Y1Y2	0.333	0.327	0.320	#NUM!	#NUM!	#NUM!	#NUM!
	Y1Y3	0.160	0.157	0.153	#NUM!	#NUM!	#NUM!	#NUM!
	Y2Y3	(0.618)	(0.616)	(0.615)	#NUM!	#NUM!	#NUM!	#NUM!
	Average Line Length	(0.392)	(0.387)	(0.383)	(0.400)	(0.416)	(0.433)	(0.449)
	Customers Added in last 10 years	0.022	0.025	0.027	-	-	-	-
	Trend	0.151	0.168	0.185	0.202	0.219	0.235	0.252
	Log of Predicted Total Cost / OM&A Price	11.5044	11.4968	11.5388	#NUM!	#NUM!	#NUM!	#NUM!
	Real Predicted Total Cost / OM&A Price	99,150	98,399	102,619	#NUM!	#NUM!	#NUM!	#NUM!
	OM&A Price	132.11	135.14	138.23	138.23	138.23	138.23	138.23
	Predicted Total Cost	13,098,824	13,297,653	14,185,462	#NUM!	#NUM!	#NUM!	#NUM!

Section 4: Benchmarking Results

	Actual Cost	14,265,653	14,433,911	15,667,316	4,054,319	3,868,225	3,690,674	3,521,272
	Predicted Cost	13,098,824	13,297,653	14,185,462	#NUM!	#NUM!	#NUM!	#NUM!
	Actual less Predicted Cost	1,166,829	1,136,259	1,481,854	#NUM!	#NUM!	#NUM!	#NUM!
	Percentage Difference (Arithmetic for Comparison)	8.91%	8.54%	10.45%	#NUM!	#NUM!	#NUM!	#NUM!
	Percent Difference (Logarithmic)	**8.53%**	**8.20%**	**9.94%**	**#NUM!**	**#NUM!**	**#NUM!**	**#NUM!**

Summary of Cost Benchmarking Results

InnPower

Cost Benchmarking Summary	2015 (History)	2016 (Bridge)	2017 (Test Year)	2018	2019	2020
Actual Total Cost	14,265,653	14,433,911	15,667,316	na	na	na
Predicted Total Cost	13,098,824	13,297,653	14,185,462	na	na	na
Difference	1,166,829	1,136,259	1,481,854	na	na	na
Percentage Difference (Cost Performance)	**8.5%**	**8.2%**	**9.9%**	**na**	**na**	**na**
Three-Year Average Performance			8.9%	na	na	na
Stretch Factor Cohort						
Annual Result	3	3	3	na	na	na
Three Year Average			3			

APPENDIX I: 2.1.13 InnPower Corporation Trial Balance Mapped to Balance Sheet

Innisfil Hydro Distribution Systems Limited
OEB RRR: 2.1.13 General Ledger Trial Balance Mapped to Balance Sheet
For the Year: 2015

Trial Balance Mapped to Financial Statement Grouping: STATEMENT OF FINANCIAL POSITION					
Account	**B/S Section**	**B/S Line Grouping**	**G/L Account Description**	**Current Year**	**Balance Sheet**
Assets					
1005	Current Asset	Cash	Cash	-	
1010	Current Asset	Cash	Cash Advances and Working Fu	-	
1040	Current Asset	Cash	Other Special Deposits	-	
1410	Current Asset	Cash	Other Special or Collateral Fund	-	-
1100	Current Asset	Receivables	Customer Accounts Receivable	3,153,027.72	
1102	Current Asset	Receivables	Accounts Receivable - Retailers	887,226.75	
1104	Current Asset	Receivables	Accounts Receivable - Recover	906,324.81	
1110	Current Asset	Receivables	Other Accounts Receivable	938,005.87	
2290	Current Asset	Receivables	Commodity Taxes	(553,677.20)	
1130	Current Asset	Receivables	Accumulated Provision for Unco	(75,600.00)	
1150	Current Asset	Receivables	Rents Receivable	53,532.37	
1200	Current Asset	Due to related party	AR Affiliate	191,273.19	5,500,113.51
1120	Current Asset	Unbilled revenue	Accounts Receivable - Unbilled	3,646,859.92	3,646,859.92
1330	Current Asset	Inventory	Plant Inventory	451,746.16	451,746.16
1180	Current Asset	Prepaids	Prepaid Expenses	400,146.41	400,146.41
2294	Current Asset	Payments in lieu of taxes paya	Accrual for Taxes, Payments in	255,168.50	255,168.50
					10,254,034.50
1805	Asset	Property and equipment	Land	1,049,592.83	
1820	Asset	Property and equipment	Distribution Station	5,485,808.74	
1830	Asset	Property and equipment	Poles, Towers and Fixtures	8,711,434.05	
1835	Asset	Property and equipment	Overhead Conductors and Devi	9,820,700.94	
1840	Asset	Property and equipment	Underground Conduit	2,696,580.19	
1845	Asset	Property and equipment	Underground Conductors and D	7,805,366.97	
1850	Asset	Property and equipment	Pole Transformers	5,102,424.70	
1855	Asset	Property and equipment	OH & UG Services	3,558,345.30	
1860	Asset	Property and equipment	Meters	2,005,671.13	
1905	Asset	Property and equipment	Land	1,015,496.30	
1908	Asset	Property and equipment	Building & Furniture	12,430,509.79	
1915	Asset	Property and equipment	Office Furniture & Equipment	223,501.51	
1920	Asset	Property and equipment	Computer Hardware	401,534.22	
1930	Asset	Property and equipment	Transportation Equipment	517,274.32	
1935	Asset	Property and equipment	Stores Equipment	135,334.29	
1940	Asset	Property and equipment	Tools, Shop & Garage Equipme	305,568.26	
1945	Asset	Property and equipment	Measurement and Testing Equi	29,667.46	
1980	Asset	Property and equipment	System Supervisory Equipment	1,587,596.52	
2055	Asset	Property and equipment	WIP	797,726.61	
2105	Asset	Property and equipment	Accumulated Depreciation - Pro	(3,610,865.84)	60,069,268.29
1806	Asset	Intangible assets	Land Rights	394,446.17	
1925	Asset	Intangible assets	Computer Software	570,535.48	
2105	Asset	Intangible assets	Accumulated Depreciation - Inta	(315,614.37)	649,367.28
1405	Asset	Long term investment	Long term investment	21,720.64	21,720.64
1460	Asset	Future income tax assets	Future PILs - Non-current	488,985.00	488,985.00
	TOTAL ASSETS				**71,483,375.71**

1460	Asset	Regulatory assets	Other Non-Current Assets	58,520.00	
1508	Asset	Regulatory assets	Other Regulatory Assets	14,492.45	
1518	Asset	Regulatory assets	RCVA Retail	61,171.35	
1548	Asset	Regulatory assets	RCVA STR	25,971.25	
1551	Asset	Regulatory assets	Smart Meter Entity	(10,232.22)	
1568	Asset	Regulatory assets	LRAM	26,366.54	
1550	Asset	Regulatory assets	LV Variance Account	408,115.48	
1563	Asset	Regulatory assets	Deferred PILS - Contra	4,168.62	
1580	Asset	Regulatory assets	RSVA Wholesale Market Servic	(521,150.09)	
1582	Asset	Regulatory assets	RSVA One Time	-	
1584	Asset	Regulatory assets	RSVA Network	(5,032.24)	
1586	Asset	Regulatory assets	RSVA Connection	25,144.33	
1588	Asset	Regulatory assets	RSVA Power	(325,605.25)	
1589	Asset	Regulatory assets	RSVA GA	809,216.83	
1592	Asset	Regulatory assets	PST Savings	1,613.23	
1595	Asset	Regulatory assets	Recovery of Regulatory Balance	322,488.17	895,248.45
	TOTAL ASSETS & REGULATORY DEFERRAL ACCOUNT BALANCES				**72,378,624.16**

Trial Balance Mapped to Financial Statement Grouping: STATEMENT OF FINANCIAL POSITION					
Account	**B/S Section**	**B/S Line Grouping**	**G/L Account Description**	**Current Year**	**Balance Sheet**
Liabilities					
2225	Current Liability	Bank Indebtedness	Short Term Debt	1,471,812.70	1,471,812.70
1110	Current Liability	Payables and accruals	AR Other	1,198.26	
2205	Current Liability	Payables and accruals	Accounts Payable	2,189,237.43	
2208	Current Liability	Payables and accruals	Customer Credit Balances	176,082.96	
2220	Current Liability	Payables and accruals	Accrued Liabilities	1,025,094.32	
2250	Current Liability	Payables and accruals	Debt Retirement Charges	-	
2252	Current Liability	Payables and accruals	Transmission Charges Payable	328,986.08	
2256	Current Liability	Payables and accruals	Independent Market Operator F	2,082,893.85	
2240	Current Liability	Due to related party	Accounts Payable to Associated	1,857,539.94	
2268	Current Liability	Due to related party	Accrued Interest on Long Term	53,024.12	
2320	Current Liability	Due to related party	Accrued Interest on Long Term	52,992.00	7,767,048.96
2440	Current Liability	Deferred revenue	Contributions in aid of construct	357,000.00	357,000.00
1104	Current Liability	Customer credit bal & deposit	Accounts Receivable - Recover	1,190,646.36	
2210	Current Liability	Customer credit bal & deposit	Current Portion of Customer De	19,984.00	1,210,630.36
2260	Current Liability	Short term debt	Short Term Debt	1,601,978.70	1,601,978.70
2260	Current Liability	Short term debt	Current Portion of Long Term D	2,596,000.00	2,596,000.00
2296	Current Liability	Future income tax	Future Income Taxes - Current	-	-
					15,004,470.72
2240	Non-Current Liabilities	Deferred Revenue	Contributions in aid of construct	10,418,890.45	10,418,890.45
2335	Non-Current Liabilities	Customer and retailer deposit	Long Term Customer Deposits	243,767.68	243,767.68
2306	Current Liability	Payables and accruals	Employee Future Benefits	163,498.00	163,498.00
2525	Non-Current Liabilities	Long term debt	Notes and Loans Payable-TD lo	29,153,044.42	
2550	Non-Current Liabilities	Long term debt	Advances from Associated Com	-	29,153,044.42
	TOTAL LIABILITIES				**54,983,671.27**
Shareholder's Equity					
3005	S/H Equity	Capital stock	Share Capital	10,852,444.00	10,852,444.00
3045	S/H Equity	Retained Earnings	Unappropriated Retained Earni	10,876,521.43	
3045	S/H Equity	Retained Earnings	Dividends Paid	(6,776,750.00)	
3046	S/H Equity	Retained Earnings	Transfer from Income	1,217,414.24	
3055	S/H Equity	Retained Earnings	Adjustment to Retained Earning	966,492.96	6,283,678.63
3046	S/H Equity	Retained Earnings	Accumulated Other Comprehen	(7,000.00)	(7,000.00)
3022	S/H Equity	Development charges	Development Charges Transfer	-	-
	TOTAL SHAREHOLDER'S EQUITY				**17,129,122.63**
1555	Liabilites	Regulatory Liabilities	Smart Meter Capital	45,665.29	
1576	Liabilites	Regulatory Liabilities	Accounting Changes Under CG	220,164.96	
2296	Liabilites	Regulatory Liabilities	Deferred Taxes	-	265,830.25
	TOTAL LIABILITIES, SHAREHOLDER'S EQUITY AND REGULATORY DEFERRAL ACCOUNT CREDIT BA				**72,378,624.15**

Trial Balance Mapped to Financial Statement Grouping: STATEMENT OF COMPREHENSIVE INCOME					
Account	**I/S Section**	**I/S Line Grouping**	**G/L Account Description**	**Current Year**	**Income Statement**
Revenue					
4006	Revenue	Sale of power	Residential Energy Sales	16,027,090.29	
4025	Revenue	Sale of power	Street Lights Energy Sales	104,298.91	
4030	Revenue	Sale of power	Sentinel Lights Energy Sales	8,770.11	
4035	Revenue	Sale of power	General Service Energy Sales	8,489,580.32	
4050	Revenue	Sale of power	Revenue Adjustment	(339,630.20)	
4055	Revenue	Sale of power	Energy Sales for Resale	2,060,012.33	
4062	Revenue	Sale of power	Billed WMS	946,469.05	
4064	Revenue	Sale of power	Billed One Time	-	
4066	Revenue	Sale of power	Billed NW	1,600,511.37	
4068	Revenue	Sale of power	Billed CN	1,145,745.43	
4075	Revenue	Sale of power	Billed LV	516,907.99	
4076	Revenue	Sale of power	Billed Smart Meter Entity Charg	144,791.85	**30,704,547.45**
4080	Revenue	Distribution	Distribution Services Revenue	8,769,808.56	
4082	Revenue	Distribution	Retail Services Revenue	14,880.40	
4084	Revenue	Distribution	Service Transaction Request Re	252.75	**8,784,941.71**
4082	Revenue	Gain on disposal	Gain on Disposal	410,401.60	**410,401.60**
4210	Revenue	Other revenues	Rental Revenue	161,206.80	
4225	Revenue	Other revenues	Late Payment Charges	96,925.26	
4235	Revenue	Other revenues	Miscellaneous Service Revenue	156,169.52	
4245	Revenue	Other revenues	Contributions	313,329.81	
4355	Revenue	Other revenues	Gain on Disposition of Utility an	29,995.88	
4375	Revenue	Other revenues	Non-Utility Operations Revenue	775,119.70	
4380	Revenue	Other revenues	Non-Utility Operations Expense	(689,823.14)	
4390	Revenue	Other revenues	Miscellaneous Revenue	30,115.79	
5705	Revenue	Other revenues	Amort Exp Deferral Acct 1576	123.72	
4405	Revenue	Other revenues	Interest and Dividend Income	3,910.82	**877,074.16**
			Total Revenues		**40,776,964.92**
Expenses					
4705	Expenses	Power Purchased	Power Purchased	20,748,477.84	
4707	Expenses	Power Purchased	GA Purchased	5,865,280.22	
4708	Expenses	Power Purchased	Charges-WMS	946,469.05	
4710	Expenses	Power Purchased	Cost of Power Adjustments	(363,636.30)	
4712	Expenses	Power Purchased	Charges-One Time	-	
4714	Expenses	Power Purchased	Charges-NW	1,600,511.37	
4716	Expenses	Power Purchased	Charges-CN	1,145,745.43	
4750	Expenses	Power Purchased	LV Charges	516,907.99	
4751	Expenses	Power Purchased	Charges - Smart Meter Entity Cl	144,791.85	**30,604,547.45**
5005	Expenses	Distribution	Operation Supervision and Engi	220,453.50	
5010	Expenses	Distribution	Load Dispatching	14,948.11	
5012	Expenses	Distribution	Station Buildings and Fixtures E	48,575.54	
5016	Expenses	Distribution	Distribution Station Equipment -	9,717.90	
5017	Expenses	Distribution	Distribution Station Equipment -	5,227.82	
5020	Expenses	Distribution	Overhead Distribution Lines and	136,301.24	
5025	Expenses	Distribution	Overhead Distribution Lines and	7,484.41	
5030	Expenses	Distribution	Overhead Subtransmission Fee	1,427.04	
5035	Expenses	Distribution	Overhead Distribution Transforr	246.40	
5040	Expenses	Distribution	Underground Distribution Lines	18,961.29	
5045	Expenses	Distribution	Underground Distribution Lines	98,965.54	
5055	Expenses	Distribution	UG TX Subcontractors	189.00	
5065	Expenses	Distribution	Meter Expense	241,352.71	
5070	Expenses	Distribution	Customer Premises - Operation	55,089.05	
5075	Expenses	Distribution	Customer Premises - Materials	101,903.73	
5085	Expenses	Distribution	Miscellaneous Distribution Expe	405,526.84	

5095	Expenses	Distribution	Overhead Distribution Lines and	11,199.19	
5105	Expenses	Distribution	Maintenance Supervision and E	8,489.36	
5114	Expenses	Distribution	Maintenance of Distribution Sta	33,377.07	
5120	Expenses	Distribution	Maintenance of Poles, Towers a	10,631.58	
5125	Expenses	Distribution	Maintenance of Overhead Cond	49,139.87	
5130	Expenses	Distribution	Maintenance of Overhead Servi	64,767.27	
5135	Expenses	Distribution	Overhead Distribution Lines and	119,800.61	
5150	Expenses	Distribution	Maintenance of Underground C	24,178.03	
5155	Expenses	Distribution	Maintenance of Underground S	76,614.06	
5160	Expenses	Distribution	Maintenance of Line Transforme	17,208.13	
5161	Expenses	Distribution	Maintenance of Line Transforme	-	
5175	Expenses	Distribution	Maintenance of Meters 5175	23,318.88	
9040	Expenses	Distribution	Maintenance of Meters 9040	-	
5305	Expenses	Billing and collecting	Supervision	124,729.11	
5310	Expenses	Billing and collecting	Meter Reading Expense	15,652.95	
5315	Expenses	Billing and collecting	Customer Billing	396,247.57	
5320	Expenses	Billing and collecting	Collecting	345,165.19	
5325	Expenses	Billing and collecting	Collecting- Cash Over and Shor	147.87	
5335	Expenses	Billing and collecting	Bad Debt Expense	59,455.15	
5340	Expenses	Billing and collecting	Miscellaneous Customer Accou	162,718.41	
5410	Expenses	Administration	Community Relations - Sundry	5,268.36	
5415	Expenses	Administration	Energy Conservation	-	
5420	Expenses	Administration	Community Relations - Safety P	350.00	
5425	Expenses	Administration	Miscellaneous Customer Servic	2,447.90	
5605	Expenses	Administration	Executive Salaries and Expense	262,072.80	
5610	Expenses	Administration	Management Salaries and Expe	329,472.79	
5615	Expenses	Administration	General Administrative Salaries	923,300.34	
5620	Expenses	Administration	Office Supplies and Expenses	216,791.33	
5630	Expenses	Administration	Outside Services Employed	199,341.52	
5635	Expenses	Administration	Property Insurance	43,942.58	
5640	Expenses	Administration	Injuries and Damages	49,895.84	
5646	Expenses	Administration	Employee Pensions and Benefit	15,753.00	
5655	Expenses	Administration	Regulatory Expenses	111,126.39	
5665	Expenses	Administration	Miscellaneous General Expense	131,055.09	
5670	Expenses	Administration	Rent	1,530.19	
5675	Expenses	Administration	Maintenance of General Plant	282,147.85	
5680	Expenses	Administration	Electrical Safety Authority Fees	9,212.30	
5685	Expenses	Administration	Independent Market Operator F	-	
6105	Expenses	Administration	Taxes Other Than Income Taxe	87,714.15	
6205	Expenses	Administration	Donations	(234.00)	
6215	Expenses	Administration	Penalties	164.79	**5,580,563.64**
5705	Expenses	Amortization	Depreciation Expense	2,044,275.01	**2,044,275.01**
			Total Expenses		**38,229,386.10**
		Income from operating activities			**2,547,578.82**
4405	Finance income	Finance Income	Interest and Dividend Income	3,642.44	**3,642.44**
6005	Finance cost	Interest on long term debt	Interest on Debt to Associated C	1,047,018.40	
6035	Finance cost	Interest on long term debt	Other Interest Expense	25,982.83	**1,073,001.23**
		Income before provision payment in lieu of income taxes			**1,478,220.03**
Payments in lieu of taxes					
6110	Current	Payments in lieu of taxes	Income Taxes	(1,666.00)	
6115	Deferred	Payments in lieu of taxes	Provision for Future Income Tax	348,008.00	**346,342.00**
		Profit for the year before net movement of reg deferral acct balances			**1,131,878.03**

Net movement in reg deferral acct balances related to P&L and deferred tax					
4006	Net movement DVA	Net movement DVA	Revenue RSVA	(1,048,000.00)	
4705	Net movement DVA	Net movement DVA	Power Purchased RSVA	948,000.00	
4080	Net movement DVA	Net movement DVA	Distribution Services Revenue D	1,000.00	
5705	Net movement DVA	Net movement DVA	Amort Expense Deferral Acct 15	165,000.00	
5315	Net movement DVA	Net movement DVA	Customer Billing DVA	8,000.00	
6115	Net movement DVA	Net movement DVA	Provision for Future Income Tax	(4,000.00)	
4405	Net movement DVA	Net movement DVA	Interest and Dividend Income	20,364.68	
6035	Net movement DVA	Net movement DVA	Other Interest Expense	(4,828.47)	**85,536.21**
		Profit for the year and net movement of reg deferral acct balances			**1,217,414.24**
Other Comprehensive Income					
7025	OCI	OCI	Other Comprehensive Income	-	**-**
		Total comprehensive income for the year			**1,217,414.24**

Trial Balance Mapped to Financial Statement Grouping: STATEMENT OF CHANGE IN EQUITY

Account	B/S Section	B/S Line Grouping	G/L Account Description	Current Year	Balance Sheet
3005	S/H Equity	Capital stock	Common Shares Issued	10,852,444.00	
3045	S/H Equity	RE, beginning of year	Unappropriate Retained Earning	4,724,771.43	
3055	S/H Equity	RE, beginning of year	Adjustment to Retained Earning	966,492.96	**16,543,708.39**
3046	S/H Equity	Net earnings			**1,217,414.24**
3045	S/H Equity	Dividends	Unappropriated Retained Earnings-Dividends current y		**(625,000.00)**
3045	S/H Equity	Retained earnings	Accumulated other comprehensive income		**(7,000.00)**
	S/H Equity	Retained earnings, end of year			**17,129,122.63**

Trial Balance by Account					
Account	F/S Section	F/S Line Grouping	G/L Account Description	Current Year	
1005	Current Asset	Cash	Cash	-	x
1010	Current Asset	Cash	Cash Advances and Working Fu	-	x
1040	Current Asset	Cash	Other Special Deposits	-	x
1100	Current Asset	Receivables	Customer Accounts Receivable	3,153,027.72	x
1102	Current Asset	Receivables	Accounts Receivable - Retailers	887,226.75	x
1104	Current Asset	Receivables	Accounts Receivable - Recover	906,324.81	x
1104	Current Liability	Customer credit bal & deposit	Other Special Deposits	(1,190,646.36)	x
1110	Current Asset	Receivables	Other Accounts Receivable-HS	938,005.87	x
1110	Current Liability	AP & Accrued Liabilites	Other Accounts Receivable-OC	(1,198.26)	x
1120	Current Asset	Unbilled revenue	Accrued Utility Revenues	3,646,859.92	x
1130	Current Asset	Receivables	Accumulated Provision for Uncc	(75,600.00)	x
1150	Current Asset	Receivables	Rents Receivable	53,532.37	x
1180	Current Asset	Prepaids	Prepayments	400,146.41	x
1200	Current Asset	Due to related party	AR Affiliate	191,273.19	x
1330	Current Asset	Inventory	Plant Materials and Operating S	451,746.16	x
1405	Asset	Long term investment	Long Term Investments in Non-	21,720.64	x
1410	Current Asset	Cash	Other Special or Collateral Func	-	x
1460	Asset	Future income taxes	Other Non-Current Assets	547,505.00	x
1460	Asset	Future income taxes	Other Non-Current Assets	(58,520.00)	x
1460	Asset	Regulatory assets	Other Non-Current Assets	58,520.00	x
1508	Asset	Regulatory assets	Other Regulatory Assets	14,492.45	x
1518	Asset	Regulatory assets	RCVA Retail	61,171.35	x
1548	Asset	Regulatory assets	RCVA STR	25,971.25	x
1550	Asset	Regulatory assets	LV Variance Account	408,115.48	x
1551	Asset	Regulatory assets	Smart Meter Entity	(10,232.22)	x
1555	Liability	Regulatory liabilities	Smart Meter Capital	(45,665.29)	x
1563	Asset	Regulatory assets	Deffered PILs Contra Account	4,168.62	x
1568	Asset	Regulatory assets	LRAM	26,366.54	x
1576	Liability	Regulatory liabilities	Accounting Changes Under CG	(220,164.96)	x
1580	Asset	Regulatory liabilities	RSVA Wholesale Market Servic	(521,150.09)	x
1582	Asset	Regulatory liabilities	RSVA One Time	-	x
1584	Asset	Regulatory liabilities	RSVA Network	(5,032.24)	x
1586	Asset	Regulatory liabilities	RSVA Connection	25,144.33	x
1588	Asset	Regulatory liabilities	RSVA Power	(325,605.25)	x
1589	Asset	Regulatory liabilities	RSVA GA	809,216.83	x
1592	Asset	Regulatory assets	PST Savings	1,613.23	x
1595	Asset	Regulatory assets	Recovery of regulatory assets	322,488.17	x
1805	Asset	Property and equipment	Land	1,049,592.83	x
1806	Asset	Intangible assets	Land Rights	394,446.17	x
1820	Asset	Property and equipment	Distribution Station	5,485,808.74	x
1830	Asset	Property and equipment	Poles, Towers and Fixtures	8,711,434.05	x
1835	Asset	Property and equipment	Overhead Conductors and Devi	9,820,700.94	x
1840	Asset	Property and equipment	Underground Conduit	2,696,580.19	x
1845	Asset	Property and equipment	Underground Conductors and D	7,805,366.97	x
1850	Asset	Property and equipment	Pole & Padmount Transformers	5,102,424.70	x
1855	Asset	Property and equipment	OH & UG Services	3,558,345.30	x
1860	Asset	Property and equipment	Meters	2,005,671.13	x
1905	Asset	Property and equipment	Land	1,015,496.30	x
1908	Asset	Property and equipment	Buildings and Fixtures	12,430,509.79	x
1915	Asset	Property and equipment	Office Furniture and Equipment	223,501.51	x
1920	Asset	Property and equipment	Computer Equipment - Hardwar	401,534.22	x
1925	Asset	Intangible assets	Computer Software	570,535.48	x
1930	Asset	Property and equipment	Transportation Equipment	517,274.32	x
1935	Asset	Property and equipment	Stores Equipment	135,334.29	x
1940	Asset	Property and equipment	Tools, Shop and Garage Equipr	305,568.26	x
1945	Asset	Property and equipment	Measurement and Testing Equi	29,667.46	x
1980	Asset	Property and equipment	System Supervisory Equipment	1,587,596.52	x
2055	Asset	Property and equipment	WIP	797,726.61	x
2105	Asset	Property and equipment	Accumulated Amortization - PPE	(3,610,865.84)	x
2105	Asset	Intangible assets	Accumulated Amortization - Inta	(315,614.37)	x
2205	Current Liability	Payables and accruals	Accounts Payable	(2,189,237.43)	x

2205	Current Liability	Payables and accruals	Reclassed to account 2240	(5,459.56)	x
2206	Current Liability	Payables and accruals	Reclassed to account 2240	(1,816,035.47)	x
2208	Current Liability	Customer credit bal & deposit	Customer Credit Balances	(176,082.96)	x
2210	Current Liability	Customer credit bal & deposit	Current Portion of Customer De	(19,984.00)	x
2220	Current Liability	Payables and accruals	Miscellaneous Current and Accr	(1,025,094.32)	x
2225	Current Liability	Bank Indebtedness	Short term debt	(1,471,812.70)	x
2240	Current Liability	Due to related party	Accounts Payable to Associatec	(36,044.91)	x
2242	Current Liability	Due to related party	Notes Payable to Associated Cc	-	x
2250	Current Liability	Payables and accruals	Debt Retirement Charges	-	x
2252	Current Liability	Payables and accruals	Transmission Charges Payable	(328,986.08)	x
2256	Current Liability	Payables and accruals	Independent Market Operator F	(2,082,893.85)	x
2260	Current Liability	Current portion of long-term d	Current Portion of Long Term D	(2,531,312.00)	x
2268	Current Liability	Due to related party	Accrued Interest On Long Term	(53,024.12)	x
2290	Current Asset	Receivables	Commodity Taxes	(553,677.20)	x
2294	Current Asset	Payments in lieu of taxes paya	Accrual for Taxes, Payments in	255,168.50	x
2296	Current Liability	Future income taxes	Future Income Taxes - Current	-	x
2306	Current Liability	Payables and accruals	Employee Future Benefits	(163,498.00)	x
2320	Current Liability	Payables and accruals	Miscellaneous Liabilities	(52,992.00)	x
2335	Non-Current Liability	Customer and retailer deposit	Long Term Customer Deposits	(243,767.68)	x
2440	Current Liability	Deferred Revenue	Contributions and Grants - Cred	(357,000.00)	x
2440	Non-Current Liability	Deferred Revenue	Contributions and Grants - Cred	(10,418,890.45)	x
2525	Non-Current Liability	Long term debt	Term Bank Loan - Long Term P	(29,153,044.42)	x
2525	Current Liability	Long term debt	Term Bank Loan - Short Term P	(1,666,666.70)	x
2550	Non-Current Liability	Long term debt	Advances from Associated Com	-	x
3005	S/H Equity	Capital stock	Common Shares Issued	(10,852,444.00)	x
3022	S/H Equity	Retained earnings	Development Charges Transfer	-	x
3045	S/H Equity	Retained earnings	Unappropriated Retained Earnir	(10,869,521.43)	x
3046	S/H Equity	Retained earnings	Accumulated other comprehens	7,000.00	x
3045	S/H Equity	Retained earnings	Unappropriated Retained Earnir	6,151,750.00	x
3045	S/H Equity	Retained earnings	Unappropriated Retained Earnir	625,000.00	x
3046	S/H Equity	Retained earnings	Balance Transferred From Incor	(1,217,414.24)	x
3055	S/H Equity	Retained earnings	Adjustment to Retained Earning	(966,492.96)	
5705	Expenses	Amortization	Amortization Expense Property,	2,044,275.01	x
6005	Interest on long term d	Interest on long term debt	Interest On Long Term Debt	1,021,546.28	x
6030	Interest on long term d	Interest on long term debt	Interest on Debt to Associated C	25,472.12	x
6035	Interest on long term d	Interest on long term debt	Other Interest Expense	25,982.83	x
6035	Net movement DVA	Net movement DVA	Other Interest Expense	4,828.47	x
6105	Expenses	Administration	Taxes Other Than Income Taxe	87,714.15	x
6110	Payments in lieu of tax	Payments in lieu of taxes	Income Taxes	(1,666.00)	x
6115	Payments in lieu of tax	Payments in lieu of taxes	Provision for Future Income Tax	352,008.00	x
6115	Payments in lieu of tax	Payments in lieu of taxes	Provision for Future Income Tax	(4,000.00)	x
6115	Net movement DVA	Net movement DVA	Provision for Future Income Tax	4,000.00	x
6205	Expenses	Administration	Donations	(234.00)	x
6215	Expenses	Administration	Penalties	164.79	x
7025	er Comprehensive Inc	Other Comprehensive Income	Other Comprehensive Income	-	x
4006	Revenue	Electricity sales	Residential Energy Sales	(14,979,090.29)	x
4006	Revenue	Electricity sales	RSVA Revenue	(1,048,000.00)	x
4006	Net movement DVA	Net movement DVA	RSVA Revenue	1,048,000.00	x
4025	Revenue	Electricity sales	Street Lighting Energy Sales	(104,298.91)	x
4030	Revenue	Electricity sales	Sentinel Lighting Energy Sales	(8,770.11)	x
4035	Revenue	Electricity sales	General Energy Sales	(8,489,580.32)	x
4050	Revenue	Electricity sales	Revenue Adjustment	339,630.20	x
4055	Revenue	Electricity sales	Energy Sales for Resale	(2,060,012.33)	x
4062	Revenue	Electricity sales	Billed WMS	(946,469.05)	x
4064	Revenue	Electricity sales	Billed One Time	-	x
4066	Revenue	Electricity sales	Billed NW	(1,600,511.37)	x
4068	Revenue	Electricity sales	Billed CN	(1,145,745.43)	x
4075	Revenue	Electricity sales	Billed LV	(516,907.99)	x
4076	Revenue	Electricity sales	Billed Smart Meter Entity Charg	(144,791.85)	x
4705	Expenses	Purchased power	Power Purchased	19,800,477.84	x
4705	Expenses	Purchased power	Power Purchased RSVA	948,000.00	x
4705	Net movement DVA	Net movement DVA	Power Purchased RSVA	(948,000.00)	x
4707	Expenses	Purchased power	GA Purchased	5,865,280.22	x
4708	Expenses	Purchased power	Charges-WMS	946,469.05	x

4710	Expenses	Purchased power	Cost of Power Adjustments	(363,636.30)	x
4712	Expenses	Purchased power	Charges-One Time	-	x
4714	Expenses	Purchased power	Charges-NW	1,600,511.37	x
4716	Expenses	Purchased power	Charges-CN	1,145,745.43	x
4750	Expenses	Purchased power	LV Charges	516,907.99	x
4751	Expenses	Purchased power	Charges - Smart Meter Entity Cl	144,791.85	x
4080	Revenue	Distribution	Distribution Services Revenue	(8,770,808.56)	x
4080	Revenue	Distribution	Distribution Services Revenue D	1,000.00	x
4080	Net movement DVA	Net movement DVA	Distribution Services Revenue D	(1,000.00)	x
4082	Revenue	Distribution	Retail Services Revenues	(14,880.40)	x
4084	Revenue	Distribution	Service Transaction Requests (	(252.75)	x
4245	Revenue	Other revenues	Contributions	(313,329.81)	x
5005	Expenses	Distribution	Operation Supervision and Engi	220,453.50	x
5010	Expenses	Distribution	Load Dispatching	14,948.11	x
5012	Expenses	Distribution	Station Buildings and Fixtures E	48,575.54	x
5016	Expenses	Distribution	Distribution Station Equipment -	9,717.90	x
5017	Expenses	Distribution	Distribution Station Equipment -	5,227.82	x
5020	Expenses	Distribution	Overhead Distribution Lines and	136,301.24	x
5025	Expenses	Distribution	Overhead Distribution Lines and	7,484.41	x
5030	Expenses	Distribution	Overhead Subtransmission Fee	1,427.04	x
5035	Expenses	Distribution	Overhead Distribution Transforr	246.40	x
5040	Expenses	Distribution	Underground Distribution Lines	18,961.29	x
5045	Expenses	Distribution	Underground Distribution Lines	98,965.54	x
5055	Expenses	Distribution	UG TX Subcontractors	189.00	x
5065	Expenses	Distribution	Meter Expense	241,352.71	x
5070	Expenses	Distribution	Customer Premises - Operation	55,089.05	x
5075	Expenses	Distribution	Customer Premises - Materials	101,903.73	x
5085	Expenses	Distribution	Miscellaneous Distribution Expe	405,526.84	x
5095	Expenses	Distribution	Overhead Distribution Lines and	11,199.19	x
5105	Expenses	Distribution	Maintenance Supervision and E	8,489.36	x
5114	Expenses	Distribution	Maintenance of Distribution Stat	33,377.07	x
5120	Expenses	Distribution	Maintenance of Poles, Towers a	10,631.58	x
5125	Expenses	Distribution	Maintenance of Overhead Cond	49,139.87	x
5130	Expenses	Distribution	Maintenance of Overhead Servi	64,767.27	x
5135	Expenses	Distribution	Overhead Distribution Lines and	119,800.61	x
5150	Expenses	Distribution	Maintenance of Underground C	24,178.03	x
5155	Expenses	Distribution	Maintenance of Underground S	76,614.06	x
5160	Expenses	Distribution	Maintenance of Line Transforme	17,208.13	x
5161	Expenses	Distribution	Maintenance of Line Transforme	-	x
5175	Expenses	Distribution	Maintenance of Meters 5175	23,318.88	x
9040	Expenses	Distribution	Maintenance of Meters 9040	-	x
4210	Revenue	Other revenues	Rent from Electric Property	(161,206.80)	x
4225	Revenue	Other revenues	Late Payment Charges	(96,925.26)	x
4235	Revenue	Other revenues	Miscellaneous Service Revenue	(156,169.52)	x
4355	Revenue	Gain on disposal	Gain on Disposition of Utility and	(410,401.60)	x
4355	Revenue	Other revenues	Loss on Disposition of Utility and	(29,995.88)	x
4375	Revenue	Other revenues	Revenues from Non-Utility Oper	(775,119.70)	x
4380	Revenue	Other revenues	Expenses of Non-Utility Operati	689,823.14	x
4390	Revenue	Other revenues	Miscellaneous Non-Operating Ir	(30,115.79)	x
4405	Revenue	Other revenues	Interest and Dividend Income	(3,910.82)	x
4405	Finance Income	Finance Income	Interest and Dividend Income	(3,642.44)	x
4405	Net movement DVA	Net movement DVA	Interest and Dividend Income	(20,364.68)	x
5705	Net movement DVA	Net movement DVA	Amort Expense Deferral Acct 15	(165,000.00)	x
5705	Revenue	Other revenues	Amort Exp Deferral Acct 1576	(123.72)	x
5305	Expenses	Billing and collecting	Supervision	124,729.11	x
5310	Expenses	Billing and collecting	Meter Reading Expense	15,652.95	x
5315	Expenses	Billing and collecting	Customer Billing	388,247.57	x
5315	Expenses	Billing and collecting	Customer Billing DVA	8,000.00	x
5315	Net movement DVA	Net movement DVA	Customer Billing DVA	(8,000.00)	x
5320	Expenses	Billing and collecting	Collecting	345,165.19	x
5325	Expenses	Billing and collecting	Collecting- Cash Over and Shor	147.87	x
5335	Expenses	Billing and collecting	Bad Debt Expense	59,455.15	x
5340	Expenses	Billing and collecting	Miscellaneous Customer Accou	162,718.41	x
5410	Expenses	Administration	Community Relations - Sundry	5,268.36	x

5415	Expenses	Administration	Energy Conservation	-	x
5420	Expenses	Administration	Community Relations - Safety P	350.00	x
5425	Expenses	Administration	Miscellaneous Customer Servic	2,447.90	x
5605	Expenses	Administration	Executive Salaries and Expense	262,072.80	x
5610	Expenses	Administration	Management Salaries and Expe	329,472.79	x
5615	Expenses	Administration	General Administrative Salaries	923,300.34	x
5620	Expenses	Administration	Office Supplies and Expenses	216,791.33	x
5630	Expenses	Administration	Outside Services Employed	199,341.52	x
5635	Expenses	Administration	Property Insurance	43,942.58	x
5640	Expenses	Administration	Injuries and Damages	49,895.84	x
5645	Expenses	Administration	Employee Pensions and Benefit	-	x
5646	Expenses	Administration	Employee Pensions and Benefit	15,753.00	x
5655	Expenses	Administration	Regulatory Expenses	111,126.39	x
5665	Expenses	Administration	Miscellaneous General Expense	131,055.09	x
5670	Expenses	Administration	Rent	1,530.19	x
5675	Expenses	Administration	Maintenance of General Plant	282,147.85	x
5680	Expenses	Administration	Electrical Safety Authority Fees	9,212.30	x
5685	Expenses	Administration	Fees & Penalties	-	

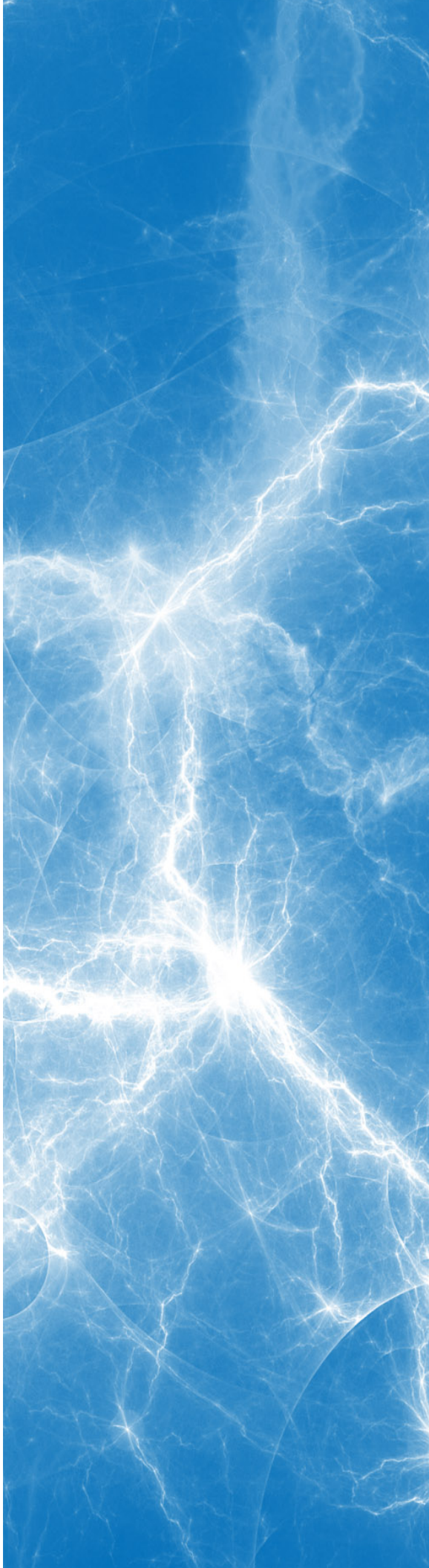
APPENDIX J: CHEC 2014 Benchmarking Report

CornerstonE
Hydro Electric Concepts

Achievement Through Collaboration

2014 CHEC Scorecard Analysis

A comparison of the 2014 Distributor's Scorecard for benchmarking purposes and to demonstrate the value CHEC Utilities deliver to the end customer.



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July 15, 2016

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Executive Summary:

Early in 2014, the OEB introduced the Renewed Regulatory Framework. This Framework is a comprehensive, performance based approach to regulation that promotes the achievement of specific outcomes (customer focus, operational effectiveness, public policy responsiveness, and financial performance). Included in this Framework is the Board's Scorecard approach, which is used to facilitate performance monitoring for electricity distributors. The Board will use the Scorecard approach to effectively translate these outcomes into a coherent set of performance measures.

On September 30, 2015, the Board released the 2015 Electricity Distributor Scorecards (covers a 5 year period from 2010 – 2014). The scorecard includes traditional metrics for assessing a distributor's services, which includes frequency of power outages, costs per customer and financial performance. In addition, future performance results (for 2015 and onward) will include a number of new metrics that directly reflect the customer experience, which includes how well the distributor resolves a customer's concern on the first contact, updates to the customer satisfaction survey methodology, release of the DSP measure, and more.

This following analysis compares CHEC Distributors to one another and CHEC Distributors to Provincial Distributors with the aim to encourage CHEC Distributors to operate effectively, to continually seek ways in which to improve their productivity and performance, and most importantly, to demonstrate the value they deliver to the end customer. The analysis concludes that CHEC Distributors are some of the higher performing electrical utilities among the province today.

Introduction:

The Renewed Regulatory Framework is a comprehensive performance-based approach to regulation that promotes the achievement of outcomes to the benefit of existing and future customers. This framework, which was introduced early in 2014, aims to align customer and distributor interests, continues to support the achievement of important public policy objectives, and places a greater focus on delivering long term value for money.

Under the Board's performance-based approach, a distributor is expected to demonstrate continuous improvement in achieving the four outcomes set out in the October 18, 2012 Report of the Board entitled "A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach". These outcomes are as follows:

- **Customer Focus:** Helps to determine if services are provided in a manner that responds to identified customer preferences;
- **Operational Effectiveness**: Demonstrates if continuous improvement in productivity and cost performance is achieved and measures how distributors deliver on system reliability and quality objectives;
- **Public Policy Responsiveness:** Determines if distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements); and
- **Financial Performance:** Demonstrates if financial viability is maintained and if savings from operational effectiveness are sustainable.

To facilitate performance monitoring and eventually distributor benchmarking, the Board will use a scorecard approach to effectively translate the four outcomes into a coherent set of performance measures (see **Table 1** below). These measures are further organized into performance categories that effectively align them with the four performance outcomes. These categories are, for the most part, based on existing standards and measures for electricity distributors.

Table 1: Measures of the Four Performance Outcomes:

Performance Outcomes	Performance Categories	Performance Measures
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential Services Connected on Time Scheduled Appointments Met on Time Telephone Calls Answered on Time
	Customer Satisfaction	First Contact Resolution Billing Accuracy Customer Satisfaction Survey Results
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Public Safety (measure to be determined)
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted Average Number of Times that Power to a Customer is Interrupted
	Asset Management	Distribution System Plan Implementation Progress
	Cost Control	Efficiency Assessment Total Cost per Customer Total Cost per Km of Line
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation and Demand Management	Net Annual Peak Demand Savings (Percent of target achieved) Net Cumulative Energy Savings (Percent of target achieved)
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed on Time New Micro-embedded Generation Facilities Connected on Time
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities) Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio Profitability: Regulated Return on Equity — Deemed (included in rates) Achieved

The measures identified for inclusion on the Scorecard are considered by the Ontario Energy Board to be most meaningful in terms of monitoring a distributor's effectiveness and continuous improvement in achieving the four stated outcomes. These performance measures selected are customer-focused, encourage continuous improvement, and are measureable. Providing a longer-term view on performance, the Scorecard will present the five most recent years of available data for each measure.

The Scorecard is designed to track and show an individual distributor's performance gains over a period of time and at a point in time. This approach organizes performance measures in a manner that facilitates evaluations and meaningful comparisons between utility companies. Furthermore, the Scorecard will be published and made available in the public domain, therefore, it needs to be relevant and meaningful to all. Once released, the Scorecard will allow stakeholders to gain a better sense of how well their distributor is currently performing. Over time, this approach will also let stakeholders see how their utility compares to others in the industry.

The analysis that follows attempts to encapsulate the Board's performance based framework of continuous improvement and comparability. First, through the comparison of CHEC utilities to one another, and secondly, through the comparison of the CHEC Group to utilities across the province. It is hoped that this analysis will assist CHEC utilities to identify areas where they may be performing well, and to identify areas that may need further improvement.

Updates from Previous Analyses:

The distributor scorecard effectively organizes performance information in a manner that facilitates evaluations and meaningful comparisons. Since its inception, a number of the scorecard measures have undergone revisions to improve the effectiveness of the scorecard. As a result, there will be differences between this analysis and other scorecard analyses previously issued. Reasons for deviations in this analysis are as follows:

Major Updates for the 2014 Scorecards:

1. **CDM** – As the 2011 – 2014 CDM programs have concluded as of December 31, 2014. The results are now based on the latest information provided by the IESO, which includes a number of updates to the Annual Peak Demand Savings and Net Cumulative Energy Savings measures. The results shown are also reflective of targets achieved for the 2011 – 2014 CDM initiative.

2. **ROE** – In 2014, the OEB began revisions as to how ROE should be calculated and reported. As a result, it has been noted that ROE for a number of distributors have been updated since the issuance of the 2013 scorecards. This analysis has been updated to include these changes.

3. **Niagara-on-the-Lake Hydro** – Niagara-on-the-Lake Hydro is a new CHEC Member as of 2015. As a result, all trends and averages for the 2014 Scorecards have been updated to include this new member. This will cause some distortions to the trends and averages compared to previous analyses.

4. **Measures** – Billing Accuracy is a new measure to the 2014 Scorecard. As a result, Billing Accuracy has been incorporated into the 2014 analysis. This measure is expected to remain active into the foreseeable future.

Part I – CHEC / CHEC Analysis:

The first part of this analysis is a comparison of CHEC utilities against each another. Please note that only select performance measures are being assessed, as not all performance measures are being monitored and/or tracked at this time. Some measures are still under development. Of those available performance measures, the following have been included in the analysis:

- **Customer Focus:**
  - New Residential Services Connected on Time
  - Scheduled Appointments Met on Time
  - Telephone Calls Answered on Time
  - Billing Accuracy

- **Operational Effectiveness:**
  - Efficiency Assessment (PEG)
  - Average Number of Hours that Power to a Customer is Interrupted
  - Average Number of Times that Power to a Customer is Interrupted

- **Public Policy Responsiveness:**
  - Net Annual Peak Demand Savings (Percent of Target Achieved)
  - Net Cumulative Energy Savings (Percent of Target Achieved)

- **Financial Performance:**
  - Liquidity: Current Ratio
  - Leverage: Debt to Equity Ratio
  - Regulated Return on Equity

Analysis & Graphical Breakdown:

The first part of this analysis involves two graphs for each measure. The first graph shows yearly results for each individual CHEC utility against the provincial average for the same period. This graph is intended to show trending for the period. The second graph is intended to provide a more apples-to-apples assessment for the period by comparing how each individual CHEC utility average measures against the provincial average for the specified period.

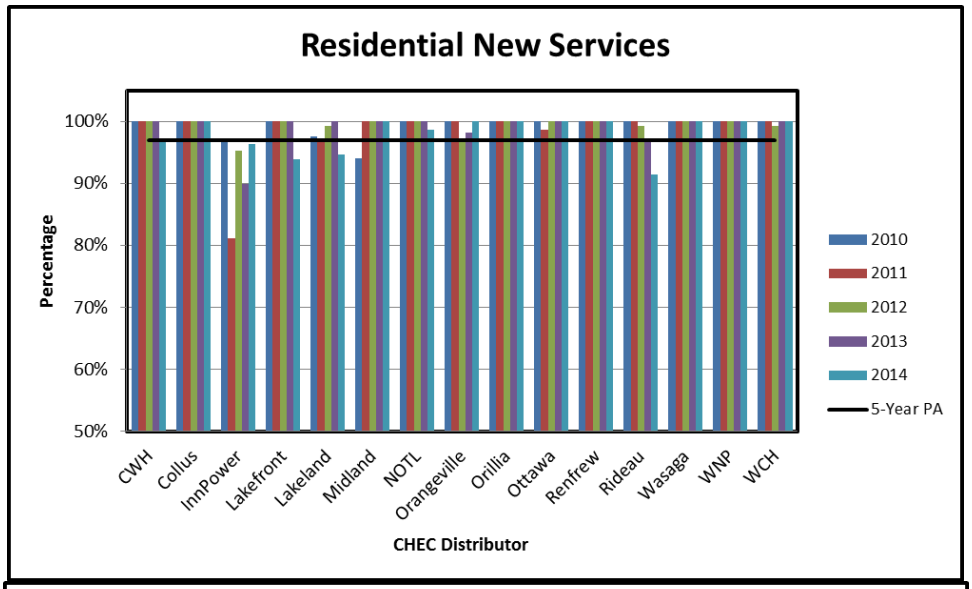
As distributors gain experience under the scorecard approach, it is expected that the Scorecard will also evolve over time. CHEC will monitor any refinements and improvements to the Scorecard on an ongoing basis to ensure they are incorporated into this analysis. Details will be documented to ensure substantial changes are identified as the analysis evolves.

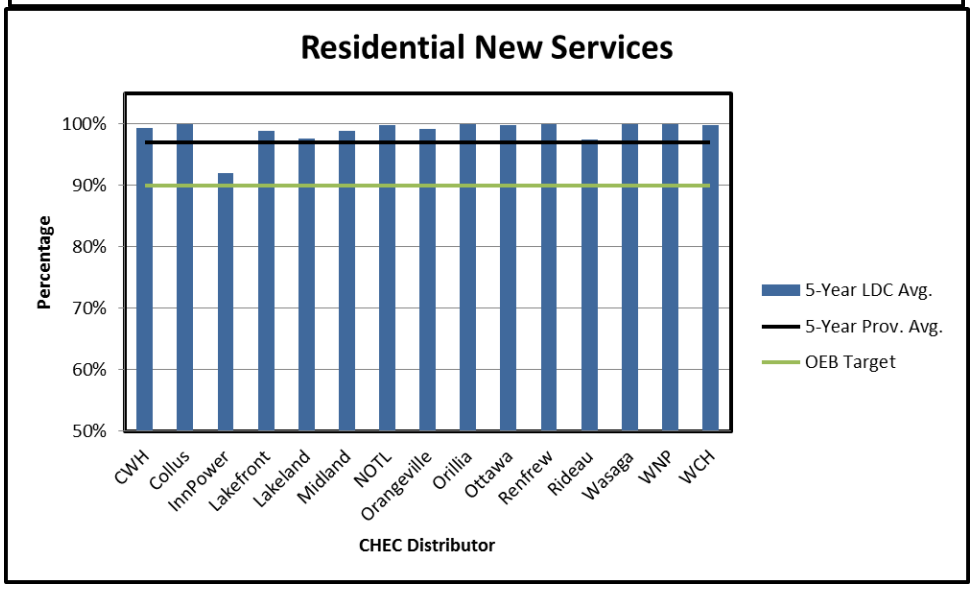
Please Note: Hydro One Networks has been excluded from this analysis. It is likely that including Hydro One Networks would skew the overall results due to the unique nature of the organization.

Residential New Services Connected on Time:

Residential New Services refers to Low Voltage Services, which is a connection for a new service request for a voltage <750 volts that must be completed within 5 business days, or at such a later date as agreed to by the customer and distributor. It can also refer to High Voltage Services, which is a connection for new services for a voltage >750 volts that must be completed within 10 business days, or at such a later date as agreed to by the customer and distributor. However, it is assumed that there are no High Voltage services within CHEC at the present time. The OEB expects this service quality requirement to be met at least 90 percent of the time on a yearly basis.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – For the most part CHEC utilities met this requirement with the exception of InnPower in 2011 (81.2%), and InnPower again in 2013 (89.9%). Growth could be the primary factor for InnPower failing to meet this target as InnPower has been identified as a high growth territory. It should also be noted that in 2013, InnPower was only 0.1% below the required target.

Provincial Averages – The provincial averages for this performance measure are as follows:

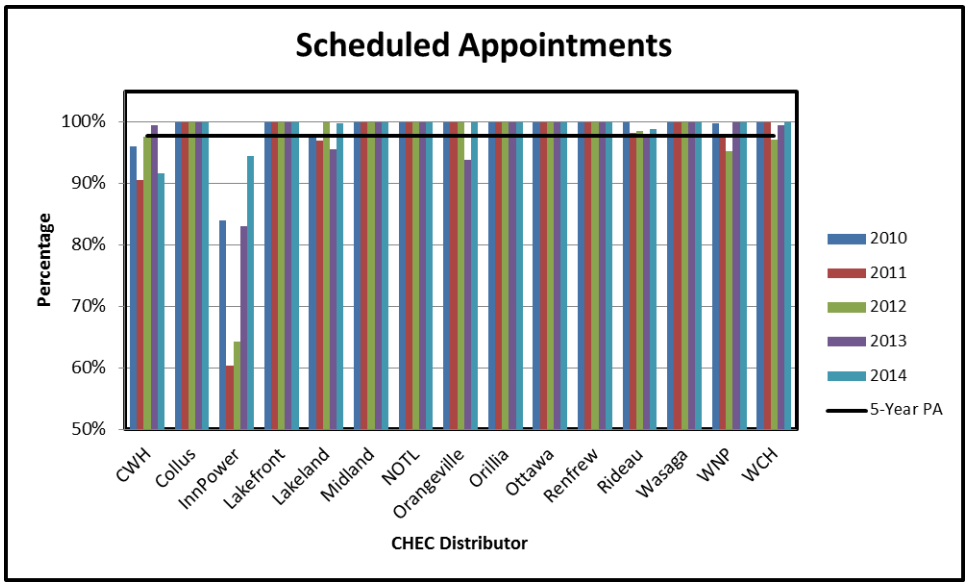
Period	Percentages
2010	98.56%
2011	96.69%
2012	98.17%
2013	96.44%
2014	95.17%
5-Year Avg. (2010 – 2014)	**97.01%**

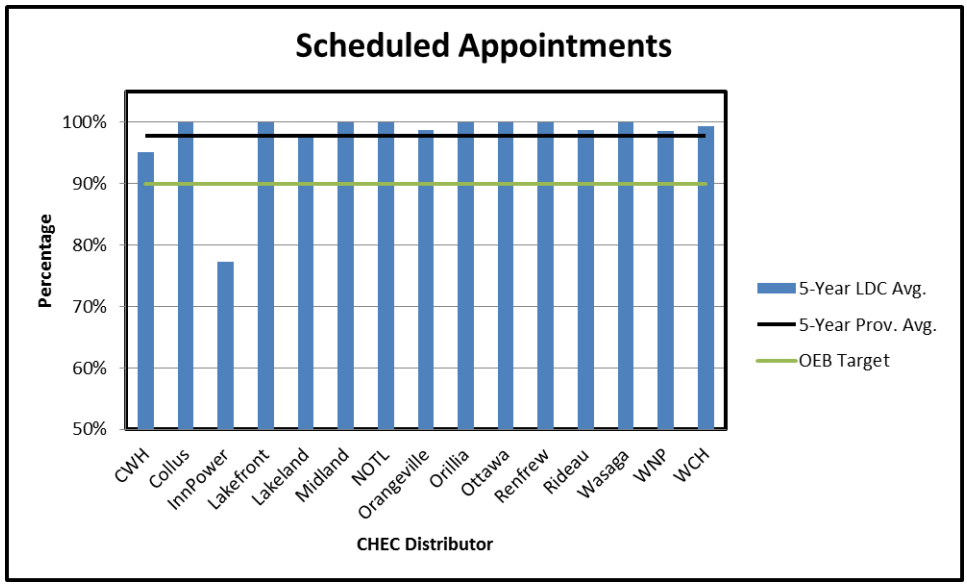
The provincial average of **97.01%** for the period 2010 – 2014 is an overall decline in performance over the 2013 provincial average of **97.40%**.

Scheduled Appointments Met on Time:

Appointments Met refers to any appointment where the customer's presence is required. The distributor must arrive for the appointment within the scheduled timeframe, which is either an AM (8:00 am – 12:00 pm) or PM (1:00 pm – 5:00 pm) appointment. Appointments where the distributor arrives at the scheduled appointment within the required time period but the appointment cannot be met because the customer failed to attend can be excluded. The OEB expects this service quality requirement to be met at least 90 percent of the time on a yearly basis.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – For the most part CHEC utilities met this requirement with the exception of InnPower (Low of 60.40% to a high of 84.00% from 2010 - 2013). The main factor involved with InnPower failing to meet the target appears to be a process issue. Prior to 2014, InnPower was incorrectly calculating appointments met, which resulted in inaccurate reporting of this measure from 2010 – 2013. InnPower has subsequently revised its process to ensure the measure is accurately calculated on a go forward basis. InnPower did exceed the required target of 90% for 2014.

Provincial Averages – The provincial averages for this performance measure are as follows:

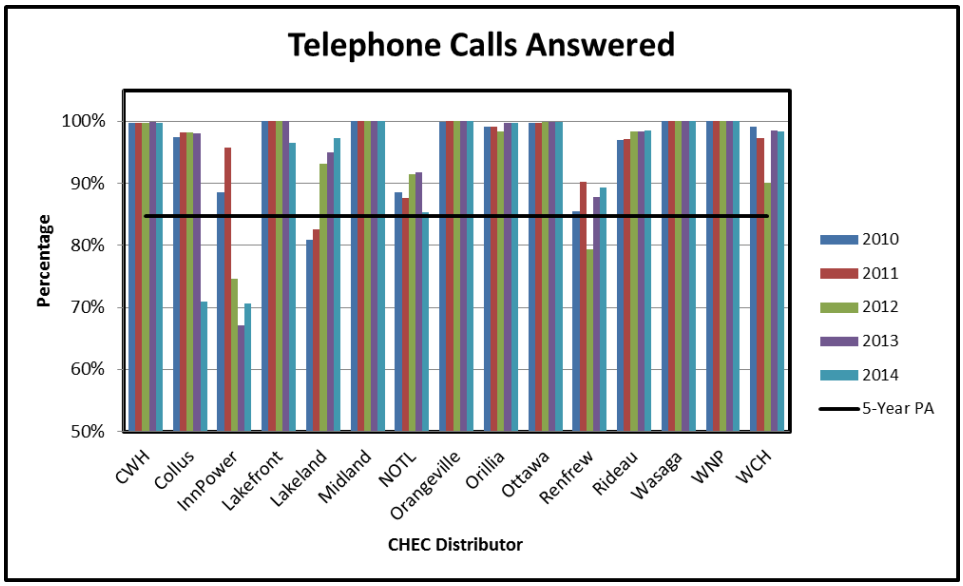
Period	Percentages
2010	97.12%
2011	96.46%
2012	97.11%
2013	98.79%
2014	98.95%
5-Year Avg. (2010 – 2014)	**97.69%**

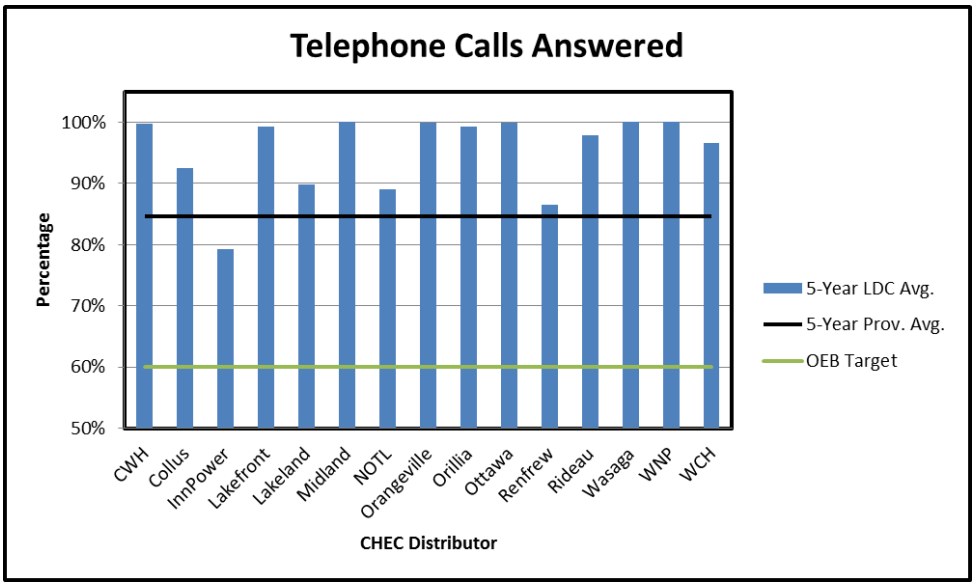
The provincial average of **97.69%** is an overall improvement in performance over the 2013 provincial average of **97.42%**.

Telephone Calls Answered on Time:

Telephone Calls Answered refers to ensuring qualified incoming calls (calls that are received during regular hours) to the distributor's customer care telephone numbers are answered within 30 seconds. For qualified incoming calls that are transferred from the distributor's IVR system, the 30 seconds shall be counted from the time the customer selects to speak to a customer service representative. In all other cases, the 30 seconds shall be counted from the first ring. The OEB expects this service quality requirement to be met at least 65 percent of the time on a yearly basis.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – All CHEC utilities met this requirement from 2010 – 2014, however, there is a concern with InnPower's downward trend between 2011 and 2013. This has been attributed to the fact that the duration of calls has increased dramatically (20% per year), making it difficult for CSR's to answer other incoming calls. InnPower will be monitoring the situation to determine if corrective action will be required, however, the trend does reverse for 2014.

Provincial Averages – The provincial averages for this performance measure are as follows:

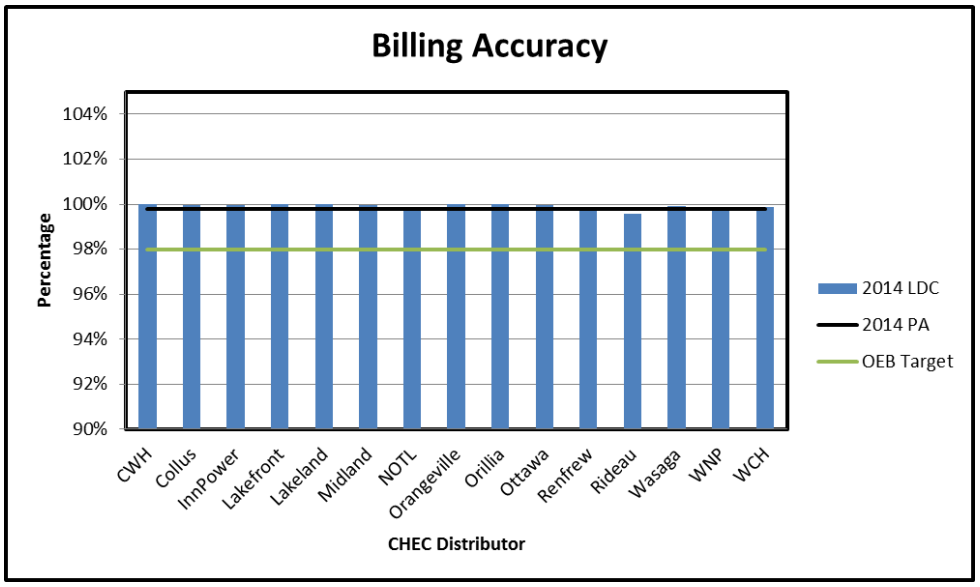
Period	Percentages
2010	83.41%
2011	84.22%
2012	84.39%
2013	86.30%
2014	85.15%
5-Year Avg. (2010 – 2014)	**84.69%**

The provincial average of **84.69%**, remains unchanged from the 2013 provincial average.

Billing Accuracy:

Billing Accuracy is a new measure to the Scorecard for 2014. Distributors are required to implement and start tracking the billing accuracy measure effective on October 1, 2014. The measure is defined as the accurate bills issued expressed as a percentage of total bills issued. Bills are considered accurate if it contains correct meter readings, customer information and rates, which results in an accurately calculated bill. A bill is considered inaccurate if a bill has been issued to a customer and is subsequently cancelled due to a billing error and/or adjustment. The OEB has set a minimum industry-wide billing accuracy performance target of 98%.

The following chart depicts how well the CHEC Group meets this requirement from 2010 – 2014:



Analysis – Only one chart is listed here as this is the first year for the Billing Accuracy measure, therefore only data for 2014 is available for analysis. Overall, CHEC did fairly well with this measure with all Member utilities exceeding the OEB specified target. It should be noted that Niagara-on-the-Lake (99.77%), Rideau St. Lawrence (99.58%), and Wellington North Power (99.73%) are slightly below the provincial average of 99.81%. Use caution with this measure as this is the first year for the Billing Accuracy measure and only 3 months' worth of data were tracked and reported by the utilities. Results may vary as experience is gained with this performance measure.

Provincial Averages – The provincial averages for this performance measure are as follows:

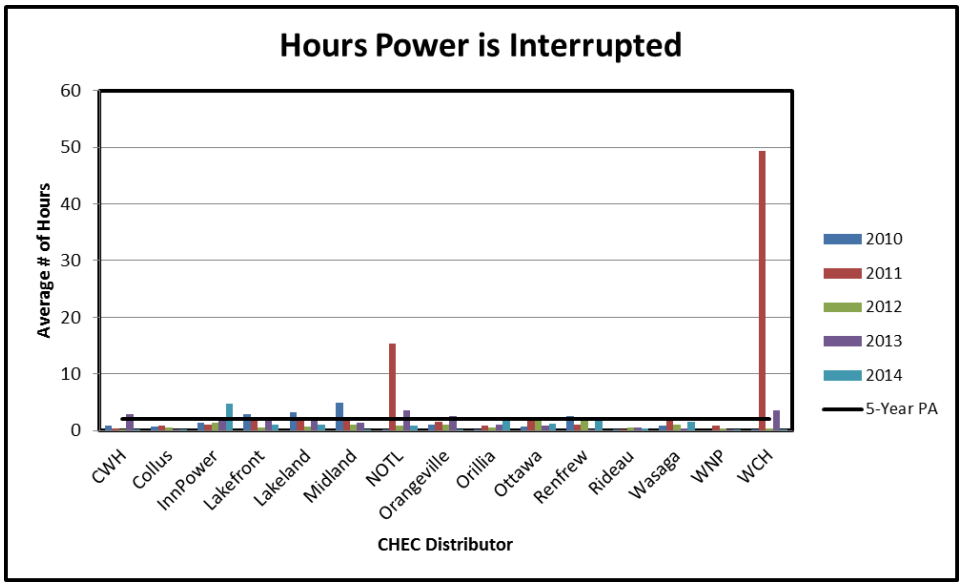
Period	Percentage
2014	**99.18%**

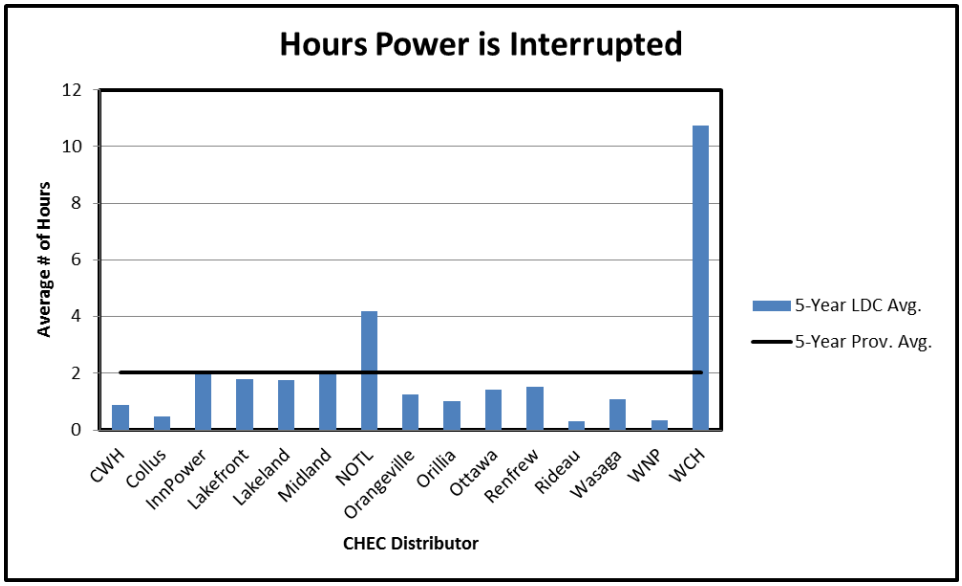
As this is a new measure for 2014, there are no 2013 results for comparative purposes.

Hours Power is Interrupted:

Hours power is interrupted is an indicator of system reliability that expresses the average amount of time, per reporting period, supply to a customer is interrupted. There is no official OEB target for this measure but ideally the goal is to strive for zero hours of uninterrupted power to the end customer.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – For the most part, CHEC utilities have kept hours of interrupted power to less than 5 hours from 2010 – 2014. The exceptions to this are West Coast Huron Energy, who experienced almost 50 hours of interrupted power in 2011, and Niagara-on-the-Lake, who experienced over 15 hours of interrupted power, also in 2011. For West Coast Huron Energy, this high loss of power is attributed to an F3 tornado that hit the Town of Goderich on August 21, 2011. Town officials quickly declared a state of emergency due to the severe damage caused by the Tornado, which included the town hall and hydro buildings. Despite the loss, West Coast Huron quickly recovered to ensure this measure returned to within norms for 2012 and subsequent years. For Niagara-on-the-Lake, the issue was related to a severe, localized wind storm.

Provincial Averages – The provincial averages for this performance measure are as follows:

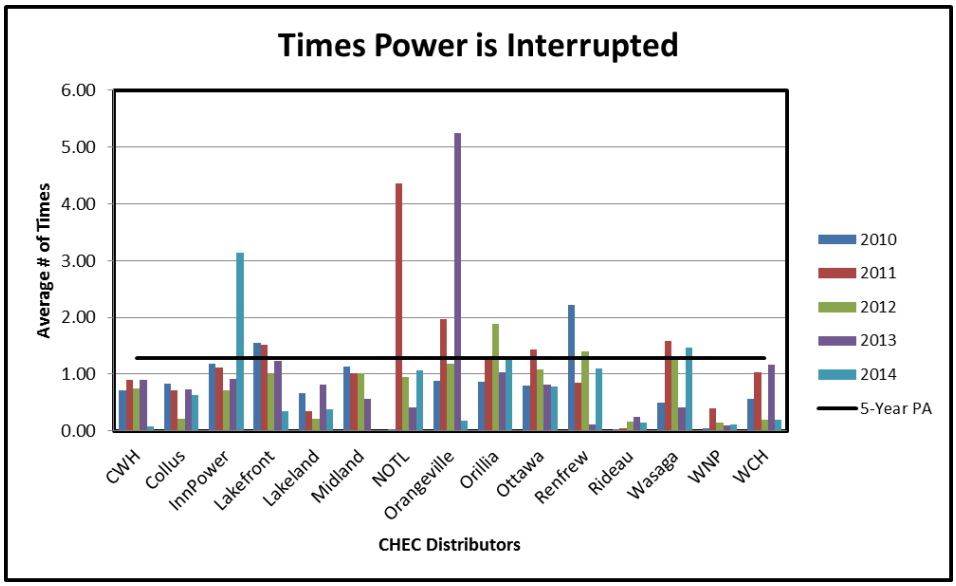
Period	Hours
2010	1.49
2011	2.91
2012	1.28
2013	3.06
2014	1.34
5-Year Avg. (2010 – 2014)	**2.02**

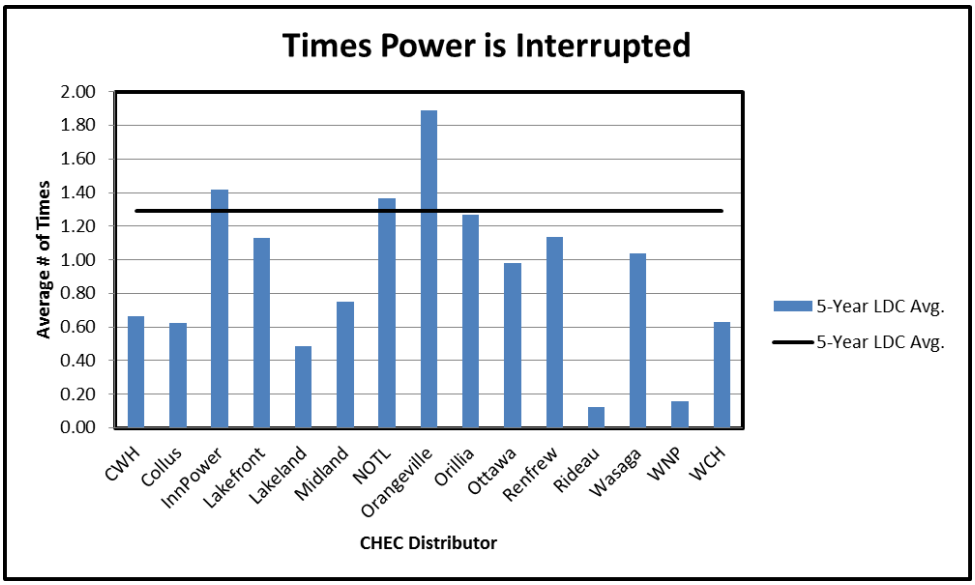
The provincial average of **2.02 hours** is an overall improvement in performance over the 2013 provincial average of **2.08 hours**.

Times Power is Interrupted:

Times power is interrupted is also an indicator of system reliability that expresses the number of times per reporting period that the supply to a customer is interrupted. It is determined by dividing the total number of interruptions experienced by all customers, by the average number of customers served. Again, there is no official OEB target for this measure but ideally the goal is to strive for zero times of uninterrupted power to the end customer.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – For the most part, CHEC utilities have kept the number of power interruptions to less than 2 occurrences for the period from 2010 – 2014. The exceptions to this are InnPower with over 3 power interruptions in 2014, Niagara-on-the-Lake with over 4 power interruptions in 2011, and Orangeville Hydro with over 5 power interruptions in 2013. The higher than usual loss of power for InnPower in 2014 is attributed to a major outage that occurred on February 5, 2014. Two primary feeder lines to Alcona were impacted due to a catastrophic failure of a distribution station which supports the feeder lines. Restoration of the outage was extensive as the 27.6V circuit had to be reconfigured and temporary switches installed. The higher than usual loss of power for Niagara-on-the-Lake and Orangeville Hydro were due to severe, localized weather conditions.

Provincial Averages – The provincial averages for this performance measure are as follows:

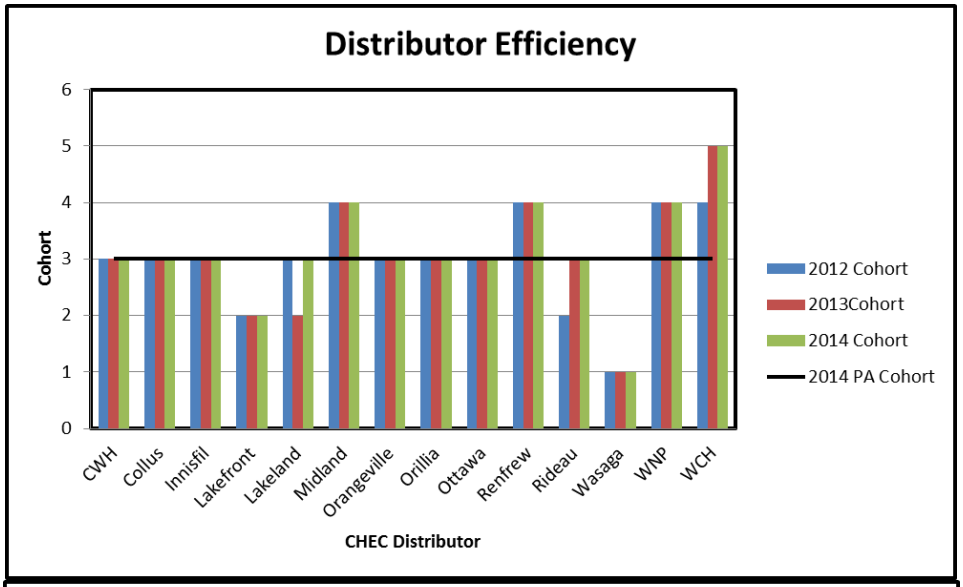
Period	Times
2010	1.21
2011	1.49
2012	1.22
2013	1.47
2014	1.06
5-Year Avg. (2010 – 2014)	**1.26**

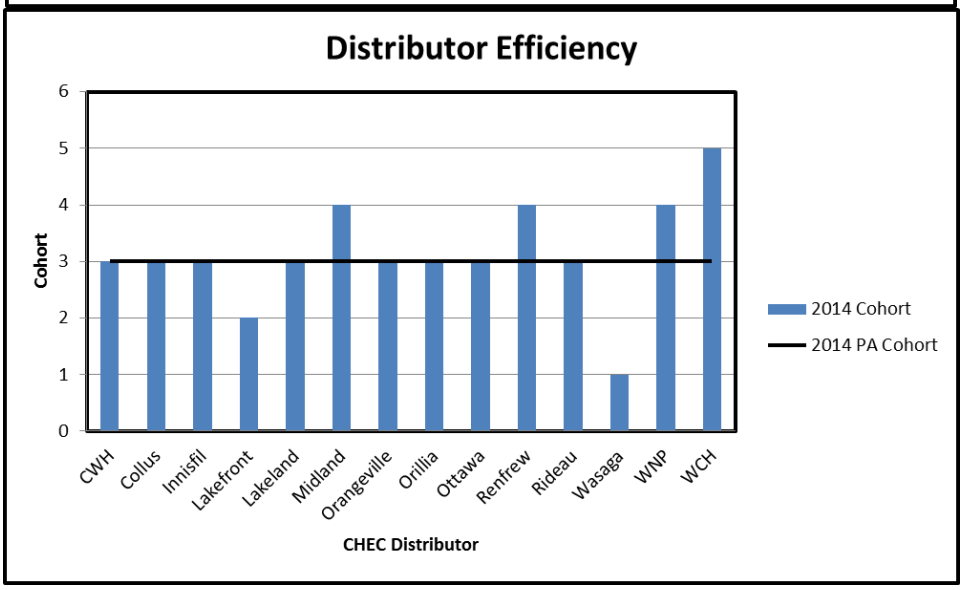
The provincial average of **1.26 hours** is an overall improvement in performance over the 2013 provincial average of **1.33 hours**.

Distributor Efficiency:

Distributor efficiency is a performance measure whereby utilities are assigned to various cohorts ranked from 5 (being the worst) to 1 (being the best). Cohort assignments are based on the results of a statistical cost benchmarking study designed to make inferences about a utility's cost efficiency. An econometric model is used to predict the level of cost associated with each distributor's operating conditions. Distribution for this measure is considered to be a normal distribution whereby utilities are distributed across a bell curve. Distributors whose actuals costs were lower than costs predicted by the model are assigned a lower cohort (e.g.: cohort 2 or cohort 1).

The following charts depict how well the CHEC Group meets this requirement from 2012 – 2014:





Analysis – For the most part, CHEC utilities follow the normal distribution curve for the provincial utilities with the majority of the members falling in cohort 3, a few members falling in the higher cohorts (4 & 5), and a few members falling in the lower cohorts (1 & 2). It should be noted that in 2014, Lakeland Power's cohort went from cohort 2 to cohort 3, which translates to a decrease in efficiency of approximately 1%. Wasaga Distribution remains in cohort 1 but is now the third (was second) most efficient utility in Ontario under this measure.

Provincial Averages – The provincial averages for this performance measure are as follows:

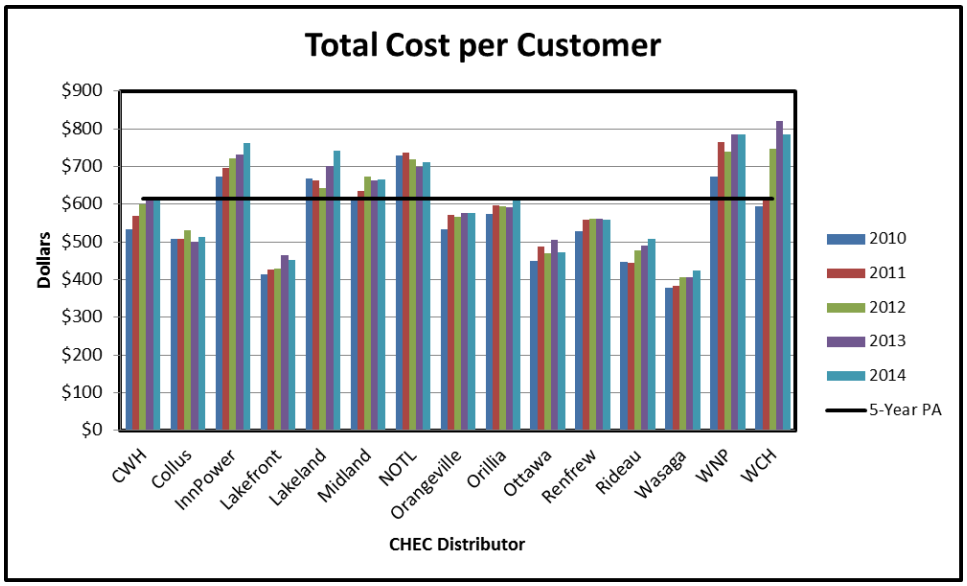
Period	Cohorts
2012	3
2013	3
2014	3
3-Year Avg. (2012 – 2014)	**3**

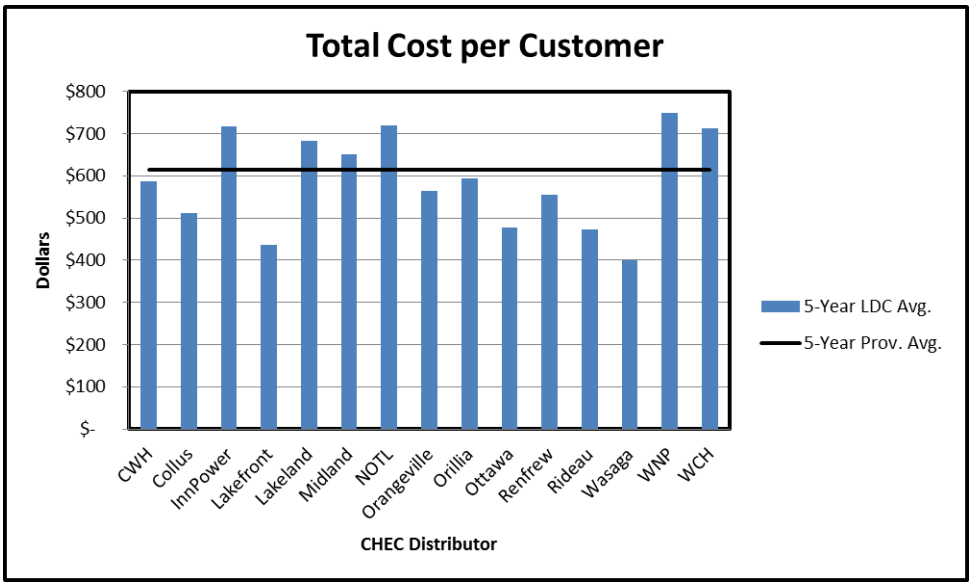
Do note that at any given time, the average cohort for this measure will be 3, do the statistical calculations and normal distribution of the results. As a result, the provincial average remains unchanged from 2013 provincial average.

Total Cost per Customer:

Total cost per customer is a simple calculation whereby "Total Cost" is divided by the number of customers in a utilities territory. "Total Cost" is determined using a complex statistical calculation (see PEG Report) that facilitates a more accurate cost that is comparable among distributors. The source of the cost and customer data used in the calculations is taken from the distributors reported RRR filings. The OEB did not set a target for this measure.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – For the most part, CHEC utilities have kept their cost per customer relatively stable from 2010 to 2014. There is a variance in cost per customer across the utilities, which is to be expected as each utility has unique characteristics (i.e.: square kms, customer base, etc.). For many utilities, there is also a gradual increase in trending over the years, which is also expected due to inflationary factors.

Provincial Averages – The provincial averages for this performance measure are as follows:

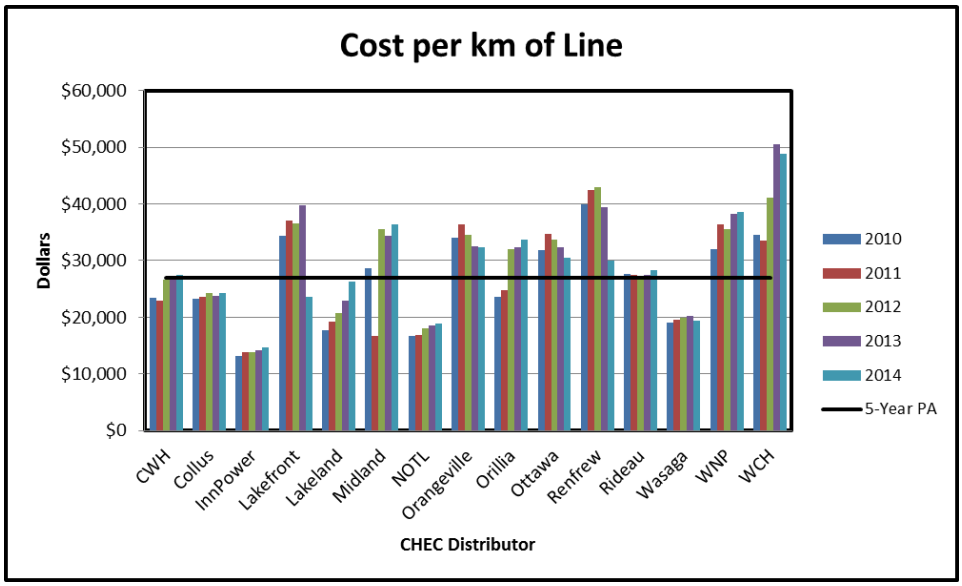
Period	Costs
2010	$585
2011	$606
2012	$616
2013	$624
2014	$635
5-Year Avg. (2010 – 2014)	**$613**

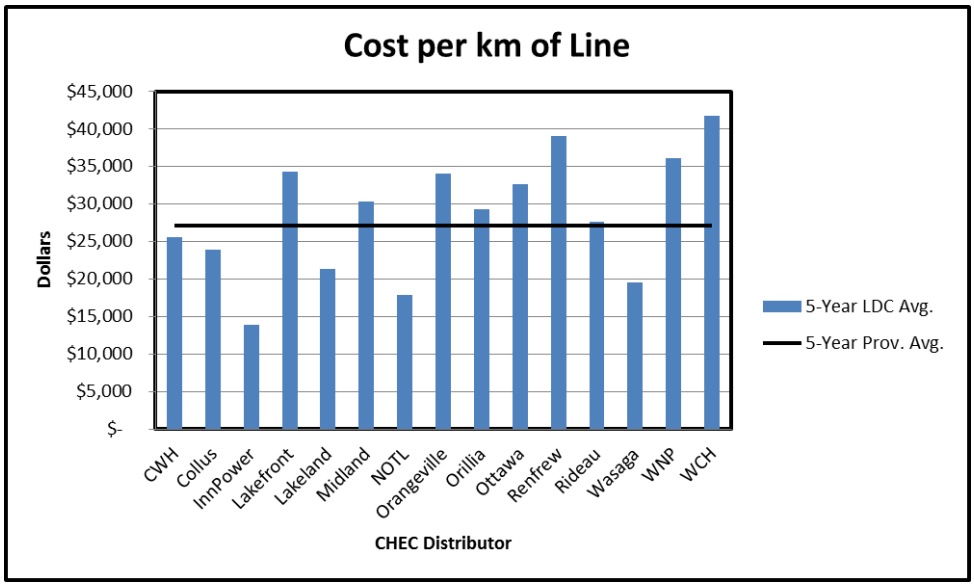
The provincial average of **$613** is an overall decline in performance over the 2013 provincial average of **$599**.

Total Cost per KM of Line:

Total cost per km of line is also a simple calculation whereby "Total Cost" is divided by the number of kilometers of line in a utilities territory. "Total Cost" is determined using a complex statistical calculation (see PEG Report) that facilitates a more accurate cost that is comparable among distributors. The source of the cost and customer data used in the calculations is taken from the distributors reported RRR filings. The OEB did not set a target for this measure.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – For the most part, CHEC utility have kept their cost per km of line relatively stable from 2010 to 2014. There is a variance in cost per km of line across the utilities, which is to be expected as each utility has unique characteristics (i.e.: square kms, customer base, etc.). The spike in West Coast Huron Energy's costs is likely due to increased costs after the tornado incident in 2011. The dip in Midland's 2011 is due to a reporting error on the data (cost per km of line should be $33,305). There is also a gradual increase in trending over the years, which is also expected due to inflationary factors.

Provincial Averages – The provincial averages for this performance measure are as follows:

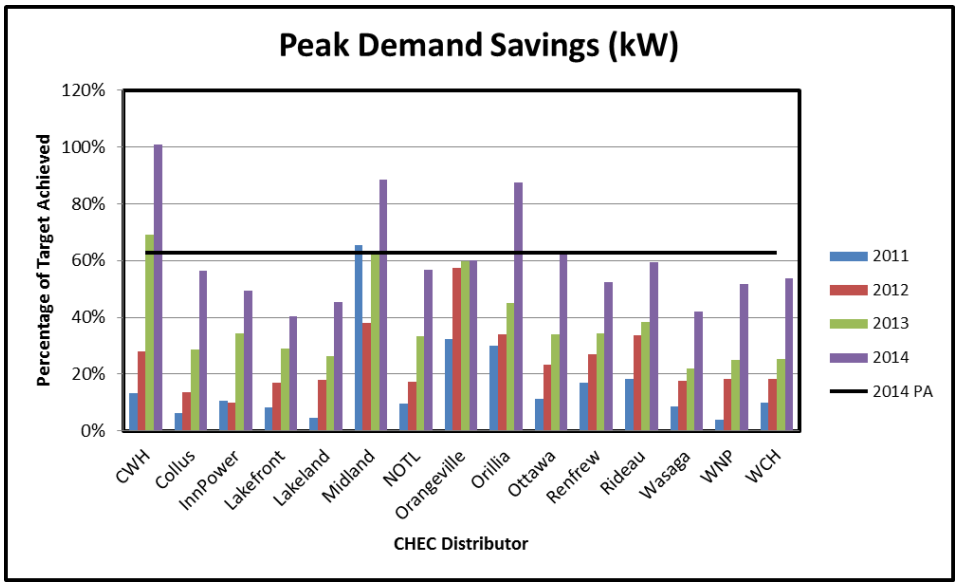
Period	Costs
2010	$25,714
2011	$26,498
2012	$27,234
2013	$27,779
2014	$27,933
5-Year Avg. (2010 – 2014)	**$27,044**

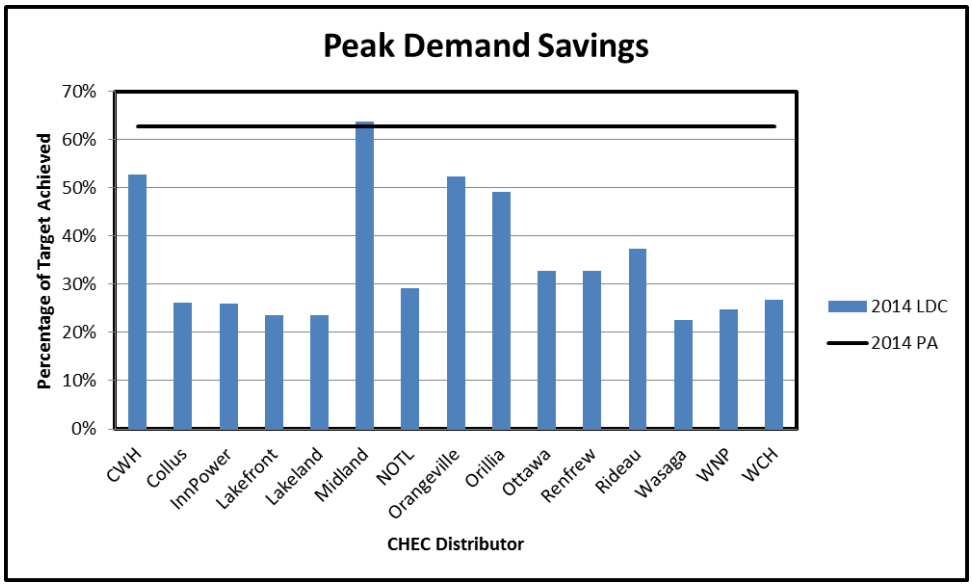
The provincial average of **$27,044** is an overall decline in performance over the 2013 provincial average of **$26,456**.

Peak Demand Savings (kW):

Peak demand savings is simply a record of the demand (MW) reduction from efforts made towards the 2011 – 2014 Conservation and Demand Management (CDM) programs. This information is taken directly from the OPA's reported findings for each distributor. Targets for this measure were established by the OPA and are a condition of the Distributor's license.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – At the time of this report, the 2011 – 2014 CDM programs are now complete. Only 1 of the 15 CHEC utilities (6.66%) met 100% of their peak demand target for 2014. This is somewhat expected as the CHEC utilities are primarily residential based and there are limited opportunities to reduce energy demand with residential customers. However, it should be noted that only 6 out of the 72 provincial utilities (8.33%) made their target for 2014, indicating this was a difficult objective to achieve for many utilities in the province.

Provincial Averages – The provincial averages for this performance measure are as follows:

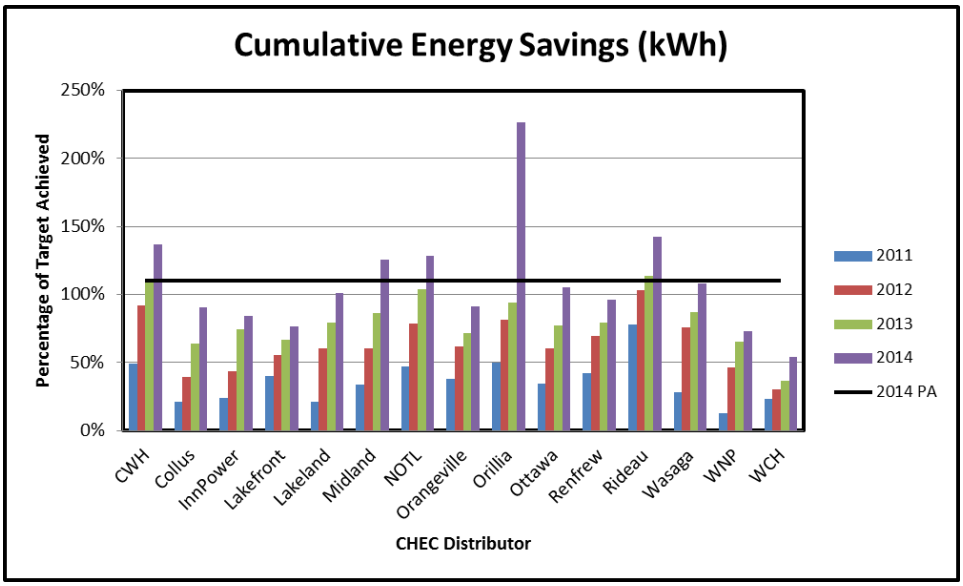
Period	% Target
2011	15.35%
2012	27.13%
2013	41.41%
2014	62.71%
2014	**62.71%**

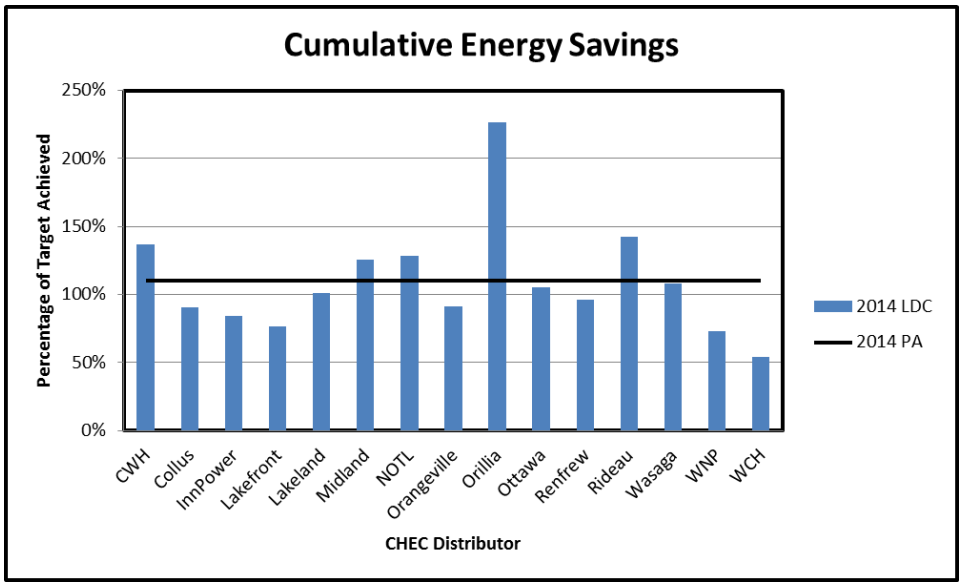
The provincial average of **62.71%** is an overall improvement in performance over the 2013 provincial average of **37.87%**

Cumulative Energy Savings (kWh):

Cumulative energy savings is simply a record of the energy (GWh) reduction from efforts made towards the 2011 – 2014 Conservation and Demand Management (CDM) programs. This information is taken directly from the OPA's reported findings for each distributor. Targets for this measure were established by the OPA and are a condition of the Distributor's license.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – At the time of this report, the 2011 – 2014 CDM programs are now complete. Only 8 out of the 15 CHEC utilities (53.33%) met 100% of their target. Again, this is somewhat expected as the CHEC utilities are primarily residential based and there are few opportunities to reduce energy consumption with residential customers. However, it should be noted that only 41 out of 72 provincial utilities (56.94%) made their target for 2014, indicating this was a difficult objective to achieve for many utilities in the province.

Provincial Averages – The provincial averages for this performance measure are as follows:

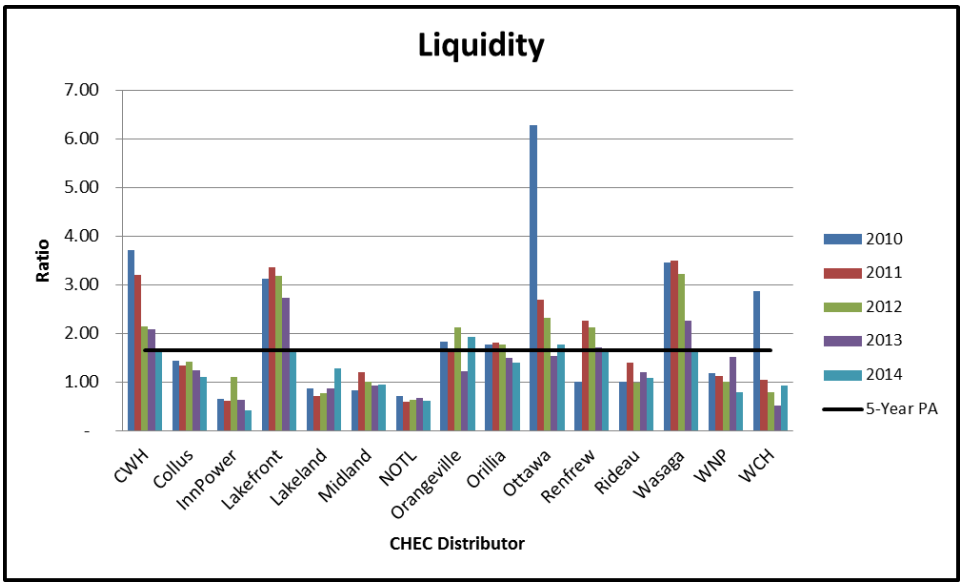
Period	% Target
2011	35.10%
2012	64.53%
2013	87.04%
2014	110.44%
2014	**110.44%**

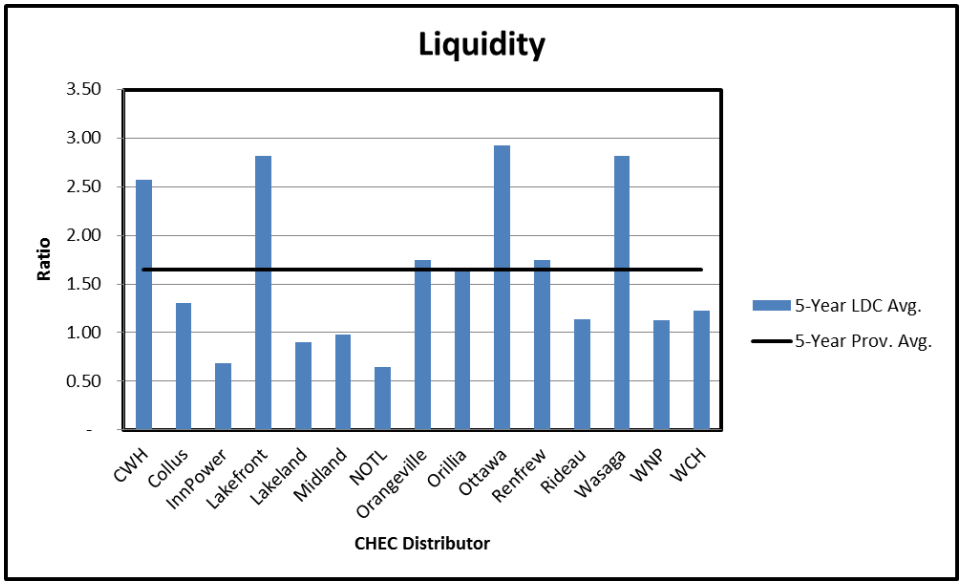
The provincial average of **110.44%** is an overall improvement in performance over the 2013 provincial average of **87.04%**.

Liquidity:

Liquidity is a financial measure of the ability of a debtor to pay their short-term obligations. It is usually expressed as a ratio or a percentage. For this measure, the scorecard utilizes a ratio called "current ratio", which is a simple calculation of current assets / current liabilities. The OEB has not set a target for this measure.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – CHEC utilities current ratios are between 0.41 and 6.29, which for the most part is reasonable for this type of industry. Financially speaking, the higher the number, the more capable the company is of paying its debts. A ratio under 1 suggests that the company would be unable to pay off its obligations if they came due at that point. A ratio over 3 suggests that the company may not be making efficient use of its current assets or its short-term financing facilities.

Provincial Averages – The provincial averages for this performance measure are as follows:

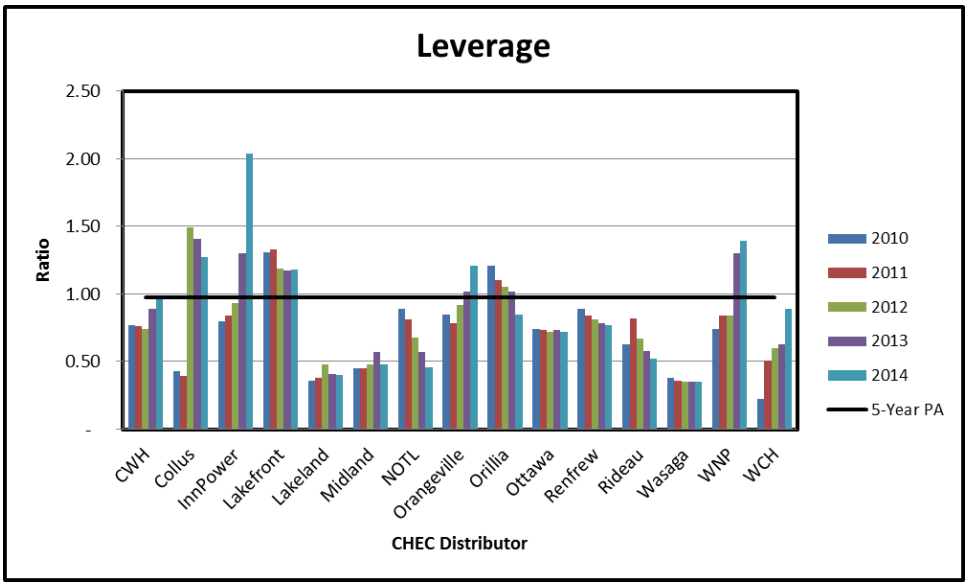
Period	Ratios
2010	1.80
2011	1.89
2012	1.65
2013	1.50
2014	1.43
5-Year Avg. (2010 – 2014)	**1.65**

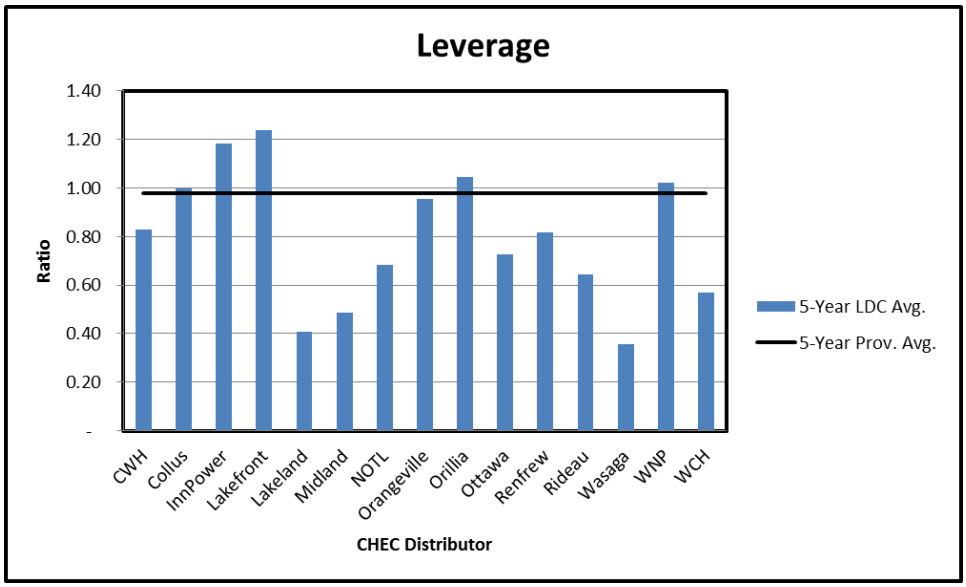
The provincial average of **1.65** is an overall improvement in performance over the 2013 provincial average of **1.74**.

Leverage:

Leverage is a financial measure of the degree to which a company uses debt and equity to finance its assets. It is usually expressed as a ratio. For this measure, the scorecard utilizes a ratio called "Debt to Equity" ratio, which is a simple calculation of Total Liabilities / Shareholder's Equity. The OEB has not set a target for this measure.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – CHEC utilities debt to equity ratios are between 0.22 and 2.04, which for the most part, is reasonable for this type of industry. Financially speaking, the debt to equity ratio depends on the industry in which the company operates. For the electrical distribution industry, the OEB suggests a ratio of 1.5 (60% debt / 40% Equity) is ideal. Actual ratios will depend on each individual utility's specific circumstances.

Provincial Averages – The provincial averages for this performance measure are as follows:

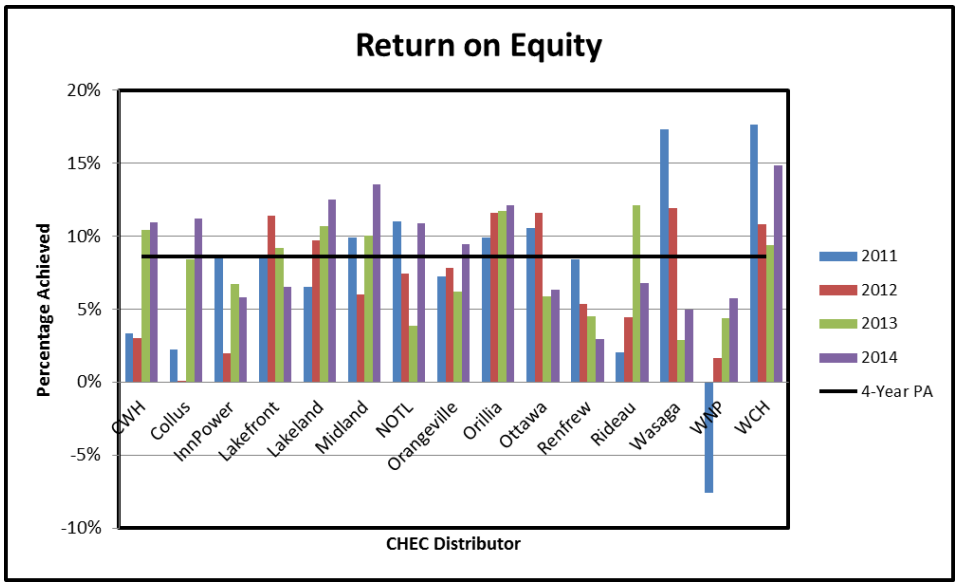
Period	Ratios
2010	0.96
2011	0.98
2012	1.04
2013	0.94
2014	0.97
5-Year Avg. (2010 – 2014)	**0.98**

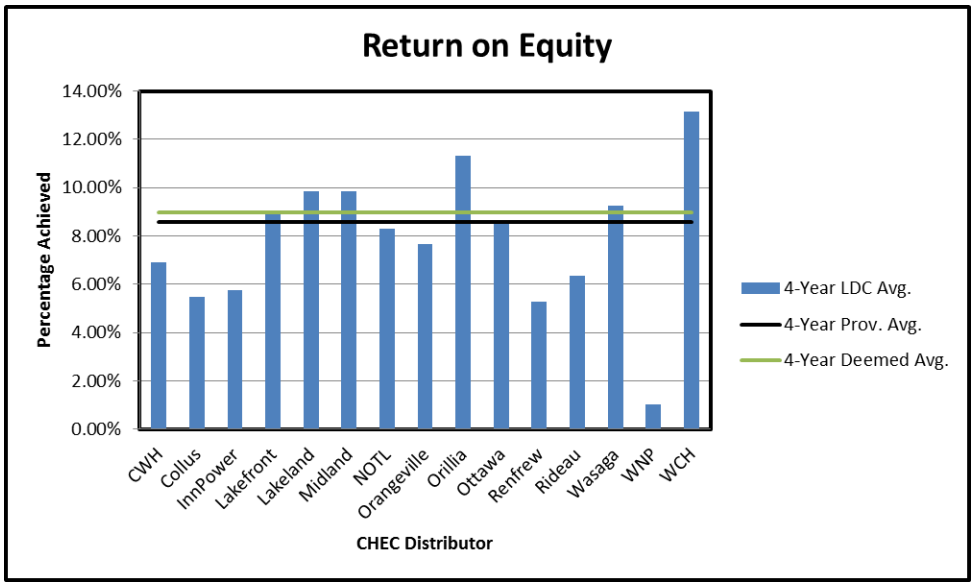
The provincial average of **0.98** is an overall improvement in performance over the 2013 provincial average of **0.97**.

Return on Equity:

Return on Equity (ROE) is a financial measure used to indicate the profitability of the company and to compare that to other firms in the same industry. It is usually expressed as a percentage. Return on Equity is a simple calculation of Net Income / Shareholder's Equity. The OEB has not set a target for this measure.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – CHEC utility's Return on Equity percentages are between 0.10% and 17.62%, which for the most part, is reasonable for this industry. Return on Equity measures a corporation's profitability by revealing how much profit a company generates with the money shareholders have invested. For the electrical distribution industry, the OEB typically requires utilities to maintain its Return on Equity percentage between 9.0% and 9.5% for recent years. Actual ratios will depend on each individual utility's specific circumstances.

Provincial Averages – The provincial averages for this performance measure are as follows:

Period	Percentages
2011	7.77%
2012	6.79%
2013	9.41%
2014	10.35%
4-Year Avg. (2011 – 2014)	**8.58%**

Deemed Averages – The deemed averages for this performance measure are as follows:

Period	Percentages
2011	8.78%
2012	8.86%
2013	9.14%
2014	9.33%
4-Year Avg. (2011 – 2014)	**8.98%**

The provincial average of **8.58%** is an overall increase from the 2013 provincial average of **8.07%**. The deemed average of **8.98%** is an overall increase from the 2013 deemed average of **8.86**%

Part II – CHEC / Provincial Analysis:

The second part of this analysis is a comparison of the CHEC utilities average against the Provincial utility average. Please note that only select performance measures are being assessed, as not all performance measures are being monitored and/or tracked at this time. Some measures are still under development. Of those available performance measures, the following have been included in the analysis:

- **Customer Focus:**
  - New Residential Services Connected on Time
  - Scheduled Appointments Met on Time
  - Telephone Calls Answered on Time
  - Billing Accuracy

- **Operational Effectiveness:**
  - Efficiency Assessment (PEG)
  - Average Number of Hours that Power to a Customer is Interrupted
  - Average Number of Times that Power to a Customer is Interrupted

- **Public Policy Responsiveness:**
  - Net Annual Peak Demand Savings (Percent of Target Achieved)
  - Net Cumulative Energy Savings (Percent of Target Achieved)

- **Financial Performance:**
  - Liquidity: Current Ratio
  - Leverage: Debt to Equity Ratio
  - Regulated Return on Equity

Analysis & Graphical Breakdown:

The second part of the analysis involves the comparison of the CHEC group average against the provincial average as a whole. The intention here is to provide some insights as to how the CHEC Group is performing compared to how the province is performing.

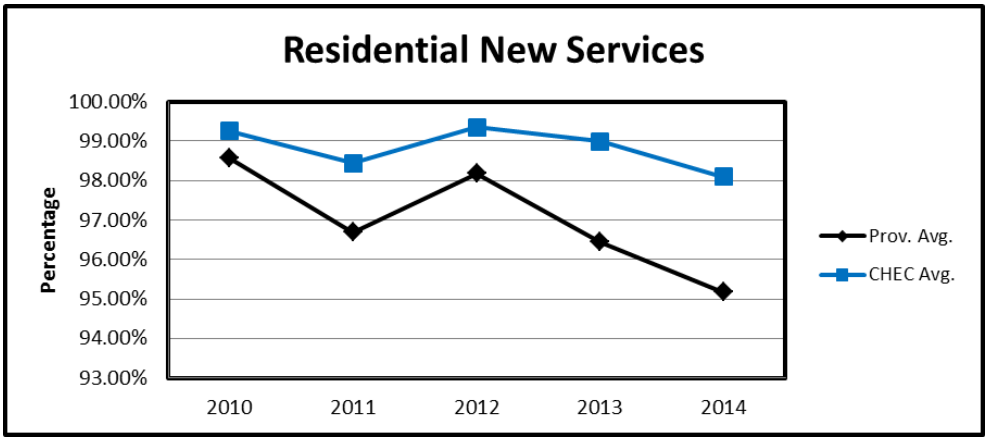
As distributors gain experience under the scorecard approach, it is expected that the Scorecard will also evolve over time. CHEC will monitor any refinements and improvements to the Scorecard on an ongoing basis to ensure they are incorporated into this analysis. Details will be documented to ensure substantial changes are identified as the analysis evolves.

Please Note: Hydro One Networks has been excluded from this analysis. It is likely that including Hydro One Networks would skew the overall results due to the unique nature of the organization.

Residential New Services Connected on Time:

Residential New Services refers to Low Voltage Services, which is a connection for a new service request for a voltage <750 volts, that must be completed within 5 business days or at such a later date as agreed to by the customer and distributor. It can also refer to High Voltage Services, which is a connection for new services for a voltage >750 volts, that must be completed within 10 business days or at such a later date as agreed to by the customer and distributor. It is assumed that there is a mixture of Low and High Voltage services across the province, with the focus on Low Voltage services. The OEB expects this service quality requirement to be met at least 90 percent of the time on a yearly basis.

The following chart depicts how well the CHEC Group compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part CHEC utilities are better at meeting this requirement than their provincial counterparts, although both the CHEC and provincial averages are above the required OEB target. The difference in averages is a reflection of the efficiencies within a utilities process for establishing residential new connections.

Averages – The averages for this performance measure are as follows:

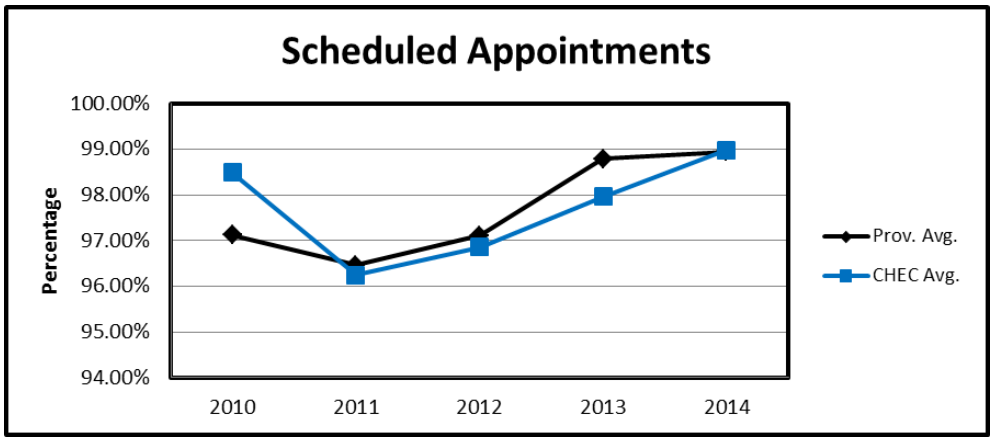
Period	CHEC Avg. %	Prov. Avg. %
2010	99.25%	98.56%
2011	98.44%	96.69%
2012	99.35%	98.17%
2013	98.99%	96.44%
2014	98.10%	95.17%
5-Year Avg. (2010 – 2014)	**98.83%**	**97.01%**

Please Note: Both the CHEC 5Y averages (**98.83% – 2014, 98.91% – 2013**) and the provincial 5Y averages (**97.01% – 2014, 97.40% – 2013**) are showing a decline in performance from 2013 to 2014.

Scheduled Appointments Met on Time:

Appointments Met refers to any appointment where the customer's presence is required. The distributor must arrive for the appointment within the scheduled timeframe, which is either an AM (8:00 am – 12:00 pm) or PM (1:00 pm – 5:00 pm) appointment. Appointments where the distributor arrives at the scheduled appointment within the required time period but the appointment cannot be met because the customer failed to attend can be excluded. The OEB expects this service quality requirement to be met at least 90 percent of the time on a yearly basis.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For 2010, the CHEC utilities are better at meeting this requirement than their provincial counterparts. Although this trend reverses in 2011, it reverses again in 2014 whereby the CHEC utilities once again out perform their provincial counterparts. Again, both the CHEC and provincial averages are above the required OEB target. The difference in averages is a reflection of the efficiencies within a utilities process for meeting scheduled appointments.

Averages – The averages for this performance measure are as follows:

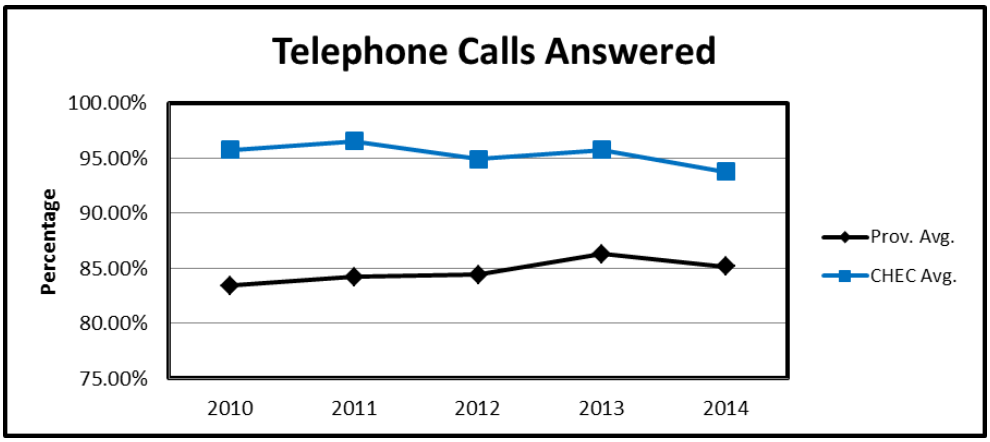
Period	CHEC Avg. %	Prov. Avg. %
2010	98.49%	97.12%
2011	96.24%	96.46%
2012	96.86%	97.11%
2013	97.95%	98.79%
2014	98.98%	98.95%
5-Year Avg. (2010 – 2014)	**97.70%**	**97.69%**

Please Note: Both the CHEC 5Y averages (**97.70% – 2014, 98.91% – 2013**) and the provincial 5Y averages (**97.69 – 2014, 97.42% – 2013**) are showing a decline in performance from 2013 to 2014.

Telephone Calls Answered on Time:

Telephone Calls Answered refers to ensuring qualified incoming calls (calls that are received during regular hours) to the distributors' customer care telephone numbers are answered within 30 seconds. For qualified incoming calls that are transferred from the distributor's IVR system, the 30 seconds shall be counted from the time the customer selects to speak to a customer service representative. In all other cases, the 30 seconds shall be counted from the first ring. The OEB expects this service quality requirement to be met at least 65 percent of the time on a yearly basis.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – The CHEC utilities are better at meeting this requirement than their provincial counterparts over the same period, although both averages are well above the OEB target requirement of 65%. The difference in averages is a reflection of the efficiencies within a utility's process for answering telephone calls on time.

Averages – The averages for this performance measure are as follows:

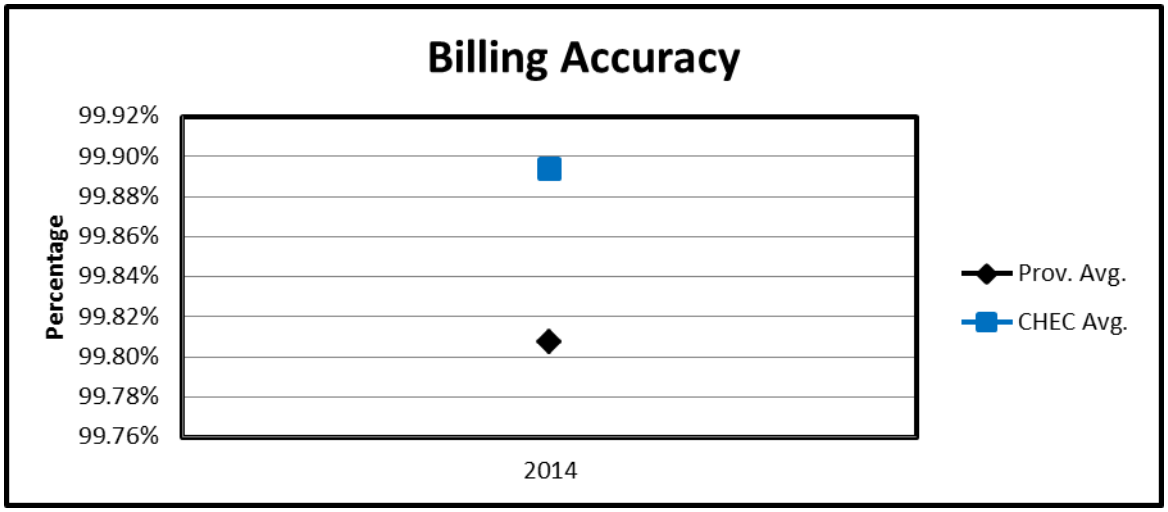
Period	CHEC Avg. %	Prov. Avg. %
2010	95.73%	83.41%
2011	96.51%	84.22%
2012	94.89%	84.39%
2013	95.73%	86.30%
2014	93.75%	85.15%
5-Year Avg. (2010 – 2014)	**95.32%**	**84.69%**

Please Note: The CHEC 5Y averages (**95.32% – 2014, 96.48% – 2013**) is showing a decline in performance while the provincial 5Y averages (**84.69% – 2014, 84.69% – 2013**) remains unchanged from 2013 to 2014.

Billing Accuracy:

Billing Accuracy is a new measure to the Scorecard for 2014. Distributors are required to implement and start tracking the billing accuracy measure effective on October 1, 2014. The measure is defined as the accurate bills issued expressed as a percentage of total bills issued. Bills are considered accurate if it contains correct meter readings, customer information and rates, which results in an accurately calculated bill. A bill is considered inaccurate if a bill has been issued to a customer and is subsequently cancelled due to a billing error and/or adjustment. The OEB has set a minimum industry-wide billing accuracy performance target of 98%.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – As this is a new measure, only data for 2014 is available. Overall, CHEC did better than the provincial average for this performance measure. Use caution with this measure as this is the first year for the Billing Accuracy measure and only 3 months' worth of data were tracked and reported by the utilities. Results may vary as experience is gained with this performance measure.

Averages – The averages for this performance measure are as follows:

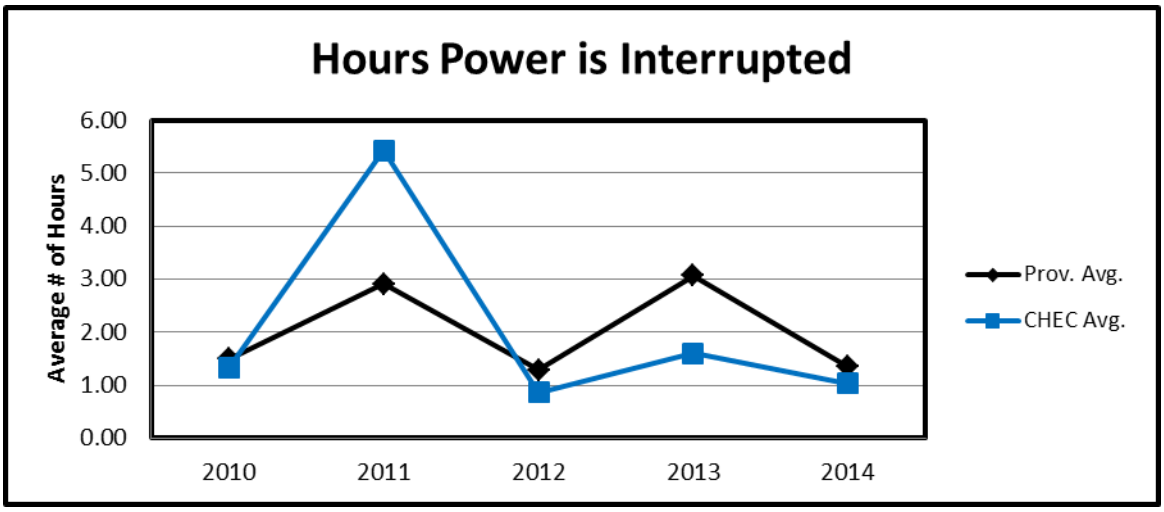
Period	CHEC Avg. %	Prov. Avg. %
2014	99.89%	99.81%
2014	**99.89%**	**99.81%**

Please Note: There is no data for 2013, therefore conclusions can only be drawn for 2014 (see analysis section above).

Hours Power is Interrupted:

Hours power is interrupted is an indicator of system reliability that expresses the average amount of time, per reporting period, supply to a customer is interrupted. There is no official OEB target for this measure but ideally the goal is to strive for zero hours of uninterrupted power to the end customer.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part, the CHEC utilities tended to fare better than the provincial average. 2011 was an issue, which was primarily due to the tornado that hit West Coast Huron Energy. The spikes in 2013 are likely due to the ice storm issues that occurred that year, which affected both the CHEC and provincial averages. The difference in averages can be somewhat attributed to a utilities response time and experience with respect to power outages.

Averages – The averages for this performance measure are as follows:

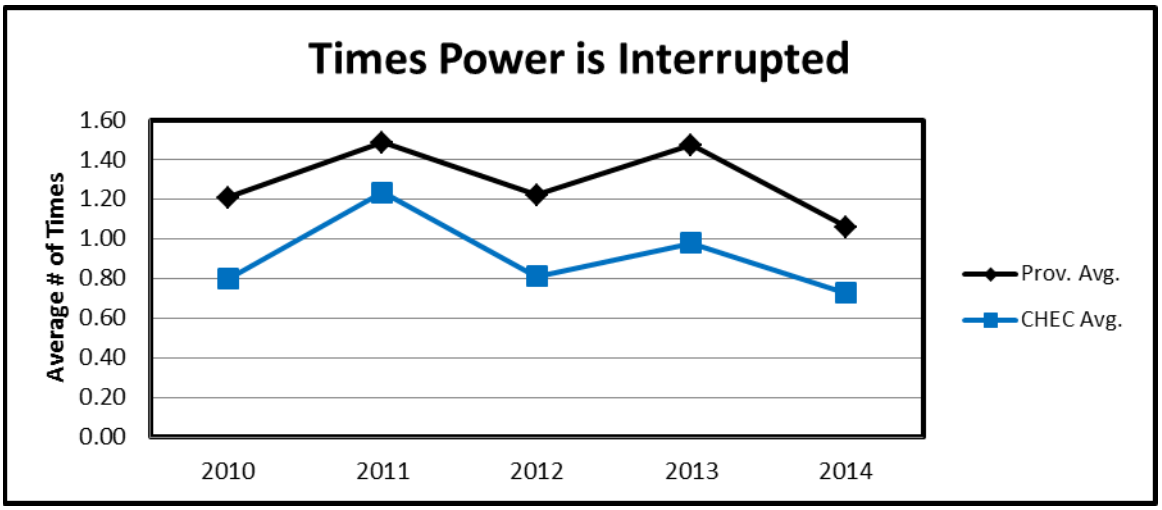
Period	CHEC Avg. Hours	Prov. Avg. Hours
2010	1.32	1.49
2011	5.43	2.91
2012	0.86	1.28
2013	1.60	3.06
2014	1.03	1.34
5-Year Avg. (2010 – 2014)	**2.05**	**2.02**

Please Note: The CHEC 5Y averages (**2.05 – 2014, 1.96 – 2013**) are showing a decline in performance while the provincial 5Y averages (**2.02 – 2014, 2.08 – 2013**) are showing an improvement in performance from 2013 to 2014.

Times Power is Interrupted:

Times power is interrupted is also an indicator of system reliability that expresses the number of times per reporting period that the supply to a customer is interrupted. It is determined by dividing the total number of interruptions experienced by all customers, by the average number of customers served. Again, there is no official OEB target for this measure but ideally the goal is to strive for zero times of interrupted power to the end customer.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part, interrupted power for the CHEC utilities was limited to less than 1 occurrence per utility, while the provincial utilities average was slightly higher than that for the period 2010 – 2014. The fact that both averages have similar trending would indicate the same factors (i.e.: weather, etc.) are at play across most utilities with respect to interrupted power. The differences in averages can be somewhat attributed to how well a utility maintains it assets.

Averages – The averages for this performance measure are as follows:

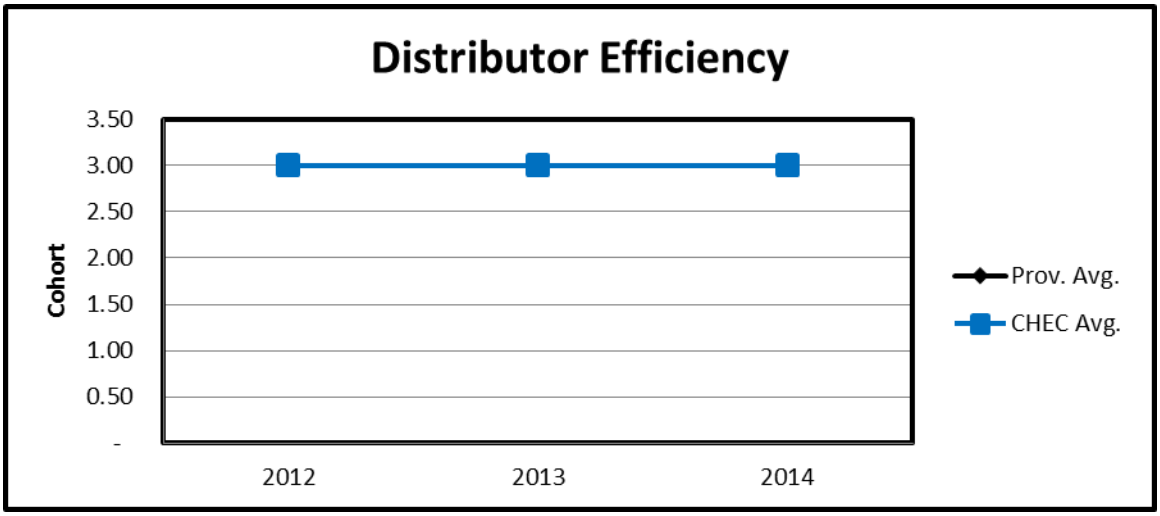
Period	CHEC Avg. Times	Prov. Avg. Times
2010	0.80	1.21
2011	1.24	1.49
2012	0.81	1.22
2013	0.98	1.47
2014	0.73	1.06
5-Year Avg. (2010 – 2014)	**0.91**	**1.29**

Please Note: The CHEC 5Y averages (**0.91 – 2014, 0.93 – 2013**) and the provincial 5Y averages (**1.29 – 2014, 1.33 – 2013**) are showing an improvement in performance from 2013 to 2014.

Distributor Efficiency:

Distributor efficiency is a performance measure whereby utilities are assigned to various cohorts ranked from 5 (being the worst) to 1 (being the best). Cohort assignments are based on the results of a statistical cost benchmarking study designed to make inferences about a utility's cost efficiency. An econometric model is used to predict the level of cost associated with each distributor's operating conditions. Distribution for this measure is considered to be a normal distribution whereby utilities are distributed across a bell curve. Distributors whose actuals costs were lower than costs predicted by the model are assigned a lower cohort (e.g.: cohort 2 or cohort 1).

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2012 – 2013:



Analysis – For the most part, CHEC utilities follow the same normal distribution curve as the provincial utilities. This translates to an average cohort of 3 for both the CHEC group and the provincial utilities over the period 2012 - 2014. Differences on this performance measure will only be seen if as a whole, the CHEC group were to be contained within a higher cohort (4 & 5) or a lower cohort (1 &2).

Averages – The averages for this performance measure are as follows:

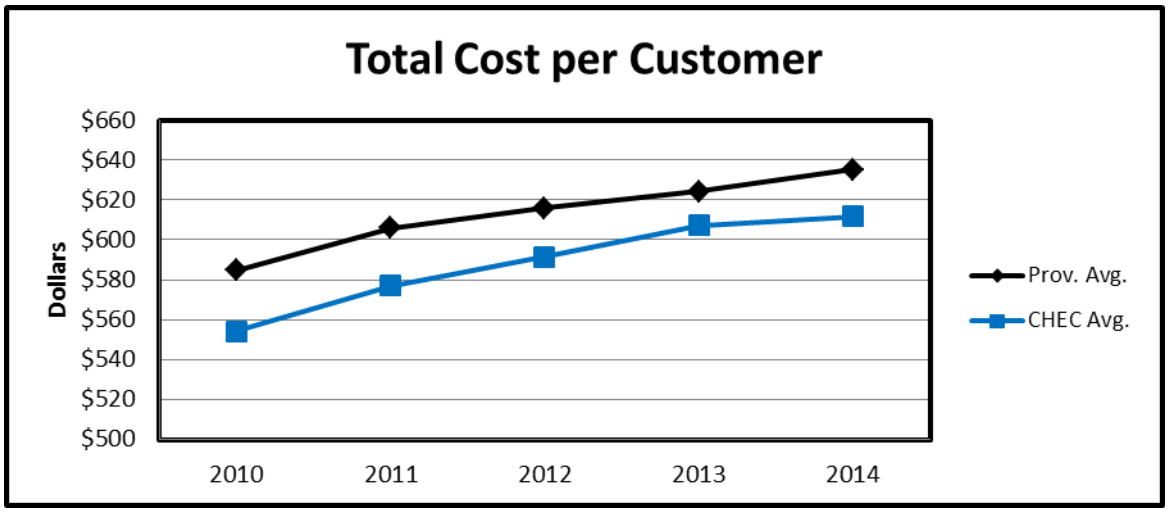
Period	CHEC Avg. Cohorts	Prov. Avg. Cohorts
2012	3	3
2013	3	3
2014	3	3
3-Year Avg. (2012 – 2014)	**3**	**3**

Please Note: The CHEC 3Y averages (**3 – 2014, 3 – 2013**) and the provincial 3Y averages (**3 – 2014, 3 – 2013**) remain unchanged for the period 2013 to 2014.

Total Cost per Customer:

Total cost per customer is a simple calculation whereby "Total Cost" is divided by the number of customers in a utilities territory. "Total Cost" is determined using a complex statistical calculation (see PEG Report) that facilitates a more accurate cost that is comparable among distributors. The source of the cost and customer data used in the calculations is taken from the distributors reported RRR filings. The OEB did not set a target for this measure.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part, CHEC utilities have kept their cost per customer relatively stable from 2010 to 2014. The provincial average is similar but higher than the CHEC average, which is likely to be influenced by factors such as territorial density, underground versus overhead configurations, and a utilities asset maintenance policy. The gradual increase in trending over the years is expected due to inflationary factors.

Averages – The averages for this performance measure are as follows:

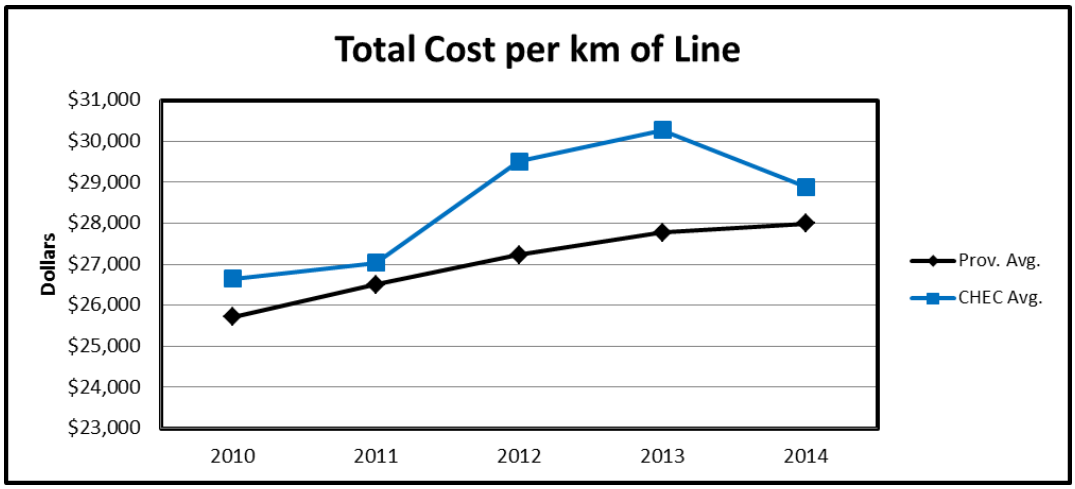
Period	CHEC Avg. Costs	Prov. Avg. Costs
2010	$554	$585
2011	$577	$606
2012	$592	$616
2013	$607	$624
2014	$612	$635
5-Year Avg. (2010 – 20143)	**$588**	**$613**

Please Note: The CHEC 5Y averages (**$588 – 2014, $562 – 2013**) and the provincial 5Y averages (**$613 – 2014, $599 – 2013**) are showing a decline in performance from 2013 to 2014.

Total Cost per KM of Line:

Total cost per km of line is also a simple calculation whereby "Total Cost" is divided by the number of kilometers of line in a utilities territory. "Total Cost" is determined using a complex statistical calculation (see PEG Report) that facilitates a more accurate cost that is comparable among distributors. The source of the cost and customer data used in the calculations is taken from the distributors reported RRR filings. The OEB did not set a target for this measure.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part, both the CHEC average and the provincial average are relatively stable from 2010 – 2014. The CHEC average is similar but higher than the provincial average, which is also likely to be influenced by factors territorial density, underground versus overhead configurations, and a utilities asset maintenance policy. There is also a gradual increase in trending over the years, which is also expected due to inflationary factors.

Averages – The averages for this performance measure are as follows:

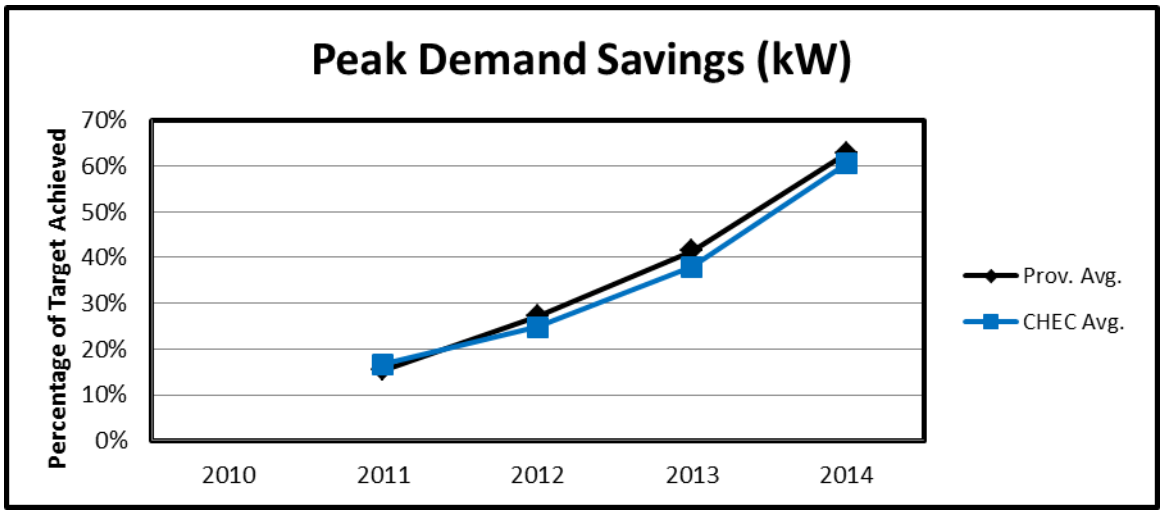
Period	CHEC Avg. Costs	Prov. Avg. Costs
2010	$26,649	$25,714
2011	$27,030	$26,498
2012	$29,503	$27,234
2013	$30,273	$27,779
2014	$38,883	$27,993
5-Year Avg. (2009 – 2013)	**$28,468**	**$27,044**

Please Note: The CHEC 5Y averages (**$28,468 – 2014, $28,687 – 2013**) are showing an improvement in performance while the provincial 5Y averages (**$27,044 – 2014, $26,456 – 2013**) are showing a decline in performance from 2013 to 2014.

Peak Demand Savings:

Peak demand savings is simply a record of the demand (MW) reduction from efforts made towards the 2011 – 2014 Conservation and Demand Management (CDM) programs. This information is taken directly from the OPA's reported findings for each distributor. Targets for this measure were established by the OPA and are a condition of the Distributor's license.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part, both the CHEC and provincial utilities are below their required targets. This is somewhat expected for the CHEC utilities as they are primarily residential based and there are limited opportunities to reduce energy demand with residential customers. The provincial utilities are trending slightly higher than the CHEC utilities, which is expected as the provincial utilities include the larger utilities where there is more opportunity for demand savings. For the 2014 Scorecard, Peak Demand savings were revised so that more of a trending pattern is now evident.

Averages – The averages for this performance measure are as follows:

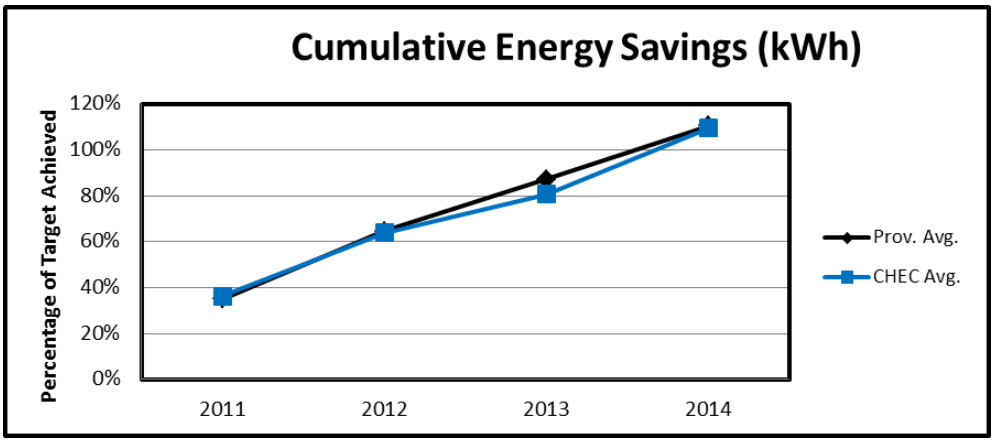
Period	CHEC % Target	Prov. % Target
2011	16.63%	15.35%
2012	24.79%	27.13%
2013	37.87%	41.41%
2014	60.43%	62.71%
2014	**60.43%**	**62.71%**

Please Note: The CHEC 2014 averages (**60.43% – 2014, 19.58% – 2013**) and the provincial 2014 averages (**62.71% – 2014, 23.21%– 2013**) are showing an improvement towards target from 2013 to 2014.

Cumulative Energy Savings:

Cumulative energy savings is simply a record of the energy (GWh) reduction from efforts made towards the 2011 – 2014 Conservation and Demand Management (CDM) programs. This information is taken directly from the OPA's reported findings for each distributor. Targets for this measure were established by the OPA and are a condition of the Distributor's license.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – On average, both the CHEC and provincial utilities have met their required OEB targets, although individually, approximately 50% of all utilities in the province have failed to meet their specified target. This is somewhat expected for the CHEC utilities as they are primarily residential based and there are limited opportunities to reduce energy consumption with residential customers. The provincial utilities are trending slightly higher, which is also expected as the provincial utilities include the larger utilities where there is more opportunity for energy savings. The trending here is steadily increasing year after year, which is to be expected as energy savings are cumulative for 2011 – 2014.

Averages – The averages for this performance measure are as follows:

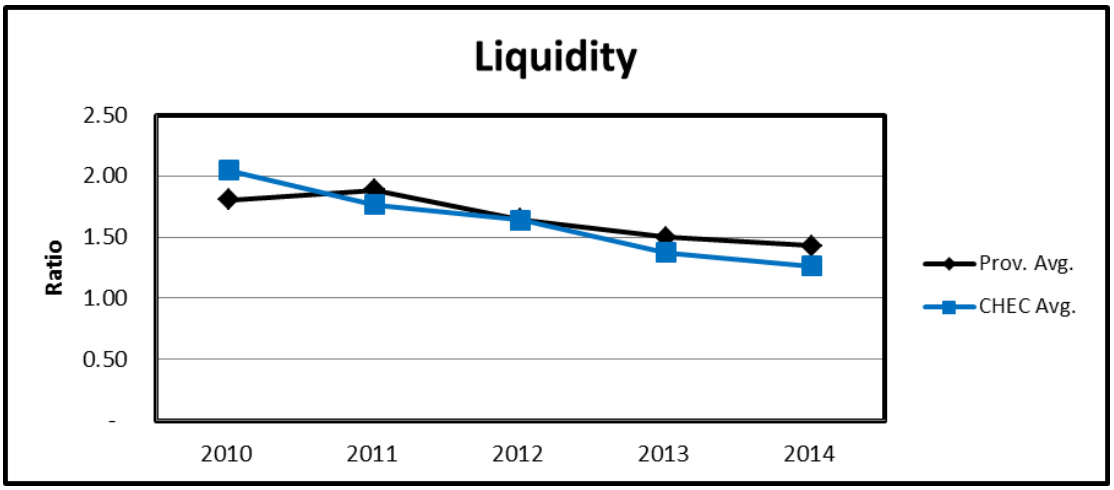
Period	CHEC % Target	Prov. % Target
2011	36.30%	35.10%
2012	63.88%	64.53%
2013	80.66%	87.04%
2014	109.37%	110.44%
2014	**109.37%**	**110.44%**

Please Note: The CHEC 2014 averages (**109.37% – 2014, 79.02% – 2013**) and the provincial 2014 averages (**110.44% – 2014, 87.05% – 2013**) are showing an improvement towards target from 2013 to 2014.

Liquidity:

Liquidity is a financial measure of the ability of a debtor to pay their short-term obligations. It is usually expressed as a ratio or a percentage. For this measure, the scorecard utilizes a ratio called "current ratio", which is a simple calculation of current assets / current liabilities. The OEB has not set a target for this measure.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part, both the CHEC utilities (~2.1 in 2010, decreasing to ~1.3 in 2014) and the provincial utilities (~1.8 in 2010, decreasing to ~1.4 in 2014) average current ratio are similar, which is typical for this type of industry, particularly for the latter years. Financially speaking, the higher the number, the more capable the company is of paying its debts. A ratio under 1 suggests that the company would be unable to pay off its obligations if they came due at that point. A ratio over 3 suggests that the company may not be making efficient use of its current assets or its short-term financing facilities.

Averages – The averages for this performance measure are as follows:

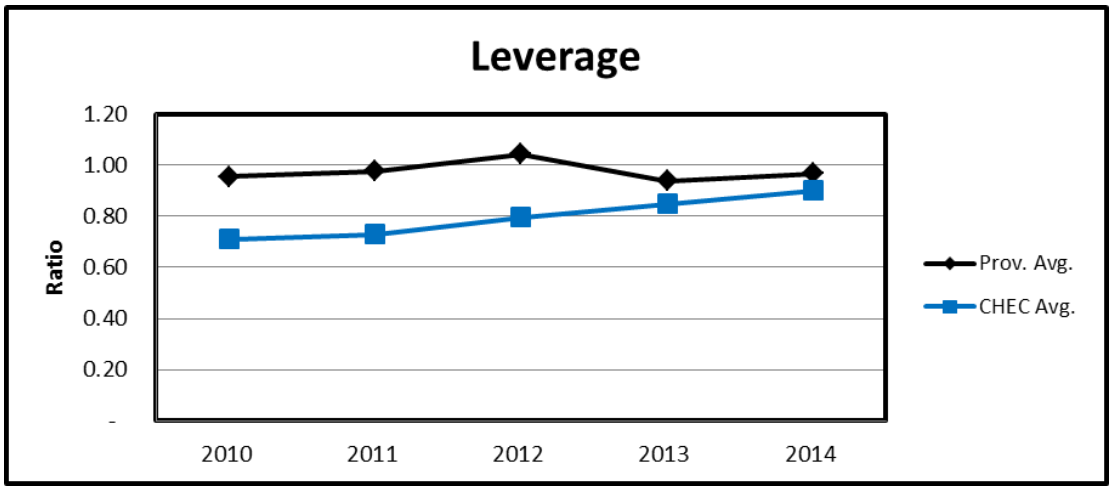
Period	CHEC Avg. Ratios	Prov. Avg. Ratios
2009	2.05	1.80
2010	1.77	1.89
2011	1.64	1.65
2012	1.38	1.50
2013	1.26	1.43
5-Year Avg. (2009 – 2013)	**1.62**	**1.65**

Please Note: The CHEC 5Y averages (**1.62 – 2014, 1.88 – 2013**) and the provincial 5Y averages (**1.65 – 2014, 1.74 – 2013**) are showing an improvement in performance from 2013 to 2014.

Leverage:

Leverage is a financial measure of the degree to which a company uses debt and equity to finance its assets. It is usually expressed as a ratio. For this measure, the scorecard utilizes a ratio called "Debt to Equity" ratio, which is a simple calculation of Total Liabilities / Shareholder's Equity. The OEB has not set a target for this measure.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part, CHEC utilities debt to equity ratios (0.71 in 2010, increasing to 0.90 in 2014) are below the provincial average (0.96 in 2010, increasing to 0.97 in 2014), which is reasonable for this type of industry. Financially speaking, the debt to equity ratio depends on the industry in which the company operates. For the electrical distribution industry, the OEB suggests a ratio of 1.5 (60% debt / 40% Equity) is ideal. Actual ratios will depend on each individual utility's specific circumstances.

Averages – The averages for this performance measure are as follows:

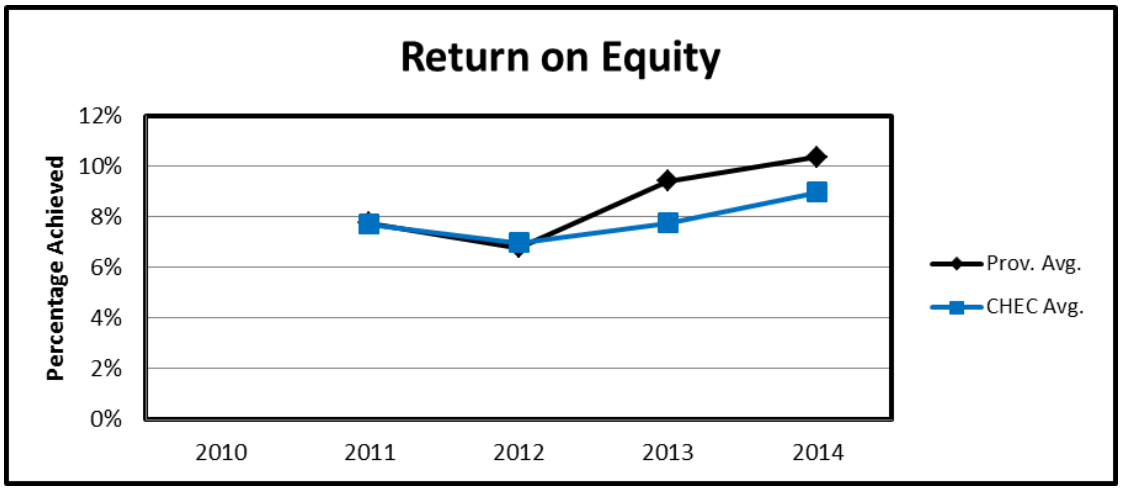
Period	CHEC Avg. Ratios	Prov. Avg. Ratios
2010	0.71	0.96
2011	0.73	0.98
2012	0.80	1.04
2013	0.85	0.94
2014	0.90	0.97
5-Year Avg. (2010 – 2014)	**0.80**	**0.98**

Please Note: The CHEC 5Y averages (**0.80 – 2014, 0.74 – 2013**) and the provincial 5Y averages (**0.98 – 2014, 0.97 – 2013**) are showing an improvement in performance from 2013 to 2014.

Return on Equity:

Return on Equity (ROE) is a financial measure used to reflect the profitability of the company and to compare that to other firms in the same industry. It is usually expressed as a percentage. Return on Equity is a simple calculation of Net Income / Shareholder's Equity. The OEB has not set a target for this measure.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part, CHEC utility's Return on Equity percentages (7.72% in 2011, 6.99% in 2012, 7.75% in 2013, and 8.97% in 2014) are similar to the provincial averages (7.77% in 2011, 6.79% in 2012, 9.41% in 2013, and 10.35% in 2014), except for 2013 and 2014, where the provincial average is somewhat higher. Return on Equity measures a corporation's profitability by revealing how much profit a company generates with the money shareholders have invested. For the electrical distribution industry, the OEB typically requires utilities to maintain its Return on Equity percentage between 9.0% and 9.5% for recent years. Actual ratios will depend on each individual utility's specific circumstances.

Averages – The averages for this performance measure are as follows:

Period	CHEC Avg. %	Prov. Avg. %	Deemed Avg. %
2011	7.72%	7.77%	8.78%
2012	6.99%	6.79%	8.86%
2013	7.75%	9.41%	9.14%
2014	8.97%	10.35%	9.13%
4-Year Avg. (2011 – 2014)	**7.86%**	**8.58%**	**8.98%**

Please Note: The CHEC 4Y averages (**7.86% – 2014, 7.46% – 2013**) and the provincial 4Y averages (**8.58% – 2014, 8.07% – 2013**) are showing an improvement in performance from 2013 to 2014.

Conclusions:

CHEC Analysis – For the CHEC Analysis, CHEC Distributors were compared to one another for the outcomes of customer focus (service quality), operational effectiveness (cost control), public policy responsiveness (conservation and demand management), and financial performance (financial ratios). For the most part, it was determined that CHEC Distributors are very similar in terms of performance and productivity. The few anomalies that were identified were also easily explained and there were no areas of major concern among the group.

Provincial Analysis - For the Provincial Analysis, CHEC Distributors were compared to Provincial distributors for the outcomes of customer focus (service quality), operational effectiveness (cost control), public policy responsiveness (conservation and demand management), and financial performance (financial ratios). For the most part, it was determined that CHEC Distributors were similar or better than the Provincial Distributors in terms of performance and productivity. The few anomalies that were identified were also easily explained and there were no areas of major concern.

Based on the above analyses, the CHEC Distributors are still considered to be some of the better performing utilities among the province today. However, it is the OEB's expectation that all distributors remain committed to continuous improvement in the electrical sector through achievement of benchmark performance on valued services and/or processes over time. As a result, it is expected that this document will be updated annually to reflect the latest Scorecard data in an effort to monitor distributor performance over time.

Appendixes:

Ontario Energy Board (2014). *Performance Measurement for Electricity Distributors: A Scorecard Approach.* 1 – 58. Retrieved from http://www.ontarioenergyboard.ca/oeb/Industry/Rules%20and%20Requirements/Electricity%20Distributor%20Scorecards

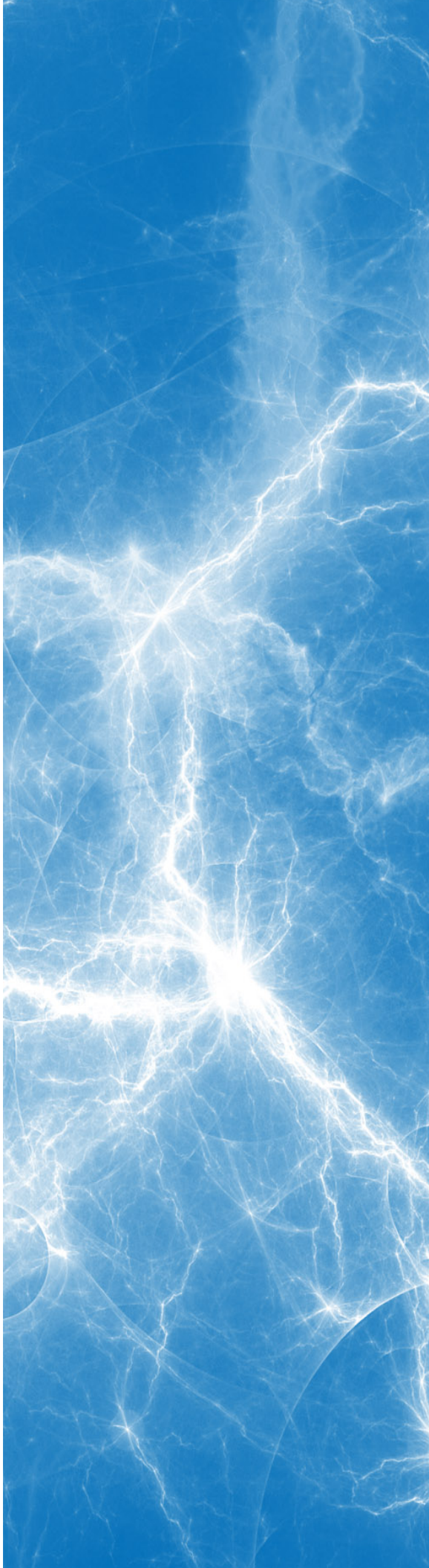
Ontario Energy Board (2015, September). *Electricity Distributor Scorecards.* Retrieved from http://www.ontarioenergyboard.ca/oeb/Industry/Rules%20and%20Requirements/Electricity%20Distributor%20Scorecards/2014%20Distributor%20Scorecards

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Achievement Through Collaboration

2014 CHEC Scorecard Analysis

A comparison of the 2014 Distributor's Scorecard for benchmarking purposes and to demonstrate the value CHEC Utilities deliver to the end customer.



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July 15, 2016

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Executive Summary:

Early in 2014, the OEB introduced the Renewed Regulatory Framework. This Framework is a comprehensive, performance based approach to regulation that promotes the achievement of specific outcomes (customer focus, operational effectiveness, public policy responsiveness, and financial performance). Included in this Framework is the Board's Scorecard approach, which is used to facilitate performance monitoring for electricity distributors. The Board will use the Scorecard approach to effectively translate these outcomes into a coherent set of performance measures.

On September 30, 2015, the Board released the 2015 Electricity Distributor Scorecards (covers a 5 year period from 2010 – 2014). The scorecard includes traditional metrics for assessing a distributor's services, which includes frequency of power outages, costs per customer and financial performance. In addition, future performance results (for 2015 and onward) will include a number of new metrics that directly reflect the customer experience, which includes how well the distributor resolves a customer's concern on the first contact, updates to the customer satisfaction survey methodology, release of the DSP measure, and more.

This following analysis compares CHEC Distributors to one another and CHEC Distributors to Provincial Distributors with the aim to encourage CHEC Distributors to operate effectively, to continually seek ways in which to improve their productivity and performance, and most importantly, to demonstrate the value they deliver to the end customer. The analysis concludes that CHEC Distributors are some of the higher performing electrical utilities among the province today.

Introduction:

The Renewed Regulatory Framework is a comprehensive performance-based approach to regulation that promotes the achievement of outcomes to the benefit of existing and future customers. This framework, which was introduced early in 2014, aims to align customer and distributor interests, continues to support the achievement of important public policy objectives, and places a greater focus on delivering long term value for money.

Under the Board's performance-based approach, a distributor is expected to demonstrate continuous improvement in achieving the four outcomes set out in the October 18, 2012 Report of the Board entitled "A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach". These outcomes are as follows:

- **Customer Focus:** Helps to determine if services are provided in a manner that responds to identified customer preferences;
- **Operational Effectiveness**: Demonstrates if continuous improvement in productivity and cost performance is achieved and measures how distributors deliver on system reliability and quality objectives;
- **Public Policy Responsiveness:** Determines if distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements); and
- **Financial Performance:** Demonstrates if financial viability is maintained and if savings from operational effectiveness are sustainable.

To facilitate performance monitoring and eventually distributor benchmarking, the Board will use a scorecard approach to effectively translate the four outcomes into a coherent set of performance measures (see **Table 1** below). These measures are further organized into performance categories that effectively align them with the four performance outcomes. These categories are, for the most part, based on existing standards and measures for electricity distributors.

Table 1: Measures of the Four Performance Outcomes:

Performance Outcomes	Performance Categories	Performance Measures
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential Services Connected on Time Scheduled Appointments Met on Time Telephone Calls Answered on Time
	Customer Satisfaction	First Contact Resolution Billing Accuracy Customer Satisfaction Survey Results
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Public Safety (measure to be determined)
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted Average Number of Times that Power to a Customer is Interrupted
	Asset Management	Distribution System Plan Implementation Progress
	Cost Control	Efficiency Assessment Total Cost per Customer Total Cost per Km of Line
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation and Demand Management	Net Annual Peak Demand Savings (Percent of target achieved) Net Cumulative Energy Savings (Percent of target achieved)
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed on Time New Micro-embedded Generation Facilities Connected on Time
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities) Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio Profitability: Regulated Return on Equity — Deemed (included in rates) Achieved

The measures identified for inclusion on the Scorecard are considered by the Ontario Energy Board to be most meaningful in terms of monitoring a distributor's effectiveness and continuous improvement in achieving the four stated outcomes. These performance measures selected are customer-focused, encourage continuous improvement, and are measureable. Providing a longer-term view on performance, the Scorecard will present the five most recent years of available data for each measure.

The Scorecard is designed to track and show an individual distributor's performance gains over a period of time and at a point in time. This approach organizes performance measures in a manner that facilitates evaluations and meaningful comparisons between utility companies. Furthermore, the Scorecard will be published and made available in the public domain, therefore, it needs to be relevant and meaningful to all. Once released, the Scorecard will allow stakeholders to gain a better sense of how well their distributor is currently performing. Over time, this approach will also let stakeholders see how their utility compares to others in the industry.

The analysis that follows attempts to encapsulate the Board's performance based framework of continuous improvement and comparability. First, through the comparison of CHEC utilities to one another, and secondly, through the comparison of the CHEC Group to utilities across the province. It is hoped that this analysis will assist CHEC utilities to identify areas where they may be performing well, and to identify areas that may need further improvement.

Updates from Previous Analyses:

The distributor scorecard effectively organizes performance information in a manner that facilitates evaluations and meaningful comparisons. Since its inception, a number of the scorecard measures have undergone revisions to improve the effectiveness of the scorecard. As a result, there will be differences between this analysis and other scorecard analyses previously issued. Reasons for deviations in this analysis are as follows:

Major Updates for the 2014 Scorecards:

1. **CDM** – As the 2011 – 2014 CDM programs have concluded as of December 31, 2014. The results are now based on the latest information provided by the IESO, which includes a number of updates to the Annual Peak Demand Savings and Net Cumulative Energy Savings measures. The results shown are also reflective of targets achieved for the 2011 – 2014 CDM initiative.

2. **ROE** – In 2014, the OEB began revisions as to how ROE should be calculated and reported. As a result, it has been noted that ROE for a number of distributors have been updated since the issuance of the 2013 scorecards. This analysis has been updated to include these changes.

3. **Niagara-on-the-Lake Hydro** – Niagara-on-the-Lake Hydro is a new CHEC Member as of 2015. As a result, all trends and averages for the 2014 Scorecards have been updated to include this new member. This will cause some distortions to the trends and averages compared to previous analyses.

4. **Measures** – Billing Accuracy is a new measure to the 2014 Scorecard. As a result, Billing Accuracy has been incorporated into the 2014 analysis. This measure is expected to remain active into the foreseeable future.

Part I – CHEC / CHEC Analysis:

The first part of this analysis is a comparison of CHEC utilities against each another. Please note that only select performance measures are being assessed, as not all performance measures are being monitored and/or tracked at this time. Some measures are still under development. Of those available performance measures, the following have been included in the analysis:

- **Customer Focus:**
  - New Residential Services Connected on Time
  - Scheduled Appointments Met on Time
  - Telephone Calls Answered on Time
  - Billing Accuracy

- **Operational Effectiveness:**
  - Efficiency Assessment (PEG)
  - Average Number of Hours that Power to a Customer is Interrupted
  - Average Number of Times that Power to a Customer is Interrupted

- **Public Policy Responsiveness:**
  - Net Annual Peak Demand Savings (Percent of Target Achieved)
  - Net Cumulative Energy Savings (Percent of Target Achieved)

- **Financial Performance:**
  - Liquidity: Current Ratio
  - Leverage: Debt to Equity Ratio
  - Regulated Return on Equity

Analysis & Graphical Breakdown:

The first part of this analysis involves two graphs for each measure. The first graph shows yearly results for each individual CHEC utility against the provincial average for the same period. This graph is intended to show trending for the period. The second graph is intended to provide a more apples-to-apples assessment for the period by comparing how each individual CHEC utility average measures against the provincial average for the specified period.

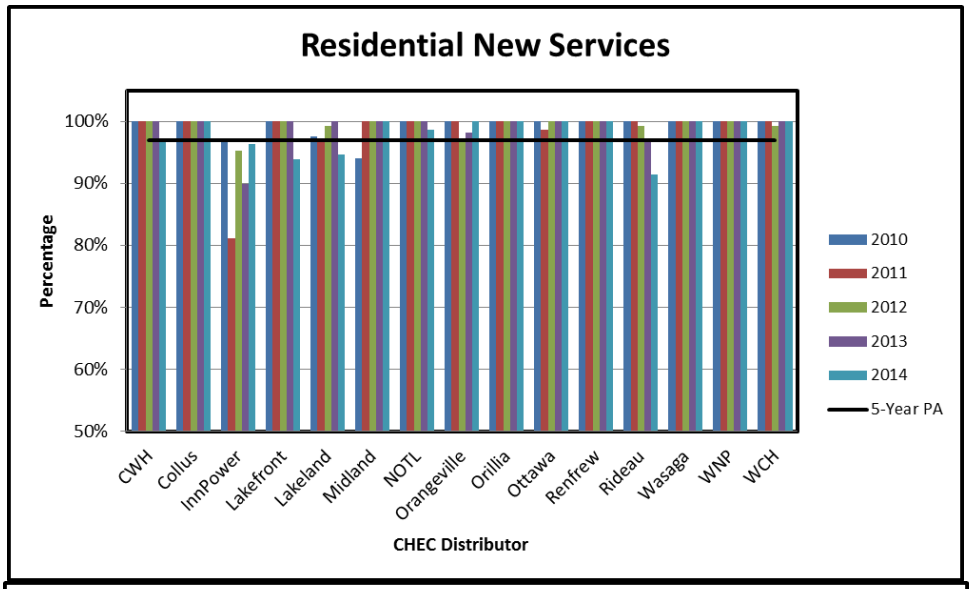
As distributors gain experience under the scorecard approach, it is expected that the Scorecard will also evolve over time. CHEC will monitor any refinements and improvements to the Scorecard on an ongoing basis to ensure they are incorporated into this analysis. Details will be documented to ensure substantial changes are identified as the analysis evolves.

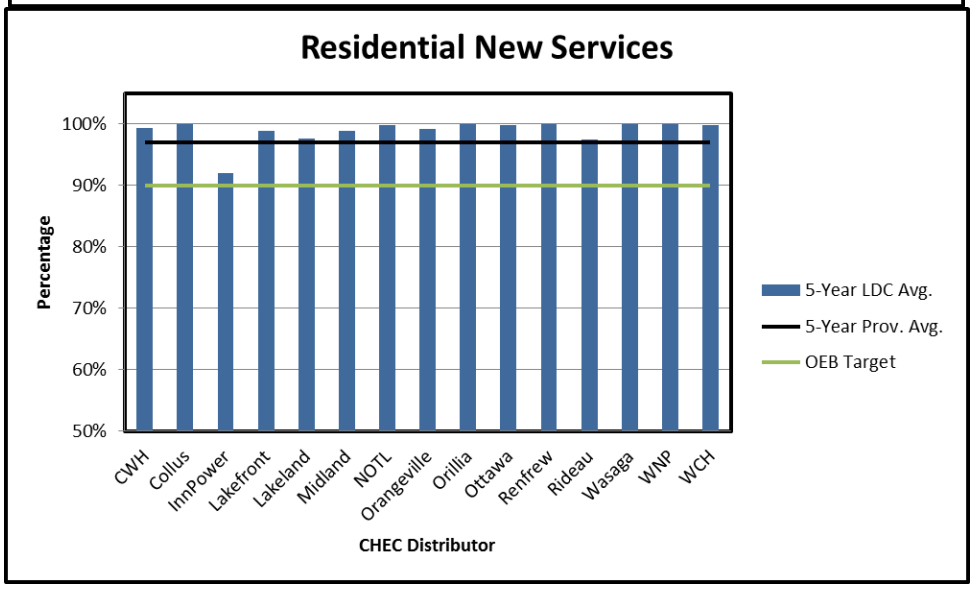
Please Note: Hydro One Networks has been excluded from this analysis. It is likely that including Hydro One Networks would skew the overall results due to the unique nature of the organization.

Residential New Services Connected on Time:

Residential New Services refers to Low Voltage Services, which is a connection for a new service request for a voltage <750 volts that must be completed within 5 business days, or at such a later date as agreed to by the customer and distributor. It can also refer to High Voltage Services, which is a connection for new services for a voltage >750 volts that must be completed within 10 business days, or at such a later date as agreed to by the customer and distributor. However, it is assumed that there are no High Voltage services within CHEC at the present time. The OEB expects this service quality requirement to be met at least 90 percent of the time on a yearly basis.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – For the most part CHEC utilities met this requirement with the exception of InnPower in 2011 (81.2%), and InnPower again in 2013 (89.9%). Growth could be the primary factor for InnPower failing to meet this target as InnPower has been identified as a high growth territory. It should also be noted that in 2013, InnPower was only 0.1% below the required target.

Provincial Averages – The provincial averages for this performance measure are as follows:

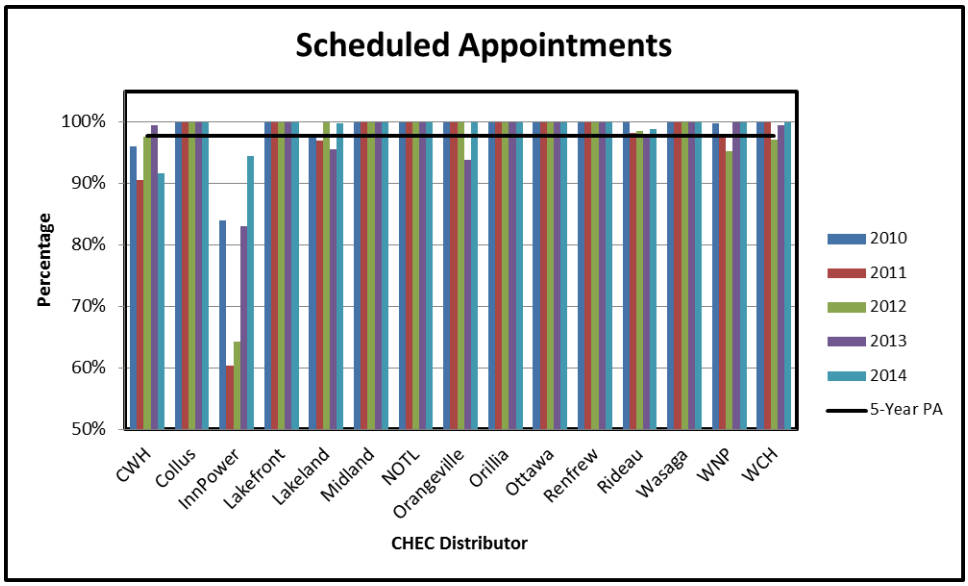
Period	Percentages
2010	98.56%
2011	96.69%
2012	98.17%
2013	96.44%
2014	95.17%
5-Year Avg. (2010 – 2014)	**97.01%**

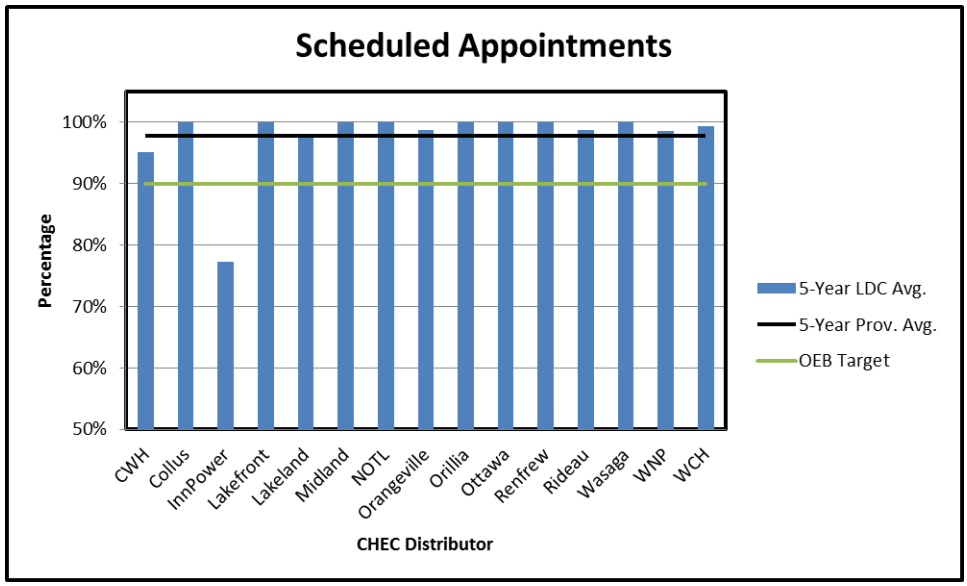
The provincial average of **97.01%** for the period 2010 – 2014 is an overall decline in performance over the 2013 provincial average of **97.40%**.

Scheduled Appointments Met on Time:

Appointments Met refers to any appointment where the customer's presence is required. The distributor must arrive for the appointment within the scheduled timeframe, which is either an AM (8:00 am – 12:00 pm) or PM (1:00 pm – 5:00 pm) appointment. Appointments where the distributor arrives at the scheduled appointment within the required time period but the appointment cannot be met because the customer failed to attend can be excluded. The OEB expects this service quality requirement to be met at least 90 percent of the time on a yearly basis.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – For the most part CHEC utilities met this requirement with the exception of InnPower (Low of 60.40% to a high of 84.00% from 2010 - 2013). The main factor involved with InnPower failing to meet the target appears to be a process issue. Prior to 2014, InnPower was incorrectly calculating appointments met, which resulted in inaccurate reporting of this measure from 2010 – 2013. InnPower has subsequently revised its process to ensure the measure is accurately calculated on a go forward basis. InnPower did exceed the required target of 90% for 2014.

Provincial Averages – The provincial averages for this performance measure are as follows:

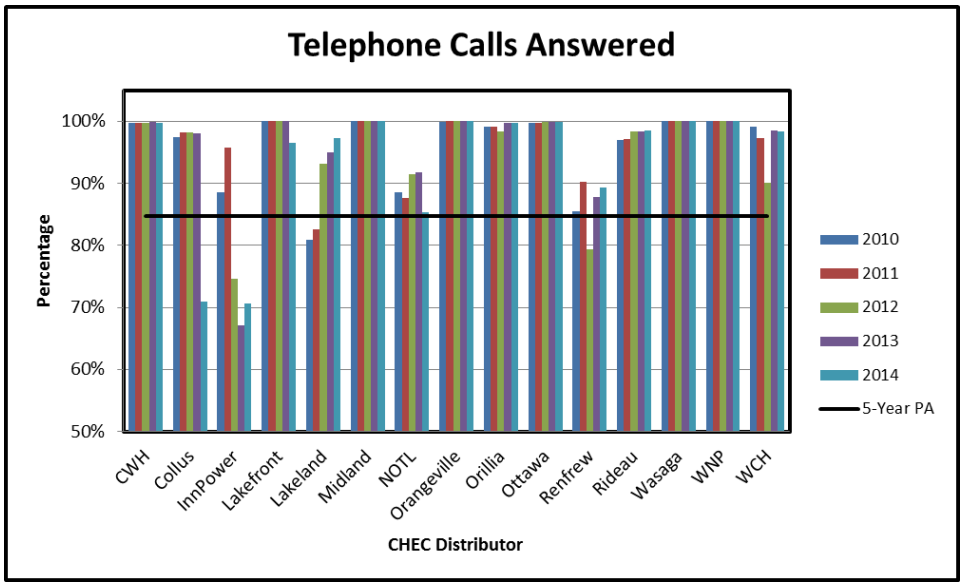
Period	Percentages
2010	97.12%
2011	96.46%
2012	97.11%
2013	98.79%
2014	98.95%
5-Year Avg. (2010 – 2014)	**97.69%**

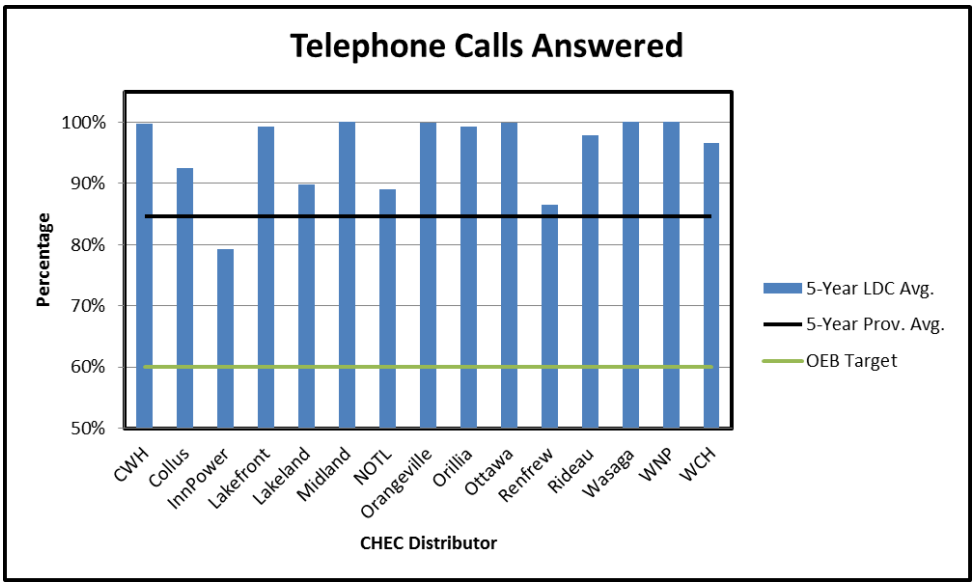
The provincial average of **97.69%** is an overall improvement in performance over the 2013 provincial average of **97.42%**.

Telephone Calls Answered on Time:

Telephone Calls Answered refers to ensuring qualified incoming calls (calls that are received during regular hours) to the distributor's customer care telephone numbers are answered within 30 seconds. For qualified incoming calls that are transferred from the distributor's IVR system, the 30 seconds shall be counted from the time the customer selects to speak to a customer service representative. In all other cases, the 30 seconds shall be counted from the first ring. The OEB expects this service quality requirement to be met at least 65 percent of the time on a yearly basis.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – All CHEC utilities met this requirement from 2010 – 2014, however, there is a concern with InnPower's downward trend between 2011 and 2013. This has been attributed to the fact that the duration of calls has increased dramatically (20% per year), making it difficult for CSR's to answer other incoming calls. InnPower will be monitoring the situation to determine if corrective action will be required, however, the trend does reverse for 2014.

Provincial Averages – The provincial averages for this performance measure are as follows:

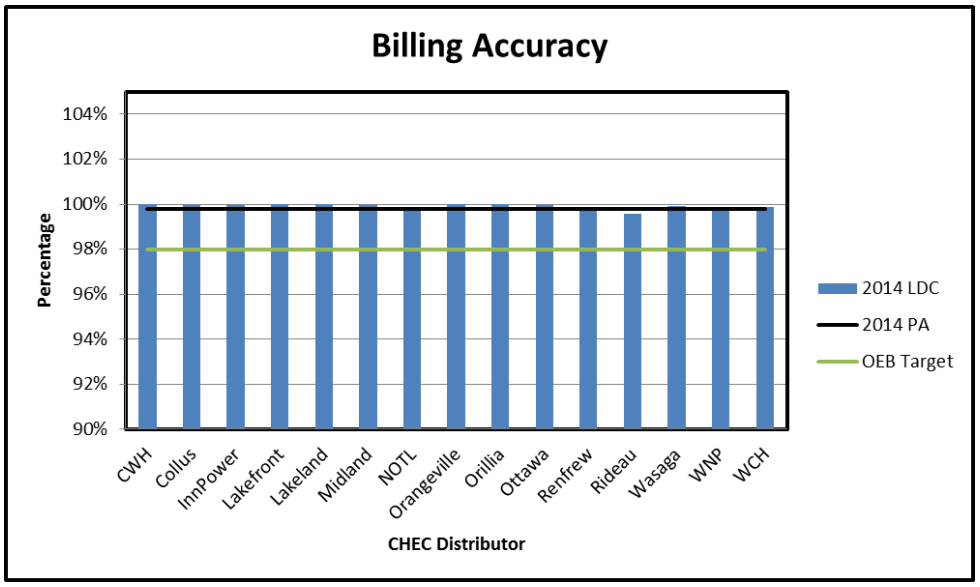
Period	Percentages
2010	83.41%
2011	84.22%
2012	84.39%
2013	86.30%
2014	85.15%
5-Year Avg. (2010 – 2014)	**84.69%**

The provincial average of **84.69%**, remains unchanged from the 2013 provincial average.

Billing Accuracy:

Billing Accuracy is a new measure to the Scorecard for 2014. Distributors are required to implement and start tracking the billing accuracy measure effective on October 1, 2014. The measure is defined as the accurate bills issued expressed as a percentage of total bills issued. Bills are considered accurate if it contains correct meter readings, customer information and rates, which results in an accurately calculated bill. A bill is considered inaccurate if a bill has been issued to a customer and is subsequently cancelled due to a billing error and/or adjustment. The OEB has set a minimum industry-wide billing accuracy performance target of 98%.

The following chart depicts how well the CHEC Group meets this requirement from 2010 – 2014:



Analysis – Only one chart is listed here as this is the first year for the Billing Accuracy measure, therefore only data for 2014 is available for analysis. Overall, CHEC did fairly well with this measure with all Member utilities exceeding the OEB specified target. It should be noted that Niagara-on-the-Lake (99.77%), Rideau St. Lawrence (99.58%), and Wellington North Power (99.73%) are slightly below the provincial average of 99.81%. Use caution with this measure as this is the first year for the Billing Accuracy measure and only 3 months' worth of data were tracked and reported by the utilities. Results may vary as experience is gained with this performance measure.

Provincial Averages – The provincial averages for this performance measure are as follows:

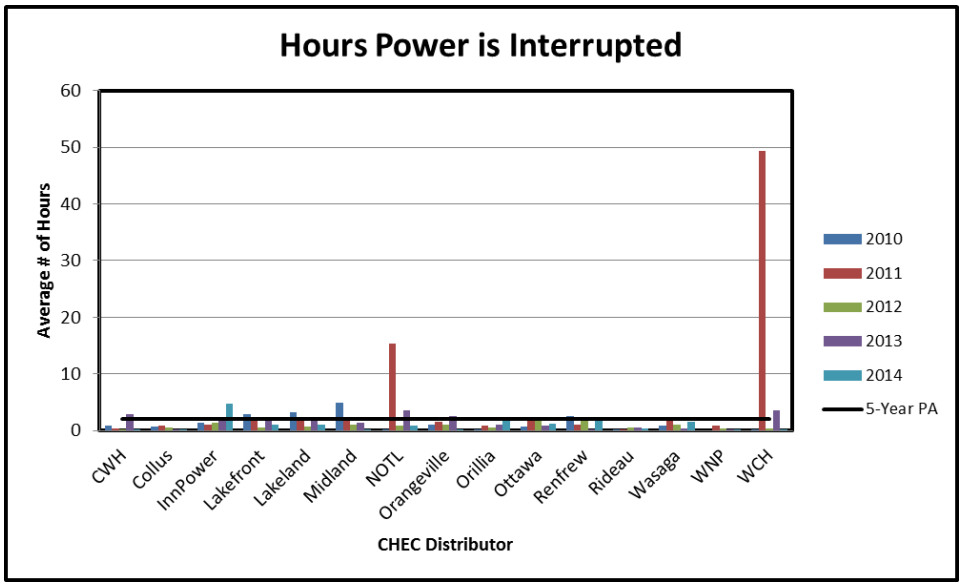
Period	Percentage
2014	**99.18%**

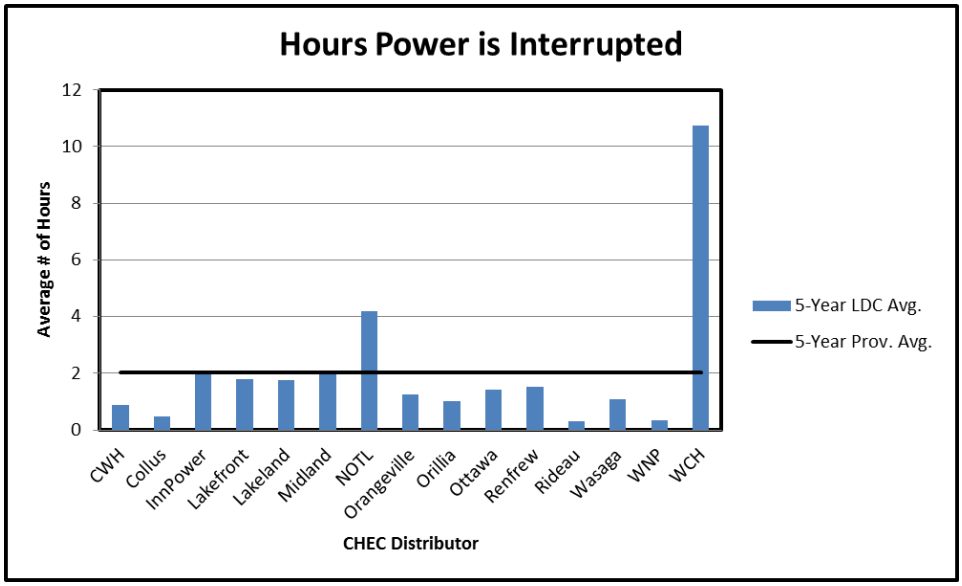
As this is a new measure for 2014, there are no 2013 results for comparative purposes.

Hours Power is Interrupted:

Hours power is interrupted is an indicator of system reliability that expresses the average amount of time, per reporting period, supply to a customer is interrupted. There is no official OEB target for this measure but ideally the goal is to strive for zero hours of uninterrupted power to the end customer.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – For the most part, CHEC utilities have kept hours of interrupted power to less than 5 hours from 2010 – 2014. The exceptions to this are West Coast Huron Energy, who experienced almost 50 hours of interrupted power in 2011, and Niagara-on-the-Lake, who experienced over 15 hours of interrupted power, also in 2011. For West Coast Huron Energy, this high loss of power is attributed to an F3 tornado that hit the Town of Goderich on August 21, 2011. Town officials quickly declared a state of emergency due to the severe damage caused by the Tornado, which included the town hall and hydro buildings. Despite the loss, West Coast Huron quickly recovered to ensure this measure returned to within norms for 2012 and subsequent years. For Niagara-on-the-Lake, the issue was related to a severe, localized wind storm.

Provincial Averages – The provincial averages for this performance measure are as follows:

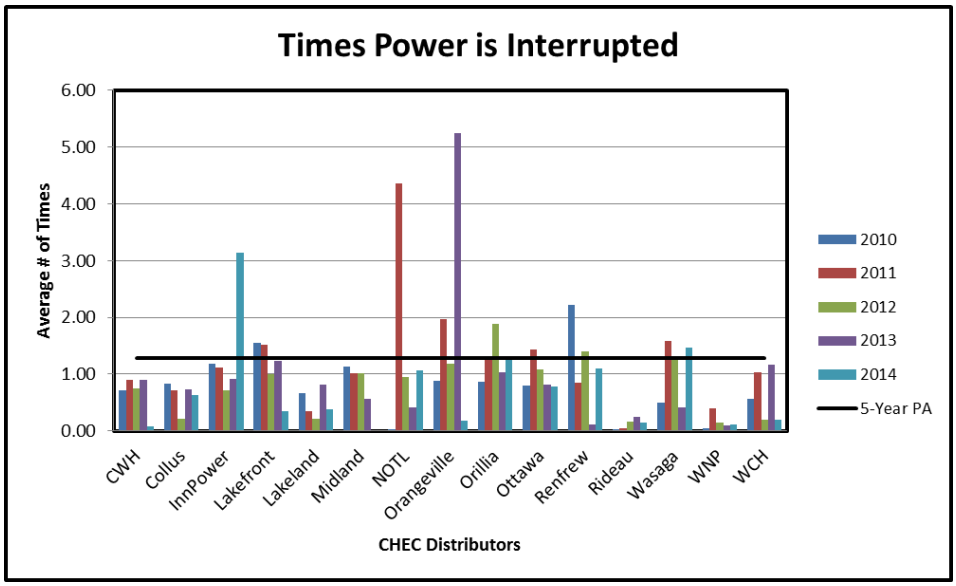
Period	Hours
2010	1.49
2011	2.91
2012	1.28
2013	3.06
2014	1.34
5-Year Avg. (2010 – 2014)	**2.02**

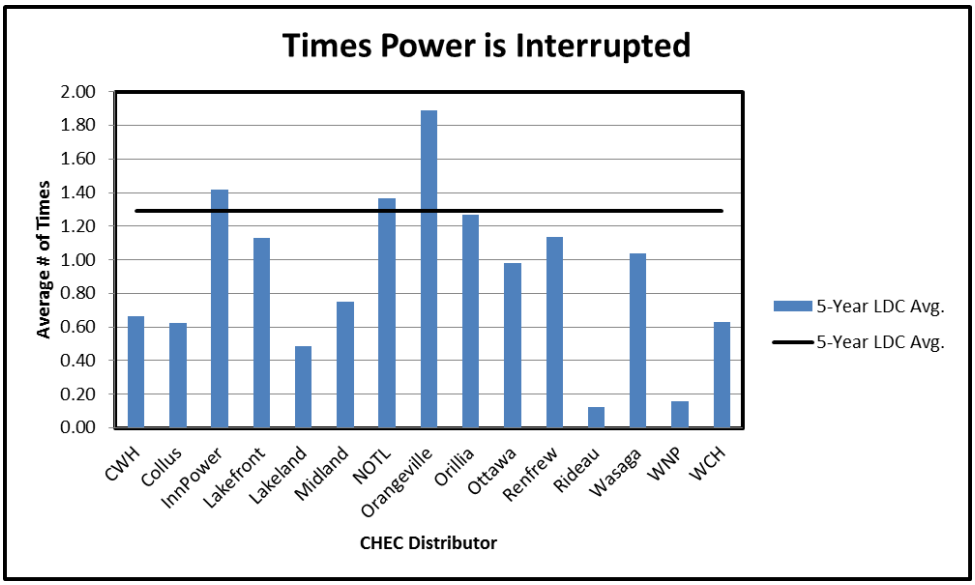
The provincial average of **2.02 hours** is an overall improvement in performance over the 2013 provincial average of **2.08 hours**.

Times Power is Interrupted:

Times power is interrupted is also an indicator of system reliability that expresses the number of times per reporting period that the supply to a customer is interrupted. It is determined by dividing the total number of interruptions experienced by all customers, by the average number of customers served. Again, there is no official OEB target for this measure but ideally the goal is to strive for zero times of uninterrupted power to the end customer.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – For the most part, CHEC utilities have kept the number of power interruptions to less than 2 occurrences for the period from 2010 – 2014. The exceptions to this are InnPower with over 3 power interruptions in 2014, Niagara-on-the-Lake with over 4 power interruptions in 2011, and Orangeville Hydro with over 5 power interruptions in 2013. The higher than usual loss of power for InnPower in 2014 is attributed to a major outage that occurred on February 5, 2014. Two primary feeder lines to Alcona were impacted due to a catastrophic failure of a distribution station which supports the feeder lines. Restoration of the outage was extensive as the 27.6V circuit had to be reconfigured and temporary switches installed. The higher than usual loss of power for Niagara-on-the-Lake and Orangeville Hydro were due to severe, localized weather conditions.

Provincial Averages – The provincial averages for this performance measure are as follows:

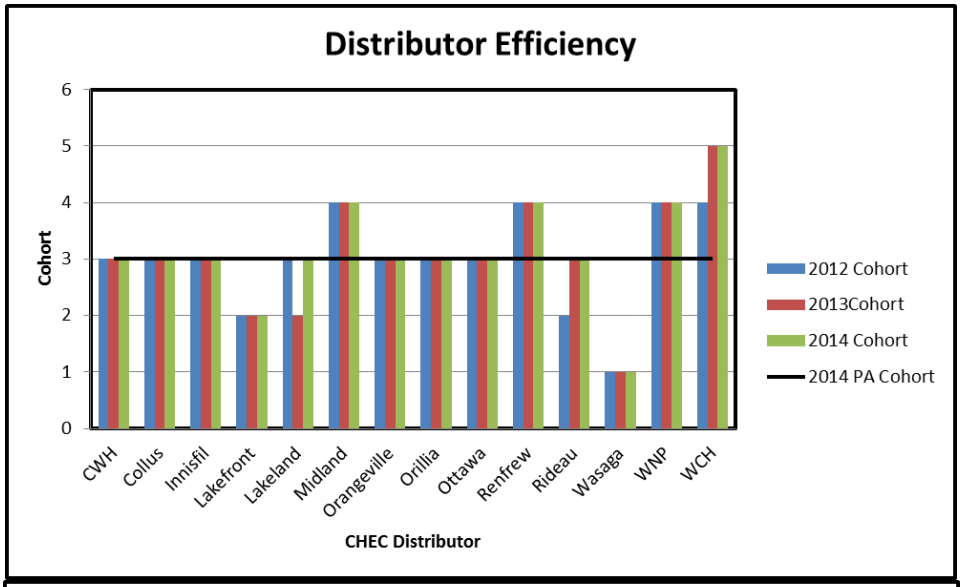
Period	Times
2010	1.21
2011	1.49
2012	1.22
2013	1.47
2014	1.06
5-Year Avg. (2010 – 2014)	**1.26**

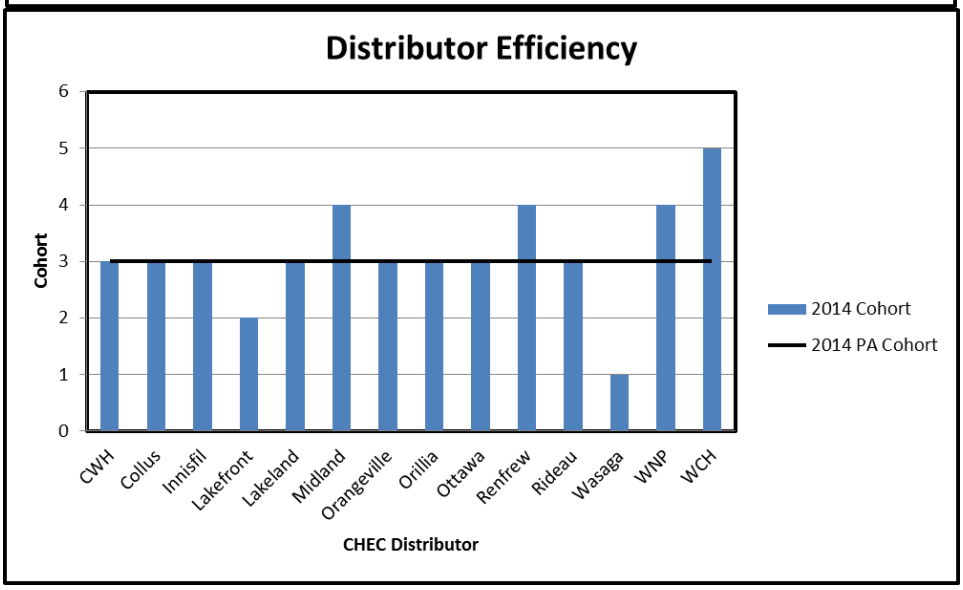
The provincial average of **1.26 hours** is an overall improvement in performance over the 2013 provincial average of **1.33 hours**.

Distributor Efficiency:

Distributor efficiency is a performance measure whereby utilities are assigned to various cohorts ranked from 5 (being the worst) to 1 (being the best). Cohort assignments are based on the results of a statistical cost benchmarking study designed to make inferences about a utility's cost efficiency. An econometric model is used to predict the level of cost associated with each distributor's operating conditions. Distribution for this measure is considered to be a normal distribution whereby utilities are distributed across a bell curve. Distributors whose actuals costs were lower than costs predicted by the model are assigned a lower cohort (e.g.: cohort 2 or cohort 1).

The following charts depict how well the CHEC Group meets this requirement from 2012 – 2014:





Analysis – For the most part, CHEC utilities follow the normal distribution curve for the provincial utilities with the majority of the members falling in cohort 3, a few members falling in the higher cohorts (4 & 5), and a few members falling in the lower cohorts (1 & 2). It should be noted that in 2014, Lakeland Power's cohort went from cohort 2 to cohort 3, which translates to a decrease in efficiency of approximately 1%. Wasaga Distribution remains in cohort 1 but is now the third (was second) most efficient utility in Ontario under this measure.

Provincial Averages – The provincial averages for this performance measure are as follows:

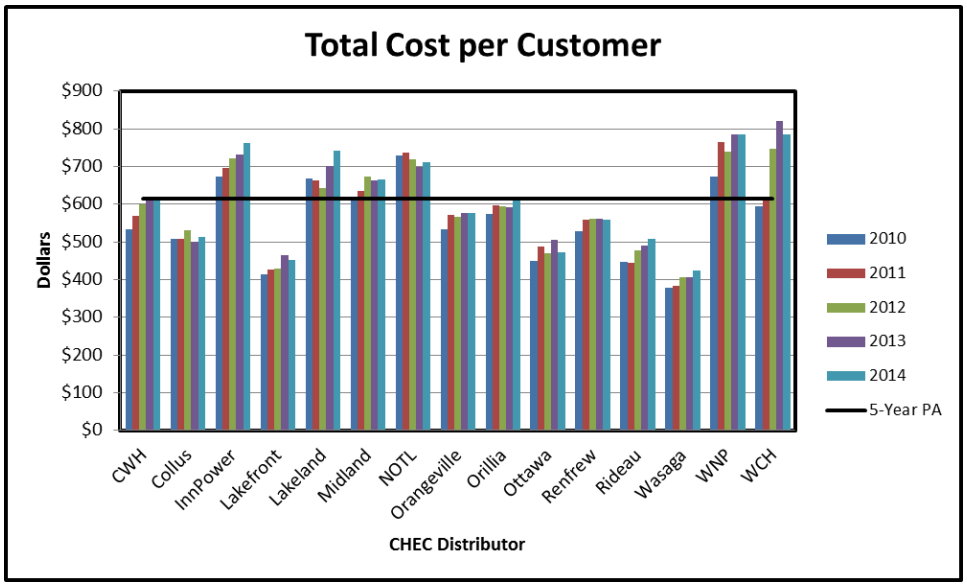
Period	Cohorts
2012	3
2013	3
2014	3
3-Year Avg. (2012 – 2014)	**3**

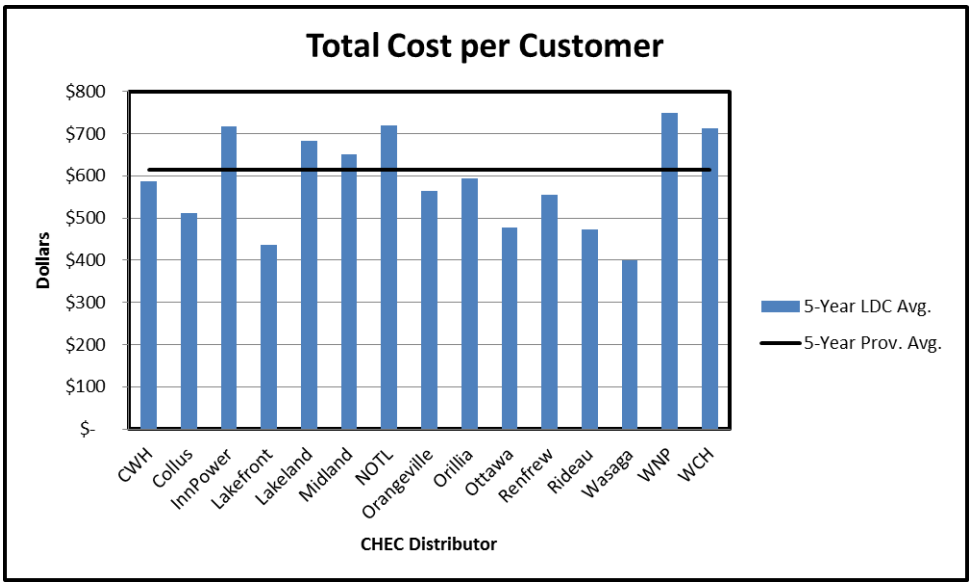
Do note that at any given time, the average cohort for this measure will be 3, do the statistical calculations and normal distribution of the results. As a result, the provincial average remains unchanged from 2013 provincial average.

Total Cost per Customer:

Total cost per customer is a simple calculation whereby "Total Cost" is divided by the number of customers in a utilities territory. "Total Cost" is determined using a complex statistical calculation (see PEG Report) that facilitates a more accurate cost that is comparable among distributors. The source of the cost and customer data used in the calculations is taken from the distributors reported RRR filings. The OEB did not set a target for this measure.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – For the most part, CHEC utilities have kept their cost per customer relatively stable from 2010 to 2014. There is a variance in cost per customer across the utilities, which is to be expected as each utility has unique characteristics (i.e.: square kms, customer base, etc.). For many utilities, there is also a gradual increase in trending over the years, which is also expected due to inflationary factors.

Provincial Averages – The provincial averages for this performance measure are as follows:

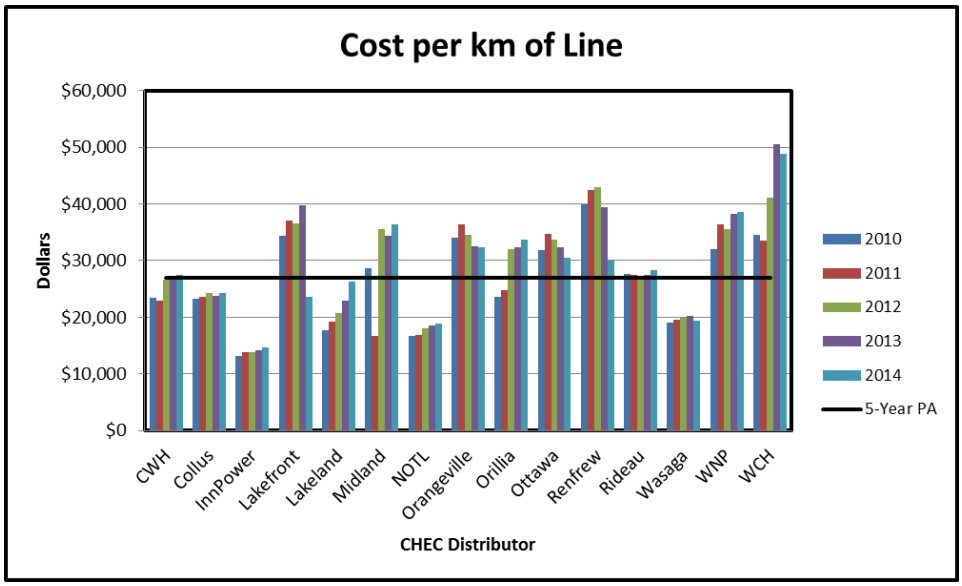
Period	Costs
2010	$585
2011	$606
2012	$616
2013	$624
2014	$635
5-Year Avg. (2010 – 2014)	**$613**

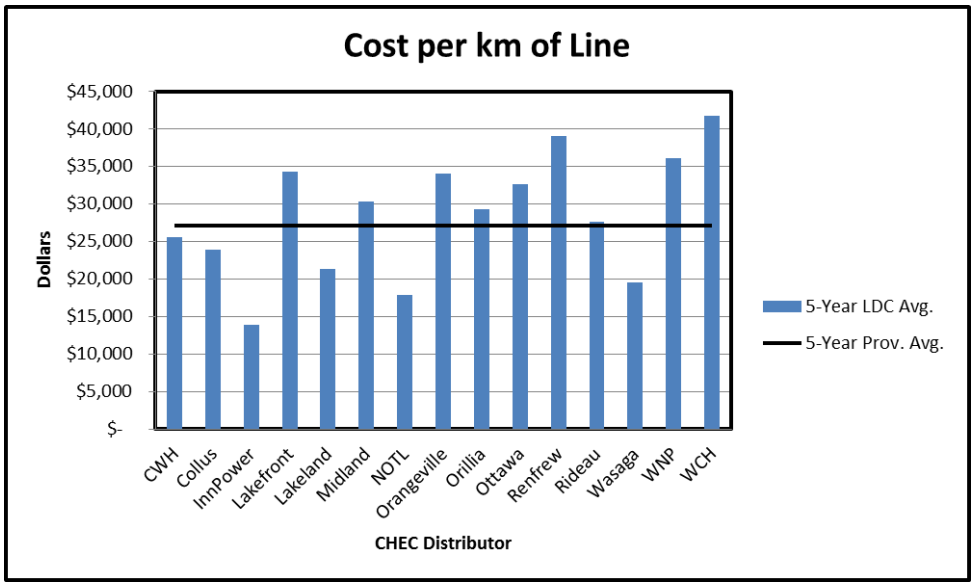
The provincial average of **$613** is an overall decline in performance over the 2013 provincial average of **$599**.

Total Cost per KM of Line:

Total cost per km of line is also a simple calculation whereby "Total Cost" is divided by the number of kilometers of line in a utilities territory. "Total Cost" is determined using a complex statistical calculation (see PEG Report) that facilitates a more accurate cost that is comparable among distributors. The source of the cost and customer data used in the calculations is taken from the distributors reported RRR filings. The OEB did not set a target for this measure.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – For the most part, CHEC utility have kept their cost per km of line relatively stable from 2010 to 2014. There is a variance in cost per km of line across the utilities, which is to be expected as each utility has unique characteristics (i.e.: square kms, customer base, etc.). The spike in West Coast Huron Energy's costs is likely due to increased costs after the tornado incident in 2011. The dip in Midland's 2011 is due to a reporting error on the data (cost per km of line should be $33,305). There is also a gradual increase in trending over the years, which is also expected due to inflationary factors.

Provincial Averages – The provincial averages for this performance measure are as follows:

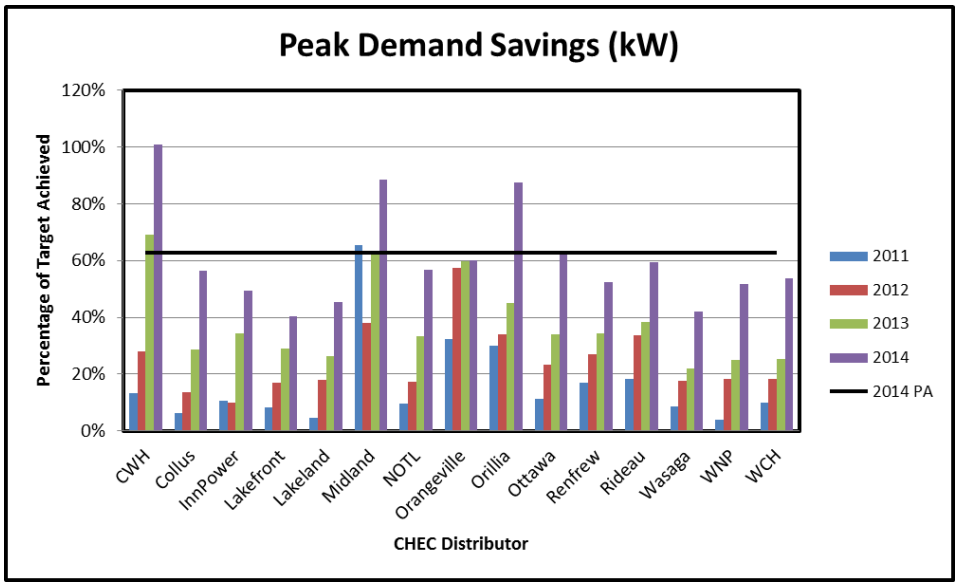
Period	Costs
2010	$25,714
2011	$26,498
2012	$27,234
2013	$27,779
2014	$27,933
5-Year Avg. (2010 – 2014)	**$27,044**

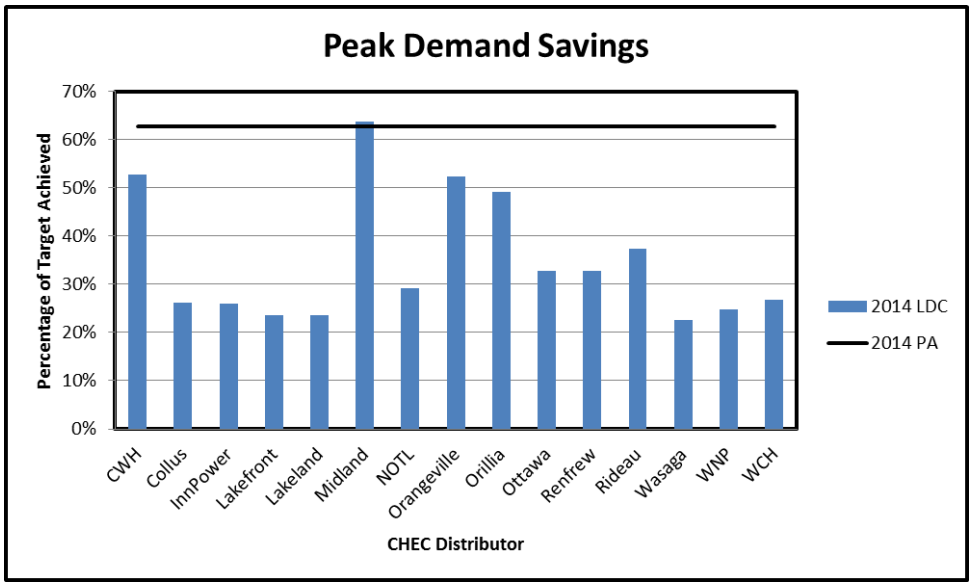
The provincial average of **$27,044** is an overall decline in performance over the 2013 provincial average of **$26,456**.

Peak Demand Savings (kW):

Peak demand savings is simply a record of the demand (MW) reduction from efforts made towards the 2011 – 2014 Conservation and Demand Management (CDM) programs. This information is taken directly from the OPA's reported findings for each distributor. Targets for this measure were established by the OPA and are a condition of the Distributor's license.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – At the time of this report, the 2011 – 2014 CDM programs are now complete. Only 1 of the 15 CHEC utilities (6.66%) met 100% of their peak demand target for 2014. This is somewhat expected as the CHEC utilities are primarily residential based and there are limited opportunities to reduce energy demand with residential customers. However, it should be noted that only 6 out of the 72 provincial utilities (8.33%) made their target for 2014, indicating this was a difficult objective to achieve for many utilities in the province.

Provincial Averages – The provincial averages for this performance measure are as follows:

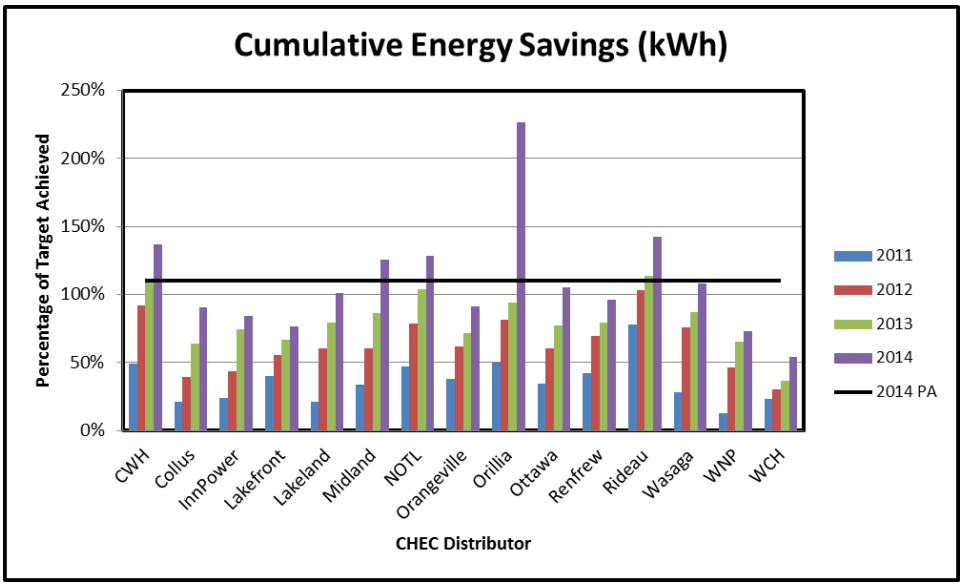
Period	% Target
2011	15.35%
2012	27.13%
2013	41.41%
2014	62.71%
2014	**62.71%**

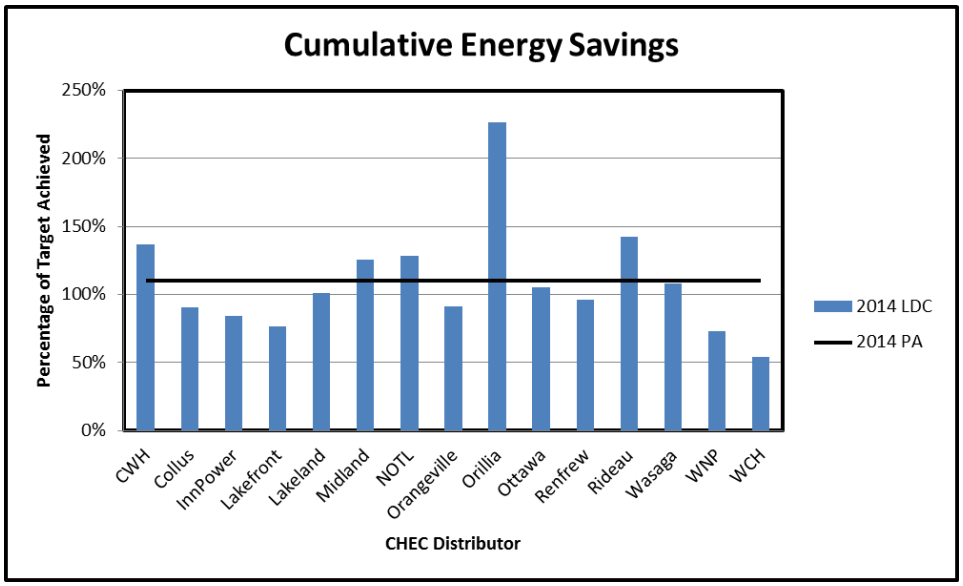
The provincial average of **62.71%** is an overall improvement in performance over the 2013 provincial average of **37.87%**

Cumulative Energy Savings (kWh):

Cumulative energy savings is simply a record of the energy (GWh) reduction from efforts made towards the 2011 – 2014 Conservation and Demand Management (CDM) programs. This information is taken directly from the OPA's reported findings for each distributor. Targets for this measure were established by the OPA and are a condition of the Distributor's license.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – At the time of this report, the 2011 – 2014 CDM programs are now complete. Only 8 out of the 15 CHEC utilities (53.33%) met 100% of their target. Again, this is somewhat expected as the CHEC utilities are primarily residential based and there are few opportunities to reduce energy consumption with residential customers. However, it should be noted that only 41 out of 72 provincial utilities (56.94%) made their target for 2014, indicating this was a difficult objective to achieve for many utilities in the province.

Provincial Averages – The provincial averages for this performance measure are as follows:

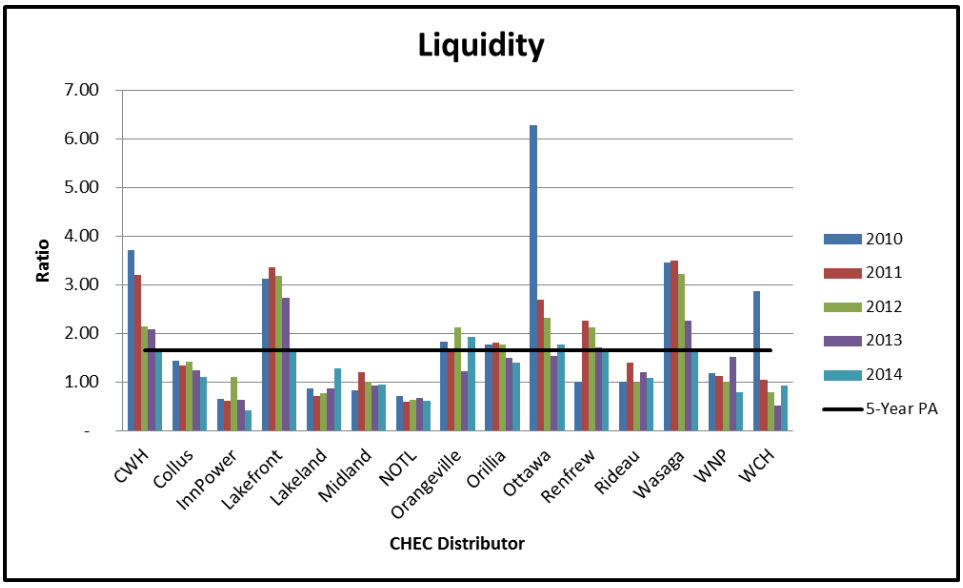
Period	% Target
2011	35.10%
2012	64.53%
2013	87.04%
2014	110.44%
2014	**110.44%**

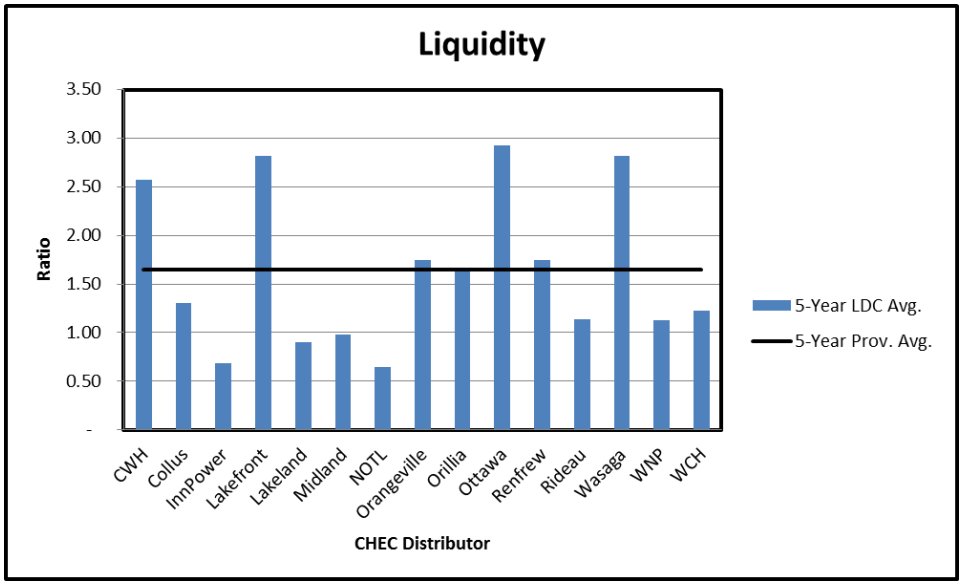
The provincial average of **110.44%** is an overall improvement in performance over the 2013 provincial average of **87.04%**.

Liquidity:

Liquidity is a financial measure of the ability of a debtor to pay their short-term obligations. It is usually expressed as a ratio or a percentage. For this measure, the scorecard utilizes a ratio called "current ratio", which is a simple calculation of current assets / current liabilities. The OEB has not set a target for this measure.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – CHEC utilities current ratios are between 0.41 and 6.29, which for the most part is reasonable for this type of industry. Financially speaking, the higher the number, the more capable the company is of paying its debts. A ratio under 1 suggests that the company would be unable to pay off its obligations if they came due at that point. A ratio over 3 suggests that the company may not be making efficient use of its current assets or its short-term financing facilities.

Provincial Averages – The provincial averages for this performance measure are as follows:

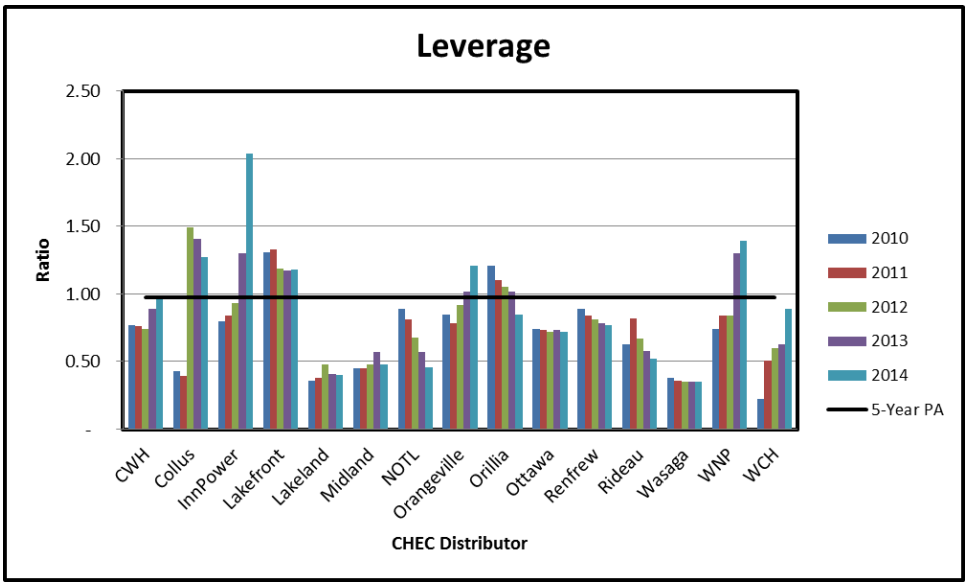
Period	Ratios
2010	1.80
2011	1.89
2012	1.65
2013	1.50
2014	1.43
5-Year Avg. (2010 – 2014)	**1.65**

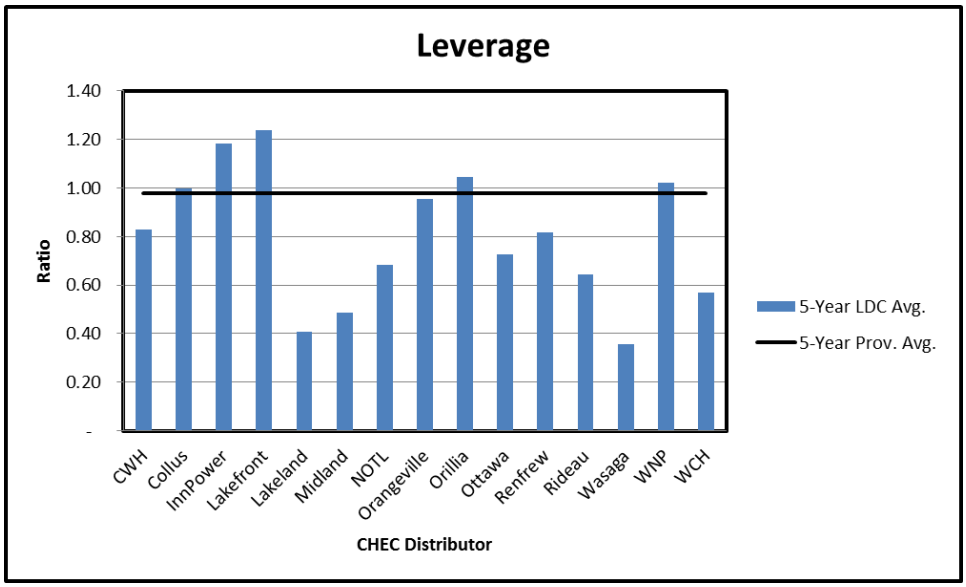
The provincial average of **1.65** is an overall improvement in performance over the 2013 provincial average of **1.74**.

Leverage:

Leverage is a financial measure of the degree to which a company uses debt and equity to finance its assets. It is usually expressed as a ratio. For this measure, the scorecard utilizes a ratio called "Debt to Equity" ratio, which is a simple calculation of Total Liabilities / Shareholder's Equity. The OEB has not set a target for this measure.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – CHEC utilities debt to equity ratios are between 0.22 and 2.04, which for the most part, is reasonable for this type of industry. Financially speaking, the debt to equity ratio depends on the industry in which the company operates. For the electrical distribution industry, the OEB suggests a ratio of 1.5 (60% debt / 40% Equity) is ideal. Actual ratios will depend on each individual utility's specific circumstances.

Provincial Averages – The provincial averages for this performance measure are as follows:

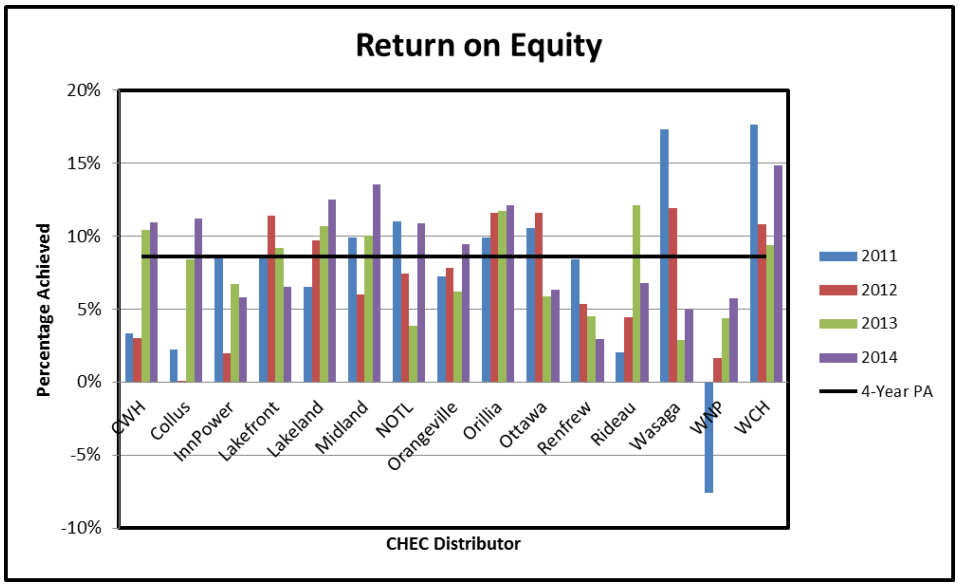
Period	Ratios
2010	0.96
2011	0.98
2012	1.04
2013	0.94
2014	0.97
5-Year Avg. (2010 – 2014)	**0.98**

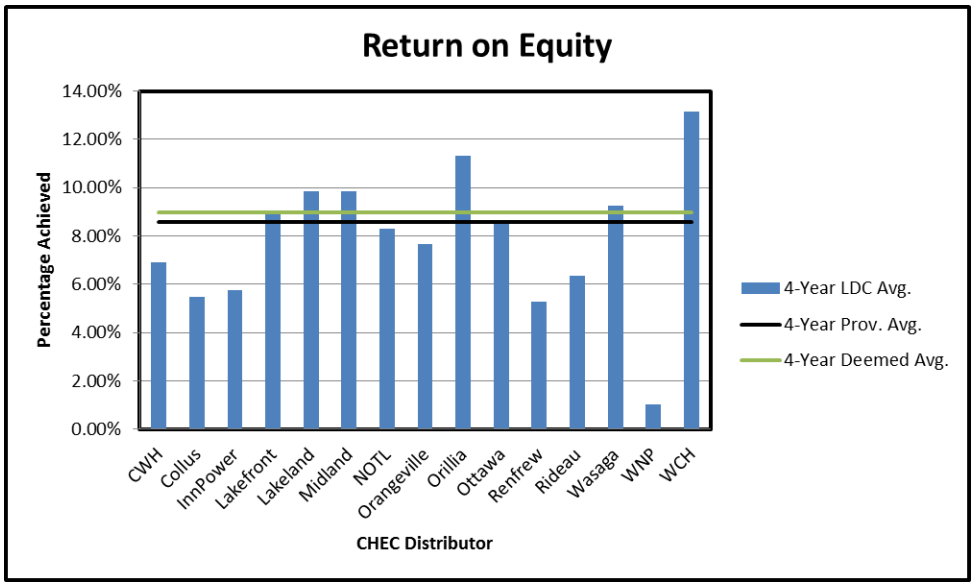
The provincial average of **0.98** is an overall improvement in performance over the 2013 provincial average of **0.97**.

Return on Equity:

Return on Equity (ROE) is a financial measure used to indicate the profitability of the company and to compare that to other firms in the same industry. It is usually expressed as a percentage. Return on Equity is a simple calculation of Net Income / Shareholder's Equity. The OEB has not set a target for this measure.

The following charts depict how well the CHEC Group meets this requirement from 2010 – 2014:





Analysis – CHEC utility's Return on Equity percentages are between 0.10% and 17.62%, which for the most part, is reasonable for this industry. Return on Equity measures a corporation's profitability by revealing how much profit a company generates with the money shareholders have invested. For the electrical distribution industry, the OEB typically requires utilities to maintain its Return on Equity percentage between 9.0% and 9.5% for recent years. Actual ratios will depend on each individual utility's specific circumstances.

Provincial Averages – The provincial averages for this performance measure are as follows:

Period	Percentages
2011	7.77%
2012	6.79%
2013	9.41%
2014	10.35%
4-Year Avg. (2011 – 2014)	**8.58%**

Deemed Averages – The deemed averages for this performance measure are as follows:

Period	Percentages
2011	8.78%
2012	8.86%
2013	9.14%
2014	9.33%
4-Year Avg. (2011 – 2014)	**8.98%**

The provincial average of **8.58%** is an overall increase from the 2013 provincial average of **8.07%**. The deemed average of **8.98%** is an overall increase from the 2013 deemed average of **8.86**%

Part II – CHEC / Provincial Analysis:

The second part of this analysis is a comparison of the CHEC utilities average against the Provincial utility average. Please note that only select performance measures are being assessed, as not all performance measures are being monitored and/or tracked at this time. Some measures are still under development. Of those available performance measures, the following have been included in the analysis:

- **Customer Focus:**
  - New Residential Services Connected on Time
  - Scheduled Appointments Met on Time
  - Telephone Calls Answered on Time
  - Billing Accuracy

- **Operational Effectiveness:**
  - Efficiency Assessment (PEG)
  - Average Number of Hours that Power to a Customer is Interrupted
  - Average Number of Times that Power to a Customer is Interrupted

- **Public Policy Responsiveness:**
  - Net Annual Peak Demand Savings (Percent of Target Achieved)
  - Net Cumulative Energy Savings (Percent of Target Achieved)

- **Financial Performance:**
  - Liquidity: Current Ratio
  - Leverage: Debt to Equity Ratio
  - Regulated Return on Equity

Analysis & Graphical Breakdown:

The second part of the analysis involves the comparison of the CHEC group average against the provincial average as a whole. The intention here is to provide some insights as to how the CHEC Group is performing compared to how the province is performing.

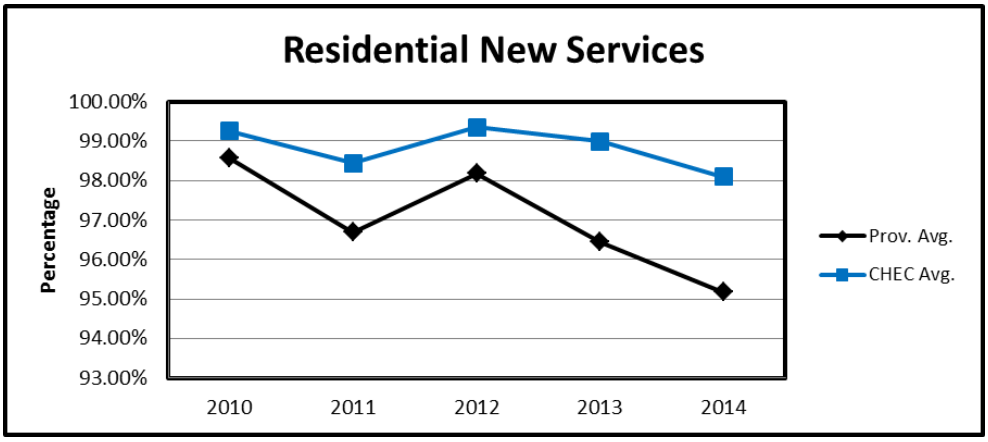
As distributors gain experience under the scorecard approach, it is expected that the Scorecard will also evolve over time. CHEC will monitor any refinements and improvements to the Scorecard on an ongoing basis to ensure they are incorporated into this analysis. Details will be documented to ensure substantial changes are identified as the analysis evolves.

Please Note: Hydro One Networks has been excluded from this analysis. It is likely that including Hydro One Networks would skew the overall results due to the unique nature of the organization.

Residential New Services Connected on Time:

Residential New Services refers to Low Voltage Services, which is a connection for a new service request for a voltage <750 volts, that must be completed within 5 business days or at such a later date as agreed to by the customer and distributor. It can also refer to High Voltage Services, which is a connection for new services for a voltage >750 volts, that must be completed within 10 business days or at such a later date as agreed to by the customer and distributor. It is assumed that there is a mixture of Low and High Voltage services across the province, with the focus on Low Voltage services. The OEB expects this service quality requirement to be met at least 90 percent of the time on a yearly basis.

The following chart depicts how well the CHEC Group compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part CHEC utilities are better at meeting this requirement than their provincial counterparts, although both the CHEC and provincial averages are above the required OEB target. The difference in averages is a reflection of the efficiencies within a utilities process for establishing residential new connections.

Averages – The averages for this performance measure are as follows:

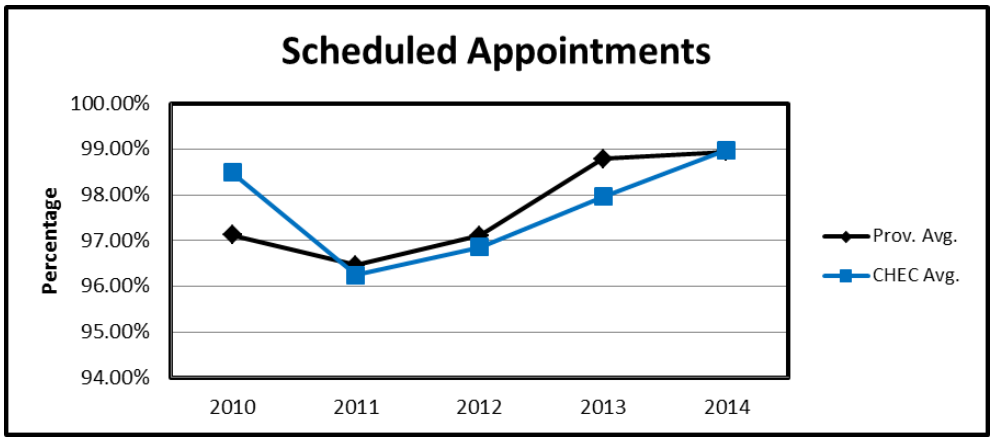
Period	CHEC Avg. %	Prov. Avg. %
2010	99.25%	98.56%
2011	98.44%	96.69%
2012	99.35%	98.17%
2013	98.99%	96.44%
2014	98.10%	95.17%
5-Year Avg. (2010 – 2014)	**98.83%**	**97.01%**

Please Note: Both the CHEC 5Y averages (**98.83% – 2014, 98.91% – 2013**) and the provincial 5Y averages (**97.01% – 2014, 97.40% – 2013**) are showing a decline in performance from 2013 to 2014.

Scheduled Appointments Met on Time:

Appointments Met refers to any appointment where the customer's presence is required. The distributor must arrive for the appointment within the scheduled timeframe, which is either an AM (8:00 am – 12:00 pm) or PM (1:00 pm – 5:00 pm) appointment. Appointments where the distributor arrives at the scheduled appointment within the required time period but the appointment cannot be met because the customer failed to attend can be excluded. The OEB expects this service quality requirement to be met at least 90 percent of the time on a yearly basis.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For 2010, the CHEC utilities are better at meeting this requirement than their provincial counterparts. Although this trend reverses in 2011, it reverses again in 2014 whereby the CHEC utilities once again out perform their provincial counterparts. Again, both the CHEC and provincial averages are above the required OEB target. The difference in averages is a reflection of the efficiencies within a utilities process for meeting scheduled appointments.

Averages – The averages for this performance measure are as follows:

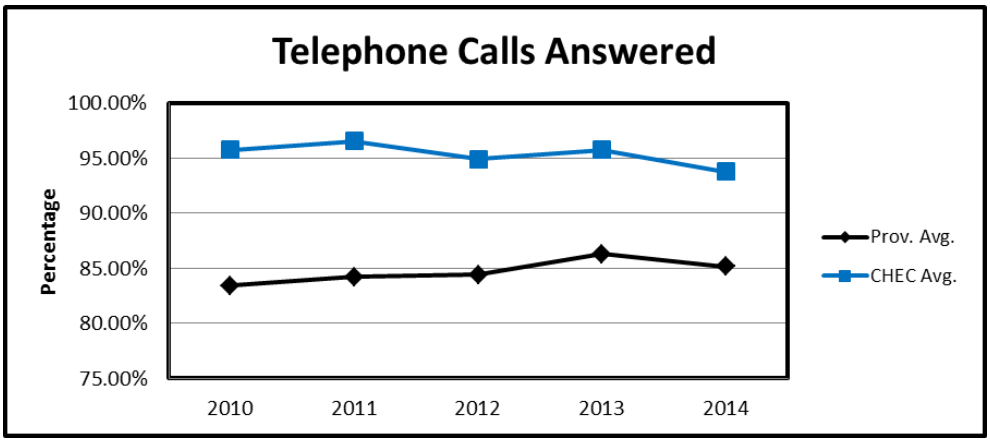
Period	CHEC Avg. %	Prov. Avg. %
2010	98.49%	97.12%
2011	96.24%	96.46%
2012	96.86%	97.11%
2013	97.95%	98.79%
2014	98.98%	98.95%
5-Year Avg. (2010 – 2014)	**97.70%**	**97.69%**

Please Note: Both the CHEC 5Y averages (**97.70% – 2014, 98.91% – 2013**) and the provincial 5Y averages (**97.69 – 2014, 97.42% – 2013**) are showing a decline in performance from 2013 to 2014.

Telephone Calls Answered on Time:

Telephone Calls Answered refers to ensuring qualified incoming calls (calls that are received during regular hours) to the distributors' customer care telephone numbers are answered within 30 seconds. For qualified incoming calls that are transferred from the distributor's IVR system, the 30 seconds shall be counted from the time the customer selects to speak to a customer service representative. In all other cases, the 30 seconds shall be counted from the first ring. The OEB expects this service quality requirement to be met at least 65 percent of the time on a yearly basis.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – The CHEC utilities are better at meeting this requirement than their provincial counterparts over the same period, although both averages are well above the OEB target requirement of 65%. The difference in averages is a reflection of the efficiencies within a utility's process for answering telephone calls on time.

Averages – The averages for this performance measure are as follows:

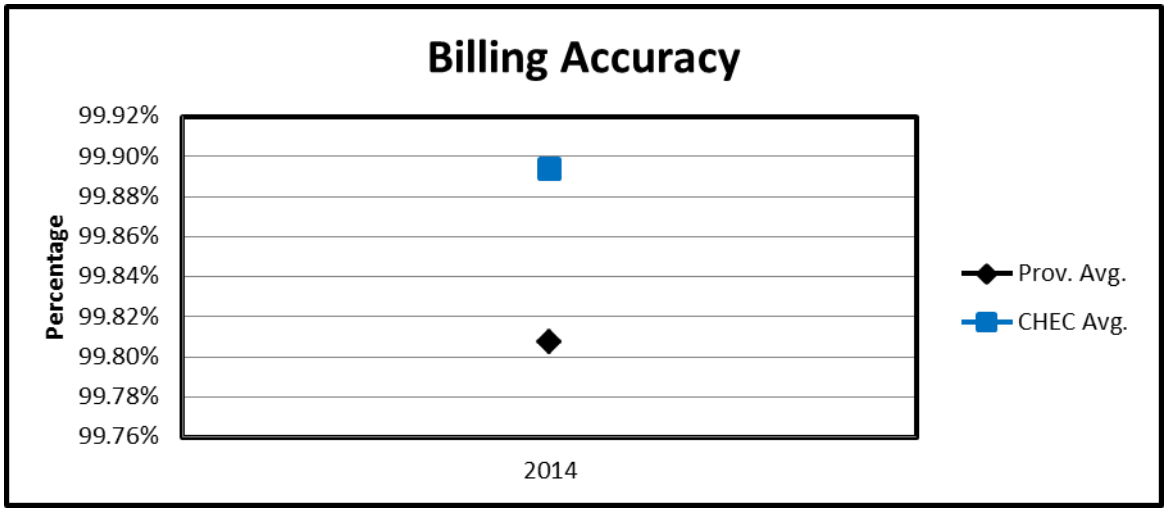
Period	CHEC Avg. %	Prov. Avg. %
2010	95.73%	83.41%
2011	96.51%	84.22%
2012	94.89%	84.39%
2013	95.73%	86.30%
2014	93.75%	85.15%
5-Year Avg. (2010 – 2014)	**95.32%**	**84.69%**

Please Note: The CHEC 5Y averages (**95.32% – 2014, 96.48% – 2013**) is showing a decline in performance while the provincial 5Y averages (**84.69% – 2014, 84.69% – 2013**) remains unchanged from 2013 to 2014.

Billing Accuracy:

Billing Accuracy is a new measure to the Scorecard for 2014. Distributors are required to implement and start tracking the billing accuracy measure effective on October 1, 2014. The measure is defined as the accurate bills issued expressed as a percentage of total bills issued. Bills are considered accurate if it contains correct meter readings, customer information and rates, which results in an accurately calculated bill. A bill is considered inaccurate if a bill has been issued to a customer and is subsequently cancelled due to a billing error and/or adjustment. The OEB has set a minimum industry-wide billing accuracy performance target of 98%.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – As this is a new measure, only data for 2014 is available. Overall, CHEC did better than the provincial average for this performance measure. Use caution with this measure as this is the first year for the Billing Accuracy measure and only 3 months' worth of data were tracked and reported by the utilities. Results may vary as experience is gained with this performance measure.

Averages – The averages for this performance measure are as follows:

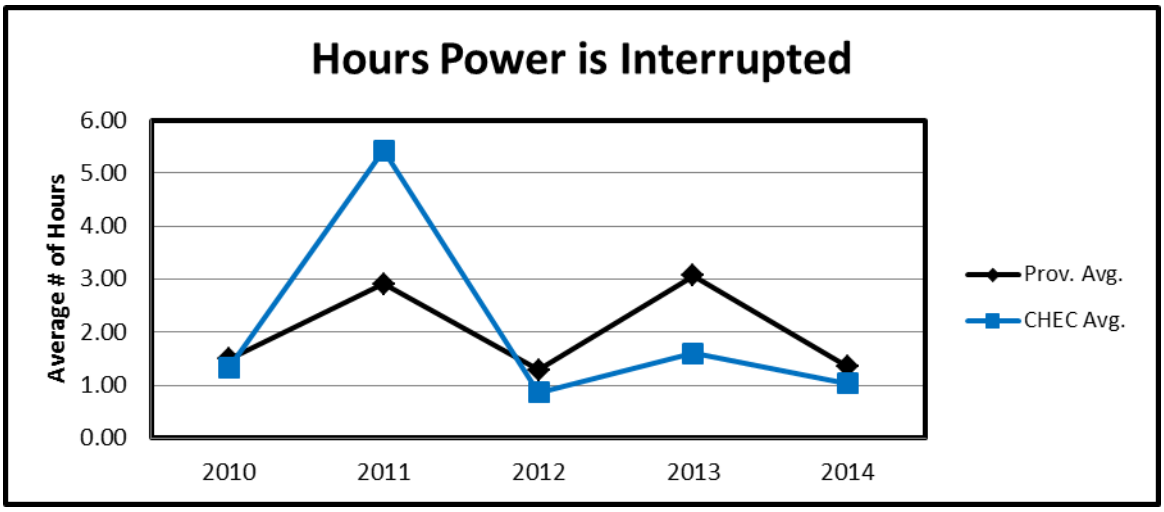
Period	CHEC Avg. %	Prov. Avg. %
2014	99.89%	99.81%
2014	**99.89%**	**99.81%**

Please Note: There is no data for 2013, therefore conclusions can only be drawn for 2014 (see analysis section above).

Hours Power is Interrupted:

Hours power is interrupted is an indicator of system reliability that expresses the average amount of time, per reporting period, supply to a customer is interrupted. There is no official OEB target for this measure but ideally the goal is to strive for zero hours of uninterrupted power to the end customer.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part, the CHEC utilities tended to fare better than the provincial average. 2011 was an issue, which was primarily due to the tornado that hit West Coast Huron Energy. The spikes in 2013 are likely due to the ice storm issues that occurred that year, which affected both the CHEC and provincial averages. The difference in averages can be somewhat attributed to a utilities response time and experience with respect to power outages.

Averages – The averages for this performance measure are as follows:

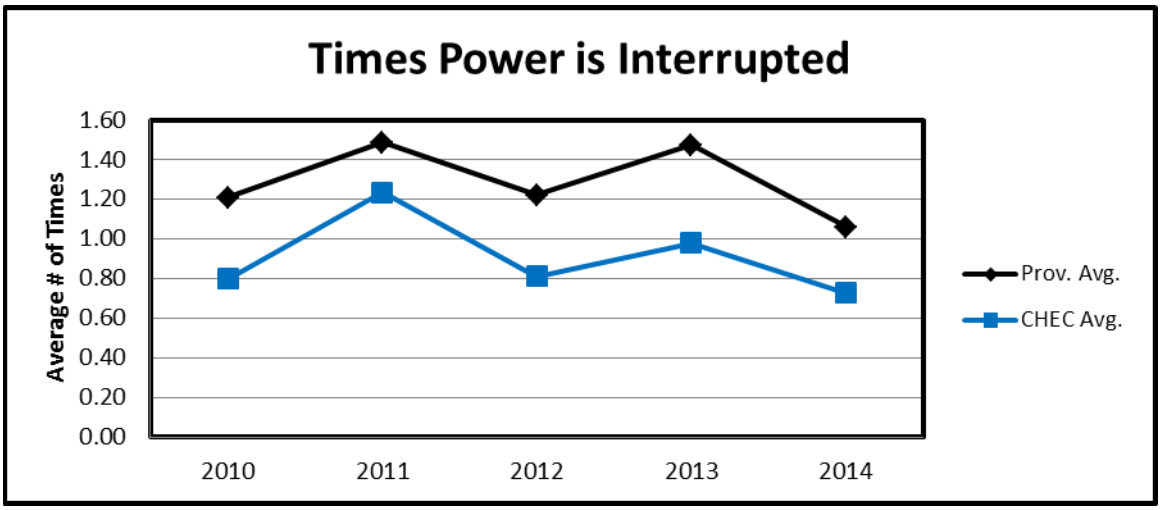
Period	CHEC Avg. Hours	Prov. Avg. Hours
2010	1.32	1.49
2011	5.43	2.91
2012	0.86	1.28
2013	1.60	3.06
2014	1.03	1.34
5-Year Avg. (2010 – 2014)	**2.05**	**2.02**

Please Note: The CHEC 5Y averages (**2.05 – 2014, 1.96 – 2013**) are showing a decline in performance while the provincial 5Y averages (**2.02 – 2014, 2.08 – 2013**) are showing an improvement in performance from 2013 to 2014.

Times Power is Interrupted:

Times power is interrupted is also an indicator of system reliability that expresses the number of times per reporting period that the supply to a customer is interrupted. It is determined by dividing the total number of interruptions experienced by all customers, by the average number of customers served. Again, there is no official OEB target for this measure but ideally the goal is to strive for zero times of interrupted power to the end customer.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part, interrupted power for the CHEC utilities was limited to less than 1 occurrence per utility, while the provincial utilities average was slightly higher than that for the period 2010 – 2014. The fact that both averages have similar trending would indicate the same factors (i.e.: weather, etc.) are at play across most utilities with respect to interrupted power. The differences in averages can be somewhat attributed to how well a utility maintains it assets.

Averages – The averages for this performance measure are as follows:

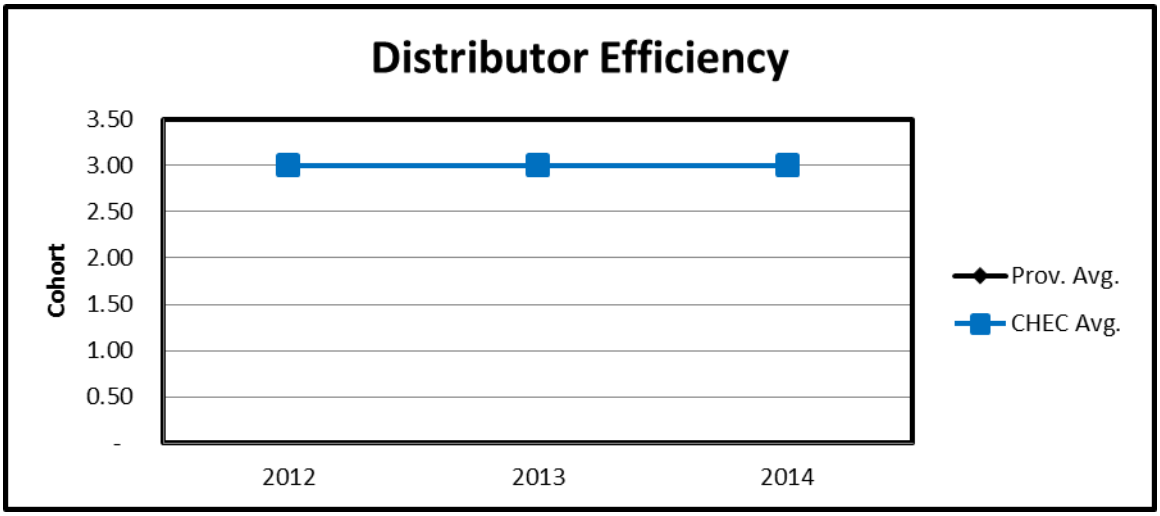
Period	CHEC Avg. Times	Prov. Avg. Times
2010	0.80	1.21
2011	1.24	1.49
2012	0.81	1.22
2013	0.98	1.47
2014	0.73	1.06
5-Year Avg. (2010 – 2014)	**0.91**	**1.29**

Please Note: The CHEC 5Y averages (**0.91 – 2014, 0.93 – 2013**) and the provincial 5Y averages (**1.29 – 2014, 1.33 – 2013**) are showing an improvement in performance from 2013 to 2014.

Distributor Efficiency:

Distributor efficiency is a performance measure whereby utilities are assigned to various cohorts ranked from 5 (being the worst) to 1 (being the best). Cohort assignments are based on the results of a statistical cost benchmarking study designed to make inferences about a utility's cost efficiency. An econometric model is used to predict the level of cost associated with each distributor's operating conditions. Distribution for this measure is considered to be a normal distribution whereby utilities are distributed across a bell curve. Distributors whose actuals costs were lower than costs predicted by the model are assigned a lower cohort (e.g.: cohort 2 or cohort 1).

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2012 – 2013:



Analysis – For the most part, CHEC utilities follow the same normal distribution curve as the provincial utilities. This translates to an average cohort of 3 for both the CHEC group and the provincial utilities over the period 2012 - 2014. Differences on this performance measure will only be seen if as a whole, the CHEC group were to be contained within a higher cohort (4 & 5) or a lower cohort (1 &2).

Averages – The averages for this performance measure are as follows:

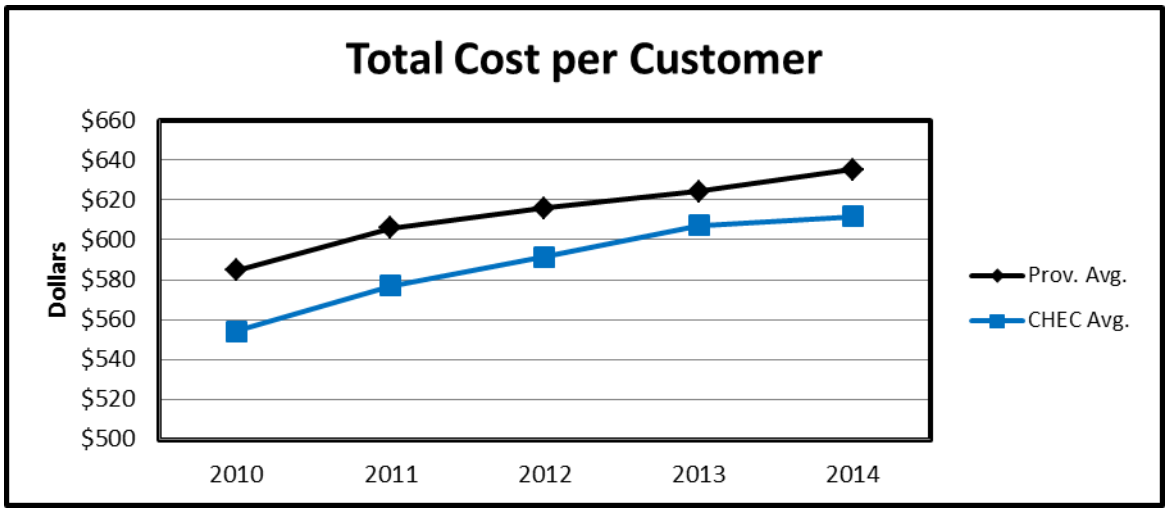
Period	CHEC Avg. Cohorts	Prov. Avg. Cohorts
2012	3	3
2013	3	3
2014	3	3
3-Year Avg. (2012 – 2014)	**3**	**3**

Please Note: The CHEC 3Y averages (**3 – 2014, 3 – 2013**) and the provincial 3Y averages (**3 – 2014, 3 – 2013**) remain unchanged for the period 2013 to 2014.

Total Cost per Customer:

Total cost per customer is a simple calculation whereby "Total Cost" is divided by the number of customers in a utilities territory. "Total Cost" is determined using a complex statistical calculation (see PEG Report) that facilitates a more accurate cost that is comparable among distributors. The source of the cost and customer data used in the calculations is taken from the distributors reported RRR filings. The OEB did not set a target for this measure.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part, CHEC utilities have kept their cost per customer relatively stable from 2010 to 2014. The provincial average is similar but higher than the CHEC average, which is likely to be influenced by factors such as territorial density, underground versus overhead configurations, and a utilities asset maintenance policy. The gradual increase in trending over the years is expected due to inflationary factors.

Averages – The averages for this performance measure are as follows:

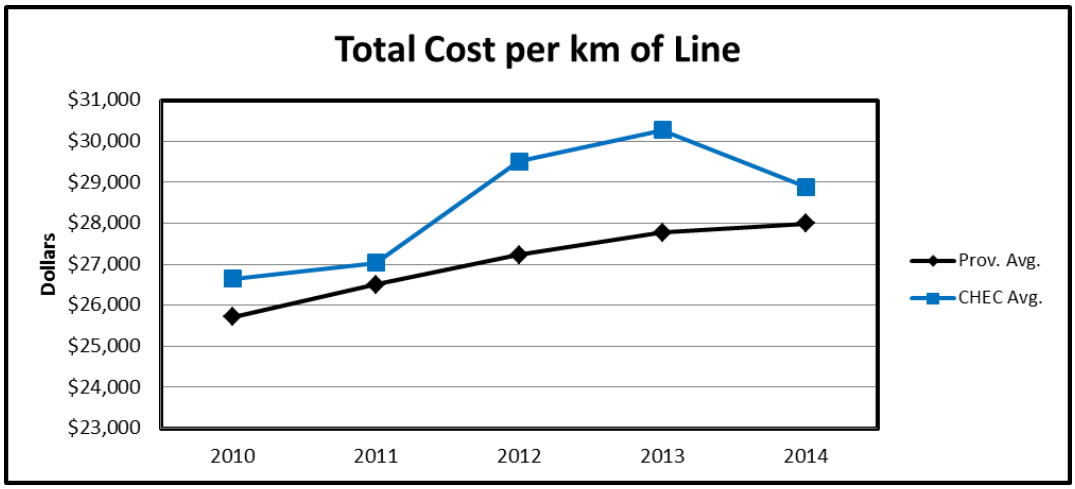
Period	CHEC Avg. Costs	Prov. Avg. Costs
2010	$554	$585
2011	$577	$606
2012	$592	$616
2013	$607	$624
2014	$612	$635
5-Year Avg. (2010 – 20143)	**$588**	**$613**

Please Note: The CHEC 5Y averages (**$588 – 2014, $562 – 2013**) and the provincial 5Y averages (**$613 – 2014, $599 – 2013**) are showing a decline in performance from 2013 to 2014.

Total Cost per KM of Line:

Total cost per km of line is also a simple calculation whereby "Total Cost" is divided by the number of kilometers of line in a utilities territory. "Total Cost" is determined using a complex statistical calculation (see PEG Report) that facilitates a more accurate cost that is comparable among distributors. The source of the cost and customer data used in the calculations is taken from the distributors reported RRR filings. The OEB did not set a target for this measure.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part, both the CHEC average and the provincial average are relatively stable from 2010 – 2014. The CHEC average is similar but higher than the provincial average, which is also likely to be influenced by factors territorial density, underground versus overhead configurations, and a utilities asset maintenance policy. There is also a gradual increase in trending over the years, which is also expected due to inflationary factors.

Averages – The averages for this performance measure are as follows:

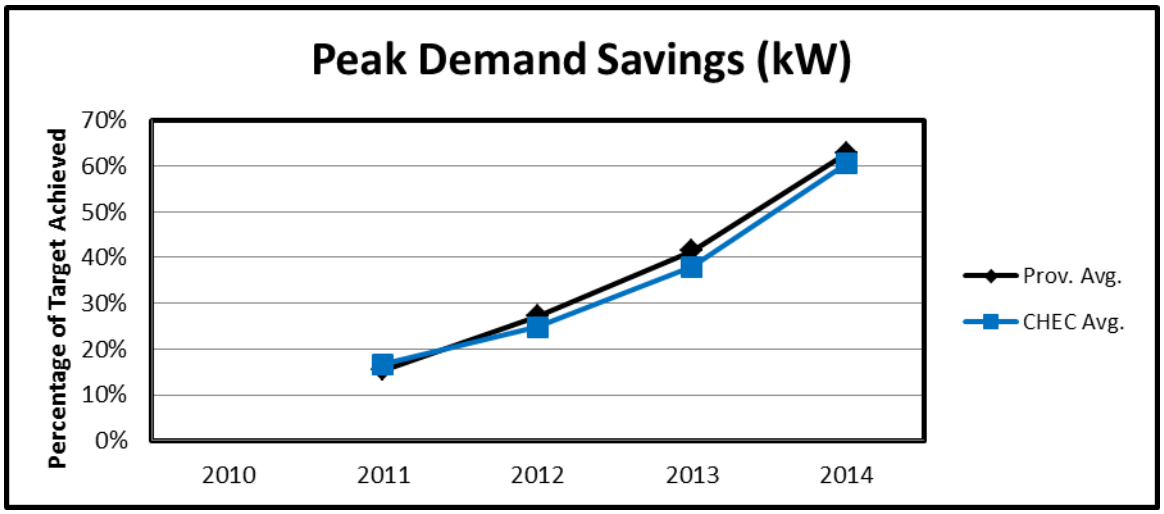
Period	CHEC Avg. Costs	Prov. Avg. Costs
2010	$26,649	$25,714
2011	$27,030	$26,498
2012	$29,503	$27,234
2013	$30,273	$27,779
2014	$38,883	$27,993
5-Year Avg. (2009 – 2013)	**$28,468**	**$27,044**

Please Note: The CHEC 5Y averages (**$28,468 – 2014, $28,687 – 2013**) are showing an improvement in performance while the provincial 5Y averages (**$27,044 – 2014, $26,456 – 2013**) are showing a decline in performance from 2013 to 2014.

Peak Demand Savings:

Peak demand savings is simply a record of the demand (MW) reduction from efforts made towards the 2011 – 2014 Conservation and Demand Management (CDM) programs. This information is taken directly from the OPA's reported findings for each distributor. Targets for this measure were established by the OPA and are a condition of the Distributor's license.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part, both the CHEC and provincial utilities are below their required targets. This is somewhat expected for the CHEC utilities as they are primarily residential based and there are limited opportunities to reduce energy demand with residential customers. The provincial utilities are trending slightly higher than the CHEC utilities, which is expected as the provincial utilities include the larger utilities where there is more opportunity for demand savings. For the 2014 Scorecard, Peak Demand savings were revised so that more of a trending pattern is now evident.

Averages – The averages for this performance measure are as follows:

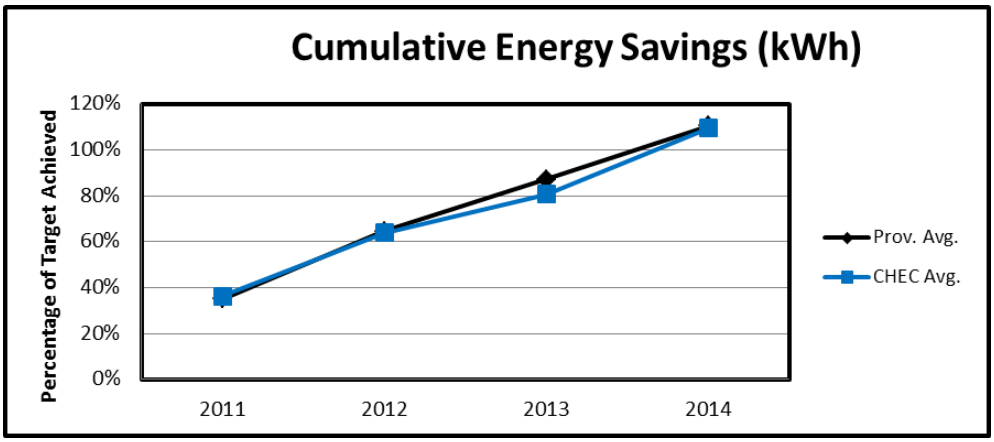
Period	CHEC % Target	Prov. % Target
2011	16.63%	15.35%
2012	24.79%	27.13%
2013	37.87%	41.41%
2014	60.43%	62.71%
2014	**60.43%**	**62.71%**

Please Note: The CHEC 2014 averages (**60.43% – 2014, 19.58% – 2013**) and the provincial 2014 averages (**62.71% – 2014, 23.21%– 2013**) are showing an improvement towards target from 2013 to 2014.

Cumulative Energy Savings:

Cumulative energy savings is simply a record of the energy (GWh) reduction from efforts made towards the 2011 – 2014 Conservation and Demand Management (CDM) programs. This information is taken directly from the OPA's reported findings for each distributor. Targets for this measure were established by the OPA and are a condition of the Distributor's license.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – On average, both the CHEC and provincial utilities have met their required OEB targets, although individually, approximately 50% of all utilities in the province have failed to meet their specified target. This is somewhat expected for the CHEC utilities as they are primarily residential based and there are limited opportunities to reduce energy consumption with residential customers. The provincial utilities are trending slightly higher, which is also expected as the provincial utilities include the larger utilities where there is more opportunity for energy savings. The trending here is steadily increasing year after year, which is to be expected as energy savings are cumulative for 2011 – 2014.

Averages – The averages for this performance measure are as follows:

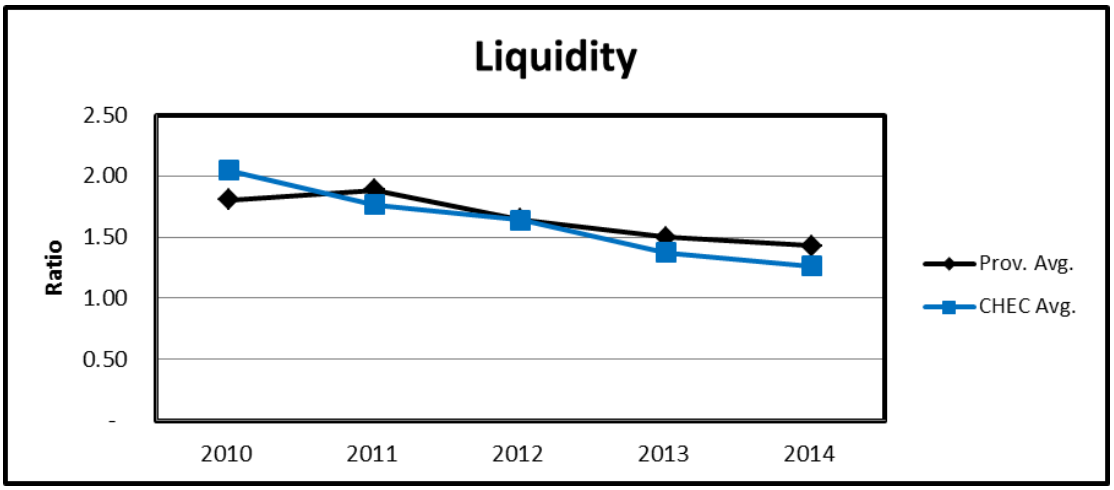
Period	CHEC % Target	Prov. % Target
2011	36.30%	35.10%
2012	63.88%	64.53%
2013	80.66%	87.04%
2014	109.37%	110.44%
2014	**109.37%**	**110.44%**

Please Note: The CHEC 2014 averages (**109.37% – 2014, 79.02% – 2013**) and the provincial 2014 averages (**110.44% – 2014, 87.05% – 2013**) are showing an improvement towards target from 2013 to 2014.

Liquidity:

Liquidity is a financial measure of the ability of a debtor to pay their short-term obligations. It is usually expressed as a ratio or a percentage. For this measure, the scorecard utilizes a ratio called "current ratio", which is a simple calculation of current assets / current liabilities. The OEB has not set a target for this measure.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part, both the CHEC utilities (~2.1 in 2010, decreasing to ~1.3 in 2014) and the provincial utilities (~1.8 in 2010, decreasing to ~1.4 in 2014) average current ratio are similar, which is typical for this type of industry, particularly for the latter years. Financially speaking, the higher the number, the more capable the company is of paying its debts. A ratio under 1 suggests that the company would be unable to pay off its obligations if they came due at that point. A ratio over 3 suggests that the company may not be making efficient use of its current assets or its short-term financing facilities.

Averages – The averages for this performance measure are as follows:

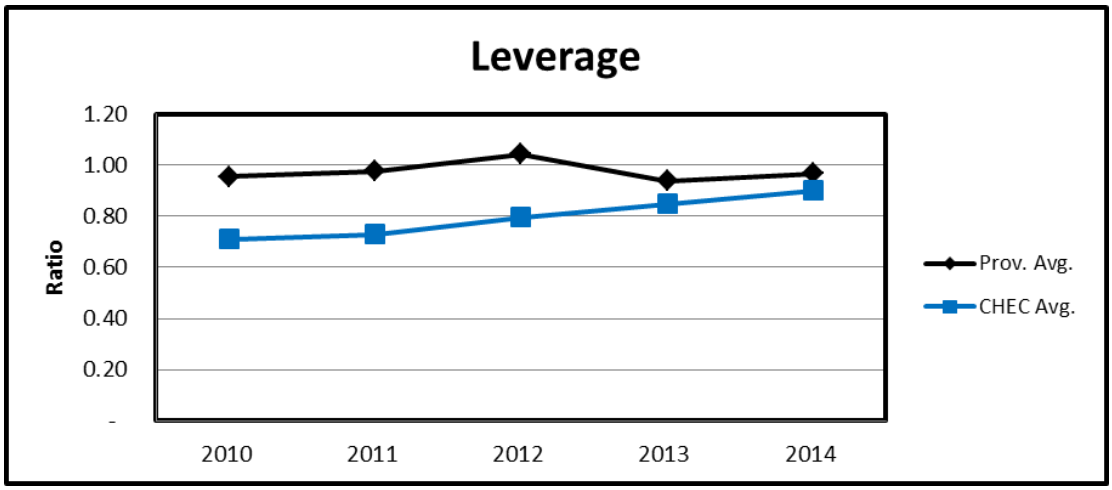
Period	CHEC Avg. Ratios	Prov. Avg. Ratios
2009	2.05	1.80
2010	1.77	1.89
2011	1.64	1.65
2012	1.38	1.50
2013	1.26	1.43
5-Year Avg. (2009 – 2013)	**1.62**	**1.65**

Please Note: The CHEC 5Y averages (**1.62 – 2014, 1.88 – 2013**) and the provincial 5Y averages (**1.65 – 2014, 1.74 – 2013**) are showing an improvement in performance from 2013 to 2014.

Leverage:

Leverage is a financial measure of the degree to which a company uses debt and equity to finance its assets. It is usually expressed as a ratio. For this measure, the scorecard utilizes a ratio called "Debt to Equity" ratio, which is a simple calculation of Total Liabilities / Shareholder's Equity. The OEB has not set a target for this measure.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part, CHEC utilities debt to equity ratios (0.71 in 2010, increasing to 0.90 in 2014) are below the provincial average (0.96 in 2010, increasing to 0.97 in 2014), which is reasonable for this type of industry. Financially speaking, the debt to equity ratio depends on the industry in which the company operates. For the electrical distribution industry, the OEB suggests a ratio of 1.5 (60% debt / 40% Equity) is ideal. Actual ratios will depend on each individual utility's specific circumstances.

Averages – The averages for this performance measure are as follows:

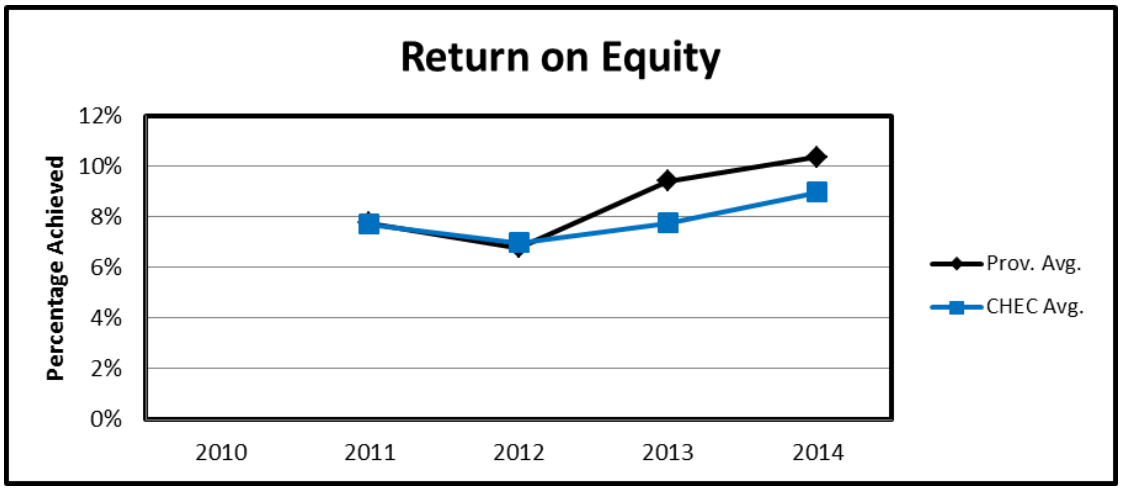
Period	CHEC Avg. Ratios	Prov. Avg. Ratios
2010	0.71	0.96
2011	0.73	0.98
2012	0.80	1.04
2013	0.85	0.94
2014	0.90	0.97
5-Year Avg. (2010 – 2014)	**0.80**	**0.98**

Please Note: The CHEC 5Y averages (**0.80 – 2014, 0.74 – 2013**) and the provincial 5Y averages (**0.98 – 2014, 0.97 – 2013**) are showing an improvement in performance from 2013 to 2014.

Return on Equity:

Return on Equity (ROE) is a financial measure used to reflect the profitability of the company and to compare that to other firms in the same industry. It is usually expressed as a percentage. Return on Equity is a simple calculation of Net Income / Shareholder's Equity. The OEB has not set a target for this measure.

The following chart depicts how well the CHEC Group average compares to the provincial average for the years 2010 – 2014:



Analysis – For the most part, CHEC utility's Return on Equity percentages (7.72% in 2011, 6.99% in 2012, 7.75% in 2013, and 8.97% in 2014) are similar to the provincial averages (7.77% in 2011, 6.79% in 2012, 9.41% in 2013, and 10.35% in 2014), except for 2013 and 2014, where the provincial average is somewhat higher. Return on Equity measures a corporation's profitability by revealing how much profit a company generates with the money shareholders have invested. For the electrical distribution industry, the OEB typically requires utilities to maintain its Return on Equity percentage between 9.0% and 9.5% for recent years. Actual ratios will depend on each individual utility's specific circumstances.

Averages – The averages for this performance measure are as follows:

Period	CHEC Avg. %	Prov. Avg. %	Deemed Avg. %
2011	7.72%	7.77%	8.78%
2012	6.99%	6.79%	8.86%
2013	7.75%	9.41%	9.14%
2014	8.97%	10.35%	9.13%
4-Year Avg. (2011 – 2014)	**7.86%**	**8.58%**	**8.98%**

Please Note: The CHEC 4Y averages (**7.86% – 2014, 7.46% – 2013**) and the provincial 4Y averages (**8.58% – 2014, 8.07% – 2013**) are showing an improvement in performance from 2013 to 2014.

Conclusions:

CHEC Analysis – For the CHEC Analysis, CHEC Distributors were compared to one another for the outcomes of customer focus (service quality), operational effectiveness (cost control), public policy responsiveness (conservation and demand management), and financial performance (financial ratios). For the most part, it was determined that CHEC Distributors are very similar in terms of performance and productivity. The few anomalies that were identified were also easily explained and there were no areas of major concern among the group.

Provincial Analysis - For the Provincial Analysis, CHEC Distributors were compared to Provincial distributors for the outcomes of customer focus (service quality), operational effectiveness (cost control), public policy responsiveness (conservation and demand management), and financial performance (financial ratios). For the most part, it was determined that CHEC Distributors were similar or better than the Provincial Distributors in terms of performance and productivity. The few anomalies that were identified were also easily explained and there were no areas of major concern.

Based on the above analyses, the CHEC Distributors are still considered to be some of the better performing utilities among the province today. However, it is the OEB's expectation that all distributors remain committed to continuous improvement in the electrical sector through achievement of benchmark performance on valued services and/or processes over time. As a result, it is expected that this document will be updated annually to reflect the latest Scorecard data in an effort to monitor distributor performance over time.

Appendixes:

Ontario Energy Board (2014). *Performance Measurement for Electricity Distributors: A Scorecard Approach.* 1 – 58. Retrieved from http://www.ontarioenergyboard.ca/oeb/Industry/Rules%20and%20Requirements/Electricity%20Distributor%20Scorecards

Ontario Energy Board (2015, September). *Electricity Distributor Scorecards.* Retrieved from http://www.ontarioenergyboard.ca/oeb/Industry/Rules%20and%20Requirements/Electricity%20Distributor%20Scorecards/2014%20Distributor%20Scorecards

APPENDIX K: InnPower Corporation Five Year Business Plan



InnPower Corporation
Business Plan 2016

for years 2016 to 2020

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1. Executive Summary

The Hydro Electric Commission of the Corporation of the Town of Innisfil was created in January 1991 as provided for in Bill 177 (1990). It continued to serve only the former Village of Cookstown until 1993 when the distribution assets in the remainder of the newly incorporated Town of Innisfil were purchased from Ontario Hydro. Innisfil Hydro Distribution Systems Limited (Innisfil Hydro) was incorporated as a for-profit local distribution company in year 2000 as required by the *Electricity Act 1998*. Innisfil Hydro has a distribution licence from the Ontario Energy Board (Licence # ED-2002-0520 defined boundary as the Town of Innisfil as of January 1, 1994) to operate its distribution system within the licensed territory of 292 square kilometres in the Town of Innisfil and the south part of the City of Barrie with the passing of *Bill 196, Barrie-Innisfil Boundary Adjustment Act, 2009*.

In January 2015, Innisfil Hydro changed its name to InnPower Corporation and relocated its Head Office and Operations Centre to the Innisfil Town Campus, where InnPower and the Town Roads and Parks divisions are establishing an operational hub whereby operational synergies will benefit both taxpayers and power users. The Head Office and Operations Centre is located at 7251 Yonge Street, Innisfil, Ontario with 37 full-time and 2 part-time staff. The building is LEED certified through the Canadian Green Building Council, with five charging stations for electric cars. The total cost for this project was $13m.

As of April 2014, InnPower had approximately 292 kilometres of 44KV circuits, 398 kilometres of three-phase distribution, 420 kilometres of single-phase circuits, 168 kilometres of primary underground cable, nine (9) distribution stations, two (2) shared distribution stations with Hydro One and four (4) private stations with distribution voltages of 16/27.6kV and 4.8/8.32kV.

InnPower has five (5) “in-house” Linemen and associated equipment. Major construction projects and substation maintenance is contracted out to independent contractors. A service agreement was negotiated with the Town of Innisfil in order for InnPower to apply water and wastewater billing onto the existing monthly Hydro bills starting August 1, 2012.

GO Transit service to Barrie commenced in 2008 with a future proposed Innisfil GO Train station location to be determined in conjunction with Metrolinx, the County and Town. The 400 Industrial Park development is slow due to the lack of waste water treatment. The Town of Innisfil has completed a business plan to bring full municipal servicing to the 400 Industrial Park area. Timelines for servicing is anticipated for 2018.

The Provincial Government’s Intergovernmental Action Plan (IGAP) Report was released on August 29, 2006. The report has deduced that the population of Simcoe County would be 667,000 by year 2031. It is projected that by 2031, InnPower will service 56,000 people in Innisfil with another 39,000 people in the new Barrie lands.

Riggs Distler (Line Contractor) is contracted until June 30, 2017. The Olameter meter reading and billing contract was renegotiated to accommodate water and wastewater billing and was extended to 2016. An analysis of in-house mailing is currently underway; if feasible

we will move our mailing services in-house mid-2016. InnPower is in the final year of a 3-year collective agreement.

InnPower is a member of the *Cornerstone Hydro Electric Concepts Association Inc.* (CHEC); The group has 15 LDC members (representing more than 100,000 customers) that have hired staff to perform "back office" functions for its members. CHEC is modeled after a cooperative to combine resources and competencies to best meet the requirements of the changing electrical industry and provide a high standard of locally supplied customer service. CHEC is governed by a Board of Directors who are responsible for ensuring that CHEC achieves its objectives, is financially accountable, and is in compliance with all relevant laws, regulations and by-laws. CHEC has allowed members to exchange ideas on a variety of issues facing utilities, to initiate combined solutions and to share insights on what worked and what did not. The cooperative format allowed a "think tank" environment to be created between members.

InnPower remains an active member in the Electricity Distributors Association, and Wade Morris, Acting President & CEO, is a member of the EDA Georgian Bay Executive. Liability, equipment, property, vehicle, bad debt and crime insurance are with The Municipal Electric Association Reciprocal Insurance Exchange Group (MEARIE), which is a division of the EDA. MEARIE is a reciprocal insurance exchange that is owned by its members, providing insurance coverage at much lower rates than other market insurance providers.

InnPower continues to be a member of the Utilities Standards Forum (USF) which was formed by many of Ontario's small to medium sized electricity distribution companies in 2005 in direct response to the passing of Ontario Regulation 22/04. Wade Morris is a long-serving director with this organization, which makes use of design, construction and material standards to meet the requirements of this regulation and promote distribution system safety. Today, USF's membership has grown to include small to medium and large Ontario LDC's. It continues to operate with a significant amount of voluntary participation and input by Member representatives. The USF Standards are maintained, with continuous updates and improvements to meet current engineering practices, tools and requirements. USF hosts a schedule of events providing technical training, networking opportunities and support to one another on common technical issues. USF also advocates with the Electrical Safety Authority (ESA), Canadian Standards Association (CSA) and other applicable legislative bodies regarding distribution standards and other technical requirements.

In January of 2015, an expression of interest was received from a corporation named EPCOR. This offer highlighted the possibility of a strategic partnership with a municipally-owned utility corporation that is involved in water, wastewater, gas and hydro distribution and transmission. Throughout 2015, the offer from EPCOR to purchase 50% of InnPower shares resulted in negotiations between EPCOR and InnPower's Board of Directors, as instructed by the shareholder (i.e. Town of Innisfil Council). As of the fourth quarter 2015, both corporations have been negotiating the terms and conditions to be outlined in a shared purchase agreement and a unanimous shareholder agreement, which will be presented to Town of Innisfil Council for final decision.

In the summer of 2015, a research consulting firm named FMR was retained by the Town of Innisfil to investigate shared services opportunities between Municipal Entities, South Simcoe police services and InnPower. A report was prepared by FMR which identified key areas where shared services could be beneficial. As of fourth quarter of 2015, a steering committee consisting of the CAO of the Town of Innisfil, the CEO of InnPower, the CEO of InnServices, the CEO of the Library, and the South Simcoe Police Chief have been meeting on a regular basis to vision and strategize on the deployment of a shared service model. Further development of this initiative will be occurring in 2016.

With the anticipated growth of InnPower's customer base approaching, development plans are becoming increasingly clear of where and when high volumes of customer connections and electrical loads will place. This year has seen an increase in communication efforts between municipal planners, consultants, developers and builders as a result of this better, more accurate information. Every section of this Business Plan reflects the timing of the anticipated growth and the complexity, opportunities and challenges InnPower will see in the future.

In August 2015, the Board of Directors approved the appointment of InnPower's CFO/Treasurer, to a dual role as CFO of InnServices Utilities Inc., the newly formed municipal services corporation charged with providing water and wasterwater services to the Town of Innisfil under a utility model.

2. Innisfil Customer Growth Assumptions

Following the aftermath of the *Oak Ridges Moraine Protection Act 2001*, property developers have acquired many Innisfil properties for the purpose of land development. Land development pressures have been reflected in the Town of Innisfil's Official Plan (2006);

http://www.innisfil.ca/strategic-planning

Council of the Corporation of the Town of Innisfil passed By-law No. 060-13 to adopt the Official Plan Amendment for the Town of Innisfil on June 5, 2013 for a proposed population of 4,500 residents in the Alcona South Secondary Plan (Sleeping Lion, on the north-east corner of the GO rail line and the 6th Line). This new development may increase the long term growth projections as specified below. In addition to this proposed plan, higher growth is anticipated in the Leonard's Beach area as well.

Draft Proposed Modified County of Simcoe Official Plan (2013)

http://www.simcoe.ca/Planning/Documents/SimcoeOfficialPlanTextasperOMBOrders-Aug31%2c2015.pdf

Places to Grow, Simcoe Strategy;

https://www.placestogrow.ca/index.php?option=com_content&task=view&id=359&Itemid=12

https://www.placestogrow.ca/index.php?option=com_content&task=view&id=387&Itemid=14

Office Consolidation (2013) to the Growth Plan for the Greater Golden Horseshoe, 2006

https://www.placestogrow.ca/index.php?option=com_content&task=view&id=359&Itemid=12

The Provincial Government's IGAP Report was released on August 29, 2006 and is located at URL

http://www.simcoe.ca/Planning/Documents/GPA%20Report%20-%20Consolidated%20Version-Rev%2009-06-06%20FINAL.pdf

The Barrie-Innisfil Boundary Adjustment Act, 2009;

http://www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_09b29_e.htm

City of Barrie Growth Plans

http://www.barrie.ca/City%20Hall/growth/Pages/PlanningfortheAnnexedLands.aspx

The various Town-wide population and employment projections are summarized in the table below (Table 2-1 Town of Innisfil transportation master plan 2013)

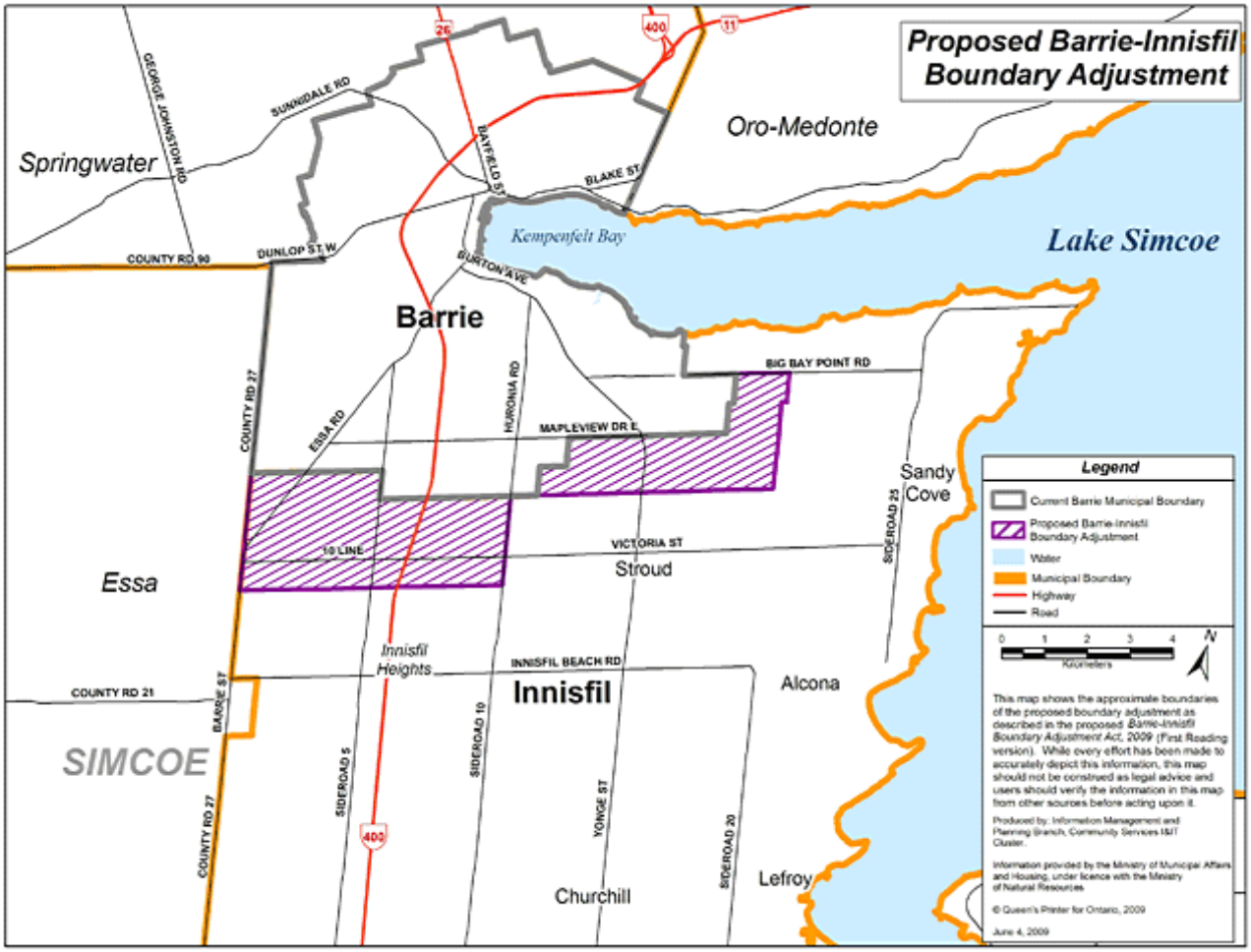
Source	Population	Employment
Innisfil, 2011 Census and 2006 employment estimate	33,080	5,700
Innisfil Official Plan, 2031	55,500	27,750
Simcoe Official Plan, 2031	65,000	13,100
Provincial Growth Plan, 2031	56,000	13,100
Provincial Growth Plan, 2031 plus Friday Harbour and Sleeping Lion	65,240	13,100

http://innisfil.ca/sites/all/files/uploads/Engineering/2013-08%20Innisfil%20TMP%20Final%20Report.pdf

Both population and employment is projected to increase by more than 100% within the next 25 years. It is this municipal growth that is fueling the need for capital expansion within the long range plan. As required in the Distribution System Code:

1.1.1 A distributor shall make every reasonable effort to respond promptly to a customer's request for connection. In any event a distributor shall respond to a customer's written request for a customer connection within 15 calendar days. A distributor shall make an offer to connect within 60 calendar days of receipt of the written request, unless other necessary information is required from the load customer before the offer can be made.

By virtue of the short timelines provided for distributors to make an offer to connect (60 days) versus the years it takes to complete large capital projects, the distributor is therefore obligated to plan and build infrastructure in advance of a request for connection as a normal course of business.



The Barrie-Innisfil Boundary Adjustment Act was effective on January 1, 2010. This has granted the City of Barrie approximately 2,300 hectares of Innisfil lands for their development purposes. Until the City of Barrie releases an official plan amendment, 40,788 residents with 68 MW of demand, has been estimated for this service territory by 2031. These lands are in InnPower's licensed distribution territory and long term plans have been incorporated in that regard.

There are five commercial development sites around the Highway 400 and Innisfil Beach Road area with a potential of over 100 lots. Three out of the five commercial sites were approved in 1990, 1991 and 1993. There has been an environmental assessment on-going for the impact of water and waste-water facilities around the Highway 400 corridor. Future development from Metrus Properties has proposed development for ~50,000 residents and 20,000 commercial jobs north of Georgian Downs. Electric power servicing for such a development would require a 70 MW supply either with 3-44kV feeders or a preferred 230kV – 27.6kV T.S. The scope of such an undertaking is not anticipated within this 5-year plan but has been discussed with the IESO regional planning team, including Hydro One and PowerStream (Appendix 6).

Long range planning strategies have been discussed with Hydro One and neighboring South Simcoe LDCs, the City of Barrie and the Town of Innisfil. InnPower believes that its best

strategy to service the new developments during the post-2022 era involves the deployment of an Innisfil Transformer Station 230kV – 27.6kV. Hydro One has indicated that Barrie TS will reach the end of it useful life in 2020. If Barrie TS gets rebuilt from 115kV to 230kV supply, it is then possible to run a double circuit 230kV compact tower line down the 100' 13M3 easement from Barrie TS into Innisfil. A three acre property for a new 230kV – 27.6kV TS has been purchased in 2012. If a 230kV supply is delayed or not possible, the new TS site could be supplied with 115kV or even multiple 44kV sub-transmission circuits.

A resort community (Friday Harbour), which is planned within the development of Big Bay Point, has been approved by Council and by the Ontario Municipal Board and is currently under construction. This 600 acre site will consist of approximately 1,600 new customers over a ten year period. It is anticipated that preliminary occupancy will occur in late 2016. It will be built to 28kV standards. Initially the development will be served by the existing Big Bay Point DS and as load increases it is anticipated to be supplied with a new 44kV-27.6 kV Distribution Station in 2018. Both InnPower and the Town of Innisfil have approved a land swap consisting of a 1/10 acre parcel (Alcona DS) to be sold to the Town in exchange for a one acre parcel at the Big Bay Point Road gravel pit. InnPower will build its distribution station to supply load growth at the resort community, along with future load in the new Barrie lands and will provide 27.6kV backup to the Brian Wilson DS in Alcona.

The Lefroy area has development approval for approximately 2,300 customers. Another development called Sleeping Lion is currently being built for an estimated 5,000 residents on 6th Line, east of the railway tracks. Together with the anticipated GO Train station, and to meet the demands for Lefroy and a back-up for Alcona, a new 44kV-27.6kV Distribution Station was built in 2014 at Belle Ewart.

The following chart was provided by the Town of Innisfil and projects Innisfil new dwelling construction activity from 2016 to 2025.

Residential Growth Forecast in Town of Innisfil											
2016-2025											
Note: SFD includes semi-detached			# of Units								
Development Name	**Location(Schedule per DCBS)**	**Residential Unit Type**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Pratt Alcona North	Alcona	SFD	10	0	0	0	0	0	0	0	0	0
Pratt Alcona North	Alcona	Rows/Multi	6	0	0	0	0	0	0	0	0	0
Previn Court 2	Alcona	SFD	30	30	30	50	50	50	50	50	50	10
Previn Court 2	Alcona	Rows/Multi	0	0	0	30	30	30	30	30	30	50
Previn Court 1	Alcona	SFD	0	20	20	3	0	0	0	0	0	0
Previn Court 1	Alcona	Rows/Multi	0	0	0	0	0	0	0	0	0	0
Innisbrook Phase 2	Alcona	SFD	3	0	0	0	0	0	0	0	0	0
Pratt Alcona East	Alcona	SFD	9	0	0	0	0	0	0	0	0	0
Innisfil By The Lake	Alcona	SFD	2	2	2	1	0	0	0	0	0	0
Pratt Alcona South	Alcona	SFD	3	0	0	0	0	0	0	0	0	0
Sandy Trail	Alcona	SFD	4	0	0	0	0	0	0	0	0	0
Alcona Downs 1 Phase 2	Alcona	SFD	30	0	0	0	0	0	0	0	0	0
Alcona Downs 1 Phase 2	Alcona	Rows/Multi	24	0	0	0	0	0	0	0	0	0
Alcona Downs 2	Alcona	SFD	40	26	0	0	0	0	0	0	0	0
Alcona Downs 3	Alcona	SFD	0	20	20	20	20	20	20	20	20	20
Alcona Downs 3	Alcona	Rows/Multi	0	10	10	10	10	10	10	10	10	10
Bremont	Alcona	SFD	4	0	0	0	0	0	0	0	0	0
Pratt Alonzi	Alcona	SFD	25	0	25	23	0	0	0	0	0	0
Pratt Alonzi	Alcona	Rows/Multi	8	0	25	21	0	25	0	0	0	0
Grand Sierra	Alcona	SFD	20	20	20	20	20	20	20	20	20	20
Grand Sierra	Alcona	Rows/Multi	0	0	0	0	0	10	10	10	10	10
Alcona Capital	Alcona	SFD	25	25	25	25	25	13	0	0	0	0
Alcona Capital	Alcona	Rows/Multi	0	0	25	25	25	24	0	0	0	0
Top Hill Estates	Churchill	SFD	0	7	7	0	0	0	0	0	0	0
Churchill Downs	Churchill	SFD	0	5	5	5	6	0	0	0	0	0
End Fields	Gilford	SFD	0	5	5	5	5	0	0	0	0	0
Belpark	Cookstown	SFD	30	30	28	0	0	0	0	0	0	0
Patson	Cookstown	SFD	6	0	0	0	0	0	0	0	0	0
Cookshill North	Cookstown	SFD	0	0	20	17	0	0	0	0	0	0
Cookshill South	Cookstown	SFD	15	0	0	0	0	0	0	0	0	0
Victoria Street Cookstown	Cookstown	SFD	0	0	0	0	0	0	30	23	0	0
Innisfil Executive Estates	Stroud	SFD	10	10	10	2	0	0	0	0	0	0
Innis Village East	Alcona	SFD	0	0	20	20	20	20	6	0	0	0
Innis Village West	Alcona	SFD	0	0	50	50	50	50	50	50	50	50
Innis Village West	Alcona	Rows/Multi	0	0	0	0	0	50	50	75	75	75
Sleeping Lion	Alcona South	SFD	0	80	80	80	80	80	70	70	70	70
Sleeping Lion	Alcona South	Rows/Multi	0	20	20	20	20	20	30	30	30	30
Friday Harbour	Friday Harbour	Rows/Multi	250	150	150	150	150	100	100	100	100	100
LSAMI P1 Phase 1	Lefroy	SFD	25	0	0	0	0	0	0	0	0	0
LSAMI P1 Phase 1	Lefroy	Rows/Multi	25	0	0	0	0	0	0	0	0	0
LSAMI P1 Other Phases	Lefroy	SFD	50	50	50	50	50	50	24	0	0	0
LSAMI P1 Other Phases	Lefroy	Rows/Multi	20	20	20	20	20	20	18	0	0	0
LSAMI P2	Lefroy	SFD	0	50	50	21	0	0	0	0	0	0
LSAMI P3	Lefroy	SFD	0	0	0	0	0	50	50	20	0	0
LSAMI P3	Lefroy	Rows/Multi	0	0	0	0	0	0	0	82	0	0
LSAMI P4	Lefroy	SFD	0	0	0	0	0	0	50	50	50	50
LSAMI P4	Lefroy	Rows/Multi	0	0	0	0	0	0	15	15	15	15
Belle Ewart Lakeview Estates	Lefroy	SFD	0	0	0	0	0	10	10	0	0	0
Kirsch Alfred Street	Lefroy	SFD	0	0	0	0	0	10	8	0	0	0
Total			674	580	717	668	581	662	651	655	530	510
Total without Friday Harbour			424	430	567	518	431	562	551	555	430	410

Utilizing growth projections from all available data, the following comprises the parameters for long range growth projections:

- Innisfil population in 2031 56,000
- New Barrie land population in 2031 40,788
- Friday Harbour development 1,600 units + commercial load

For our analysis, InnPower has employed a more conservative estimate for load growth as noted below. Factoring the potential for additional commercial customer growth, the following growth assumptions have been forecasted over the next seven years:

Customer Growth (Residential Only)

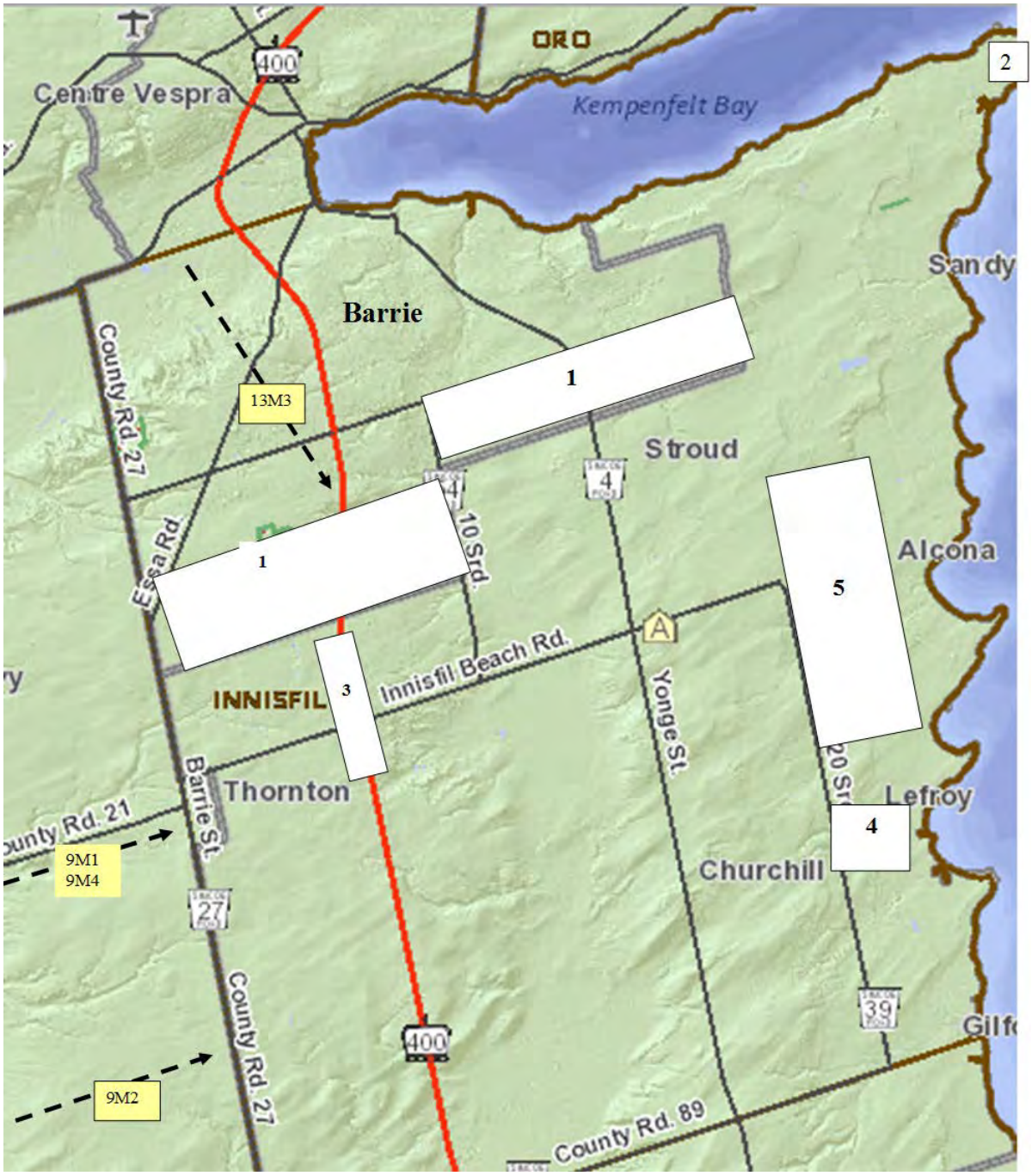
	2016	2017	2018	2019	2020	2021	2022
Historical Residential							
New Customers Residential - Barrie	0	0	714	750	606	600	550
New Customers Residential -TOI	674	348	430	401	349	397	391
Total New Customers	674	348	1144	1151	955	997	941
Total Residential Customers (EOY)	15808	16156	17300	18451	19405	20403	21343
% Residential Growth	4.5%	2.2%	7.1%	6.7%	5.2%	5.1%	4.6%

* A seven year window was considered for long term planning purposes

Our load gorowth projection stated above is a conservative estimate taking into consideration a lower adsorption rate than the estimates reported in the “Residential Growth Forecast in Town of Innisfil” table above.

InnPower Load Growth by Location (2016-2022):
(A seven year window was considered for long term planning purposes)

Zone 1 (Annexed Lands): 13MW
Zone 2 (Friday Harbor): 1.25MW
Zone 3 (HWY 400 Strategic Employment Lands): 0
Zone 4 (Lefroy): 1.8MW
Zone 5 (Alcona, Includes Sleeping Lion): 5.44MW



3. Human Resources Five-Year Plan

The three-year Collective Agreement between InnPower Corporation and the Power Workers' Union, C.U.P.E. Local 1000 Innisfil, will expire on July 6, 2016. Negotiations will commence in the spring of 2016.

On January 26, 2015, the doors opened at our new Administration and Operations Centre on Yonge Street. The new location is a state-of-the art, LEED certified building, certified through the Canadian Green Building Council. The building footprint takes into consideration the growth demands for our respective communities.

With the move to the Town Campus, an increase in customer traffic was anticipated. To manage the expected increase, one full-time and one part-time Customer Accounts Representative were hired in February 2015, to assist customers coming into the office. This was offset by an unfilled Customer Service Representative vacancy, created by a promotion to the IT department.

The end of 2014 and mid-2015 saw two senior management retirements. The Vice President of Corporate Services retired on December 31, 2014. The Metering/IT Manager was promoted to fill the Vice President vacancy, while the manager position was left unfilled at this time. The attached table shows that this vacancy is planned to be filled in 2018.

On July 31, 2015, the President & CEO also retired. This vacancy was filled by the Vice-President of Engineering and Operations in an acting role. At the same time, the Engineering Manager was promoted to Vice President of Engineering and Operations, also in an acting capacity. The search for an Engineering Manager for a one-year contract was filled in September.

Engineering capital projects and new subdivisions continue to increase. To assist with the demand, and to prepare for the retirement of the current contracted inspector, staff plan to hire a full-time Inspector in third quarter 2015. This will alleviate some of the burden of the Engineering Technologist, allowing more time for capital project planning and design. As this is a largely-capitalized position, the impact to expenses will be minimal.

In order to provide back-up and support for the existing Meter Technician, a SCADA/Meter Technician is planned for 2016. Under the guidance of the Smart Grid Engineer, the incumbent will also provide support for SCADA, communication tower network and other smart grid initiatives. This position was included in the 2016 budget.

The recent appointment of InnPower's CFO to a dual role with InnServices Utilities Inc. has required additional responsibilities be placed on the Accounting Manager. In order to accommodate the extra workload, staff are investigating recruiting for a Business Analyst. This position would take on some of the Accounting Manager's responsibilities, as well as providing analytical and financial support for the Engineering Department and our affiliate company. The support to the Engineering department would include assisting with decision making, researching business cases, assisting with Economic Evaluations, etc. There would

be no financial impact as costs will be absorbed through the CFO's budgeted salary. In addition, a Dispatcher is planned for end of second quarter 2016 to address the issues that were identified in the Ontario Energy Board audit in 2014. This position was also included in the 2016 budget.

The hiring of two locators and three additional line crew positions, originally planned for 2016 and 2017 respectively, has been delayed until 2017 and 2018. This delay is a result of the customer growth now expected to occur a year later. There is minimal financial impact for these positions as they would displace sub-contractor expenses.

Staff are working towards another Cost of Service application for submission in April 2016, setting rates for the next five years. Included in the application will be the addition of the following positions. With any new positions, Board approval is required prior to recruiting.

- ***HR Assistant to full-time***
- ***Regulatory Assistant to full-time***
- ***Executive Assistant***
- ***Accounting Clerk***
- ***Network Administrator***
- ***Engineering Technologist***
- ***Metering/IT Manager***
- ***Meter Technician***
- ***Customer Service Representative***
- ***Operations Assistant***
- ***Inspector***
- ***Purchaser***
- ***Human Resources Assistant***

These additions to our work force are necessary to continue to meet the ongoing and increasing requirements as our customer base grows and as new legislation continues to be introduced.

The work force shortage that is on the minds of most LDCs is not an issue for InnPower. With an average age of approximately 38 years, InnPower will not be facing the challenges of increasing retirements of long-term employees in the foreseeable future. However, with the younger workforce, maternity and parental leaves are at the forefront. There is the potential of four such leaves to fill in 2016 and we will be challenged with filling those vacancies with qualified personnel.

The following table outlines an increase in headcount of 13.5 bodies over the next five years, along with the estimated growth expectations with a predicted employee per customer ratio (end of year). It is worthwhile noting that, when possible, new staff resources correlate to the cost of service rate applications that occur every five years. Also contained within the table are 6 additional bodies which are contractor displacement.

Human Resources Five Year Plan

	Forecast 2015	Projection 2016	2017	2018	2019	2020
Customer Growth	470	744	374	1,233	1,246	1,032
Customer Growth %	3.0%	4.6%	2.2%	7.1%	6.7%	5.2%
Total Customers Y/E	16,245	16,989	17,363	18,595	19,841	20,873
Employees	41.0	44.0	50.5	59.5	60.5	60.5
Customer to employee	396	386	344	313	328	345

	Forecast 2015	Projection 2016	2017	2018	2019	2020
President & CEO	1	1	1	1	1	1
Executive Assistant	0	0	1	1	1	1
HR Manager	1	1	1	1	1	1
HR/Admin. Assistant	0.5	0.5	1	1	2	2
CFO	1	1	1	1	1	1
Accounting Manager	1	1	1	1	1	1
Accounting Clerk	2	2	3	3	3	3
Financial Analyst	1	1	1	1	1	1
Business Analyst	0	1	1	1	1	1
P/T Finance Support	0.5	0.5	0	0	0	0
Regulatory/Consv Mgr	1	1	1	1	1	1
CDM Rep.	1	1	1	1	1	1
Regulatory Assistant	0.5	0.5	1	1	1	1
VP, Corp Services	1	1	1	1	1	1
Metering/IT Manager	0	0	0	1	1	1
Meter Technician	1	1	1	2	2	2
Network Administrator	1	1	2	2	2	2
IS Analyst	1	1	1	1	1	1
Customer Service Mgr	1	1	1	1	1	1
Customer Accounts Rep.	2.5	2.5	2.5	2.5	2.5	2.5
Customer Service Rep.	6	6	6	7	7	7
VP, Eng. & Opers.	1	1	1	1	1	1
Eng. & Ops. Assistant	1	1	1	2	2	2
Engineering Mgr	1	1	1	1	1	1
Smart Grid	1	1	1	1	1	1
Engineering Supervisor	0	0	0	0	0	0
SCADA/Meter Tech.	0	1	1	1	1	1
Engineering Technologist	1	1	2	2	2	2
Engineering Technician	2	2	2	2	2	2
GIS Technician	1	1	1	1	1	1
Inspector	1	1	1	2	2	2
Dispatcher	0	1	1	1	1	1
Locator	0	0	2	2	2	2
Operations Manager	1	1	1	1	1	1
Operations Supervisor	0	0	0	0	0	0
Sub Foreman	1	1	1	2	2	2
Line Crew	4	4	4	6	6	6
Stockkeeper	2	2	2	2	2	2
Purchaser	0	0	0	1	1	1
Total	41	44	50.5	59.5	60.5	60.5
Change		3	6.5	9	1	0

4. Regulatory Management Plan

The Regulatory Management Plan for InnPower Corporation encompasses the following components:

- Rate setting (5 year COS cycle, annual IRM, data collection and analysis);
- Policy – analyzing decisions, providing commentary to regulators to influence policy direction;
- Reporting -- internal and to external regulatory entities, Ontario Energy Board (OEB), Independent Electricity System Operator (IESO), Electricity System Authority (ESA), and the Ministry of Energy (MOE);
- Certification/Compliance/Quality Assurance/Continuous Improvement; and
- Business impacts resulting from the aforementioned.

Commencing in the third quarter of 2015, InnPower undertook activities to complete our 2017 Cost of Service (COS) application. The 2017 COS application is due to be filed with the OEB in April 2016 for new rates effective January 1, 2017. This filing contains two new components resulting from outcomes of the Renewed Regulated Framework for Electricity (RRFE):

- Distribution System Plan (DSP) - the DSP outlines InnPower's asset condition assessment and how ACA assessment influenced our long term capital plan. The DSP is a critical component of our 2017 COS application and as such InnPower has contracted an energy consultant to assist in the development of the plan; and
- Regional Planning – provincial planning process linked to the DSP which requires planning for infrastructure with IESO, Hydro One Transmission and shoulder LDC's.

With the introduction of the RRFE in 2012 by the OEB and increasing pressure for LDC's to either amalgamate or obtain greater efficiencies within their respective organizations, the Regulatory demands have increased dramatically. The increased demand is demonstrated by the number of open OEB cases, increased reporting requirements, annual changes to IRM/COS models, compliance audits, scorecard data and certification requirements by LDC executives. Additionally, the OEB released its 2015 - 2018 business plan on October 26, 2015 in which continued support for a consumer centric approach, enhancing utility performance, enabling access to competitive energy choices and ensuring regulatory effectiveness are emphasized.

It is critical that InnPower remains up to date on Regulatory impacts as any one change component can have material impact to business planning. To this end, InnPower will be adding an additional part-time resource of 24 hours for a combined team total of 2 resources. This resource addition will allow InnPower to manage all RRR reporting, annual RRR changes and the resulting process audits to mitigate risk to the InnPower organization.

Following is a list of active and closed OEB and Ministry of Energy initiatives that InnPower is monitoring and have adjusted our processes as a result.

Active Ontario Energy Board Initiatives

EB #	Name / Description	Critical Dates	General Notes
EB-2010-0364	**Time of Use Rates in Ontario**	**11-Jan-11**	**Comments requested by OEB**
		23-Dec-13	Navigant Report - TOU Impact
EB-2011-0043 (RRFE)	**Regional Planning for Electricity Infrastructure**	**27-Oct-10**	**Announced intent to develop a renewed framework.**
		27-Jan-11	Material posted for Stakeholder Conference - Feb 2nd
		8-Nov-11	Staff Discussion Papers Issued
		23-Nov-11	Stakeholders invited to 2 day information session.
		8-Dec-11	Stakeholder information session.
		6-Feb-12	Update on the Consultation Process
		22-Feb-12	Stakeholder Conference Announced for March 28, 2012
		21-Mar-12	Executive Roundtable Meetings
		5-Apr-12	Provision for Written Comments by Stakeholders.
		18-Oct-12	OEB issues Board Report on RRFE
		30-Oct-12	EOB announces Working Group members for RRFE
		31-Oct-12	OEB Stakeholder Session on RRFE
		5-Feb-13	Working Group Draft Report Released less App. 1
		15-Feb-13	Full Working Group Draft Report Released
		28-Mar-13	Chapter 5 Filing Requirements released
		17-May-13	OEB releases proposed amendments to TSC & DSC
		26-Aug-13	Amendments to the Distribution System Code for Regional Planning
		25-Jul-14	OEB Establishes a standing committee for Regional Planning
		17-Nov-14	Standing Committee Established
EB-2013-0004	**Development of a Standby Rates Policy for Load Displacement Generation**	**24-Jan-13**	**The OEB is initiating a consultation process to develop standby rates for Load Displacement Generation**
		4-Mar-13	Working Group members selected.
		5-Apr-13	Working Group Meeting
		25-Jun-13	Working Group Meeting
EB-2013-0421	**HONI - Supply to Essex County Transmission Reinforcement Project**	**23-May-14**	**HONI Application**
		28-Jan-15	Request for Interveners for Phase II of the project - Cost Allocation
		4-Mar-15	Interveners selected
		30-Mar-15	Interrogatories to applicant
		30-Apr-15	Evidence Submitted
		1-May-15	HONI Submission
		22-May-15	Procedural Order Issued
		28-May-15	Interrogatories to applicant (Technical Conference)
		22-Jun-15	Procedural Order Issued
		10-Jul-15	Procedural Order Issued
		16-Jul-15	Decision and Order - Phase 1 (Leave to Construct)
		28-Aug-15	Procedure Order Phase 2

EB #	Name / Description	Critical Dates	General Notes
EB-2014-0138	**Board Staff Discussion Paper - SAAs and MAADs**	**31-Mar-14**	**Staff Discussion Paper Issued - Board Policy on SAAs and MAADs**
		5-May-14	Comments posted on OEB website
		26-Mar-15	OEB releases Report of the Board on MAADs
EB-2014-0158	**Consultation on the Effectiveness of Part II of the Energy Consumer Protection Act, 2010**	**8-Apr-14**	**Announcement letter issued**
		21-Jul-14	Update on consultation process
		15-Oct-14	OEB releases on-line survey
		23-Oct-14	OEB releases information on stakeholder forum
		20-Nov-14	Comments received
		15-Dec-14	Deadline for supplementary written comments extended to stakeholders
		12-Jan-15	Written comments submitted
EB-2014-0189	**OEB Announces Initiative to Develop Electricity Distribution System Reliability Performance Targets**	**15-Jul-14**	**Announcement letter issued**
		20-Aug-14	Comments Submitted
		25-Aug-15	Report of the Board issued
EB-2014-0198	**Policy Review of Electricity Residential Billing Practices**	**27-Jun-14**	**Announcement letter issued**
		18-Sep-14	Draft Report of the Board released.
		9-Oct-14	Comments received
		5-Feb-15	Notice of Proposal to Amend the DSC issued
		15-Apr-15	Amendments to the DSC & RRR Released
EB-2014-0227	**Development of an ongoing, Ratepayer Funded, Electricity Bill Assistance Program**	**23-Oct-14**	**OEB releases information on stakeholder forum**
		10-Nov-14	Comments received
		26-Mar-15	Report of the Board Released
EB-2015-0006	**Proposal to amend the DSC for long term load transfers**	**20-Feb-14**	**Announcement letter issued**
		6-Mar-15	Comments Submitted
EB-2015-0040	**Regulatory Treatment of Pensions and other Post-Employment Benefit Costs**	**14-May-15**	**Announcement letter issued**
		31-Jul-15	Comments Submitted
EB-2015-0043	**Rate Design for Commercial and Industrial Customers**	**28-May-15**	**Announcement letter issued**
EB-2015-0148	**Code Amendments for OESP**	**14-Sep-15**	**Notice of proposal issued to amend codes for OESP**
		19-Oct-15	Results of 2014 LEAP Review Released
		19-Oct-15	OESP & LEAP Manual Released
EB-2015-0159	**Intervenor Framework II**	**17-Apr-15**	**Announcement letter issued**

Ministry Of Energy Active Initiatives

	Name / Description	Critical Dates	General Notes
Minister of Energy	**Review of Electrical Sector by Ministry of Energy**	**1-Jan-12**	**Review of Electrical Sector by Ministry of Energy**
		29-Jun-12	Submission to Panel
		12-Dec-12	Sector Review Panel report released
Minister of Energy	**Letter from Minister of Energy**	**19-Mar-13**	**Request for comments on the Panel Report and recommendations**
Minister of Energy	**Long-Term Energy Plan**	**16-Jul-13**	**Request for comments on the Ministry's Long Term Energy Plan**
		2-Dec-13	Liberal Government releases its LT energy plan
Minister of Energy	**Conservation First**	**16-Jul-13**	**Request for comments on the Ministry's Conservation First Vision**
		2-Dec-13	Liberal Government releases its CDM plan
Miniser of Energy	**On-Bill Financing**	**6-Mar-15**	**MOE requests input for On-Bill Financing**
Minister of Energy	**Ontario Electricity Support Program**	**26-Mar-15**	**MOE announces new OESP program**

5. Conservation and Demand Management Plan

The Green Energy Act 2009, put forth by the Provincial government, received royal assent on May 14, 2009. With this Bill, energy conservation and demand management is now a condition of the distribution license. In support of the Green Energy Act 2009 and further Ministerial direction, the Ontario Energy Board (OEB) has issued energy reduction targets and CDM Codes for local distribution companies via amendments to LDC's Distribution Licenses.

With the amendments to our license, InnPower Corporation (InnPower) successfully navigated the 2011-2014 Conservation timeframe securing 7.8 GWh in energy savings towards our allocated target of 9.2 GWh or 84.43%. The 7.8 GWh of energy savings is equivalent to 633 homes in InnPower's service territory turning their power off for a period of 4 years. Considering InnPower's demographics are primarily residential with only 8% business, this is quite the achievement.

Throughout 2014, IESO and members of the CDM Working Groups, of which InnPower staff is a contributing member, prepared the infrastructure and supporting documents for the Conservation First Framework (CFF) for the new CDM framework.

In August 2014, IESO issued the "tool kit" for LDC's which provided 23 documents on guidelines and tools to assist LDC's in developing their CDM Plans for the Conservation First Framework. In preparation of developing InnPower's CFF CDM Plan it was necessary to first understand the differences between the two conservation frameworks:

Conservation Framework Comparisons

	2011 - 2014	2015 - 2020
Target	9.2 GWh	13.008 GWh
Budget	$544,427	$3,680,478
Budget Accountability	Administrative	Administrative, Incentive and Program Design
Reporting	Annually	Monthly, Quarterly, Annually, and TRC/PACT results for program cost effectiveness
Funding	Invoiced twice a year and trued up on an annual basis	Full Cost Recovery, 25% prefunded and then trued up quarterly and again annually
Target Forecast	Based on forecast of measures that the LDC could obtain. IPC forecasted 75% of allocated target	100% forecast requirement. Forecast linked to actual budget, if a program did not exist for areas that were identified as "potential" then budget parked until program designed to capture end use measures.
Program Design	Programs outside of the IESO designed programs to be approved by the OEB and IESO with funding from rates.	LDC's required to design new programs to attain allocated target. Although assistance from IESO this is a new skillset for most LDC's.
GAS Collaboration	Not Required	Collaboration on program design and implemention with Enbridge a requirement

In October 2014, InnPower executed the Energy Conservation Agreement (ECA) with IESO. The 6 year CFF CDM forecast by market segmentation (Residential, Commercial and Institutional and Industrial) was prepared and submitted to IESO in May 2015 and the plan was approved by IESO on July 27, 2015. Following is an overview of InnPower's market segmentation:

InnPower Market Segmentation Overview

Residential

ACHIEVEABLE POTENTIAL BY END USE - RESIDENTIAL

End Use	2015	2016	2017	2018	2019	2020	% of AP	kWh of Target	Avg kWh/yr
Appliances	1.639	2.283	2.899	3.191	3.420	3.627	20.49%	2,664,979.13	444,163.19
DHW	0.120	0.150	0.179	0.193	0.206	0.219	1.24%	160,698.90	26,783.15
Electronics	0.275	0.235	0.226	0.453	0.656	0.909	5.13%	667,874.32	111,312.39
HVAC	0.000	1.283	3.101	3.959	4.782	5.523	31.19%	4,057,840.17	676,306.69
Lighting	0.000	0.000	0.127	0.000	0.001	0.259	1.46%	190,467.13	31,744.52
Other	0.068	0.087	0.106	0.162	0.219	0.277	1.56%	203,343.21	33,890.53
						10.813	61.08%	7,945,202.85	1,324,200.47

RESIDENTIAL SUMMARY

TOTAL AP (GWh)	17.704
TARGET (GWh)	13.009
RES AP (GWh)	10.813
RES TARGET (GWh)	7.945

The Residential segment (which represents 61% of the AP), 51% of the achievable potential is attributable to the "Appliances" and "HVAC" end use categories. Commencing in 2015 there are no appliance programs and the HVAC program currently has no opportunity for direct LDC involvement. These end use categories will be the focus of LDC designed programs to address the "unassigned" target.

Commercial

ACHIEVEABLE POTENTIAL BY END USE - COMMERCIAL (GWh)

End Use	2015	2016	2017	2018	2019	2020	% of AP	kW of Target	Avg/year
Cooking	0.043	0.052	0.060	0.079	0.097	0.116	0.65%	84,896.69	14,149.45
DHW	0.232	0.286	0.338	0.549	0.762	0.978	5.52%	718,717.98	119,786.33
HVAC	0.000	0.088	0.718	1.180	1.398	1.944	10.98%	1,428,452.53	238,075.42
Lighting	0.089	0.890	2.241	1.877	1.376	1.273	7.19%	935,427.57	155,904.60
Other	0.196	0.230	0.264	0.315	0.368	0.421	2.38%	309,260.82	51,543.47
Plug Loads	0.354	0.450	0.544	0.754	0.968	1.183	6.68%	869,568.81	144,928.13
Refrigeration	0.204	0.249	0.293	0.426	0.552	0.690	3.90%	507,243.24	84,540.54
						6.606	37.31%	4,853,567.65	808,927.94

COMMERCIAL SUMMARY

TOTAL AP (GWh)	17.704
TARGET (GWh)	13.009
COMMERCIAL AP (GWh)	6.606
COMMERCIAL TARGET (GWh)	4.854

In the Commercial segment (which represents 37% of the AP), 23% of the achievable potential is attributable to "HVAC", "Plug Loads" and "DHW" end use categories. These are areas in which InnPower has seen minimal RetroFit/ERII applications. Collaboration with other LDC's with a focus on these end use categories will be required to attain the required energy savings in the Commercial market segment.

Industrial

ACHIEVEABLE POTENTIAL BY END USE - INDUSTRIAL (GWh)

End Use	2015	2016	2017	2018	2019	2020	% of AP	kW of Target	Avg/year
Compressed Air	0.013	0.017	0.021	0.047	0.072	0.098	0.55%	72,024.67	12,004.11
ElectroChemical	0.000	0.000	0.000	0.000	0.000	0.000	0.00%	0.00	0.00
HVAC	0.017	0.022	0.027	0.028	0.030	0.031	0.17%	22,764.83	3,794.14
Lighting	0.010	0.012	0.015	0.018	0.021	0.023	0.13%	17,070.83	2,845.14
Motors Fans Blowers	0.000	0.000	0.000	0.008	0.017	0.025	0.14%	18,369.44	3,061.57
Motors Other	0.013	0.017	0.021	0.023	0.026	0.028	0.16%	20,628.25	3,438.04
Motors Pumps	0.000	0.000	0.000	0.014	0.028	0.043	0.24%	31,334.61	5,222.44
Other	0.000	0.000	0.000	0.000	0.000	0.000	0.00%	86.76	14.46
Process Cooling	0.000	0.000	0.000	0.000	0.001	0.001	0.00%	596.63	99.44
Process Heating	0.010	0.012	0.014	0.018	0.022	0.025	0.14%	18,727.66	3,121.28
Process Specific	0.006	0.007	0.008	0.009	0.010	0.011	0.06%	8,178.71	1,363.12
						0.286	1.61%	209,782.41	34,963.73

INDUSTRIAL SUMMARY

TOTAL AP (GWh)	17.704
TARGET (GWh)	13.009
INDUSTRIAL AP (GWh)	0.286
INDUSTRIAL TARGET (GWh)	0.210

Opportunities in the Industrial segmentation for InnPower are minimal as this customer classification does not exist at this timeframe. Carryover measures from some of our larger commercial customers will account in the Industrial segmentation under the PSUI programs.

InnPower Corporation Budget and Forecast Summary

FORECAST SUMMARY	
2015-2020 Target kWh	13,008,552.900
Target Achievement (IESO Prov Programs)	9,897,279
Target (%)	76.08%
2015-2020 Budget	$3,680,241.00
Total Forecast Incentive	$2,148,812
Incentive Budget Existing Programs (%)	58.39%
Budget Remaining	$1,531,429
Total "Unassigned Target"	3,111,274
Residential Allocation	2,514,612
Business Allocation	392,684
Non-Incented Allocation	203,978
Residential Budget for Unassigned	$729,237
Business Budget for Unassigned	$94,244
Non-Incented Budget	$0.00
Admin, Marketing, 3rd Party Budget	$707,947

The summary identifies several key areas of focus and opportunities for InnPower in terms of delivery and implementation for the CFF CDM plan:

- 76.08% of InnPower's target can be achieved via existing IESO provincial programs which includes High Performance New Construction (HPNC) for new homes,
- The remaining 23.92% will have to be "designed" in the appropriate market segmentation to achieve InnPower's total target,
- As the current IESO provincial programs will only deliver 76.08% of the allocated target, $823,421 has been reserved for new program design for the Residential and Business/Commercial segmentations,
- Achieving 76.08% in the forecasted market segmentation categories provides $2,148,812 of incentives to Innisfil customers or 58.39% of InnPower's budget. This is a win/win scenario for our customers ,
- Statistics from the 2011-2014 CDM timeframe confirm that over 70% of InnPower energy savings resulted from the Commercial market segmentation. Currently, with only 1076 commercial customers of which 374 have already participated in the saveONenergy programs, saturation may be an issue to address commencing in 2018.

The CFF 2015-2020 framework for InnPower will have its challenges, new work functions, demographics of rate classes and new program design/implementation. InnPower has structured our CDM plan to allow for both the transition in 2015 to the new framework and flexibility in 2016 to collaborate with IESO on new program design. The ability to design and implement conservation programs allows InnPower to look at value ads that are specific to Innisfil customers versus provincial assumptions; i.e. programs involving electric heating storage and/or direct incentives on customers' electricity invoices.

6. Information Technology and Metering Five Year Capital Plan

Information Technology (IT) continues to be an integral part of the electricity industry in Ontario. The challenges and demands for increased efficiencies and security with zero down time provide on-going opportunities to improve our network infrastructure. Disaster recovery planning and implementation are key to maintaining a healthy network. A comprehensive security audit of InnPower's internal network is conducted annually. Remedial actions required are scheduled and undertaken collaboratively with third party support and internal IT staff. InnPower's network currently consists of 30 virtual servers, 7 physical servers and over 75 devices.

InnPower's new website was launched in January 2015. The new site offers timely information and links to Customer Connect, our new self-serve portal, as well as power outage information. Continued investment in online customer engagement is a key focus for InnPower's long term plan.

During the fourth quarter of 2015 a Customer Information System (CIS) utilization review will be conducted to identify areas where process change, automation and new add-ons or integrations could be implemented to maximize software and resource utilization. The Northstar automation platform will allow automation of routine processes. Automation software implementation is scheduled for first quarter 2016. Mobile workforce management supports a paperless work order solution for field staff and is currently extended to all departments.

An upgrade of Microsoft Great Plains (MGP) (financial software) to the current version GP 2013 was recently implemented. Prophix capital budgeting, forecasting and planning software was added to the suite of financial software applications in 2015. Prophix software streamlines the overall budgeting process eliminating much of the manual work. Automation software for accounts payable is planned for 2016.

Implementation of Springboard software in 2012, which automated the tracking of Human Resources and Safety training, continues to track training compliance. FUSE software continues to provide video training modules of safe work procedures for our Operations staff. Penny software, used for daily time reporting, was upgraded in 2013. The next upgrade to the payroll software is scheduled in 2016.

Engineering continues to build on the implementation of a Map3D solution supplied by AutoDesk. CYME software for distribution system planning, analysis and Connection Impact Assessment for distributed generation will continue and will be enhanced with additional CYME applications in 2016. A work order management application is planned to be added to the suite of engineering software in 2016.

Between 2016 and 2020 further system integrations will be undertaken to achieve asset data integration. In 2014 significant work was successfully undertaken to integrate Smart Meter data provided by the Operational Data Store (ODS) with InnPower`s Outage Management

System (OMS). In 2016 both the GIS and CYME modeling software will have enhancements to improve functionality. A new control room was launched with the move to the new facility in 2015. A controller and software were added to increase functionality providing operators and on-call staff the tools required to maintain reliability.

Contracts with the Alliance Service Bureau operated by Savage Data Systems continue to provide timely processing of our daily settlement statements from the Independent Electricity System Operator (IESO). Local embedded generation, 75 micro FIT and 5 FIT projects, have been integrated into our daily settlements by the Service Bureau for import into the CIS allowing streamlined billing and settlement. Further developments include integration of the smart meter data into InnPower's power distribution analysis software to assist in distribution grid planning, maintenance and upgrades.

Electricity retailers continue to be active in our service area but the number of customers continues to decline. There are service agreements with 18 electricity retailers, of whom 14 have active enrollments. North Star Utilities Division of Harris Computer Systems and ERTH Corp Business Technologies division provide dependable software solutions that allow us to transact over 90,000 Electronic Business Transactions (EBT) annually with electricity retailers via our Customer Information and Billing System (CIS) through the EBT HUB.

As part of a consortium of 32 LDC's, InnPower participated in security audits of the Advanced Metering Infrastructure (AMI) in 2012 and 2014. Remediation efforts are being reviewed by the smart meter vendor, Sensus Metering Systems Inc., to address vulnerabilities identified in the audit reports. A subcommittee of several utilities continues to work on remediation progress during 2015. Meter encryption is currently in progress and is planned to be rolled out in early 2016, eliminating many of the identified vulnerabilities. AMI security audits are expected to continue as meter functionality changes to meet market demands and safety requirements.

Projected growth, combined with the opportunity to add water metering to InnPower's existing AMI network, requires additional infrastructure to support the increased volume. A Tower Gateway Basestation (TGB) is budgeted in the 5 year plan for 2018.

In 2015, Measurement Canada released a bulletin advising that the Sensus smart meters under approval number AE-1611 installed in Ontario have been given a 10-year unconditional seal extension period. This accounts for over 90% of our current population extending the reverification timeframe to 2019. Second generation smart meters enabling two-way communication for in-home devices with which consumers can monitor their electricity usage continue to be installed. New generation meters containing safety enhancements and UL certification will be purchased in the near future upon Measurement Canada approvals. Alternative metering solutions are being researched for a unique phased resort development planned to be connected to our distribution system in 2016. These solutions can be utilized to support multi-unit installations expected in the growth projections within the 5 year plan.

The following IT and Metering Five Year Capital Plan is designed to sustain the existing network infrastructure, server capacity, processing speed and user workstations required to

operate efficiently and profitably in the electricity market. The goal is to facilitate system integration to improve efficiency while maintaining the high level of security required to ensure data integrity and system reliability.

Budgets for general office furniture, equipment, building and fixture requirements for the next five years have also been included in the following long range forecast to support growth in staffing levels as the customer base grows.

5 YEAR CAPITAL PLAN for IT, Metering, Buildings, Furniture, Equipment

Hardware/Metering	2016	Description	2017	Description	2018	Description	2019	Description	2020	Description
Network/Security Infrastructure	30,000	Network/Security Infrastructure	30,000	Network/Security Infrastructure	30,000	Network/Security Infrastructure	30,000	Network/Security Infrastructure	30,000	Network/Security Infrastructure
Printers/Peripherals	0	Add network printers	15,000	Add network printers	15,000	Add network printers	15,000	Add network printers	15,000	Add network printers
		and other peripherals		and other peripherals		and other peripherals		and other peripherals		and other peripherals
Network Enhancements/Replacements	50,000	Network Enhancements/Replacements	50,000	Network Enhancements/Replacements	50,000	Network Enhancements/Replacements	50,000	Network Enhancements/Replacements	50,000	Network Enhancements/Replacements
Servers/Virtualization		Servers/Virtualization	50,000	Servers/Virtualization	35,000	Servers/Virtualization	35,000	Servers/Virtualization	35,000	Servers/Virtualization
General Hardware	30,000	Mailing Printer/Inserter								
Workstation Addition/Replacement	20,000	Workstation Addition/Replacement	20,000	Workstation Addition/Replacement	20,000	Workstation Addition/Replacement	20,000	Workstation Addition/Replacement	20,000	Workstation Addition/Replacement
		workstations & monitors		workstations & monitors		workstations & monitors		workstations & monitors		workstations & monitors
		cyclical by department		cyclical by department		cyclical by department		cyclical by department		cyclical by department
Wholesale Meters	0	Wholesale Meter Upgrades	0	Wholesale Meter Upgrades	70,000	Additional Wholesale Meter Point	0	Wholesale Meter Upgrades	0	Wholesale Meter Upgrades
Retail Meters	147,500	Residential and C&I	230,000	Residential and C&I	250,000	Residential and C&I	250,000	Residential and C&I	250,000	Residential and C&I
AMI Infrastructure	0		0		50,000	Additional TGB(s) for AMI	0		0	
Measuring and testing Equip	0	Measuring and Testing Equip	23,000	Measuring and Testing Equip	5,000	Measuring and Testing Equip	5,000	Measuring and Testing Equip	5,000	Measuring and Testing Equip
Hardware/Metering Total	**$277,500**		**$418,000**		**$525,000**		**$405,000**		**$405,000**	
1860	147,500		230,000		370,000		250,000		250,000	
1920	130,000		165,000		150,000		150,000		150,000	
1945	0		23,000		5,000		5,000		5,000	
Total	**277,500**		**418,000**		**525,000**		**405,000**		**405,000**	

Software	2016	Description	2017	Description	2018	Description	2019	Description	2020	Description
IT Security Software	0	IT Security Software	15,000	IT Security Software	15,000	IT Security Software	15,000	IT Security Software	15,000	IT Security Software
General Software	35000	in-house mailing software								
IT Network Software	15,000	Network Software	15,000	Network Software	15,000	Network Software	15,000	Network Software	15,000	Network Software
CIS Software	50,000	Harris NS upgrades/automation/integration	50,000	Harris NS upgrades/automation/integration	50,000	Harris NS upgrades/automation/integrati	50,000	Harris NS upgrades/automation/integrati	50,000	Harris NS upgrades/automation/integratio
Finance/Regulatory Software	40,000	Paperless AP Solution	52,000	Finance upgrades and integrations	50,000	Finance upgrades and integrations	60,000	Finance upgrades and integrations	50,000	Finance upgrades and integrations
	25,000	Prohpix design services	25,000	Prohpix design services						
	12,000	2015 GP Upgrade								
	45,000	Regulatory Dashboard software								
Engineering Software	40,000	EngineGIS Enhancements	40,000	Mobile Work Force Systems for Field Crews	65,000	FDIR - Phase 1	71,500	FDIR - Phase 2	100,000	Engineering Projects
	16,500	Asset Data Integration	17,325	Asset Data Integration	18,191	Mobile Work Force - Phase 2				
	65000	Work Management	65000	Work Management - Phase 2	17,325	Asset Data Integration				
			45,000	GIS Enhancements	45,000	GIS Enhancements	47,500	GIS Enhancements		
Workstation software	15,000	Workstation applications upgrades	15,000	Workstation applications upgrades	15,000	Workstation applications upgrades	15,000	Workstation applications upgrades	15,000	Workstation applications upgrades
		cyclical by department		cyclical by department		cyclical by department		cyclical by department		cyclical by department
Software Total	**$358,500**		**$339,325**		**$290,516**		**$274,000**		**$245,000**	

Building	2016	Description	2017	Description	2018	Description	2019	Description	2020	Description
Building Fixtures	15,000	Misc Building Fixtures	15,000	Misc Building Fixtures	15,000	Misc Building Fixtures	15,000	Misc Building Fixtures	15,000	Misc Building Fixtures
Furniture & Equip	15,000	Misc Furniture & Equipment	15,000	Misc Furniture & Equipment	15,000	Misc Furniture & Equipment	15,000	Misc Furniture & Equipment	15,000	Misc Furniture & Equipment
Total	**$30,000**		**$30,000**		**$30,000**		**$30,000**		**$30,000**	
Grand Total	**$666,000**		**$787,325**		**$845,516**		**$709,000**		**$680,000**	

Summary	2016	Description	2017	Description	2018	Description	2019	Description	2020	Description
1860	147,500		230,000		370,000		250,000		250,000	
1920	130,000		165,000		150,000		150,000		150,000	
1925	358,500		339,325		290,516		274,000		245,000	
1908	15,000		15,000		15,000		15,000		15,000	
1915	15,000		15,000		15,000		15,000		15,000	
1945	0		23,000		5,000		5,000		5,000	
Total IT & Metering	**666,000**		**787,325**		**845,516**		**709,000**		**680,000**	
Engineering capital	**-**		**-**		**-**		**-**		**-**	
WIP changes	**-**		**-**		**-**		**-**		**-**	
Total IHDSL capital	**666,000**		**787,325**		**845,516**		**709,000**		**680,000**	

7. Engineering Five Year Capital Plan

The capital infrastructure necessary to meet the 20-year demand, which is more than double the existing demand, will require long term planning with staging of the capital infrastructure. Failure to plan capital requirements will prohibit InnPower from meeting the needs of the growing community which would, therefore, restrict growth due to lack of capacity, contrary to the Distribution System Code (DSC).

The DSC requires an LDC to maintain its distribution system in good working condition, as follows:

> *"4.4.1 A distributor shall maintain its distribution system in accordance with good utility practice and performance standards to ensure reliability and quality of electricity service, on both a short-term and long-term basis."*

Furthermore, the introduction of *Ontario Regulation 22/04*, Electrical Distribution Safety, in late 2004 established additional legislated focus on maintaining municipal distribution systems. Specifically the Regulation requires an LDC to:

"Section 4. Safety standards…

> *(2) All distribution systems and the electrical installations and electrical equipment forming part of such systems shall be designed, constructed, installed, protected, used, maintained, repaired, extended, connected and disconnected so as to reduce the probability of exposure to electrical safety hazards. O. Reg. 22/04, s. 4 (2)."*

Section 4 goes on to identify all components of the distribution system and specifies for each component as follows:

"1. Operating electrical equipment shall be maintained in proper operating condition."

InnPower has established a documented program to address the legislated requirements to maintain its distribution system. Appendix 3 includes the Asset Management Plan which was first developed in 2008.

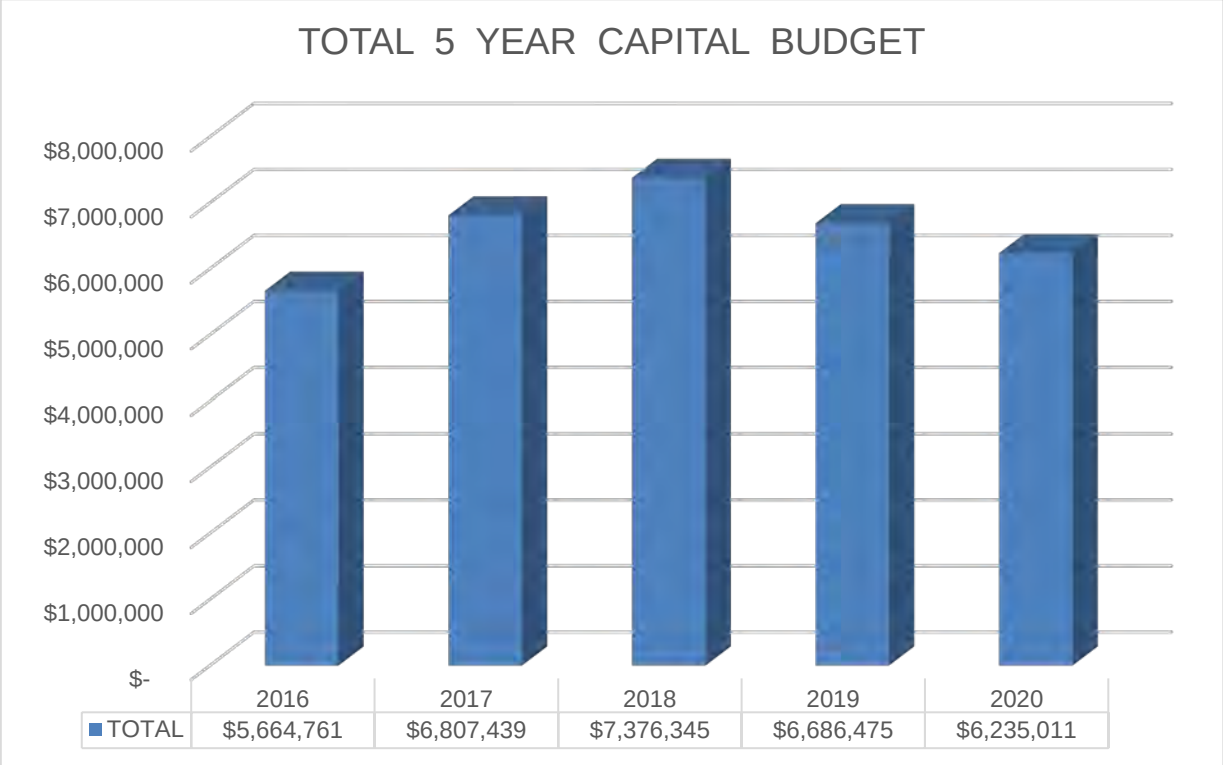
Whether O&M or Capital, programs are generally prioritized as follows:

1. Health & Safety
2. Legislative
3. Growth
4. Reliability

OVERALL 5 YEAR CAPITAL BUDGET

Investment	2016	2017	2018	2019	2020
System Access	$ 1,362,295	$ 1,753,806	$ 1,984,220	$ 1,594,757	$ 1,598,442
System Renewal	$ 1,136,744	$ 1,215,739	$ 1,140,219	$ 2,919,105	$ 2,399,973
System Service	$ 2,505,220	$ 2,337,760	$ 2,828,750	$ 1,275,800	$ 1,556,279
General Plant	$ 660,502	$ 1,500,135	$ 1,423,156	$ 896,813	$ 680,317
TOTAL	$ 5,664,761	$ 6,807,439	$ 7,376,345	$ 6,686,475	$ 6,235,011

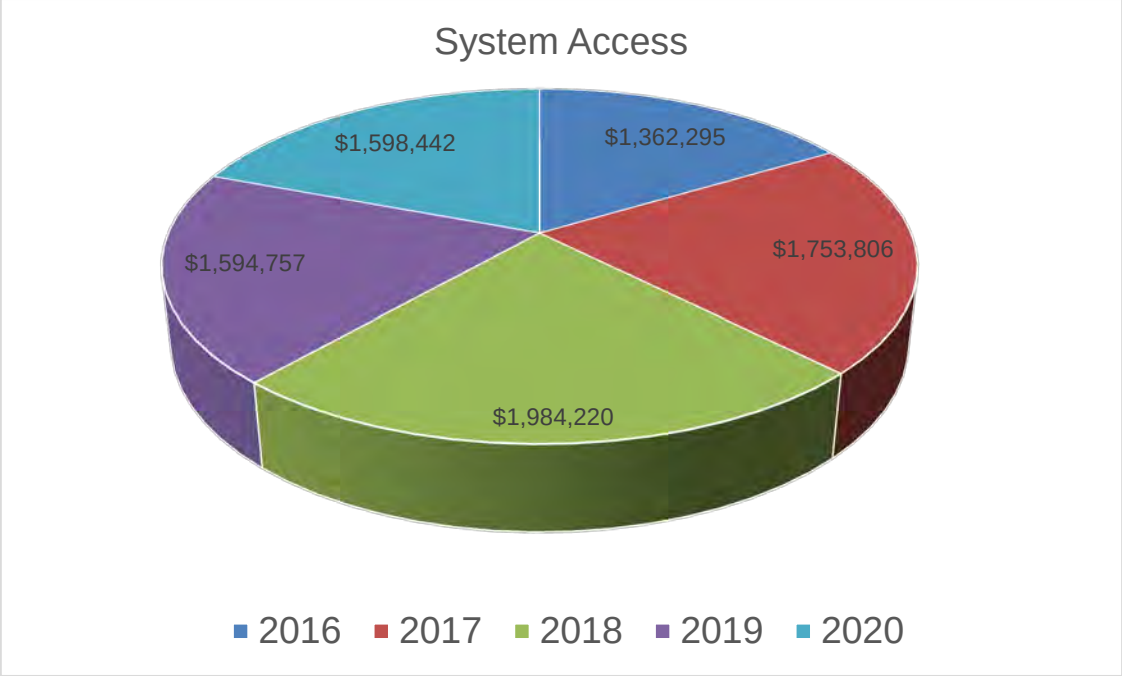
The above four categories of investments have been defined by the OEB under Chapter 5 of the Filing Requirements. In the sections below each of these investment categories have been described with specific project descriptions and their budgets for the five year period.



System Access Projects and Investments

System access investments are modifications (including asset relocation) to the distribution system an LDC is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system.

Projects/activities in this category are driven by statutory, regulatory or other obligations on the part of the distributor to provide customers with access to their distribution system. Most frequently, investments relate to requests by customers for connections or connection modifications, but also include requests from municipal authorities to relocate system assets in order to accommodate infrastructure development or modifications.



Base Capital Budget:

Carried through the 5 year plan, allowances for unplanned capital like legacy hydro trespasses are in every year for 2016 to 2020. Another major component of the base category is the amount paid out to Developers of subdivisions as part of the Economic Evaluation (EE) process. This amount can vary considerably from year to year. In 2015 the EE payout is expected to be just over $550k; however, this amount is expected to increase in the years to come. We are currently evaluating available options to account for the large EE payouts while ensuring that our Capital spend remains consistent. The base category also represents customer demand and municipal projects that may or may not have contributions.

County Relocates

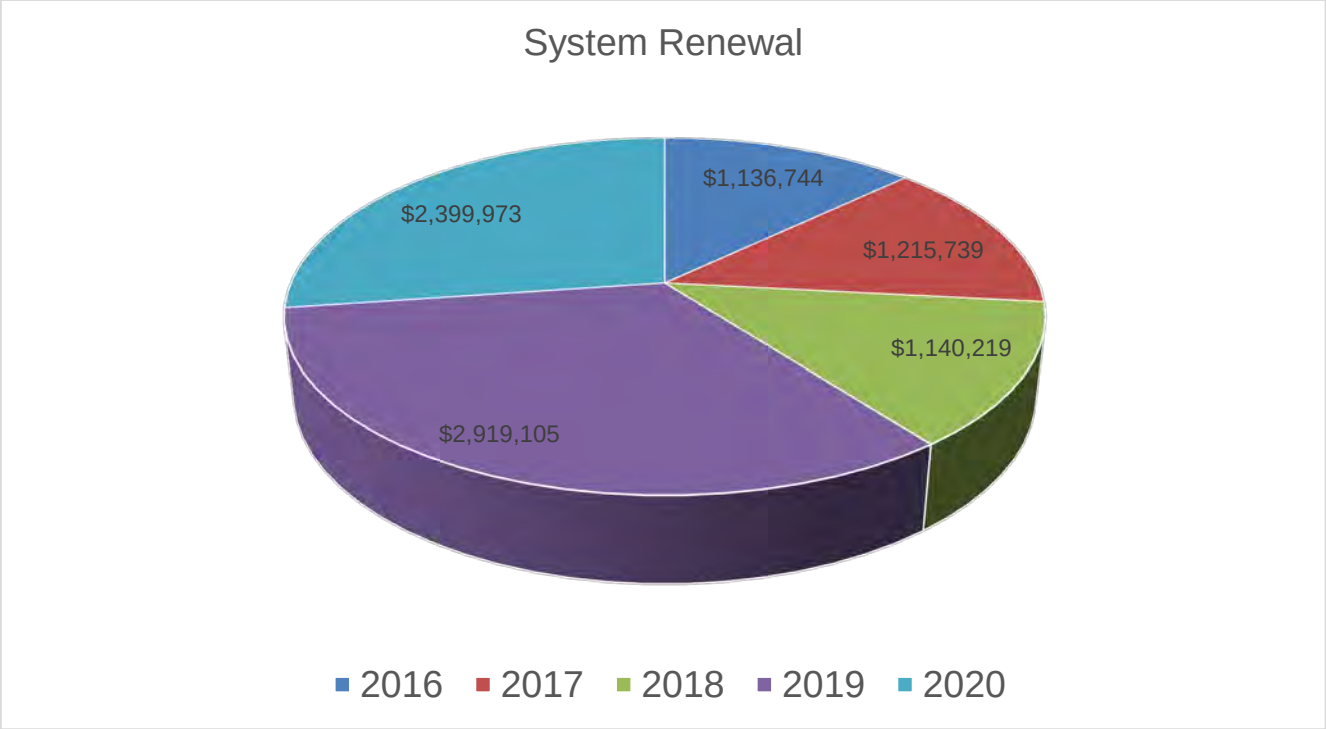
As part of its transportation engineering plan, the County of Simcoe is widening Innisfil Beach Road (IBR), between Thornton on the west end to 20th Side Road on the east end, covering a distance of about 12 km. This project requires the moving of multi-circuit pole line infrastructure to accommodate their requirements. The project was started in 2012 with the widening of the intersection of IBR and 10th Side Road, and is expected to continue each year until 2020. In 2015, the intersection of IBR and 20th Side Road is scheduled for expansion, with the intersection of IBR and the 5th Side Road scheduled for 2016, and the intersection of IBR and Yonge Street in 2017. In the following years, sections of Innisfil Beach Road are planned for widening; Yonge Street to 20th Side Road in 2018, Yonge Street to 10th Side Road in 2019, and Highway 400 to 10th Side Road in 2020.

System Access	2016	2017	2018	2019	2020
Total	$ 1,362,295	$ 1,753,806	$ 1,984,220	$ 1,594,757	$ 1,598,442
Base 1 (50%)	$ 137,500	$ 116,880	$ 122,725	$ 134,998	$ 148,497
Base 2	$ 36,248	$ 34,254	$ 35,970	$ 39,567	$ 43,523
- contributions for Base 2	-$ 10,255	-$ 11,486	-$ 10,175	-$ 11,193	-$ 12,311
Base 3	$ 900,530	$ 945,557	$ 1,087,390	$ 1,359,237	$ 1,699,046
- contributions for Base 3	-$ 900,530	-$ 945,557	-$ 1,087,390	-$ 1,359,237	-$ 1,699,046
Base 4	$ 635,938	$ 5,558,640	$ 9,349,360	$ 9,349,360	$ 9,349,360
- contributions		-$ 4,446,912	-$ 8,254,960	-$ 8,254,960	-$ 8,254,960
Metering	$ 147,500	$ 230,000	$ 270,000	$ 250,000	$ 250,000
County Road Widening					
IBR & 5 SR	$ 656,981				
- contributions	-$ 241,617				
Intersection Widening IBR & Yonge St		$ 430,000			
- contributions		-$ 157,570			
Road widening IBR between Yonge St & 20 SR			$ 745,000		
- contributions			-$ 273,700		
Road widening IBR between Yonge St & 10 SR				$ 137,500	
- contributions				-$ 50,515	
Road widening IBR between Hwy 400 & 10 SR					$ 117,500
- contributions					-$ 43,167

System Renewal Projects & Investments

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintaining the ability of the distributor's distribution system to provide customers with electricity services.

Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. failure). Generally, the lower the former and/or higher the latter, the more important it becomes to replace or refurbish the asset(s) sooner rather than later.



Base Capital Budget:

Carried through the 5 year plan, allowances for unplanned capital like storm replacements and capital repairs of the distribution system are in every year for 2016 to 2020.

Distribution Reliability Projects

Throughout the five-year plan, seven ongoing projects are budgeted year over year to address the need to remove and replace rotten and damaged infrastructure, and substandard or defective devices that pose a danger to the public and safety of workers. These projects are: **Substandard Infrastructure Improvements**, which updates legacy and substandard construction within the distribution system; the **Pole Replacement Program** replaces aged and failing poles that have been tested or deemed in need of replacement; **Infrastructure Replacements and Betterments Program** assists with the replacement of aged or defective devices; the **Underground Padmounted Transformer and Switchgear Replacements and Painting Program** helps repair and renew gears and transformers adversely affected by weather conditions and salt contamination; **DS Oil Re-inhibit program** helps to restore oxidation inhibitor levels inside the main tank of the station transformer to effective levels; and the **Station Rehab** projects are aimed at performing repairs to deteriorating infrastructure in our aging distribution stations. Finally, capital has been budgeted over the next five years for **Line Recloser Refurbishments** which has all reclosers on a four-year cycle to rebuild and renew these sectionalizing devices ensuring correct operation every time.

Other General Distribution Reliability Projects

Throughout the five year plan, other general reliability projects are scheduled to take place. Starting in 2016 and phased over a five-year period old sub transmission infrastructure along Lockhart Road between our Stroud DS (Yonge Street) and the 25th Side Road will be replaced ensuring reliability in the 44 kV. Also as part of our sub transmission reliability upgrade work the pole line north of Highway 89 on 5th Side Road will be rebuilt using a phased approach starting in 2017, and continuing in 2019 and 2020.

At the distribution level, starting in the year 2016 and phased over the next four years, Ewart Street will receive a line upgrade south of Maple Road where several of the existing poles are sinking lower into the swamp land they were originally constructed on. Several other poles in this section have also been flagged for immediate replacement by our pole inspectors.

Starting in 2017/18 and phased over the next three years smaller scale general reliability projects are scheduled to take place in the Alcona, Cookstown, Lefroy, and Strathallan Woods areas. These projects include infrastructure upgrades and rehabilitation work replacing aged infrastructure to new construction standards for increased reliability.

In 2018, the start of a two-year project to replace aged infrastructure that span over top of Highway 400 is to be replaced to new construction standards.

Finally, year 2019 will have a reliability project to relocate legacy backyard construction in an effort to provide better reliability, and worker and public safety, and another project to replace aged underground cables also to improve reliability. Both Everton Drive and Parkview Drive will see the replacement of aged infrastructure relocated from rear lots to the street boulevard, while Sandycove acres will see their direct-buried 40 year old underground cables replaced for greater reliability.

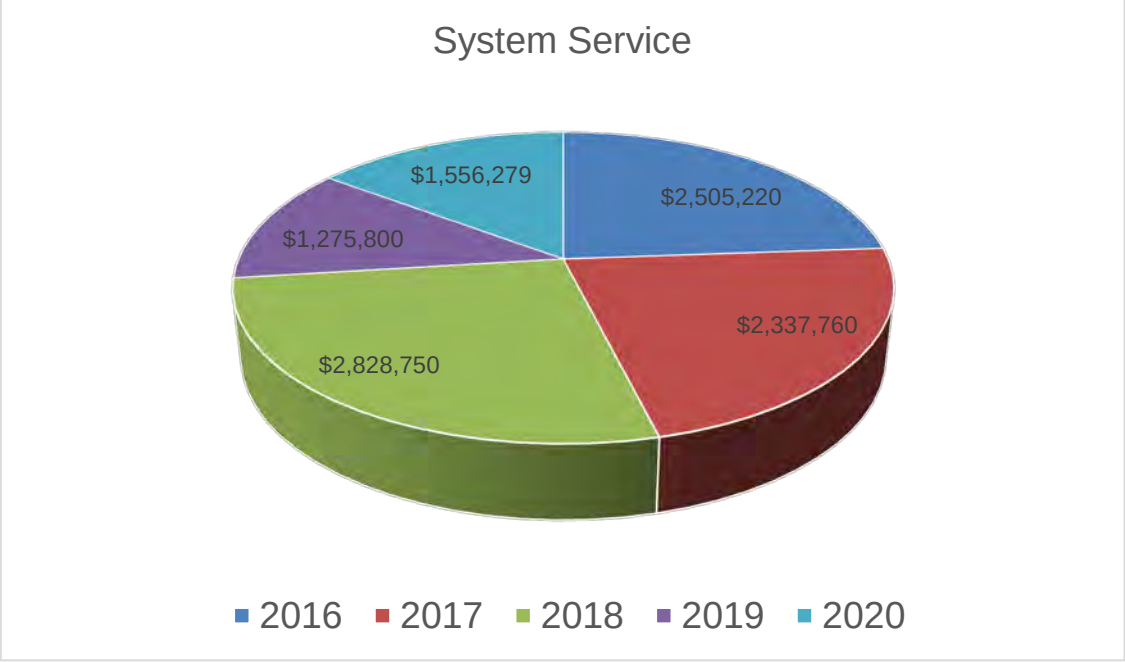
System Renewal	2016	2017	2018	2019	2020
Total	$ 1,136,744	$ 1,215,739	$ 1,140,219	$ 2,919,105	$ 2,399,973
Base 1 (50%)	$ 137,500	$ 116,885	$ 122,725	$ 128,861	$ 135,304
Substandard Transformer Rehab	$ 109,505	$ 85,000	$ 30,000	$ 31,500	$ 33,075
Pole Replacement Program	$ 200,914	$ 126,470	$ 148,500	$ 155,925	$ 163,721
Infrastructure Replacements and Betterments	$ 143,098	$ 150,253	$ 157,766	$ 165,654	$ 173,936
Line Reclosure Refurbishments - 4 Year Cycle	$ 15,186	$ 15,945	$ 16,742	$ 17,579	$ 18,458
DS Oil Re-inhibit Treatment	$ 26,216	$ 27,527	$ 57,806	$ 60,696	$ 30,000
Padmounted Transformer and Switchgear Replacements and Painting	$ 83,256	$ 43,710	$ 45,895	$ 48,190	$ 50,599
Station rehab	$ 199,280	$ 104,300	$ 109,853	$ 115,346	$ 242,226
Ewart Street Rebuild - Phased Approach	$ 101,790	$ 105,000	$ 50,000	$ 52,500	$ 56,700
Transformers	$ 120,000	$ 100,000	$ 110,000	$ 121,000	$ 133,100
Everton Back Lot Conversion - Phased Approach				$ 155,000	$ 135,000
Reliability rebuild-Distribution: 400 Crossing - Phased Approach			$ 22,500		$ 75,000
Reliability Rebuild-Subtransmission: Lockhart east of 20SR - Phased Approach		$ 85,000		$ 200,000	$ 103,910
Reliability Rebuild-Subtransmission: Lockhart east of Stroud DS - Phased Approach		$ 85,650	$ 89,933	$ 94,429	$ 99,150
Reliability Rebuild-Subtransmission: 5th Sideroad Hwy 89 to 5th Line - Phased Approach		$ 75,000		$ 550,000	$ 225,000
Reliability rebuild-Distribution: Strathallan Woods - Phased Approach			$ 31,500	$ 33,075	$ 34,728
Reliability rebuild-Distribution: Cookstown Area - Phased Approach		$ 50,000	$ 52,500	$ 55,125	$ 200,880

System Renewal	2016	2017	2018	2019	2020
Reliability rebuild-Distribution: Lefroy Area - Phased Approach		$ 22,500	$ 47,250	$ 49,613	$ 52,093
Reliability rebuild-Distribution: Alcona Area - Phased Approach		$ 22,500	$ 47,250	$ 49,613	$ 52,093
Sandy Cove - U/G cable replacement Phase Approach				$ 700,000	$ 250,000
Parkview rear lot 1 phase relocate to street front - Phased over 2 years				$ 135,000	$ 135,000
Degrassi Cove U/G conversion					

System Service Projects & Investments

System service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements.

Projects/activities in this category are driven by the distributor's expectations that evolving customer use of the system may occasion the creation of system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor's service delivery standards or objectives.



Station Upgrades:

In 2016 Stroud DS, the first of the two remaining legacy construction DS' equipped with hydraulic reclosers, will be upgraded to vacuum type reclosers with electronic controls, while Sandy Cove DS will be upgraded in 2017 to complete our multi-year DS upgrade project. With the completion of this project we will have SCADA capability between our control room and all our distribution stations.

SCADA and Distribution Automation Projects and Smart Grid

With a new SCADA program implemented in 2012 and the new outage management system commissioned in 2013, efforts were undertaken in 2014 and 2015 to construct a WiMAX communication network for use by both the Town of Innisfil and InnPower. Due to the increase in the use of unlicensed radio frequency in the area, InnPower and the Town were experiencing issues with intermittent communication caused by radio interference (noise). Due to strict latency requirements for Distribution Automation and with the increasing demand in bandwidth, acquiring a WiMAX (4G) communication network operating on a licensed frequency dedicated by Industry Canada for electric utilities became the obvious choice to ensure grid communication reliability.

The new communication network will serve Hydro, Water and Wastewater for SCADA and other monitoring and control applications. For continued growth into InnPower's automation, 27.6 KV and 44 KV automated switches will be added each year starting in 2017, replacing several old mid-span openers and airbrake style switches. These new switches provide remote switching capability and real-time data acquisition to better manage outages. Crew time will be reduced during emergency and non-emergency operations and built in functionality can be used for future smart grid, self-healing configurations.

Advancements like the automated capacitor controller will occur in 2019 and 2020 to monitor and control the amount of reactive power in the system, and in 2019 and 2020 two (2) motorized SCADA controlled padmount switch gear will be installed each year in strategic locations for faster restoration during outages.

Load Growth:

The population increase in our service territory has created the need for us to increase our power supply capacity, resulting in the need to phase in new distribution stations, capacity upgrades to existing stations, and line builds to add circuitry to supply the new loads.

Based on information currently available InnPower will see increased load growth in the following areas during the five year horizon: South Barrie – Hewitt Secondary Plan and Salem Secondary Plan, Friday Harbour, 400 Corridor, Alcona, Churchill, Cookstown, Gilford, Lefroy, Alcona South, and Stroud. Our peak demand is expected to increase from 60.9MW in 2015 to 83.1 MW in 2020, or 136%.

- **Barrie Lands Development:**

The Barrie-Innisfil Boundary Adjustment Act, 2009 (Bill 196) extended the southern boundary of Barrie to include 2,335 hectares (approximately 5,700 acres) of land previously in the Town of Innisfil, effective January 1, 2010. It is expected, based on conservative estimates, that the number of residences constructed in the Barrie South lands starting in 2018 will be 3,600 units by the end of 2020, adding approximately 1,200 units per year on average, likely resulting in a load increase (residential and commercial) of 17.1 MW.

- **Innisfil Lands Development:**

The number of residential units expected to be constructed during the next five years:

Residential Unit Development	2016	2017	2018	2019	2020
Total Alcona	145.8	91.8	163.2	178.8	150
Total Alcona South (Sleeping Lion)	0	60	60	60	60
Total Churchill	0	7.2	7.2	3	3.6
Total Gilford	0	3	3	3	3
Total Cookstown	30.6	18	28.8	10.2	0
Total Stroud	6	6	6	1.2	0
Total Friday Harbour	150	90	90	90	90
Total Lefroy	72	72	72	54.6	42
	0	0	0	0	0
Total Growth per year	404.4	348	430.2	400.8	348.6

To accommodate the increase in residential growth several capacity upgrade projects have been planned for the next 5 years. Anticipated within the five year plan is the development of commercial and industrial lands within the 400 corridor; however at this time load projections are unknown. We recognize that industrial/commercial load servicing will be required and through our continued networking with our developers and municipal planners, we are prepared to meet our obligations to serve the load as the need arises.

Planned Capacity Upgrades

- **Cedar Point DS Upgrade:**

The load increase in the area served by the Cedar Point DS (Belle Air Beach, Belle Ewart and surrounding area) and the summer peak loads in 2015 indicate that the transformer will require the station capacity to be increased from a 5MVA transformer to a 7.5 MVA during the summer of 2016.

- **Lines upgrade: Distribution:**

Starting in 2016 a project will rebuild the circuitry on McKay Road between 5th Side Road and 10th Side Road as part of our master plan to serve (and firm) new loads in south Barrie by extending existing circuits; and another project will build a 27.6kV line on the north side of

Big Bay Point Road as part of the master plan to serve the new Friday Harbour developments. Another project will upgrade the pole line on Lockhart Road between 10th Side Road (Huronia Road) and Stroud DS on a phased approach to add two distribution circuits to serve as a "back-bone" link between Salem and Hewitt lands. Finally, in 2017 a project will rebuild the pole line on Mapleview Drive between Prince William Way and Seline Crescent to serve new residential loads on the south side of Mapleview Drive in the Hewitt lands.

- **Lines upgrade: Sub transmission:**

In 2019 and 2020, a 44kV pole line rebuild and replacement on the 5th Side Road between the 5th Line and Innisfil Beach Road will take place to rebuild and replace the old small conductor infrastructure. This 44kV line will be constructed to have an additional sub-transmission 44kV circuit on it to accommodate the new Alliston 9M6 feeder scheduled to reach InnPower in the early 2020's for load growth.

- **New Distribution Station**

In an effort to serve the increased loads at Friday Harbour and part of the loads in the Hewitt developments a new Distribution Station is planned to be built in 2018 in the Friday Harbour area.

Voltage Conversion:

In an effort to serve our increasing load requirements and to provide reliable power, two voltage conversion projects will be completed in multiple phases between 2019 and 2020 along the 400 corridor and in south Alcona.

Reducing Environmental Hazards:

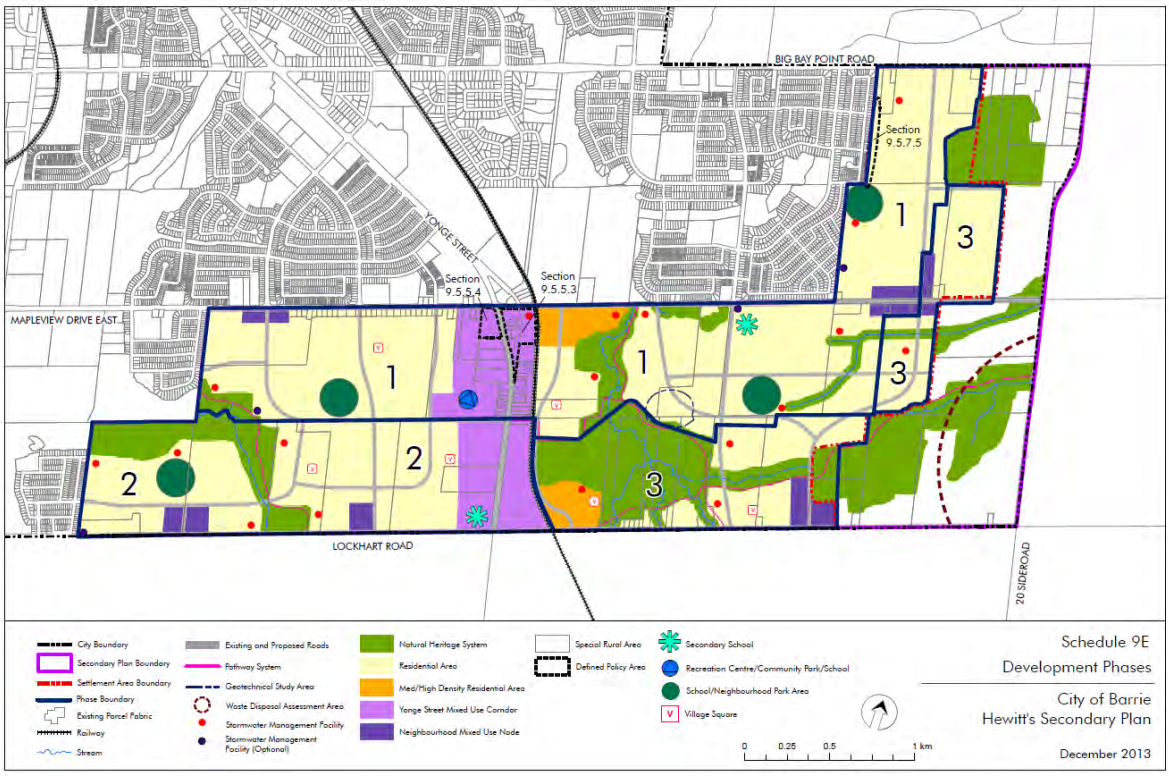
Several of our distribution stations do not currently have oil containment systems and it is planned to install such systems to limit environmental hazard risks on a phased approach, completing one station each year in 2017, 2019 and 2020.

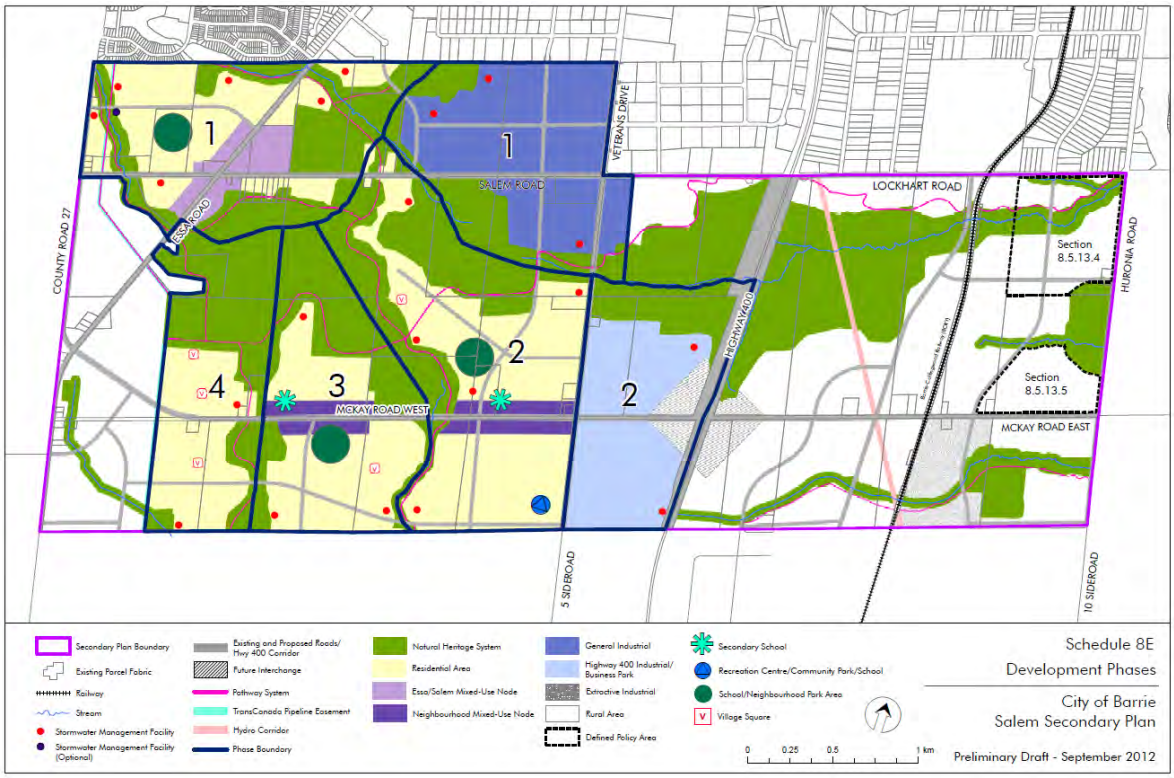
Load Growth Projections

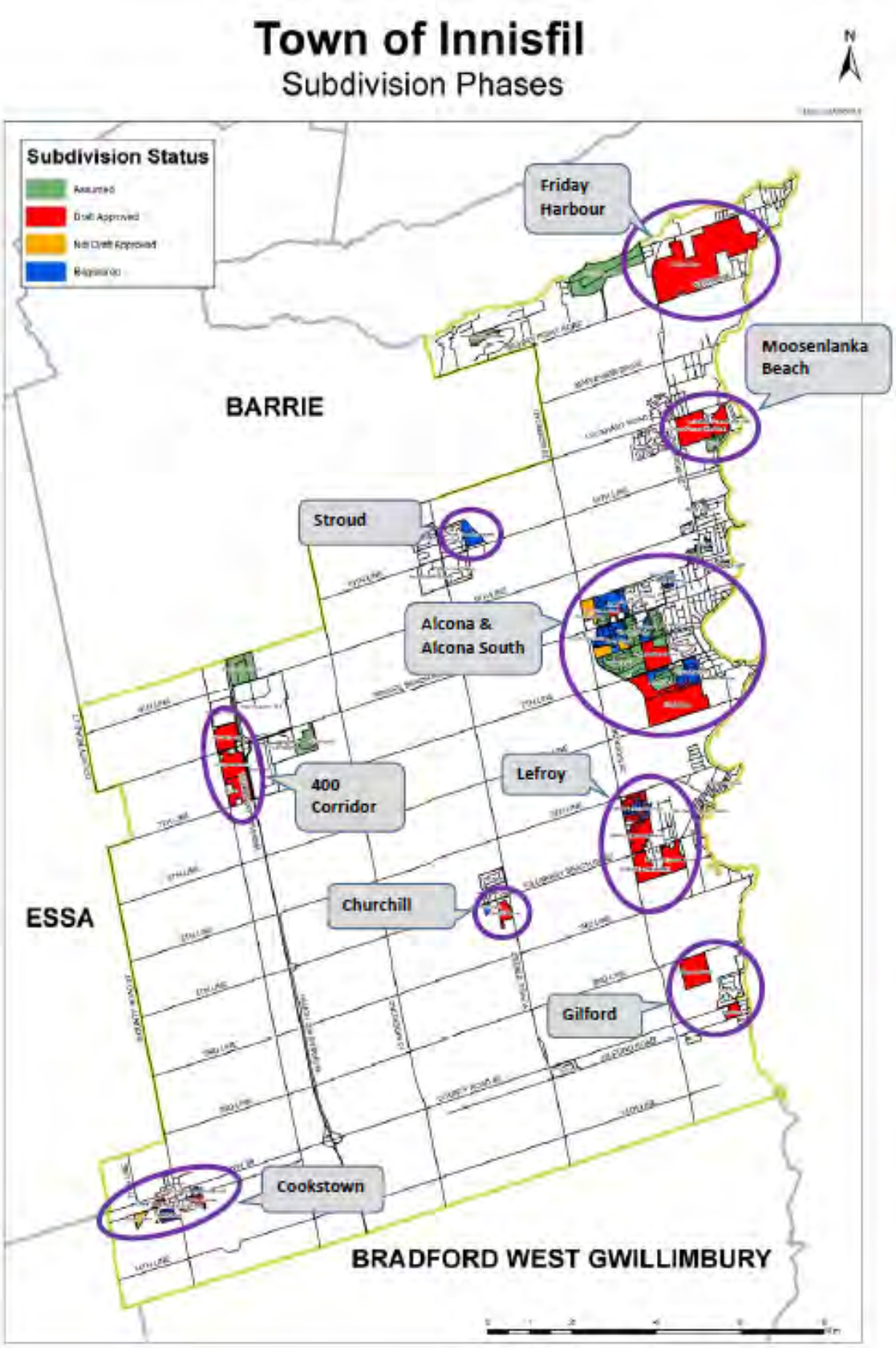
Transformer Station	Gross Median Weather Station Peak Demand Forecast (MW) IPC Usage Peaks - Revised as Per 11th Nov 2015											
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Barrie TS - Aggregate	**14.3**	**15.3**	**16.0**	**19.6**	**24.7**	**29.2**	**33.3**	**37.1**	**40.9**	**44.7**	**48.5**	**52.3**
Total Customer Growth - Barrie Annex, Friday Harbour, Stroud)	0.0	260	96	940	1006	847	798	748	748	748	748	748
Total Load Growth per year residential	0.00	0.99	0.36	3.57	3.82	3.22	3.03	2.84	2.84	2.84	2.84	2.84
Total Load Growth per year commercial (25% of total Load)			0.33	0.12	1.19	1.27	1.07	1.01	0.95	0.95	0.95	0.95
Everett TS - Aggregate	**3.0**	**3.1**	**3.2**	**3.3**	**3.3**	**3.3**	**3.3**	**3.4**	**3.4**	**3.4**	**3.4**	**3.4**
Total Load Growth per year residential	0.19	0.07	0.11	0.04	0.00	0.00	0.07	0.05	0.00	0.00	0.00	0.00
Total Load Growth per year commercial (None)	0	0	0	0	0	0	0	0	0	0	0	0
Alliston TS - Aggregate	**44**	**45**	**47**	**48**	**49**	**51**	**52**	**54**	**55**	**57**	**58**	**59**
Total Load Growth per year residential	1.40	1.44	0.95	1.22	1.19	1.04	1.34	1.24	1.27	1.04	0.99	0.99
Total Load Growth per year commercial (% of population)		0.28	0.29	0.19	0.24	0.24	0.21	0.27	0.25	0.25	0.21	0.20
Total Load Requirements	60.9	63.7	65.7	70.8	77.3	83.1	88.8	94.2	99.5	104.6	109.6	114.5

* Barrie land growth is based on the information available from the city plan
*HWY 400 Strategic employment lands not taken into account
* Information for TOI development taken from TOI plans, provincial requirements for popı
*Customers at EOY for 2014 include all rate classes except microFIT
* As phasing is not available for Barrie Lands after 2021, no of units are equally divided between salem and hewitt
* Available TOI data is from 2016-2026, rest is taken from George's business plan
* Load forecast does not have DG or CDM Correction

Maps of Barrie South lands development plan





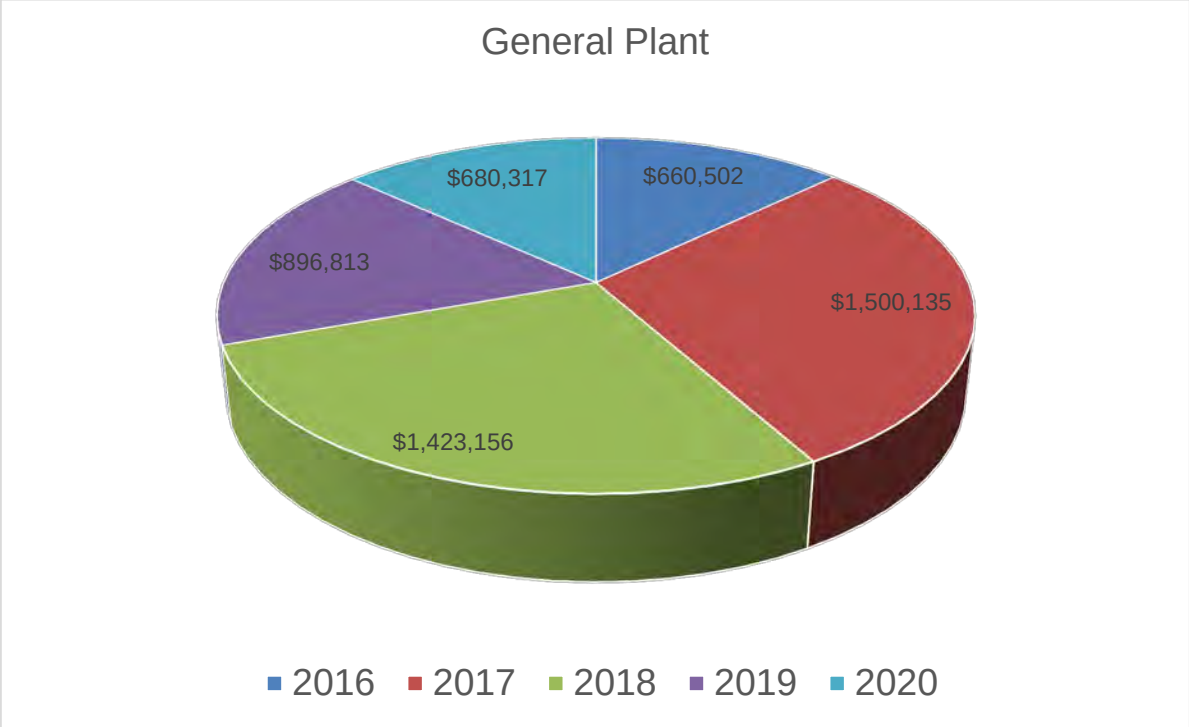

Town of Innisfil
Subdivision Phases
N
Subdivision Status
Assumed
Draft Approved
Not Draft Approved
Registered
Friday Harbour
Moosenlanka Beach
BARRIE
Stroud
Alcona & Alcona South
400 Corridor
Lefroy
Churchill
ESSA
Gilford
Cookstown
BRADFORD WEST GWILLIMBURY

System Service	2016	2017	2018	2019	2020
Total	$ 2,505,220	$ 2,337,760	$2,828,750	$1,275,800	$1,556,279
Distribution SCADA controlled load interrupting gang switch		$ 75,000	$ 78,750	$ 82,688	$ 86,821
Subtransmission SCADA controlled switches				$ 148,500	$ 155,925
SCADA PME motorized switch gear				$ 165,000	$ 173,250
Capacitor Intelilink to SCADA				$ 65,000	$ 65,000
Stroud DS Automation	$ 164,590				
McKay Rd Rebuild from 5th SR to 10th SR	$ 400,041				
Cedar Point DS Transformer Upgrade	$ 1,578,016				
BBP DS-Friday Harbour North Entrance to be reallocated for Salem Rd Project* see below	$ 362,573				
BBP DS-Friday Harbour North Entrance		$ 362,570			
Line Rebuild: Lockhart from Yonge to Huronia		$ 546,932			
Sandy Cove DS automation		$ 125,000			
Line Extension: Mapleview Dr., from Prince William Way to Rail Track		$ 293,333			
Load: Rail Track to St. Paul + St. Paul to Yonge St		$ 204,498			
Line Extension: Lockhart Rd, Stroud DS to Yonge St		$ 72,000			
Friday Harbour DS			$2,750,000		
*Load growth: Repoling North on 5th SR to Salem Rd		$ 273,427			
New Subtransmission Feeder: Line upgrade 5 SR from 5th Line to IBR				$ 315,000	$ 330,750
DS Transformer oil containment		$ 45,000		$ 49,613	$ 52,093
Line Rebuild to serve new developments south of Belle Ewart DS					$ 219,940
400 Corridor Voltage Conversion & Servicing				$250,000	$ 262,500
Alcona South Voltage Conversion				$ 200,000	$ 210,000
Line Rebuild: Mapleview Drive Yonge to Seline Crescent		$ 340,000			

General Plant Projects and Investments

General plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system including: land and buildings, tools and equipment, rolling stock and electronic devices and software used to support day-to-day business and operations activities.

Projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities.



Vehicles and Tooling

In 2017, the replacement of a 1993 Double Bucket truck will be necessary as this truck was purchased second hand from another power company in 2010 and will be at the end of its useful life. Additionally, the replacement of a 2006 half-ton pickup used by Stores will be necessary given its condition and age.

In addition, for new personnel added to our full time staff, four new smaller technician vehicles will be required in 2017, and two in 2018.

The increase in lines work and subdivision work resulting from the load growth has created the need to add a new line crew in 2018. The addition of this crew will require investment in a new bucket truck, a pick-up for the foreman, and additional tooling and equipment. An RBD truck will be added to the list but will be purchased in the year prior (2017) and a tension

machine will be purchased the following year (2019) to spread out the total investment required for the new crew.

In 2020 a 2005 half-ton truck will need to be replaced based on our Fleet Management Policy. Throughout the five year plan, vehicle replacement on smaller technician vehicles has been scheduled based also upon the Fleet Management Policy.

Tooling for the utility's needs has been carried through the five year plan.

Smart Grid

Moving throughout the five year plan, the system supervisory project, representing automation and smart grid plans, will continue to grow, as well as fault indicator installation plan for all 5 years except 2018.

General Plant	2016	2017	2018	2019	2020
Total	$ 660,502	$ 1,500,135	$ 1,423,156	$ 896,813	$ 680,317
IT Hardware	$ 130,000	$ 165,000	$ 150,000	$ 150,000	$ 150,000
IT Software	$ 115,000	$ 95,000	$ 95,000	$ 95,000	$ 95,000
Furniture and Equipment	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000
Buildings and Fixtures	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000
Finance IT	$ 122,000	$ 77,000	$ 50,000	$ 60,000	$ 50,000
Engineering IT	$ 121,500	$ 167,325	$ 145,516	$ 119,000	$ 100,000
Measuring Tools & Equipment IT & Meter		$ 23,000			
Fleet Tools	$ 15,000	$ 15,750	$ 16,538	$ 17,364	$ 18,232
Stores Equipment	$ 5,000	$ 5,250	$ 5,513	$ 5,788	$ 6,077
Tools, Shop and Garage Equipment	$ 23,000	$ 24,150	$ 25,358	$ 26,625	$ 27,956
Measurement and Testing Equipment	$ 15,000	$ 28,000	$ 30,800	$ 32,340	$ 33,957
Replacement Double Bucket Truck - 1993 Altec		$ 373,500			
Fleet vehicle replacement 1-2006 Ford 1/2 ton		$ 45,000			
Tech Vehicle - Ford Escape 2009 Replacement (#89)		$ -	$ 45,000		
Locator Vehicle Mini-van (x2)		$ 63,000			
Technologist Vehicle - NEW		$ 43,500			
Inspector vehicle - NEW		$ 43,500			
Distribution Fault Current Indicators	$ 41,002	$ 18,760		$ 15,000	$ 15,750
System Supervisory	$ 43,000	$ 32,400	$ 47,408	$ 49,778	$ 52,266
Tech Vehicle - Ford Escape 2008 Replacement (#85)			$ 45,675		
Meter Tech Vehicle - NEW			$ 45,675		
Inspector vehicle - NEW			$ 45,675		
Tech Vehicle - Ford Escape 2009 & 2010 Replacement (#88 & 95)				$ 95,918	
Fleet vehicle replacement 2005 1/2 ton (#87)					$ 51,750
Tech Vehicle - Ford Escape 2008 Replacement (#92)					$ 49,329
Fleet vehicle replacement 2011- 1/2 ton (#96)					
Fleet vehicle replacement 2011- 1 ton (#101)					
65' Double Bucket-new crew			$400,000		
1 Ton Pickup Truck-new crew			$45,000		
Clothing for 3 Men			$10,000		
Tools for Three Men			$15,000		
Tooling for Bucket & RBD			$150,000		
100 Travellers			$5,000		
Additional Spider system			$20,000		
Tension Machines				$ 200,000	
RBD - new Crew		$ 250,000			

8. Financial Five Year Forecast Plan

The following Proforma Financial statements (2016 - 2020) have been attached in Appendix 1:

- Executive Summary
- P&L Budget
- Balance Sheet Budget
- Cash from Operations Budget

Assumptions:

- Rebasing will occur January 2017.
- Projections are correlated with HR, IT and Engineering forecasts.
- Expenses have utilized 2.615%per year.
- Revenue growth is based on customer growth.
- Load trends are based on the Town's economic development activity.

Executive Summary

	Forecast 2015	Projection 2016	2017	2018	2019	2020
Total Customers Y/E	16,245	16,989	17,363	18,595	19,841	20,873
Growth Numbers	470	744	374	1,233	1,246	1,032
Growth %	3.0%	4.6%	2.2%	7.1%	6.7%	5.2%
Total Revenues	10,305,944	10,587,654	11,689,023	13,086,312	14,656,430	16,174,442
Total Expenses	7,958,767	8,416,374	9,850,888	10,736,805	11,426,546	11,996,987
NIAT	1,183,883	702,241	321,412	679,608	1,428,173	2,300,288
Retained Earnings	4,751,454	4,828,695	5,150,108	5,829,715	7,257,888	9,558,176
Return S/H Equity	7.3%	4.3%	1.9%	3.9%	7.7%	11.0%
Net Capital requirements	5,175,947	5,882,565	6,725,209	7,290,003	6,595,817	6,139,819
Dividends	781,250	625,000	-	-	-	-
Dividends yield	4.9%	3.9%	0.0%	0.0%	0.0%	0.0%
Change in cash	(1,521,580)	-	(0)	0	(0)	(0)
Debt	35,430,197	39,441,033	42,910,882	46,976,704	49,434,286	50,526,378
Change in debt	3,294,602	4,010,837	3,469,849	4,065,822	2,457,582	1,092,092
Debt ratio	68.7%	70.8%	72.2%	73.2%	72.6%	70.7%
Equity ratio	31.3%	29.2%	27.8%	26.8%	27.4%	29.3%
Rate impact			8%	4%	4%	4%
Debt @ 65%			30,153,983	30,750,892	32,013,021	34,665,341
Equity required			5,798,843	5,913,633	6,156,350	6,666,412
ROE			321,412	679,608	1,428,173	2,300,288
Rate impact			5%	2%	2%	2%
Debt @ 65%			30,153,983	30,164,061	30,391,801	31,419,465
Equity required			5,798,843	5,800,781	5,844,577	6,042,205
ROE			5,427	122,629	553,358	1,219,460

IPC

5 Year Projection

P&L Budget

	Actual 2014	Forecast 2015	Projection 2016	2017	2018	2019	2020
Energy Revenue	27,773,907	26,661,326	28,058,645	30,263,581	33,320,200	36,552,300	39,549,600
Energy Costs	(27,773,907)	(26,661,326)	(28,058,645)	(30,263,581)	(33,320,200)	(36,552,300)	(39,549,600)
Distribution Revenue	7,727,563	8,918,484	9,445,739	10,422,819	11,543,680	12,769,670	13,938,360
Other Revenue	532,765	1,387,460	1,141,915	1,266,204	1,542,632	1,886,760	2,236,082
Total Gross Margin & other revenue	**8,260,328**	**10,305,944**	**10,587,654**	**11,689,023**	**13,086,312**	**14,656,430**	**16,174,442**
Operating Expenses:							
Distribution Ops & Maintenance	1,814,456	1,994,902	2,098,730	2,525,615	2,730,200	2,801,600	2,874,800
Billing and Collecting	1,169,536	1,149,114	1,203,967	1,184,825	1,295,900	1,329,700	1,364,400
Administration	2,285,340	2,991,182	2,816,085	3,290,082	3,474,900	3,645,900	3,741,200
Depreciation	1,252,112	1,823,569	2,297,592	2,850,366	3,235,805	3,649,346	4,016,587
Total Operating Expenses	**6,521,444**	**7,958,767**	**8,416,374**	**9,850,888**	**10,736,805**	**11,426,546**	**11,996,987**
Earnings from Operations	1,738,884	2,347,177	2,171,280	1,838,135	2,349,508	3,229,884	4,177,454
Interest on Long term debt	858,048	1,163,294	1,469,039	1,516,722	1,669,900	1,801,711	1,877,166
Earnings before Income Taxes	880,837	1,183,883	702,241	321,412	679,608	1,428,173	2,300,288
Income Taxes	492,543	-	-	-	-	-	-
Net Earnings	388,294	1,183,883	702,241	321,412	679,608	1,428,173	2,300,288
ROE	2.5%	7.3%	4.3%	1.9%	3.9%	7.7%	11.0%
Retained Earnings, Beginning	4,429,273	4,348,816	4,751,454	4,828,695	5,150,108	5,829,715	7,257,888
Dividends	(468,750)	(781,250)	(625,000)	-	-	-	-
Change in Future Income Tax	-	-	-	-	-	-	-
Retained Earnings, Ending	4,348,816	4,751,454	4,828,695	5,150,108	5,829,715	7,257,888	9,558,176

IPC

5 Year Projection

Balance Sheet Budget

	Actual 2014	Forecast 2015	Projection 2016	2017	2018	2019	2020
Assets							
Cash	1,521,580	0	0	-	0	0	-
Short term investments	-	-	-	-	-	-	-
Receivables	4,677,078	3,150,000	3,200,000	3,250,000	3,300,000	3,350,000	3,400,000
Unbilled revenue	3,493,913	3,250,000	3,605,000	3,655,000	3,705,000	3,755,000	3,805,000
Inventory	439,097	470,000	470,000	484,100	498,600	513,600	529,000
Income taxes receivable	26,806	-	-	-	-	-	-
Future Income taxes-Current	-	-	-	-	-	-	-
Prepaids	337,601	340,000	350,000	360,500	371,300	382,400	393,900
Due from Interco	-	-	-	-	-	-	-
Notes due from IESL	-	-	-	-	-	-	-
Property & Equipment-NBV	45,804,570	62,189,086	69,571,288	79,520,978	92,936,958	105,295,950	117,146,241
Intangibles	597,034	738,727	865,274	896,141	858,225	809,708	770,690
Long Term Investment	21,721	-	-	-	-	-	-
Regulatory assets	2,050,937	881,033	506,613	-	75,000	75,000	75,000
Future Income Taxes	733,500	733,500	733,500	633,500	533,500	433,500	333,500
Total Assets	59,703,837	71,752,346	79,301,675	88,800,219	102,278,584	114,615,157	126,453,331
Liabilities							
Cash	-	-	-	0	-	-	0
Current portion of LTD	12,580,292	3,929,315	3,960,986	1,183,182	1,297,276	1,392,736	1,480,331
Payables	6,483,998	6,249,994	6,249,995	6,306,856	6,364,456	6,423,056	6,482,456
Customer credit bal & deposits	1,561,351	275,000	300,000	294,000	288,000	282,000	276,000
Income taxes payable	-	-	-	-	-	-	-
Due to related party	2,784,885	-	-	-	-	-	-
Future Taxes	433,000	433,000	433,000	433,000	433,000	433,000	433,000
Customer & retailer deposits	162,841	125,000	110,000	108,000	106,000	104,000	102,000
Regulatory Liabilities	385,288	295,658	5,100	5,100	5,100	5,100	5,100
Long term debt	19,555,303	31,500,882	35,480,047	41,727,700	45,679,428	48,041,550	49,046,047
Deferred Revenue	-	12,783,979	16,525,787	22,184,208	30,867,542	39,267,760	47,662,153
Total Liabilities	43,946,961	55,592,827	63,064,915	72,242,046	85,040,803	95,949,204	105,487,090
Shareholder Equity							
Capital Stock	10,852,444	10,852,444	10,852,444	10,852,444	10,852,444	10,852,444	10,852,444
Development chgs	555,621	555,621	555,621	555,621	555,621	555,621	555,621
Retained Earnings	4,348,810	4,751,454	4,828,695	5,150,108	5,829,715	7,257,888	9,558,176
Total Shareholder Equity	15,756,875	16,159,519	16,236,760	16,558,173	17,237,780	18,665,953	20,966,241
Total Liabilities and Equity	59,703,837	71,752,346	79,301,675	88,800,219	102,278,584	114,615,157	126,453,331

IPC

5 Year Projection

Cash from Operations Budget

	Actual 2014	Forecast 2015	Projection 2016	2017	2018	2019	2020
Operating							
Net Earnings	388,294	1,183,883	702,243	321,412	679,608	1,428,173	2,300,288
Future income taxes	519,000	-	-	100,000	100,000	100,000	100,000
(Gain)Loss on disposal	26,113	(392,359)	136,450	81,294	85,360	89,628	94,109
Depreciation	1,557,167	1,823,569	2,297,592	3,071,858	3,539,147	3,962,280	4,339,113
	2,490,574	2,615,093	3,136,285	3,574,564	4,404,114	5,580,080	6,833,510
Customer Deposits	363,365	13,799	10,000	(2,000)	(2,000)	(2,000)	(2,000)
Change in non-cash oper working cap	1,516,340	(2,517,311)	(415,000)	(73,739)	(73,700)	(73,500)	(73,500)
	4,370,279	111,581	2,731,285	3,498,825	4,328,414	5,504,580	6,758,010
Financing							
Dividends	(468,750)	(781,250)	(625,000)	-	-	-	-
Proceeds from property sale	-	-	-	-	-	-	-
Advances of debt	13,807,817	11,945,579	3,979,162	7,430,835	5,249,004	3,754,858	2,484,828
Repayment of debt	(1,495,157)	(8,650,976)	31,673	(3,960,986)	(1,183,182)	(1,297,276)	(1,392,736)
Loan to related party	-	-	-	-	-	-	-
	11,843,910	2,513,353	3,385,835	3,469,849	4,065,822	2,457,582	1,092,092
Investing							
Net additions to property and equip	(14,829,811)	(17,957,418)	(9,942,790)	(13,133,709)	(17,002,570)	(16,362,380)	(16,244,495)
Capital contributions	1,412,597	12,708,906	3,741,807	5,658,421	8,683,334	8,400,218	8,394,393
Net additions to regulatory liabilities		-	-	-	-	-	-
Net additions to regulatory assets	(710,755)	1,080,273	83,862	506,613	(75,000)	-	-
Net additions to LT investments	-	21,721	-	-	-	-	-
	(14,127,970)	(4,146,515)	(6,117,121)	(6,968,675)	(8,394,236)	(7,962,163)	(7,850,102)
S/H Equity-Development Chges	-	-	-	-	-	-	-
Increase(Decrease) in Cash	2,086,219	(1,521,580)	-	(0)	0	(0)	(0)
Cash, beginning of year	(564,637)	1,521,580	0	0	(0)	0	0
Cash, end of year	1,521,580	0	0	(0)	0	0	(0)

Transformer Station	Weather-Corrected Historical Station Peak Demand (MW)	Gross Median Weather Station Peak Demand Forecast (MW) IPC Usage Peaks - Revised as Per 11th Nov 2015											
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Barrie TS - Aggregate	14.3	**14.3**	**15.3**	**16.0**	**19.6**	**24.7**	**29.2**	**33.3**	**37.1**	**40.9**	**44.7**	**48.5**	**52.3**
Total Customer Growth - Barrie Annex, Friday Harbour, Stroud)		0.0	260	96	940	1006	847	798	748	748	748	748	748
Total Load Growth per year residential		0.00	0.99	0.36	3.57	3.82	3.22	3.03	2.84	2.84	2.84	2.84	2.84
Total Load Growth per year commercial (25% of total Load)				0.33	0.12	1.19	1.27	1.07	1.01	0.95	0.95	0.95	0.95
Everett TS - Aggregate	2.8	**3.0**	**3.1**	**3.2**	**3.3**	**3.3**	**3.3**	**3.3**	**3.4**	**3.4**	**3.4**	**3.4**	**3.4**
Total Load Growth per year residential		0.19	0.07	0.11	0.04	0.00	0.00	0.07	0.05	0.00	0.00	0.00	0.00
Total Load Growth per year commercial (None)		0	0	0	0	0	0	0	0	0	0	0	0
Alliston TS - Aggregate	42	**44**	**45**	**47**	**48**	**49**	**51**	**52**	**54**	**55**	**57**	**58**	**59**
Total Load Growth per year residential		1.40	1.44	0.95	1.22	1.19	1.04	1.34	1.24	1.27	1.04	0.99	0.99
Total Load Growth per year commercial (% of population)			0.28	0.29	0.19	0.24	0.24	0.21	0.27	0.25	0.25	0.21	0.20
Total Load Requirements	59.3	60.9	63.7	65.7	70.8	77.3	83.1	88.8	94.2	99.5	104.6	109.6	114.5

* Barrie land growth is based on the information available from the city plan
*HWY 400 Strategic employment lands not taken into account
* Information for TOI development taken from TOI plans, provincial requirements for population and subdvision information available t
*Customers at EOY for 2014 include all rate classes except microFIT
* As phasing is not available for Barrie Lands after 2021, no of units are equally divided between salem and hewitt
* Available TOI data is from 2016-2026, rest is taken from George's business plan
* Load forecast does not have DG or CDM Correction

Appendix 3

InnPower

Asset Management Plan

2016



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Appendix C, DSC Minimum Maintenance Standards

Background

The Hydro Electric Commission of the Corporation of the Town of Innisfil was originally formed in January 1991, and in July 1993, the distribution assets were purchased from Ontario Hydro for the service area expansion. InnPower Corporation (InnPower) was incorporated as a for-profit local distribution company in year 2000 as required by the *Electricity Act 1998*. InnPower has a distribution licence from the Ontario Energy Board (Licence # ED-2002-0520) to operate its distribution system within the licensed territory of 292 square kilometres, defined as the Town of Innisfil as of January 1, 1994.

InnPower's industrial customer base is minimal in comparison to residential customers. We have had significant growth in the area in the past 10 years and expect this trend to continue into the next decade. We predict our customer base to double in the next 8-12 years.

We currently operate our sub transmission system at 44 kV and our three-phase distribution system at 27,600 and 8,320 volts. We own, operate and maintain ten (10) distribution substations. We jointly own, operate, and maintain four (4) private substations; and inspect and maintain seven (7) other customer-owned substations.

InnPower hired five "in-house" Linemen in 2010 that perform daily service work requirements. All other associated Line construction projects and Substation work is contracted out to an independent contractor.

The Head Office and Operations Centre for InnPower was relocated to 7251 Yonge Street in Innisfil, Ontario at the beginning of the year, with 37 full time staff and 2 part-time staff. The site consists of an integrated building situated on approximately 3.6 acres. To coincide with the move to the new site, the name was changed from Innisfil Hydro Distribution Systems Limited to InnPower Corporation (InnPower).

Following the aftermath of the *Oak Ridges Moraine Protection Act 2001*, property developers have acquired many Innisfil properties for the purpose of land development. Land development pressures have been reflected in the Town of Innisfil's Official Plan (2006).

Utilizing growth projections from all available data, the following population projections comprise the parameters for growth:

- Innisfil population in 2031 56,000
- New Barrie land population in 2031 40,788
- Friday Harbour development 1,600 units + commercial load

Both population and employment is projected to increase by more than 100% within the next 20 years. It is this municipal growth that is fueling the need for capital expansion within this rate application. As required in the Distribution System Code:

6.1.1 A distributor shall make every reasonable effort to respond promptly to a customer's request for connection. In any event a distributor shall respond to a customer's written request for a customer connection within 15 calendar days. A distributor shall make an offer to connect within 60 calendar days of receipt of the written request, unless other necessary information is required from the load customer before the offer can be made.

The capital infrastructure necessary to more than double existing demand requires long term planning where capital infrastructure is staged. Failure to approve planned capital requirements will prohibit the ability for InnPower to meet the needs of the growing community and therefore growth would be contrary to the Distribution System Code.

AESI Acumen Engineering Solutions was engaged in 2012 to review, provide commentary and make recommendations on the Asset Management Plan. In 2015 this report has been updated. InnPower staff have implemented all reasonable recommendations from the AESI report into the Asset Management Plan.

Programs whether O&M or Capital are generally prioritized as follows:

1. Health & Safety
2. Legislative
3. Growth
4. Reliability

*** This Asset Management Plan is a 'living document' and will receive on-going review.**

2.0 Regulatory Requirements

The Distribution System Code (DSC) requires an LDC to maintain its distribution system in good working condition, as follows:

"4.4.1 A distributor shall maintain its distribution system in accordance with good utility practice and performance standards to ensure reliability and quality of electricity service, on both a short-term and long-term basis."

The DSC has an ***Appendix C, Minimum Maintenance Standards***. Appendix C, as amended from time to time, will be attached to and will be a part of this plan.

Furthermore, introduction of Ontario Regulation 22/04, Electrical Distribution Safety, in late 2004 introduced additional legislated focus on maintaining municipal distribution systems. Specifically the Regulation requires an LDC to:

"Section 4. Safety standards…

(2) All distribution systems and the electrical installations and electrical equipment forming part of such systems shall be designed, constructed, installed, protected, used, maintained, repaired, extended, connected and disconnected so as to reduce the probability of exposure to electrical safety hazards. O. Reg. 22/04, s. 4 (2)."

Section 4 goes on to identify all components of the distribution system and specifies for each component as follows:

"1. Operating electrical equipment shall be maintained in proper operating condition."

InnPower has established a documented program to address the legislated requirements to maintain its distribution system.

Historical and present electrical system maintenance endeavours to meet the all of the minimum maintenance standards in DSC Appendix C. Reductions in Operations or Maintenance funding may erode InnPower's ability in achieving all of the maintenance requirements in the DSC.

3.0 Overhead Lines

3.1 Tree Trimming



Vegetation and Right of Way control is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. InnPower has a large rural and urban area where overhead hydro lines are in the proximity to trees.

Trees contacting energized lines have the ability to inflict the following:

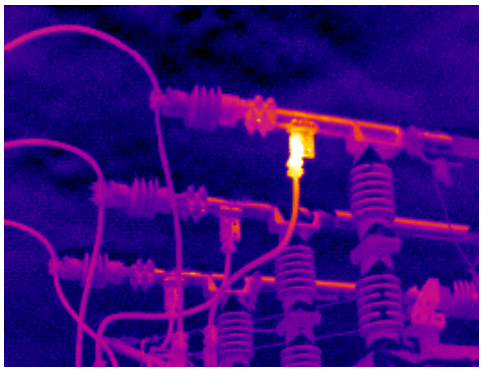
- Interruption of power due to short circuit to ground or between phases;
- Damage to conductors, hardware and poles;
- Danger to persons and property within the vicinity due to falling conductors, hardware, poles and trees;
- Danger of electric shock potential from electricity energizing vegetation.

In an effort of mitigating direct contact between trees and distribution assets, tree trimming is conducted on a three-year cycle. InnPower does not have any in-house tree trimming personnel or equipment and therefore uses an independent contractor at market rates. Depending on the size, shape and growth aspect of relevant trees, the tree trimmers remove sufficient foliage from the tree to limit the possibility of contact during high wind situations within a three-year time frame.

Following tree trimming, the independent contractor removes all debris and returns the site to as-found condition. Any pole line damage or anomaly noticed by the tree trimming crew is reported to InnPower for remedial action. The cost for tree trimming has been budgeted in account 5135.

3.2 Infra-red Scanning





Electrical energy forces the movement of electrons through a conductor. In situations where a restriction in a conductor or an electrical connection exists, the movement of electrons through the restriction heats up. Left unabated, the effect of 'hot spots' can have the following effects:

- Increased line losses
- Radio interference
- Damage to equipment
- The danger of energized equipment falling to the ground
- Power interruption

The pictures above show an infrared scan of a hot connection which would require immediate action. InnPower does not have trained personnel nor the equipment necessary for infra-red scanning. This service is contracted out to an independent contractor at market rates.

In an effort to be pro-active, infrared scanning is performed on InnPower's high voltage assets on a three-year cycle as follows:

Year 1. All overhead primary voltage 3 phase and single phase lines (44kV, 27.6kV, 8.32kV) including Distribution Stations.

Year 2. All 44kV overhead lines including Distribution Stations, half of (27.6 kV & 8.32kV) 3-phase overhead primary voltage lines and half of all underground primary voltage lines.

Year 3. All 44kV overhead lines including Distribution Stations, the other half of (27.6 kV & 8.32kV) 3-phase overhead primary voltage lines and the other half of all underground primary voltage lines.

Any abnormal condition is reported to InnPower for remedial action. Critical abnormalities are reported to InnPower for immediate action. The cost for infra-red scanning has been budgeted in accounts 5020 and 5045.

3.3 Line Patrol



Line patrol is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Line patrol may highlight problems or may identify conditions that warrant a more thorough or vigorous inspection or the need for specific maintenance. Visual inspection of major distribution system components identify problems and hazards such as leaning poles, damaged equipment, enclosures and vandalism. The attached picture was taken as a result of line patrol. The centre 44 kV conductor is resting on the wooden cross arm. Left unabated, the conductor would burn through the cross arm

and possibly cause the pole to catch fire. The 44 kV circuit would lock-out affecting thousands of customers and possibly contact the lower circuit, affecting hundreds of customers with power interruption and possible electrical damage to their homes and businesses. Line patrol in this situation had the potential of saving thousands of customer interruption hours, saving several thousand dollars in asset replacement and the diversion of hundreds of insurance claims.

Line patrol includes a visual inspection of all related equipment as follows:

Conductors and Cables

- Low conductor clearance
- Broken/frayed conductors or tie wires
- Tree conditions, exposed broken ground conductors
- Broken strands, bird caging, and excessive or inadequate sag
- Insulation fraying on secondary especially open wire

Poles/Supports

- Bent, cracked or broken poles
- Excessive surface wear or scaling
- Loose, cracked or broken cross arms and brackets
- Woodpecker or insect damage, bird nests
- Loose or unattached guy wires or stubs
- Guy strain insulators pulled apart or broken
- Guy guards out of position or missing
- Grading changes, or washouts
- Indications of burning

Hardware and Attachments

- Loose or missing hardware
- Insulators unattached from pins
- Conductor unattached from insulators
- Insulators flashed over or obviously contaminated
- Tie wires unraveled
- Ground wire broken or removed
- Ground wire guards removed or broken

Vegetation and Right of Way

- Leaning or broken “danger” trees
- Growth into line of “climbing” plants
- Unapproved/unsafe occupation or secondary use

Civil Infrastructure

- Buildings that house equipment that need attention
- Cable chambers, underground vaults and tunnels that need attention

Staff perform line patrol whenever driving through InnPower's distribution territory. Distribution system problems are either remedied immediately or scheduled for remedial action. Line patrol is also performed by line personnel and engineering staff when a problem has been identified within a circuit by SCADA and or by customer calls.

During routine patrols through Innisfil, many trouble calls are identified each year. Electrical system problems ranging from tree limbs to failing parts and materials are repaired as emergency calls at any time of day or night.

Pole top maintenance and pole inspection is a program where line staff perform a physical inspection at each pole in a defined route by setting up a Line truck to tighten and inspect all hardware (insulators, cross-arms, bolts, etc.). Over time, wood poles shrink, wear and deteriorate to a point that original installations become loose. With weather elements such as wind and ice loading, hardware can eventually loosen and fail. The solution for this is on a yearly basis, a defined route of approximately one eighth of all poles (approximately 1,250), would be inspected from a Line truck and all hardware tightened. By staying proactive with this program the aim is to lower the SAIDI & SAIFI reporting and lower emergency calls where expense dollars are currently being drawn from. The extra cost to do this work has been included in our long-range budget starting in 2017. To date, $5,000 to $7,000 per year is being spent on an as needed basis when identified by a trouble call.

3.4 Poles

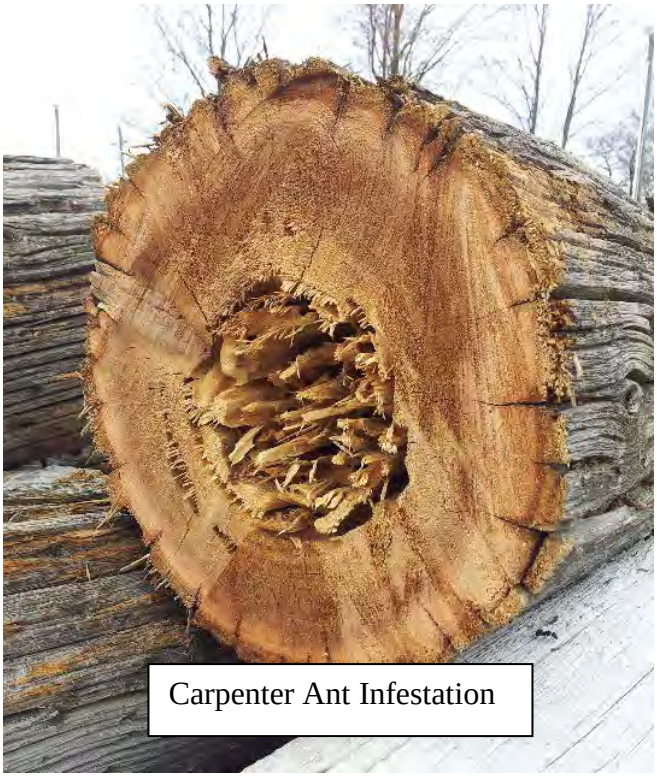


Pole inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. InnPower utilizes approximately 10,000 poles within its distribution system incorporating Jack Pine, Red Pine, Western Red Cedar and Yellow Cedar, ranging from 30' to 90' in length. These pole species involve creosote, chromium copper arsenate or pentachlorophenol treatment to extend the life of the wood. There are no steel or composite poles that are in service in Innisfil. Two concrete poles are in service where feeder 9M6 enters Innisfil. These two concrete poles were installed in 2009 to facilitate installations where guying was not possible.

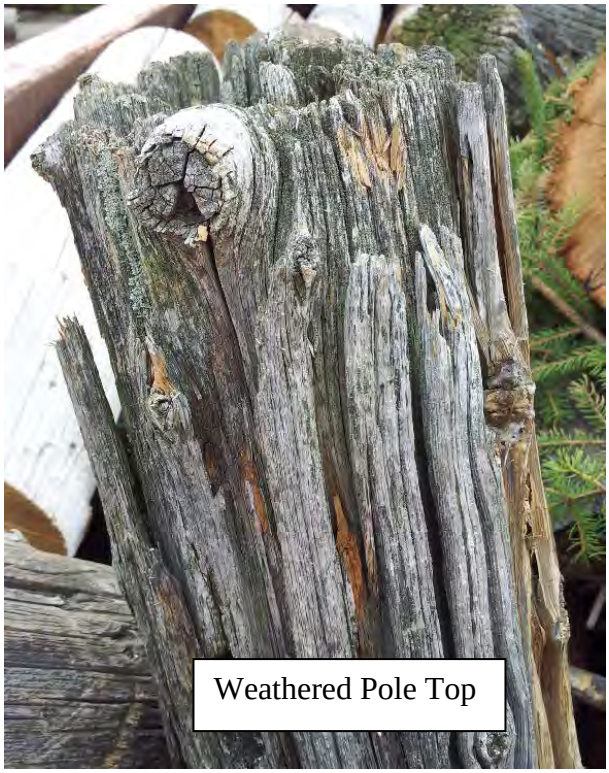
The majority of wood pole deterioration occurs at the pole butt, basically where the pole enters the ground. The amount of pole below the surface is 2 feet plus 10% of the pole height. It is the area flush with the ground that receives the greatest impact of moisture and oxygen that enables the rotting of the pole which occurs from the inside-out. Poles are, therefore, tested to see the extent by which that they are hollow. The extent to which the pole is structurally sound correlates to the pole's ability to withstand structural loadings such as transformers, switches, hardware and wind sheer. Depending on the circumstances, poles that lack structural integrity have the risk of falling down and being injurious to property, personnel, equipment and the public.

InnPower has been implementing a six-year cycle-based pole testing program. The poles are tested using non-destructive devices that measure the moisture content of the wood just above ground level. The higher the moisture level within the wood relates to a higher level of deterioration. When a threshold level of moisture is detected, a resistograph is used to physically measure the extent of the deterioration. The pole testing results are logged and pole replacement is scheduled as required.

While pole testing at grade identifies the need of pole replacements due to ground level pole deterioration, poles also require replacement as a result of carpenter ant/termite damage and age-related weathering above grade. Example of these two pole deficiencies are shown below.



Carpenter Ant Infestation



Weathered Pole Top

Historically, a pole replacement rate of approximately 2% has been experienced and is budgeted for within the capital budget. However, an approximate 200-215 of the tested poles per year receive comments back to InnPower from the pole testers indicating deficiencies. Items such as slack or loose guy wires, guy strain insulators pulled apart or broken, guy guards out of position or missing, loose grounding connections and missing nomenclature are a few examples. A maintenance program has not been budgeted before in the past; however with an Annual Pole Maintenance Program, InnPower would be able to address the issues raised by our contractor and remediate potential hazards to the public and staff. This annual maintenance cost of $13,440. was not approved during the 2013 COS application process.

Along with the pole testing results, the poles are numbered, tagged with a GPS coordinate and tagged with other hardware and nomenclature. The results are inputted into the Geographical Information System (GIS).

Each year in Innisfil, at least 10 complaint calls are received from customers for leaning poles. These are existing poles in Innisfil that over time have leaned due to weather or soil conditions. Whether on a rural or urban road it, is becoming more noticeable that the existing poles are leaning more with each passing year. Presently, InnPower uses a small amount of expense budget out of the 5120 account to deal with this issue; however the small amount of money available for this problem is not nearly enough to combat the larger picture outside of a few complaints.

A better initiative is an annual program to straighten poles that are currently leaning. This issue will always be present with existing poles. The detrimental effect of leaning poles is that, once over centre to a varying degree dependent on soil conditions, the pole has a much higher potential to be pushed over or break in storm winds or ice loading conditions. A domino effect can then occur, toppling pole after pole. Aside from the fact that leaning poles are visually displeasing to look at, the potential for more dangerous situations may exist. Moving forward a budget figure of $35,000 would accommodate the straightening of only 50 poles, but would constitute the start of an ongoing program year over year to deal with the problem.

Pole Replacements are undertaken for the following different reasons:

- Pole decomposition or structural damage
- Vehicle accidents
- Customer service requests requiring taller or different class of pole
- Road widenings and grade changes
- Line rebuilds
- ESA compliance

InnPower replaces poles that can exhibit a health and safety hazard to the public and staff. Each year, one sixth of InnPower wood poles are tested and rated to determine when they should be replaced or retested. Poles have been identified as needing a subsequent retest may undergo ‘butt treatment’ whereby the useful life of the pole can be extended.

Poles are replaced to current ESA requirements. With an approximate 1-2% replacement program of the poles that are tested annually, the following number of poles are anticipated to be replaced each year over the next 5 years, which includes pole replacements triggered by accidents, capital growth and project requirements:

	2016	**2017**	**2018**	**2019**	**2020**
Total Count	10,212	10,217	10,234	10,249	10,267
Total Replacement	248	279	246	265	285
Additional	5	17	15	18	18

Poles are replaced as required to maximize the health and safety of the public, system reliability and the ability to connect new customers.

3.5 Switches

Switch inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Switches are devices that allow or disallow the conductivity of high voltage conductors. They are available in single-phase solid or fused configurations and three-phase applications involving load break (remote and local operation), and air break (remote and local operation).



Fused switches (cut-outs) accept different sizes of fuses, which are used for the protection of lines, equipment or transformers from main feeder amperages. Fused cut-outs are inspected during the infra-red scanning process. Fused cut-outs that fail are replaced as needed. When fused cut-outs fail with an abnormal frequency, fused cutout statistics are investigated to see if a manufacturer's defect has occurred. If a manufacturer's defect is suspected, then all related fused cut-outs may be replaced as an act of due diligence. Failure to do so will not only decrease reliability and the safety of operational personnel would be compromised.

Load break and air break switches are predominately on the 44kV system and perform switching operations to allow for maintenance and emergency procedures. Along with inspections carried out by infra-red scanning, these switches have scheduled maintenance once every four years. Line staff perform switch maintenance on one quarter of all airbreak and loadbreak switches on an annual basis. The cost to perform three phase switch maintenance has been budgeted in account 5125 which does not include repair parts.

There are numerous in-line switches and mid span openers (MSOs) on the 44kV, 27.6kV and 8.32kV system. These are single phase switches or mid span openers that can be grouped together on a three phase feeder. These switches are used for sectionalizing circuits for maintenance and emergency requirements. In-line switches can be used to break load when a load-break tool is used. In-line switches are inspected during the infra-red scanning process and are replaced as required. Failure to do so will not only decrease reliability, the safety of operational personnel would be compromised. These devices have traditionally received proactive maintenance via the infra red scanning process. An actual physical inspection would require three crew hours to perform in-line switch or MSO maintenance which would require an extra $13,150 of internal labour annually to implement a cycle program. This annual maintenance cost was not approved during the 2013 COS application process.

Switch Replacements are undertaken for the following different reasons:

- Mechanical or electrical failure;
- Vehicle accidents, lightning strikes;
- New customer requirements;
- Road reconstruction;
- Line rebuilds or circuit reconfigurations;
- ESA compliance;
- Upgrades for system security involving the SCADA system;
- Systemic failures involving a particular manufacturer or style.

The following switch addition and replacement schedule has been incorporated to deal with capital requirements:

Disconnect Cutouts Single & Three Phase					
	2016	**2017**	**2018**	**2019**	**2020**
Total Count	447	463	479	495	511
Replacement	10	10	10	10	10
Additional	16	16	16	16	16

These cut-outs include in-line devices on our distribution infrastructure, but exclude transformer protection fuses.

Air Break and Load Break Three Phase Switches

	2016	**2017**	**2018**	**2019**	**2020**
Total Count	77	82	87	93	99
Replacement	3	3	4	4	4
Additional	5	5	6	6	6

Includes manual and automatic switches, on both our sub transmission and distribution system. Types include SCADA-Mate's, Alduti-Rupter's, reclosers (used as **switches**), and manual gang switches.

In-Line Switches & MSOs					
	2016	**2017**	**2018**	**2019**	**2020**
Total Count	344	346	348	350	352
Replacement	10	10	10	10	10
Additional	2	2	2	2	2

3.6 Reclosers



Recloser inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. IPC currently has twenty four (24) three-phase reclosers and 52 single-phase reclosers installed and fully operational on its distribution infrastructure. While all twenty four (24) three-phase reclosers are radio controlled and serve as circuit breakers inside eight (8) of our Distribution Stations (DS), 15 single phase hydraulic reclosers serve as protective devices for station transformers inside the other two (2) of our DS'. The remaining 37 single-phase hydraulic reclosers are installed on our distribution lines in InnPower's system. The list is kept in an Excel directory by the Engineering and Operations Assistant. These devises are

programmable switches that open and close depending on how the current limits are set. These devises break load within an oil bath or vacuum chamber for dielectric purposes. After a number of operations, the oil bath becomes contaminated with carbon, which is formed by the oxidation of the oil by the arc squelching process. The carbon impregnated oil looses dielectric properties and needs to be inspected and the oil replaced. The oil reclosers are inspected and rebuilt once every 4 years. They are also inspected by the infra-red process. Reclosers that are damaged will be replaced as required. The cost for rebuilding the reclosures is capitalized and the cost for maintaining reclosers is in account 5125.

3.7 Voltage Regulators



Voltage regulator inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Voltage regulators are single-phase devices that are situated on high voltage lines, far away from the Distribution Station. When line losses drop the voltage potential below acceptable levels, the voltage regulators increase the line voltage to within CSA standards. Innisfil has four voltage regulators in the distribution system. These devices are patrolled and inspected by the infra-red process. The devices are not physically removed from service for inspection. They are, however, visually inspected monthly. The cost for inspecting voltage regulators is in account 5016. There are no voltage regulators budgeted for replacement in 2016.

3.8 Transformers



Transformer inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. InnPower has 3,358 overhead and pad mounted transformers in its distribution system. The transformer list is kept in the Northstar Billing system. InnPower does not have any transformers in confined spaces or below grade.

Transformers are able to transform high distribution voltage into low voltage (< 750V) that can be utilized by customers. All transformers have had their mineral oil tested and verified so that as of 2005, all transformers are PCB free (< 50 PPM). Transformers are visually inspected according to the Minimum Inspection Requirements in the Distribution system Code (every 3 years Urban and every 6 years rural).

The typical line patrol inspections address the following issues:

- Hot connects via infra red scanning
- General appearance
- Loose wires
- Bird or animal nests

For InnPower to have internal staff or external contractors either climb poles or set-up bucket trucks to inspect transformers up close, it is estimated that the cost of $60 per overhead transformer would be required. This translates into an annual cost increase of $45,000. This has not been budgeted for in 2015.

The annual cost for inspecting transformers has been budgeted within the infra-red scanning process.

Transformers are changed with different sized units as needed. Transformers are replaced when they fail due to lightning strike, vehicle accident, potential oil leakage or internal/external problems. The following overhead transformer addition and replacement schedule has been incorporated to deal with capital requirements:

Overhead Transformers

Overhead Transformers	2016	2017	2018	2019	2020
Total Count	2,203	2,223	2,243	2,266	2,290
Replacement	28	38	20	35	35
Additional	21	22	23	24	24

The cost for infra-red scanning overhead transformers has been budgeted in account 5020 and 5045.

3.9.1 Capacitors



Capacitor inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. When AC power flows through the conductor, there is a loss of power in the conductor due to its resistance and reactance. Capacitor banks are installed to reduce line losses, improve power factor and balance feeders for easier switching.

InnPower has 9 sets of capacitor banks in its distribution system. Capacitors are visually inspected according to the

Minimum Inspection Requirements in the Distribution System Code (every 3 years Urban and every 6 years rural) and are also inspected by the infra-red scanning program. Capacitors are inspected annually (basic inspection) and damaged capacitors are repaired or replaced as required. The cost for inspecting capacitors has been budgeted in account 5125. There are no plans to replace any capacitors within the next five year horizon.

Fault Indicators

The installation and use of overhead radio controlled fault indicators has been deployed since 1996. These units send radio signals to the InnPower Supervisory Control and Data Acquisition (SCADA) system when fault currents have been detected. They assist in finding a problem section of line and for sectionalizing damaged sections of high voltage lines. Lowering System Average Interruption Duration Index (SAIDI) reporting is the root function of these indicators. Fault indicator inspection and testing is now required more urgently than in past years as InnPower has been experiencing problems in communications via the radio system and also water infiltration into several of fault indicators themselves, causing false reporting and failure of the units. A plan of testing and inspecting is a necessity to ensure good reporting with high reliability. With forty sets of indicators scattered over InnPower territory, an expected cost of $12,100 would be needed on a yearly basis to make this happen on an annual basis. This annual maintenance cost was not approved during the 2013 COS application process.

3.11 Load Balancing

Due to the change in seasons through the year, distribution station loads fluctuate from electric heat loads in winter to air conditioning loads in summer. The addition of customer upgrades and new services going into the distribution system also contribute to unbalancing loads out of these stations. The typical solution and remedy for this ongoing issue is to balance the distribution feeders out of the station. In doing so it accomplishes several things, the first of which is lowering line losses within the distribution system. It also increases the power factor of the station output and is operationally better for the life of the power transformer. To accomplish this goal, balancing is done at the onset of peak seasons (summer and winter) and would require $9,000 of crew labour to complete. This has not been budgeted for in 2016.

4.0 Underground Lines

4.1 Switching Cubicles

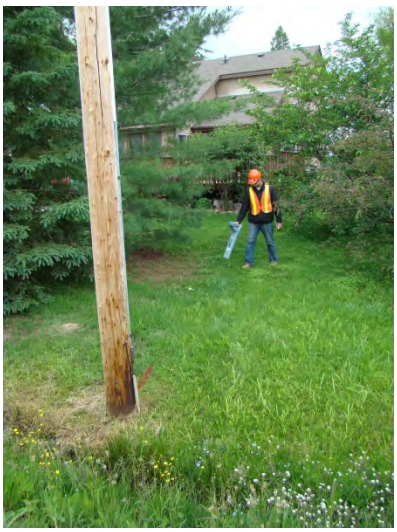
Switching cubicle inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. InnPower has 49 switching cubicles in its distribution system. The manufacturer, S&C, has been the standard supplier for these devices (PME configuration). The function of these devices is to provide an above-ground mechanism for underground express cables to be switched and a connection for fused local cables. The PME standard utilizes a ‘dead



front' configuration whereby there are no high voltage connections exposed when the switching cubicle doors are open. As opposed to the S&C PMH live front configuration, the PME's exhibit fewer problems and need less maintenance.

Switching cubicles are visually inspected according to the Minimum Inspection Requirements in the Distribution system Code (every 3 years Urban and every 6 years rural) and are also inspected by the infra-red scanning program every three years. Damaged switching cubicles are repaired or replaced as required. The cost for infra-red inspecting switching cubicles has been budgeted in accounts 5020 and 5045. Switch Gears are exposed to a variety of elements which can cause potential public safety hazards, equipment deterioration and operational challenges. In addition to infra-red testing , a more in-depth maintenance program will create an opportunity to lubricate and operate infrequently used load break elbows and switches; repair and/or replace corroded connectors caused by acidic soil conditions and standing water; identify and correct any abnormal soil infiltration; inspect, repair or replace transformer grounding; re-fresh deteriorated nomenclature and identify any damage to the outside of the equipment caused by pedestrian, vehicular and municipal maintenance traffic. An annual maintenance cost of $49,780.00 under the heading of Underground Transformer and Switch Gear Maintenance has not been included. This annual maintenance cost was not approved during the 2013 COS application process.

4.2 Locates



As specified in section 228 the Occupational Health and Safety Act:

(1) Before an excavation is begun,

(a) gas, electric and other services in and near the area to be excavated shall be accurately located and marked; and

(b) if a service may pose a hazard, the service shall be shut off and disconnected.

(2) The employer who is responsible for the excavation shall request the owner of the service to locate and mark the service.

(3) If a service may pose a hazard and cannot be shut off or disconnected, the owner of the service shall be requested to supervise the uncovering of the service during the excavation.

(4) Pipes, conduits and cables for gas, electrical and other services in an excavation shall be supported to prevent their failure or breakage. O. Reg. 213/91, s. 228.

The current minimum standard contained in the Ontario Energy Board's service quality requirements is that underground cable locates must be completed within five working days of a customer's request, at least 90% of the time. For customers requesting a specific date, the locate must be completed within five working days of the requested date. Since the development of the service quality indicators in 1999, Ontario Regulation 22/04 has been proclaimed in force. Adherence to the standards set out in Regulation 22/04 is a legal requirement.

The cost for underground cable locating has been budgeted in accounts 5070, 5075, 5040 and 5045.

4.3 Elbows and Terminators





High voltage elbow and underground cable terminator inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Elbows and terminators are visually inspected according to the Minimum Inspection Requirements in the Distribution system Code (every 3 years Urban and every 6 years rural), which are inspected by the infra-red scanning program. Pad mounted transformers have their lids opened and are inspected by the infra-red scanning process. Damaged elbows and terminators are repaired or replaced as required.

InnPower does not log the number of elbows or cable terminators in its distribution system. Elbows or cable terminators are nomenclatured to the connecting switch, transformer or switching cubicle.

The standard for underground distribution is to use 28kV class equipment even on 8.32kV distribution. This standardization improves reliability and allows for easier voltage conversion upgrades. The cost for infra-red inspecting underground elbows and terminators has been budgeted in account s5020 and 5045. In addition to infra-red testing , a more in-depth maintenance program will create an opportunity to lubricate and operate infrequently used load break elbows and switches; repair and/or replace corroded connectors caused by acidic soil conditions and standing water; identify and correct any abnormal soil infiltration; inspect, repair or replace transformer grounding; re-fresh deteriorated nomenclature and identify any damage to the outside of the equipment caused by pedestrian, vehicular and municipal maintenance traffic. An annual maintenance cost of $49,780.00 under the heading of Underground Transformer and Switch Gear Maintenance has not been included. This annual maintenance cost was not approved during the 2013 COS application process.

4.4 Transformers



Underground transformer inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Elbows and terminators are visually inspected according to the Minimum Inspection Requirements in the Distribution system Code (every 3 years Urban and every 6 years rural) which are inspected by the infra-red scanning program. Underground transformers have their lids opened and all connections are inspected by the infra-red scanning process. Damaged transformers or components are repaired or replaced as required. All transformers have the mineral oil tested and or verified so that all transformers are PCB free (< 50 PPM). Transformers are visually inspected according to the Minimum Inspection Requirements in the Distribution System Code (every 3 years Urban and every 6 years rural). The typical infra-red inspections address the following issues:

- Hot connects via infra red scanning
- Check for lock and penta bolt in place
- General appearance
- Placement of pad or vault
- Leaking oil
- Loose wires
- Bird or animal nests

InnPower does not have any submersible transformers which operate below grade level. All underground transformers sit at or above grade, on top of a pad or vault.

All underground transformers are numbered, their secondary services are tagged as are the high voltage elbows. The cost for inspecting underground transformers has been budgeted in the infra-red scanning budget. The cost for infra-red scanning underground transformers has been budgeted in accounts 5020 and 5045. Underground Transformers are exposed to a variety of elements which can cause potential public safety hazards, equipment deterioration and operational challenges. In addition to infra-red testing , a more in-depth maintenance program will create an opportunity to lubricate and operate infrequently used load break elbows and switches; repair and/or replace corroded connectors caused by acidic soil conditions and standing water; identify and correct any abnormal soil infiltration; inspect, repair or replace transformer grounding; re-fresh deteriorated nomenclature and identify any damage to the outside of the equipment caused by pedestrian, vehicular and municipal maintenance traffic. An annual maintenance cost of $49,780.00 under the heading of Underground Transformer and Switch Gear Maintenance has not been included. This annual maintenance cost was not approved during the 2013 COS application process.

Transformers are changed with different sized units as needed. Transformers are replaced when they fail due to lightning strike, vehicle accident or internal/external problems. The following underground transformer addition and replacement schedule has been incorporated to deal with capital requirements:

Pad Mounted Transformers

	2016	2017	2018	2019	2020
Total Count	1,364	1,456	1,554	1,699	1,844
Replacement	9	9	9	9	9
Additional	93	97	145	145	145

All additional transformers are required to meet load growth and load demand.

4.5 Underground Primary Cables



Underground primary cable inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. With respect to underground systems, riser poles are checked by overhead patrols with a visual check of cable, cable guards, terminators and arrestors. While it is not possible to inspect underground cable directly, the system may be checked for exposed cable and or grade changes that may indicate that the cable has been brought too close to the surface.

The majority of primary underground cable in Innisfil is 'cross-linked, polymer encased' and in duct. Cables with a premature failure rate are repaired or replaced as required. The cost for maintaining and inspecting underground primary services has been budgeted in account 5150.

4.6 Secondary Services

Underground secondary service inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. With respect to underground systems, riser poles are checked by an overhead patrol with a visual check of cable, cable guards and connections. While it is not possible to inspect underground cable directly, the system may be checked for exposed cable and or grade changes that may indicate that the cable has been brought too close to the surface.



The old buss works that is now starting to lose its insulation from UV and other weather-related factors is becoming a danger to working utility staff and wildlife. The old secondary buss is removed from service and the new larger buss is installed, thus handling higher capacities and lower line loses.

The majority of 120/240V underground secondary service wire in Innisfil is 300V aluminum secondary cable and in duct. The majority of 600/347V underground secondary service wire in Innisfil is 600V aluminum secondary cable and in duct. Secondary services with a premature failure rate are repaired or replaced as required. The cost for maintaining and inspecting underground secondary services has been budgeted in account 5155.

4.7 Grounding

Lightning from storms can cause extreme damage on hydro utility equipment and subsequently cause prolonged customer interruptions. Lightning mitigation that includes good grounding has for the longest time been on the fore front of InnPower's operating plan. Past capital budgets had incorporated tens of thousands of dollars put in to arrestor and grounding installations to protect InnPower's assets. Older installations like overhead and pad mounted transformers installations, steel cross arm locations and separate dead end arrestor locations that have been existing for many years generally confirm that ground rods decay below the ground line. Acidic soils and moisture cause older galvanized steel ground rods to decay to the point where only a few feet are left from a ten foot rod. This deterioration causes high resistance in the grounding system and decreases the ability to prevent catastrophic lightning damage to InnPower's and customers' equipment. Ground rod resistance testing is a program that can be implemented to check the resistance at individual locations. If the grounding is unsatisfactory by means of a ground rod resistance tester, then repair or replacement will need to be made to the grounding deficiency. If an approximate 300 lightning arrestor locations were done annually, $18,000 would be needed. This amount has not been budgeted in the 2016 capital or maintenance budgets. Also not budgeted for are inspections to approximately 3,100 transformer grounding locations and over 100 miscellaneous other grounding points within InnPower's system.

4.8 Mapping

Mapping inspection and verification is mentioned in the DSC Minimum Maintenance Standards, (Phase indicators and unit numbers match operating map where used).

Although extreme due diligence as a rule warrants the best upkeep of mapping information, errors can still occur with even the greatest care. These operational maps describe the sub-transmission and distribution systems and are what crews and staff use to guide them in the restoration of power or for switching to complete jobs. If changes have been made without notification or open points moved in the field, time is required to verify theses problems in the maps. The end result can mean longer interruption times to customers in outage situations or, worse, confusion of field staff risking their health and safety. Nomenclature checks, map verification and open point confirmation should be done on a yearly basis to ensure that all maps match the actual field conditions in service. An amount of $14,500 is required to verify operation maps in the field, which has not been budgeted for in 2016.

5.0 Distribution Stations

5.1 Monthly Inspection



Distribution station inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code and good utility practice. Distribution stations in Innisfil are connected to the 44kV system on the primary side and the 27.6kV or 8.32kV system on the secondary side. Distribution stations are necessary to reduce the 44 kV sub-transmission voltage so that it can be utilized for single phase loads (< 35 kV). The 44 kV sub-transmission voltage is necessary to contend with the voltage losses engendered by the vast distances of the circuits. There are presently 10 distribution stations in service. Three stations are 44 kV – 27.6 kV and the rest are 44 kV – 8.32 KV. It is expected that the actual transformer replacement will need to occur after 50 years of service. Within the foreseeable five year horizon, actual transformer replacements are not anticipated according to distribution station records.

Monthly inspections are undertaken for both rural and urban distribution station sites. The inspection involves the following parameters:

- Theft of copper
- Vegetation
- Fencing
- Litter
- Health & Safety
- Station Grounding (visual)
- Condition of SCADA building
- Transformer temperature
- Reclosure operations
-



There are ten privately owned 44 kV transformer stations connected to InnPower's distribution system. InnPower performs monthly inspections on privately-owned stations to assure continued integrity with regard to reliability and health and safety. Since privately-owned stations are connected directly to InnPower's system, power quality problems at the private station can affect other customers on InnPower's system. InnPower's inspection forms are sent directly to the private station owners so that any remedial action can be undertaken.

The cost for monthly inspections is budgeted in account 5016. Annual distribution station maintenance includes weed and vegetation control, grass cutting, snow plowing, supervisory control and data acquisition (SCADA) maintenance. The cost for annual maintenance is budgeted in accounts 5114, 5125 and 5012. Due to the evidence of copper theft from substation sites, security at substations is being considered for implementation in 2016. Each station security system will have the following features and response protocol.

- Driveway sensor to activate flood light(s) inside the station upon vehicle entering driveway;
- Key activated arm and disarm switch at main entry;
- Magnetic contact on main entry gate;
- Motion sensor(s) inside gated compound (designed to minimize nuisance alarms) which will activate alarm and flood light(s);
- Alarm signals will be communicated via existing SCADA system to on-call Manager;
- Securitas Guard Service will provide onsite alarm verification at request of on-call Manager prior to Police dispatch;
- On-site motion triggered camera will record activity within station.

The contingent cost of copper theft remediation greatly exceeds the scrap copper value that is being taken. Substation security will deter unauthorized entry and therefore improve public safety and system reliability.

5.2 Major Service

On a four year rotation, distribution stations are switched out of service and maintenance is performed. This maintenance service includes the following:

- Bus connection inspection and tightening
- Ground resistance test
- Transformer oil analysis
- Switch cleaning and lubrication
- Inspection and cleaning of terminators, insulators, arrestors
- Cleaning of site, structures and hardware.

Substation maintenance crews generally perform major service over a 1-2 day period. Failure to perform major service could affect system reliability and the life-span of the related equipment. The cost for performing major distribution station service and maintenance for 2016 is budgeted in account 5114. This excludes any repairs or oil related problems. For example, oil treatment of a distribution station transformer may cost upwards of $18,000. There is no schedule to replace any substation transformer within the next five year horizon.

Distribution Stations – Transformer Year of Manufacture

SUBSTATION	SIZE	Volt	Vintage
BIG BAY POINT DS	5,000 KVA	44/8.32 KV	1971
BOB DEUGO DS	10,000 KVA	44/27.6 kV	2006
BRIAN WILSON DS	20,000 KVA	44/27.6 kV	1991-T1 2014-T2
Belle Ewart DS	10,000 KVA	44/27.6 kV	2014
CEDAR POINT DS	5,000 KVA	44/8.32 kV	1976
INNISFIL DS	5,000 KVA	44/8.32 kV	1978
LEFROY DS	5,000 KVA	44/8.32 kV	1967
LEONARDS BEACH DS	5,000 KVA	44/8.32 kV	1974
SANDY COVE DS	5,000 KVA	44/8.32 kV	1975
STROUD DS	5,000 KVA	44/8.32 kV	1969

6.0 Metering



6.1 Wholesale Meters

InnPower has seven wholesale meters within its distribution system. These meters are pole mounted and measure the electrical energy entering InnPower's distribution territory from Hydro One. Five of the wholesale meters are on 44 kV circuits and two are on 8.32 kV circuits. InnPower is a 'Market Participant' as defined by the Independent

Electricity System Operator. The meters are regulated under the authority of Measurement Canada. The wholesale meters and accompanying instrument transformers are certified once every six years, after which they must be re-sealed by a licensed Meter Service Provider. InnPower has contracted with CRU Solutions Inc., operated by ERTH Holdings Inc. (formerly Erie Thames Power Corporation) to perform licensed meter services. Wholesale meters are patrolled with periodic line patrols and infra-red scanning on an annual basis. The meters are connected to Bell Canada's land lines and are read on a daily basis by the IESO and InnPower's agent. Any meter reading problems are investigated immediately by InnPower and or CRU Solutions for remedial service. The cost for maintaining wholesale meters is budgeted in account 5175.

6.2 Retail Meters

InnPower has over 15,850 retail meters in service. These range from typical 240 V single phase meters to 44 kV primary meters at privately-owned transformer stations. The demarcation point between InnPower and the customer's property is specified in InnPower's Conditions of Service.

The meters are regulated under the authority of Measurement Canada with meter seals ranging from 6-12 years, after which the meters must be resealed or sample tested. If sample testing shows meter accuracy for residential meters, then sample groups can pass inspection without being re-sealed.

All retail smart meters are read on a daily basis by wireless technology. Until recently, there are approximately seven residential meters that were not replaced with smart meters due to access restrictions. Staff is diligently working with customers to alleviate the restrictions. Three phase conventional meters for general service customers continue to be replaced with meters fitted with the Sensus flex-net communication module to facilitate meter reading via the AMI network.

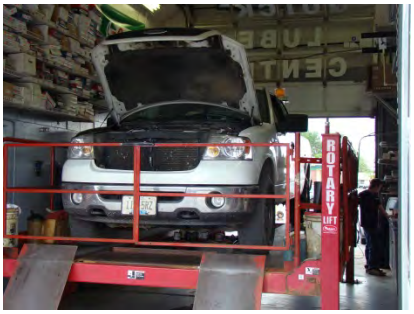
Interval meters are read on a daily basis by InnPower's agent though phone lines. Any meter reading problems are reported immediately for remedial action by InnPower. The annual cost for maintaining retail meters is budgeted in accounts 5065 and 5175.

Contract negotiations were completed in 2009 with KTI/Sensus for supply of smart meters, with Olameter for mass deployment of the meters and with Kinetiq/Savage Data Systems for Operational Data Storage of the flow of data from the smart meters. The Advanced Metering Infrastructure (AMI) installed is a tower-based solution for communicating with deployed smart meters. Two existing towers were chosen, the Town of Innisfil's Churchill Tower and the Town's Big Bay Point Tower on InnPower's substation site. Communications equipment was installed at both locations early in 2009, with communications established between the towers in early May. Mass deployment of smart meters commenced mid-September 2009, with substantial completion of March 2010. InnPower is registered with the provincial Meter Data Management Repository (MDM/R) and has been billing time-of-use rates to standard supply residential and low volume general service customers from the MDM/R since June 2011.

Between 2016 and 2019, re-verification of installed smart meters will commence. The implementation of remedial actions recommended from an AMI Security Audit conducted in 2013 is in progress. One upgrade to the AMI Regional Network Interface (RNI) has been completed to ensure network integrity. A second RNI upgrade is required, and testing of the functionality is being undertaken collaboratively with other electric distributors who have deployed Sensus AMIs. Installation of next generation smart meters commenced in 2014 enabling two way communication for in-home devices with which consumers can monitor their electricity usage.

7.0 Vehicle Maintenance

7.1 Service



InnPower contracts out some line and all substation maintenance and construction. InnPower does not have internal vehicle maintenance staff or equipment and out-sources that function. InnPower has 18 motorized vehicles in its fleet consisting of 1-double bucket line truck, 1-single bucket line truck, 1-RBD, 1-1 ton dump truck, 5 pick-up trucks, 5 Ford Escape Hybrids, 2 Honda CRV's and 2 forklifts. No new vehicles will be added in 2016. Most of the current vehicles do not meet the weight threshold for Commercial Vehicle Operator Registration (CVOR) except for the one ton dump truck and the three line vehicles. They receive basic maintenance in accordance with the manufacturer's recommendation. Any other maintenance or repairs are conducted in accordance with the Ministry of Transportation vehicle safety standards. It is anticipated that in 2016 vehicle maintenance will be done at the Town of Innisfil's new Operation Centre.

Vehicles are ammortized over their useful life of 10 years. The following actions are undertaken to extend the useful life of vehicles:

- The availability to rotate vehicles between users to maximize the mileage driven in respect of the vehicle's age.
- The availability to transfer a vehicle to another department where usage is less severe or addressing a need for a spare vehicle or for parts.
- Analysis if the vehicle in sufficiently good shape to extend its useful life past the evaluation criteria.

The cost for maintaining InnPower's fleet is allocated to projects on a vehicular hourly basis.

7.2 Replacement



The basic criterion for vehicle replacement is 10 years of age or 200,000 km. Vehicles deteriorate differently depending on factors such as quality of manufacture and the severity of usage. Vehicle replacement is not intended to follow a stringent set of rules that does not allow for the flexibility needed for asset management, but is a working target. Criteria that affects vehicle useful life includes:

- Other facets or technologies required of the vehicle that can no longer receive maintenance support or uses parts or updates that can no longer be supplied.
- Analysis if the vehicle is a “lemon” where expenses exceed depreciation which may warrant an early retirement date.
- Analysis if the vehicle no longer has a useful purpose or is in sufficiently poor shape to warrant an early retirement date.
- Sufficient mechanical or structural damage caused by an accident or abnormal wear.

Vehicles that exhibit good service past 10 years of age or greater than 200,000 km may be kept in the fleet as determined by analysis. Maintenance costs will be monitored to determine if they exceed the depreciation of a replacement vehicle. Surplus equipment is sold or disposed of for the greatest benefit to InnPower.

YEAR	VEHICLE	TRUCK #	PLATE #
1993	GMC BUCKET TRUCK MODEL WG64	301	359 1YH
2000	GMC PICK-UP WITH DUMP BOX	94	1339XV
2005	DODGE RAM PICK-UP	87 (ON CALL)	AF 78557
2006	FORD F150	93 (Stores)	1185RZ
2008	FORD ESCAPE (HYBRID)	92 (Milan Baldin)	BDBA902
2008	FORD ESCAPE (HYBRID)	85 (Mia Gill)	ACMR852
2009	FORD ESCAPE (HYBRID)	88 (Tony Mendicino)	AEME615
2009	FORD ESCAPE (HYBRID)	89 (GIS/Smart Grid)	AEME616
2010	POSI PLUSSINGLE BUCKET MODEL FM2	302	185 9ZB
2010	FORD ESCAPE (HYBRID)	95 (Steve Eduardo)	BJWA 824
2010	REEL TRAILER	402	H6112Y
2010	PORTABLE TRAFFIC SIGNALERS (2)	404 (For Both)	NO PLATES
2011	CHEVY SILVERADO HYBRID	96 (Rob Reed)	AA52433
2011	FORD SRW F350 PICK UP	101 (Kent Courtable)	3809ZJ
2011	FLOAT TRAILER	403	H6607W
2011	POLE TRAILER	401	H6113Y
2011	FREIGHTLINER RBD	201	554 8ZR
2014	HONDA CRV	97 (Wade & John)	BSST 522
2014	HONDA CRV	98 (Meeting/Office)	BSST 523

8.0 Property Maintenance

8.1 Sites

InnPower owns 11 substation sites and one 6.5 acre head office site. These sites have the grass cut and snow plowed as required. InnPower also owns numerous registered easements and non-registered easements for distribution assets registered on title, requiring on-going monitoring in an effort to protect the easement rights of InnPower.

The following list includes all properties owned by InnPower and their respective land size and 1999 assessment values.

InnPower Land Values

Distribution Stations			
Land Description	Address	Size Acreage	FMV 1999 ($)
Big Bay Point Land	25th SR	1.0	45,000
Brian Wilson DS	1434 Innisfil Beach Rd	2.00	112,000
Big Bay Point DS	709 13th Line	0.91	66,000
Cedar Point DS	733 6th Line	1.84	106,000
Cookstown Land	18 Victoria St.	0.08	17,700
Innisfil DS	2255 Hwy 89	0.28	36,500
Belle Ewart DS	20th Side Road & 5th Line	1.74	179,065
Lefroy DS	1495 Kilarney Beach Rd	0.82	62,000
Leonard's Beach DS	2895 25th SR	0.28	35,500
Sandy Cove DS	1104 Lockhart Rd	0.91	66,000
Stroud DS	2135 Lockhart Rd	0.38	45,000
Innisfil TS Land	22 Saunders Rd	3.5	(2012) 465,000
New Building	7251 Yonge ST	6.5	12,000,000
Yard	2033 Commerce Park Dr	1.3	88,000

8.2 Buildings, Head Office



The head office site includes a LEED building for Customer Service, Engineering/Finance, warehouse and garage. Parking for ~78 cars is provided along with outside storage for line hardware. The site is in a commercially zoned area within the Roads & Parks cluster on the Town of Innisfil's administration campus. Fleet fueling and maintenance is expected to be constructed by the Town of Innisfil in early 2016. The cost for maintaining the head office is budgeted for in accounts 5085, 5340 and 5620.

9.0 Equipment Maintenance

9.1 Office Equipment

Office equipment includes desks, chairs, filing cabinets, office partitions, etc. Repairs to office furniture occurs as needed and replacements occur generally after 10 years plus. When the need for expansion occurs and new furniture is purchased, displaced office equipment is re-used or re-cycled to other areas of the corporation where appropriate. The cost of office equipment is budgeted in account 1915. Surplus equipment is sold or disposed of for the greatest benefit to InnPower.

9.2 Computer Hardware



Computer hardware includes the phone system, photo copiers, fax machines, printers, monitors, personal computers, network servers, power supplies, network cables, wireless equipment, etc. The parameters for the replacement of computer hardware are as follows:

- Improved space and speed requirements from new software
- New technologies not supported by existing equipment
- Existing equipment not supported by suppliers
- Reliability problems from existing equipment

When the need for expansion occurs and new computer equipment is purchased, displaced computer equipment is re-used or re-cycled to other areas of the corporation where appropriate. The cost of computer hardware is budgeted in account 1920. Surplus equipment is sold or disposed of for the greatest benefit to InnPower.

9.3 Line Tools

InnPower incorporated in-house line staff and line tools in 2010 so line equipment is generally in new condition. InnPower also purchases and operates line equipment such as underground cable locating equipment, fault locating equipment, meter analyzers and AVO meters, etc. The equipment is generally kept until it is no longer working or cost beneficial to maintain or replaced with new technologies. The cost of tools is budgeted in accounts 1935, 1940 and 1945.

10.0 Long Range Load Projections

Load Growth:

The population increase in our service territory has created the need for us to increase our power supply capacity, resulting in the need to phase in new distribution stations,

capacity upgrades to existing stations, and line builds to add circuitry to supply the new loads.

Based on information currently available InnPower will see increased load growth in the following areas during the five year horizon: South Barrie – Hewitt Secondary Plan and Salem Secondary Plan, Friday Harbour, 400 Corridor, Alcona, Churchill, Cookstown, Gilford, Lefroy, Alcona South, and Stroud. Our peak demand is expected to increase from 60.9MW in 2015 to 83.1 MW in 2020, or 136%.

- **Barrie Lands Development:**

The Barrie-Innisfil Boundary Adjustment Act, 2009 (Bill 196) extended the southern boundary of Barrie to include 2,335 hectares (approximately 5,700 acres) of land previously in the Town of Innisfil, effective January 1, 2010. It is expected, based on conservative estimates, that the number of residences constructed in the Barrie South lands starting in 2018 will be 3,600 units by the end of 2020, adding approximately 1,200 units per year on average, likely resulting in a load increase (residential and commercial) of 17.1 MW.

- **Innisfil Lands Development:**

The number of residential units expected to be constructed during the next five years:

Residential Unit Development	2016	2017	2018	2019	2020
Total Alcona	145.8	91.8	163.2	178.8	150
Total Alcona South (Sleeping Lion)	0	60	60	60	60
Total Churchill	0	7.2	7.2	3	3.6
Total Gilford	0	3	3	3	3
Total Cookstown	30.6	18	28.8	10.2	0
Total Stroud	6	6	6	1.2	0
Total Friday Harbour	150	90	90	90	90
Total Lefroy	72	72	72	54.6	42
	0	0	0	0	0
Total Growth per year	404.4	348	430.2	400.8	348.6

To accommodate the increase in residential growth several capacity upgrade projects have been planned for the next 5 years.

Planned Capacity Upgrades:

- **Cedar Point DS Upgrade:**

The load increase in the area served by the Cedar Point DS (Belle Air Beach, Belle Ewart and surrounding area) and the summer peak loads in 2015 indicate that the transformer will require the station capacity to be increased from a 5MVA transformer to a 7.5 MVA during the summer of 2016.

- **Lines upgrade: Distribution:**

Starting in 2016 a project will rebuild the circuitry on McKay Road between 5th Side Road and 10th Side Road as part of our master plan to serve (and firm) new loads in south Barrie by extending existing circuits; and another project will build a 27.6kV line on the north side of Big Bay Point Road as part of the master plan to serve the new Friday Harbour developments. Another project will upgrade the pole line on Lockhart Road between 10th Side Road (Huronia Road) and Stroud DS on a phased approach to add two distribution circuits to serve as a "back-bone" link between Salem and Hewitt lands. Finally, in 2017 a project will rebuild the pole line on Mapleview Drive between Prince William Way and Seline Crescent to serve new residential loads on the south side of Mapleview Drive in the Hewitt lands.

- **Lines upgrade: Sub transmission:**

In 2019 and 2020, a 44kV pole line rebuild and replacement on the 5th Side Road between the 5th Line and Innisfil Beach Road will take place to rebuild and replace the old small conductor infrastructure. This 44kV line will be constructed to have an additional sub-transmission 44kV circuit on it to accommodate the new Alliston 9M6 feeder scheduled to reach InnPower in the early 2020's for load growth.

- **New Distribution Station**

In an effort to serve the increased loads at Friday Harbour and part of the loads in the Hewitt developments a new Distribution Station is planned to be built in 2018 in the Friday Harbour area.

- **Voltage Conversion:**

In an effort to serve our increasing load requirements and provide reliable power, two voltage conversion projects will be performed in multiple phases between 2019 and 2020 along the 400 corridor and in south Alcona.

- **Reducing Environmental Hazards:**

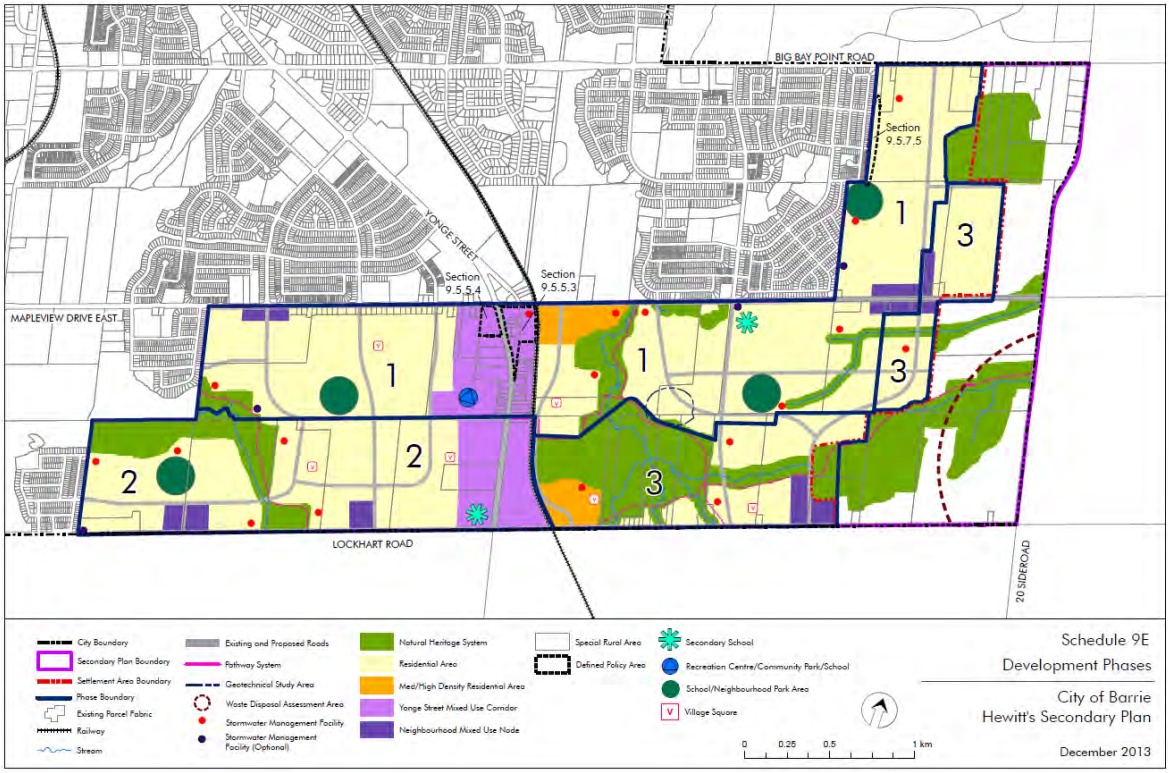
Several of our distribution Stations do not currently have oil containment systems and it is planned to install such systems to limit environmental hazard risks on a phase approach, completing one station each year in 2017, 2019 and 2020.

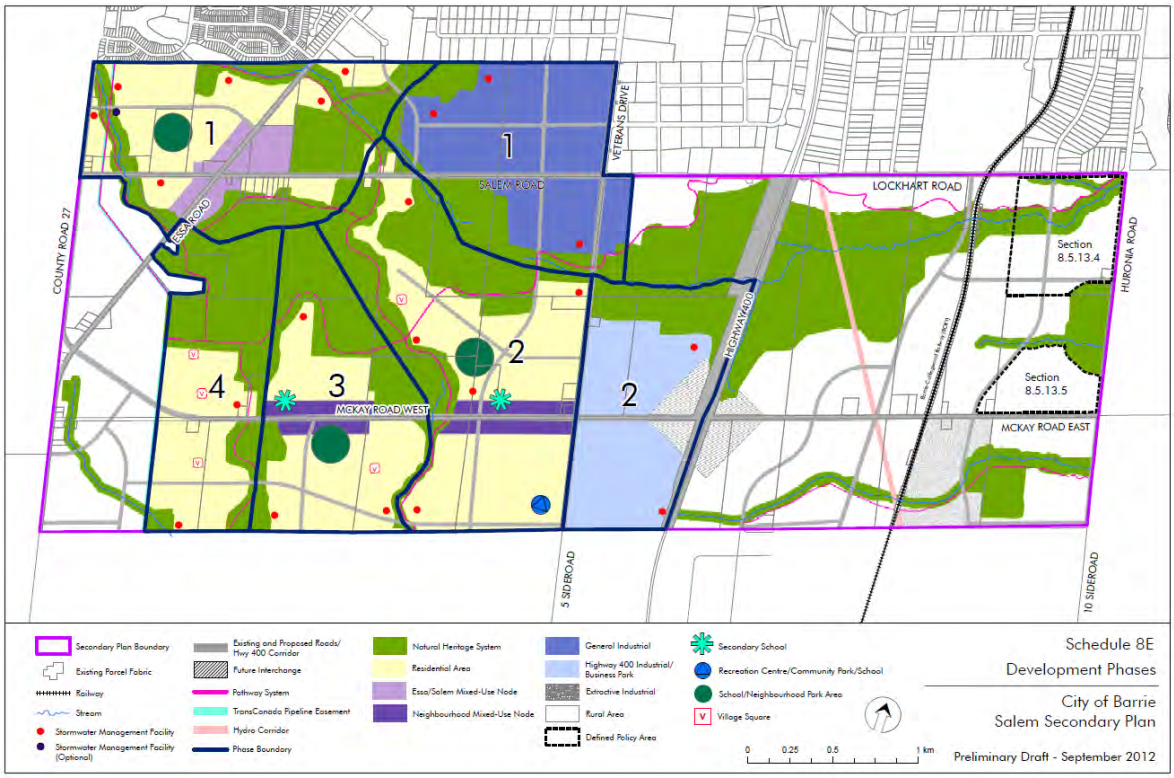
Load Growth Projections

Transformer Station	Gross Median Weather Station Peak Demand Forecast (MW) IPC Usage Peaks - Revised as Per 11th Nov 2015											
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Barrie TS - Aggregate	**14.3**	**15.3**	**16.0**	**19.6**	**24.7**	**29.2**	**33.3**	**37.1**	**40.9**	**44.7**	**48.5**	**52.3**
Total Customer Growth - Barrie Annex, Friday Harbour, Stroud)	0.0	260	96	940	1006	847	798	748	748	748	748	748
Total Load Growth per year residential	0.00	0.99	0.36	3.57	3.82	3.22	3.03	2.84	2.84	2.84	2.84	2.84
Total Load Growth per year commercial (25% of total Load)			0.33	0.12	1.19	1.27	1.07	1.01	0.95	0.95	0.95	0.95
Everett TS - Aggregate	**3.0**	**3.1**	**3.2**	**3.3**	**3.3**	**3.3**	**3.3**	**3.4**	**3.4**	**3.4**	**3.4**	**3.4**
Total Load Growth per year residential	0.19	0.07	0.11	0.04	0.00	0.00	0.07	0.05	0.00	0.00	0.00	0.00
Total Load Growth per year commercial (None)	0	0	0	0	0	0	0	0	0	0	0	0
Alliston TS - Aggregate	**44**	**45**	**47**	**48**	**49**	**51**	**52**	**54**	**55**	**57**	**58**	**59**
Total Load Growth per year residential	1.40	1.44	0.95	1.22	1.19	1.04	1.34	1.24	1.27	1.04	0.99	0.99
Total Load Growth per year commercial (% of population)		0.28	0.29	0.19	0.24	0.24	0.21	0.27	0.25	0.25	0.21	0.20
Total Load Requirements	60.9	63.7	65.7	70.8	77.3	83.1	88.8	94.2	99.5	104.6	109.6	114.5

* Barrie land growth is based on the information available from the city plan
*HWY 400 Strategic employment lands not taken into account
* Information for TOI development taken from TOI plans, provincial requirements for popı
*Customers at EOY for 2014 include all rate classes except microFIT
* As phasing is not available for Barrie Lands after 2021, no of units are equally divided between salem and hewitt
* Available TOI data is from 2016-2026, rest is taken from George's business plan
* Load forecast does not have DG or CDM Correction

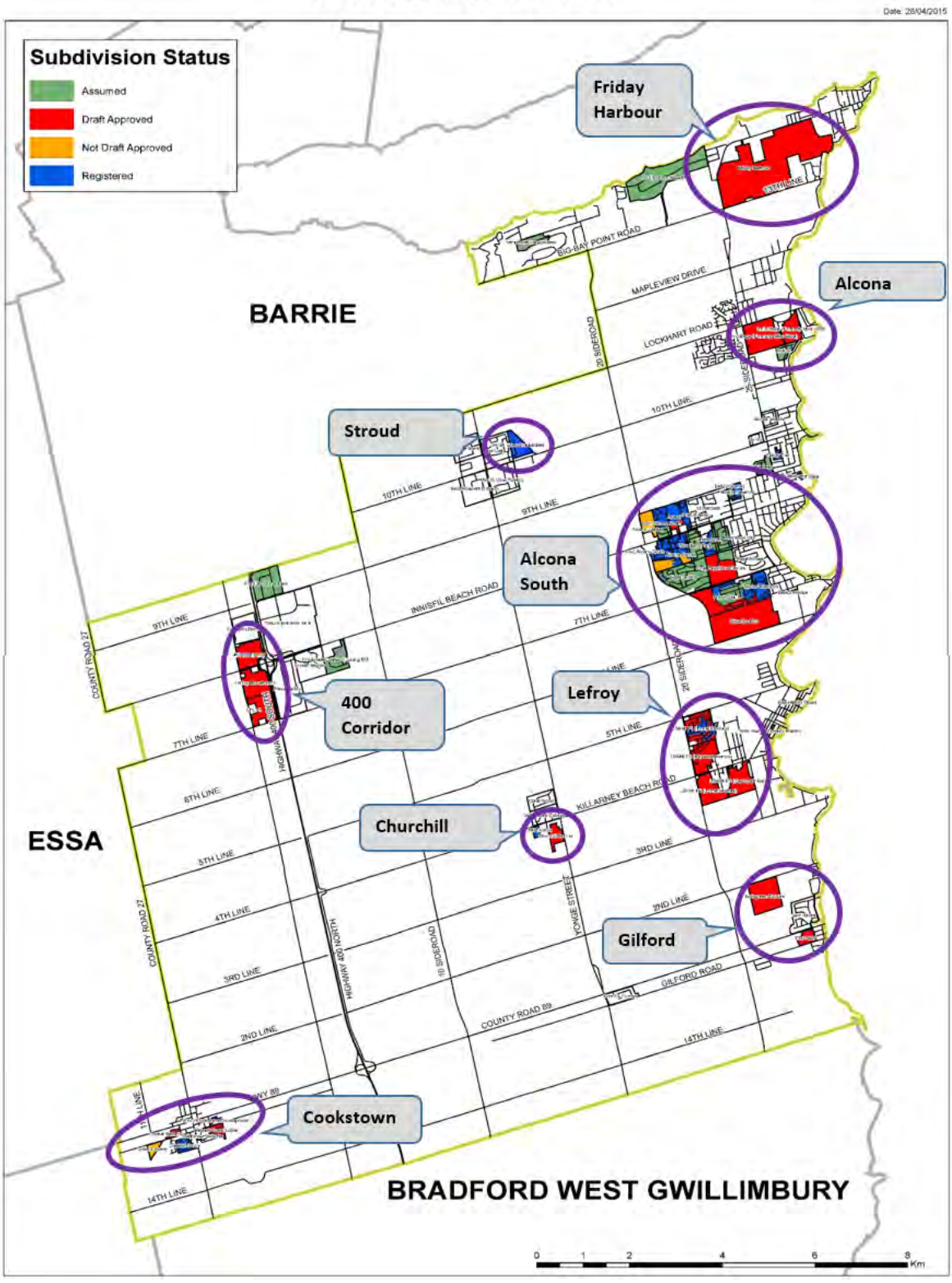
Maps of Barrie South lands development plan




1
1
2
2
3
4
SALEM ROAD
LOCKHART ROAD
MCKAY ROAD WEST
MCKAY ROAD EAST
VETERANS DRIVE
COUNTY ROAD 27
ESSA ROAD
HURONIA ROAD
HIGHWAY 400
5 SIDEROAD
10 SIDEROAD
Section 8.5.13.4
Section 8.5.13.5
Secondary Plan Boundary
Existing Parcel Fabric
Railway
Stream
Stormwater Management Facility
Stormwater Management Facility (Optional)
Existing and Proposed Roads/ Hwy 400 Corridor
Future Interchange
Pathway System
TransCanada Pipeline Easement
Hydro Corridor
Phase Boundary
Natural Heritage System
Residential Area
Essa/Salem Mixed-Use Node
Neighbourhood Mixed-Use Node
General Industrial
Highway 400 Industrial/ Business Park
Extractive Industrial
Rural Area
Defined Policy Area
Secondary School
Recreation Centre/Community Park/School
School/Neighbourhood Park Area
V Village Square
0 0.25 0.5 1 km
Schedule 8E
Development Phases
City of Barrie
Salem Secondary Plan
Preliminary Draft - September 2012

Town of Innisfil

Subdivision Phases



11.0 Innisfil Beach Road Urbanization

The Town of Innisfil has 'urbanized' a section of Innisfil Beach Road between the 20th Side Road and Lake Simcoe. In 2005, the Town retained a consulting firm of MBPD to undertake an Urban Design Study of Innisfil Beach Road in the community of Alcona. The intent was to determine the future urban design of the public road allowance and the lands and buildings adjoining the road. There has been a series of public consultations and public participation involving members of the general public, landowners, business operators and members of Town staff and Council.

As a result of this consultation process and the work of MBPD, a draft document has been prepared entitled the Innisfil Beach Road Urban Design Study and Guidelines. A presentation was made to Council on February 28, 2007 by the Town's consultants.

This was a multi-year project involving property acquisition, road widening, curbs, gutters, roadside parking and streetscaping. The project was initially a four-year project with utility relocates starting in 2009. The project was changed to a two-year project with Utility relocates completed in 2011.



The Town of Innisfil has finalized the urbanization design through a By-law. The same By-law requiring utility relocates to be underground. InnPower was provided notice to relocate a portion of the overhead infrastructure due to the improvement of the highway. According to the *Public Service Works on Highways Act., R.S.O. 1990, CHAPTER P.49,* without a cost sharing agreement between the Road Authority (Town of Innisfil) and the Operating Corporation (InnPower), the Town of Innisfil will be responsible for half of the labour costs and InnPower shall be responsible for the other half of labour costs and all material costs as outlined in Section 2 below:

Notice to operating corporation to take up works

2. *(1) Where in the course of constructing, reconstructing, changing, altering or improving a highway it becomes necessary to take up, remove or change the location of appliances or works placed on or under the highway by the operating corporation, the road authority may by notice in writing served personally or by registered mail require the operating corporation, without prejudice to their respective rights under section 3, so to do on or before the date specified in the notice. R.S.O. 1990, c. P.49, s. 2 (1).*

Apportionment of costs of taking up

(2) The road authority and the operating corporation may agree upon the apportionment of the cost of labour employed in such taking up, removal or change, but, subject to section 3, in default of agreement such cost shall be apportioned equally between the road authority and the operating corporation, and all other costs of the work shall be borne by the operating corporation. R.S.O. 1990, c. P.49, s. 2 (2).

If the Town of Innisfil incurs a loss due to neglect by InnPower, *Sec 2 (5) of the Public Service Works on Highways Act., R.S.O. 1990, CHAPTER P.49, indicates that InnPower shall make due compensation as follows:*

Compensation

(5) Where a road authority incurs a loss or expense by reason of an operating corporation neglecting to take up, remove or change the location of appliances or works by the date specified in a notice given under subsection (1) or such date as altered by a judge under subsection (4), the operating corporation shall make due compensation to the road authority for such loss or expense, and a claim for compensation, if not agreed upon by the operating corporation and the road authority, shall be determined by the Ontario Municipal Board. R.S.O. 1990, c. P.49, s. 2 (5).

In an effort to mitigate any claims for compensation (*R.S.O. 1990, c. P.49, s. 2 (5)*), InnPower budgeted capital funds (which is the total project cost without including contributions from the Town of Innisfil) for the relocation of distribution assets on Innisfil Beach Road as follows:

2009 - $1,000,000

2010 - $3,900,000

2011 - $ 464,800

2012 - $ 50,000

The electrical distribution infrastructure in the urbanized area is designed to incorporate smart grid technologies at a later date. It is possible to automate all switching cubicles and have Smart Grid self-healing technologies. Automation design will be undertaken annually to determine its feasibility and system benefits.

C.1 DISTRIBUTION INSPECTION STANDARDS

Inspection Cycles

A distributor should ensure that only persons qualified under the Occupation of Health and Safety Act are involved in inspection activities. Since some inspections can expose inspectors to energized lines or high voltage circuits and equipment, and may include inspection and repair, a qualified person should be assigned to this work. This assumes that they are both properly trained to protect both themselves and the public, and to respond to those emergencies, which may arise during inspections.

In developing the standards for facilities inspections, the patrol inspection is defined as follows:

> Patrol or simple visual inspections consists of walking, driving or flying by equipment to identify obvious structural problems and hazards such as leaning power poles, damaged equipment enclosures, and vandalism. In cases where a patrol notices that a problem exists or identifies a condition that warrants a more thorough or rigorous inspection, patrol may then include situations where structures are opened as necessary, and individual pieces of equipment carefully observed and their condition noted and recorded. The specifics of these inspections would be recorded, and a summary document prepared in the distributor's annual reports as part of their rates or licensing submissions.

In all cases, a distributor is responsible to ensure that appropriate follow up and corrective action is taken regarding problems identified during a patrol.

The Board or a Board-designated party reserves the right to conduct random audits of inspection reports to ensure that appropriate follow up and corrective action is taken regarding problems identified during a patrol.

It is expected that distributors will file both annual summary reports of detailed patrol inspection activities that have taken place during the previous year as well as an outline of inspection plans ("compliance plans") for the forthcoming year.

Inspection cycles are categorized by the following major distribution facilities:

Distribution Transformers
Stations
Switching and Protective Devices
Regulators
Capacitors
Conductors and Cables

Vegetation
Poles/Supports
Civil Infrastructure

For each of these facilities, the distributor shall further distinguish between overhead facilities, underground facilities. The distributor shall also separate according to the facilities' location and the relative population density in the locale.

- **Rural** means those areas that are less populous suburban areas and are outside of a standard metropolitan area. Generally, rural will be defined on a circuit or sub-circuit basis by each utility, as areas with a line density of less than 60 customers per kilometer of line. It is recognized that there may be circumstances where the utility might want to treat something as urban though it would otherwise be defined as 'rural' according to this definition.

- **Urban**, means areas with higher density and, by definition pose safety and reliability consequences to greater numbers of people.

The following description provides a list of the requirements to be expected from a typical distribution line patrol inspection in terms of the types of defects that may be detected visually. Clearly, the list will vary depending on the equipment specifics and locations, thus this should be viewed as a 'generic' patrol expectation.

Transformers and switching kiosks:
Paint condition and corrosion
Placement on pad or vault
Check for lock and penta bolt in place
Grading changes
Access changes (Shrubs, trees, etc.)
Phase indicators and unit numbers match operating map (where used)
Leaking oil
Flashed or cracked insulators
Pad mounted – lid damage, missing bolts, cabinet damage, public security lock damage

Substation- May consist of one or all types of equipment listed

Switching/Protective Devices
Overhead
Bent, broken bushings and cutouts,
Damaged lightning arresters, control boxes, current and potential transformers
Underground
Security and structural condition of enclosure
Pad mounted
Security and structural condition of enclosure

Regulators

Condition of bushings
Tank corrosion/leaks
Damaged disconnect switches or lightning arresters

Capacitors

Condition of bushings
Tank corrosion/leaks
Damaged cutouts, disconnects or control cabinet

Conductors and Cables

Low conductor clearance
Broken/frayed conductors or tie wires
Tree conditions, exposed broken ground conductors
Broken strands, bird caging, and excessive or inadequate sag.
Insulation fraying on secondary especially open wire

Poles/Supports:

Bent, cracked or broken poles
Excessive surface wear or scaling
Loose, cracked or broken cross arms and brackets
Woodpecker or insect damage, bird nests
Loose or unattached guy wires or stubs
Guy strain insulators pulled apart or broken
Guy guards out of position or missing
Grading changes, or washouts
Indications of burning

Hardware and attachments:

Loose or missing hardware
Insulators unattached from pins
Conductor unattached from insulators
Insulators flashed over or obviously contaminated (difficult to see)
Tie wires unraveled
Ground wire broken or removed
Ground wire guards removed or broken

Equipment Installations (includes transformers)

Contamination/discoloration of bushings
Oil leaks
Rust
Ground lead attachments
Ground wires on arrestors unattached
Bird or animal nests
Vines or brush growth interference

Evidence of bushing flashover
Accessibility compromised

Vegetation and Right of Way:
Leaning or broken "danger" trees
Growth into line of "climbing" trees
Unapproved/unsafe occupation or secondary use

Civil Infrastructure - For example, buildings that house the equipment may need attention (cracking, fire hazards, etc). In addition, cable chambers, underground vaults and tunnels crossing the rail track or water are also included in this category. These inspections would likely be conducted in the patrol of the equipment with which they are "associated."

Underground Systems:

With respect to underground systems, riser poles should be checked as with an overhead patrol, with a visual check of cable, cable guards, terminators and arrestors. While it is not possible to inspect underground cable directly, the system may be checked for exposed cable and or grade changes that may indicate that the cable has been brought too close to the surface. Patrol inspection of cable chambers is not required since a visual inspection will not reveal faults because the failure mechanism for underground cable (e.g. voids, water trees) is not visually detectable.

Cable is hard to check, but the system can be checked for exposed cable and/or grading changes that may have brought cable or wire too close to the surface.

TABLE C-1
Electric Utility System Inspection Cycles
(Maximum Intervals in Years)

Major or Substantial Distribution Facility*	Patrol	Patrol
Distribution Transformers	**Urban**	**Rural**
Overhead	3	6
Submersible	3	6
Vault	3	6
Pad Mounted	3	6

Stations (see note below)	Outdoor Open	Outdoor Enclosed	Indoor Enclosed	Outdoor Open	Outdoor Enclosed	Indoor Enclosed
Transformer Station	1 month	1	1	6 month	1	1
Distribution Station	1 month	1	1	6 month	1	1
Customer Specific Substation	1	3	3	1	3	3

Lines and Associated Equipment		
Regulators	3	6
Switching and Protective Devices	3	6
Capacitors	3	6
Conductors and Cables		
Overhead	3	6
Underground	3	6
Submarine	3	6
Vegetation (see note below)	3	6
Poles	3	6
Civil Infrastructure	3	6

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

Notes to Table C-1:

1. The above distribution system patrol cycles form part of the regulatory framework and are minimum inspection requirements for each major or substantial distribution component and related hardware.

2. A distributor may determine that more frequent inspections may be required due to local conditions such as geographic location, climate, environmental conditions such as air pollution or highway salt spray, technologies available to perform the inspection, type and vintage of distribution technology in place, manufacturer specifications, system design, or relative importance to overall system reliability of a particular piece of equipment or portion of the distributor's distribution system.

   The burden of proof is on the distributor to demonstrate that it should not have to comply with these the inspection schedules or requirement in Table C-I. To demonstrate that it should not have to comply with these inspection schedules, the distributor would have to present a comprehensive and detailed case establishing:

   Revised inspection cycles may be allowed when justified by:
   - Documented historical good utility maintenance and inspection practices, including a program to manage reliability.
   - Alternative or additional maintenance activities that are practiced by the utility and can be demonstrated as being practiced.
   - Achieved reliability performance. The utility will be required to submit both the current and historic reliability statistics over five years. These statistics must be verifiable. This will be measured by the following:
     - Once the data is available over the course of Generation 1 and 2 of the PBR regime, the reliability indices that are better than the average of distributors which are comparable in size and type. The reliability indices to be used are those that are defined over time in the PBR regime, including initially SAIDI, CAIDI and SAIFI averaged over the previous three year period, and;
     - The reliability indices over time for the individual utility that are at least as good, if not better, than the average of the indices over the previous five year period. Again, the reliability indices to be used are those that are defined over time in the PBR regime, including initially SAIDI, CAIDI and SAIFI averaged over the previous five-year period.

3. The method by which inspection cycles are structured and the work carried out is at the discretion of the distributor. The above table is organized according to major classification of equipment, however distributors may choose to conduct and record the inspections on some other basis such as:
   - Circuit or feeder basis
   - Overhead & underground
   - System voltage
   - Dividing its service area into geographical areas
   - Other

   It is intended that if the inspections are organized by one of the above approaches, all major equipment categories identified in the table and related hardware along the line or within the area will be inspected. It is intended that the utility would perform the inspection on a minimum of approximately 1/3 (urban) or 1/6 (rural) of their system in each year, such that at the end of the first term of the PBR framework, a utility would have performed an inspection of their entire system in urban areas and approximately half of rural systems. If, in any one year of the PBR framework, a utility has performed the inspection on less or more than the 1/3 (urban) or 1/6 (rural) of their system, the utility would provide an explanation of this deviation in their annual submission. For clarity, the plant will be inspected on a cyclical basis, and the cyclical interval is specific to a particular region or portion of plant, and not on the system as a whole.

4. "Civil Infrastructure": Refers to facilities and structures such as tunnels, ducts suspended from or attached to bridges, underground chambers and hand holes, towers supporting distribution plant, communication towers, buildings that house substation equipment. It is intended that civil infrastructure will be inspected as part of the patrol of the distribution system or in the course of doing normal, routine utility work. It is recognized that there may be instances where it will be extremely difficult to perform a visual inspection (e.g. where access is restricted due to energized equipment in cable chambers), and therefore the civil infrastructure associated with this would be inspected in the course of doing normal utility work which would require entrance to the chamber, which would require the utility to de-energize the equipment. In other words, the equipment should not be de-energized simply to comply with this scheduled inspection routine.

5. "Patrol": Visual inspection of major distribution system components to identify problems and hazards such as leaning poles, damaged equipment enclosures, and vandalism. This will include an inspection of all related peripheral equipment, hardware, connections, all supports and attachments (e.g. cross arms, braces, guys and anchors). This would also include an assessment of vegetation encroachment on right-of-ways.

   The patrol may highlight that a problem exists or may identify conditions that warrant a more thorough or rigorous inspection or the need for specific maintenance. The specific follow up or corrective action shall be according to the best judgment of the distributor considering best industry practices. To further clarify the nature of problems detected during the inspection, the distributor may choose to utilize diagnostic tools such as infrared thermography, ultrasonic testing or other technologies that may emerge. Several technologies are also available for wood pole testing. Distributors may choose, (as post inspection follow up or ongoing maintenance), to conduct tests of major distribution system components on a sample basis. Issues such as the age, equipment design, exposure to adverse conditions, manufacturer specifications, and relative impact on overall system reliability may influence a distributor's decisions regarding corrective action and application of these diagnostic technologies following a patrol. In all cases, a distributor is responsible to ensure that appropriate follow up and corrective action is taken regarding problems identified during a patrol. This may entail upgrade or replacement of specific components or equipment.

   Maintenance activities and schedules are not specified in the above table and are left to the discretion of the distributor. It is not practical to attempt to establish a regulatory regime for literally hundreds of maintenance activities that range from insulator washing, cable replacement, CO_2 cleaning of switchgear, to gas-in-oil testing of station transformers, etc. The absence of more detailed inspection or maintenance criteria in the above table in no way reduces the distributor's obligation to maintain the distribution system in a safe and serviceable condition.

   The Board or a Board- designated party reserves the right to conduct random audits of inspection reports to ensure that appropriate follow up and corrective action is taken regarding problems identified during a patrol.

7. "Rural": Generally will be defined on a circuit or sub-circuit basis by each distributor, as areas with a customer density of less than 60 customers per kilometer of line. It is recognized that there may be circumstances where the distributor may choose to treat some parts of its distribution system as urban though it is "rural" according to this definition.

   "Urban": Each distributor will define "Urban", or more populated areas, on a circuit or sub-circuit basis, as areas with higher density and, by definition pose safety and reliability consequences to greater numbers of people.

8. "Stations": The terms "substations", "distribution /municipal stations", etc. Are frequently interpreted and applied differently by various distributors. In some jurisdictions the term "substation" refers to a large 125 MVA station directly connected to the 115 or 230 kV

transmission system while in other jurisdictions "substation" refers to a customer specific station that provides transformation from a distribution voltage to a utilization voltage of 600V for example.

The impact on overall distribution system reliability of any particular station varies considerably according to the nature of the station and local system design. Specific station design features such as indoor versus outdoor may warrant different inspection cycles according to the relative exposure to unauthorized access and associated public safety concerns.

The following definitions are provided to assist with interpretation of the above table such that the resulting inspection cycles are appropriate for the nature of the station.

8.1 "Transformer Station" (TS): A transformation facility with the primary connected to the 115/ 230 kV or higher transmission system and the secondary operating at 50 kV or less.

8.2 "Distribution Station" (DS): Also known as "municipal Station (MS), a transformation facility with the primary operating at a sub transmission or distribution voltage and the secondary operating at lower distribution voltage. The upstream transformation facility will typically be a Transformer Station. A Distribution Station supplies main feeders for wide area distribution.

8.3 "Customer-Specific Substation": A transformation facility supplying a specific industrial/commercial customer. The primary operates at a distribution or sub transmission voltage and the secondary typically operates at 600V. The upstream station could be either of the stations identified in 8.1 or 8.2. Typically these facilities are on the customer's private property and include customer-owned equipment in addition to a Distributor-owned transformer.

8.4 "Outdoor Open": Typically refers to a station surrounded by a locked security fence. Within the station fence bare energized components operating at distribution voltage levels or higher are readily accessible. More frequent inspections are required for public safety considerations and to ensure integrity of the station fence.

8.5 "Outdoor Enclosed": Similar to 8.4 above however all bare live components are enclosed in locked metal enclosures. Due to reduced accessibility to energized components less frequent inspections are appropriate.

8.6 "Indoor": Typically refers to a station located within a secure building. Access by the public to bare energized components within the station is prevented by the building enclosure. Due to reduced exposure to unauthorized public access less frequent inspections are appropriate.

9. "Conductors and Cables: Underground": It is not possible to inspect underground cable directly, however, the system can be checked for exposed cable and or grade changes that may indicate that the cable has been brought too close to the surface. Patrol inspection of cable chambers is not required since a visual inspection will not reveal faults because the failure mechanism for underground cable (e.g. voids, water trees) is not visually detectable.

10. "Vegetation": Refers to encroachment of vegetation upon distribution lines on any right-of-way; either public road allowance or private property. It is intended that vegetation will be inspected as part of the regular patrol of distribution equipment.

C.2 DISTRIBUTION INSPECTION REPORTING

TABLE C-2
Sample Annual Inspection Summary Report

Distributor					
Reviewed by	**Name:**		**Position/Title:**		
Date:	**Signature:**				
DESCRIPTION **Part 1 - Lines**		**Percentage of Distribution System Scheduled for Patrol (%)**	**Percentage of Distribution System Actually Patrolled (%)**	**Reason Patrol was not Completed**	**Date Patrol will be Completed**
Overhead Plant Transformers Switching & Protective Devices Regulators Capacitors Conductor Vegetation Poles Civil Infrastructure	**Urban**				
	Rural				
Underground Plant Transformers Switching & Protective Devices Regulators Capacitors Cable Civil Infrastructure	**Urban**				
	Rural				

Part 2 – Substations	**Number of Substations in Distribution System**	**No. of Substation Patrols Scheduled**	**No. of Scheduled Patrols not completed**	**Reason Patrols were not Completed**	**No. of Substations not Patrolled During Reporting Period**	**Date Substation Patrol Schedule will be Resumed**
Transformer Station						
Distribution Station						
Customer Specific Substation						

Notes to Table C-2:

APPENDIX C - MINIMUM INSPECTION REQUIREMENTS

1. This report provides a summary of the patrols scheduled and carried out during the year as well as the target dates for completion of patrols which were not completed as planned.

2. This format is a sample of a summary report for patrols carried out on a geographical, system characteristic (overheard or underground) basis.

3. Major equipment categories need not be reported separately however, all categories of equipment within the particular area or circuits shall be inspected.

4. Civil infrastructure is intended to be inspected as part of patrol of the distribution system or in the course of doing normal routine utility work.

5. This report is to be submitted to the OEB on an annual basis.

TABLE C-3
Sample Patrol Deficiency Record

Area/District _____ **Date** _____

Circuit _____ **Patrolled by** _____

Grid _____ **Page** _____ of _____

Location	Equipment Id. No.	Equipment Classification	Repair Required/ Problem	Corrective Action Priority		Assigned to or Work Order No.	Date Repair Completed or Scheduled
				Grade 1	Grade 2		
Number of Deficiencies for the Circuit/Area							

Notes to Table C-3:

1. The format of this record is to be determined by the distributor based on their own system data input forms. This format is a sample for inspections done on a geographical or circuit basis and indicates the information that is expected to be collected.

2. Deficiencies and corrective action for all major equipment classifications for the area or circuit would be recorded.

3. Distributors are required to retain this information and make it available to the Board upon request.

4. Corrective Action Grade 1 is defined as a condition requiring urgent and immediate response and continued action until the condition is repaired or no longer presents a potential hazard.

5. Corrective Action Grade 2 is defined as a condition requiring timely corrective action to mitigate an existing condition which, at the time of identification, does not present an immediate hazard to the public, Distributor employees, or property.

Appendix 4



Reliability Management Plan

2016

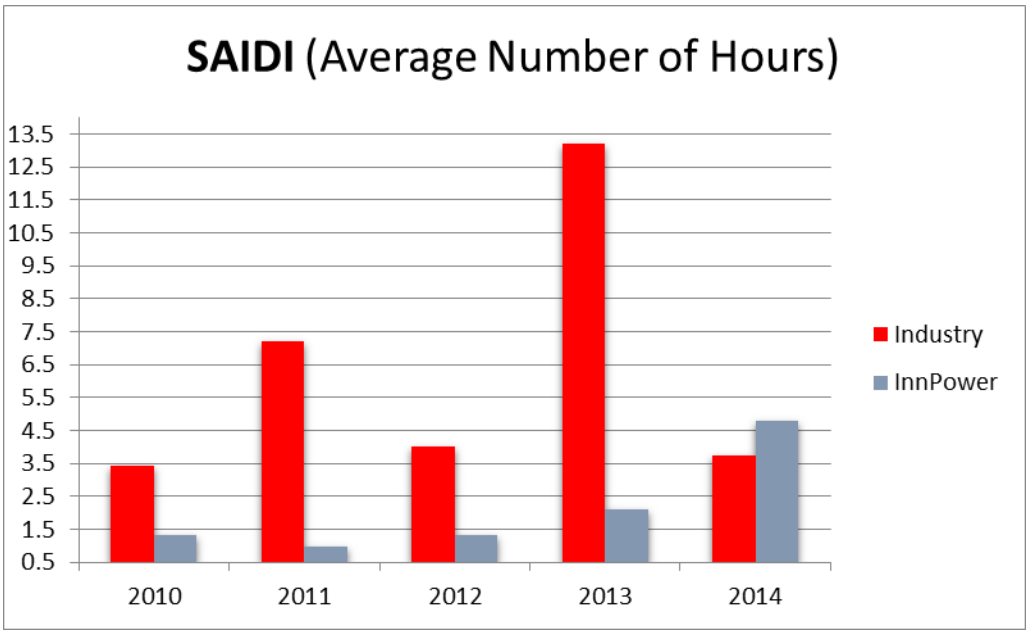
The Distribution System Code (DSC) requires an LDC to maintain its distribution system in good working condition, as follows:

"4.4.1 A distributor shall maintain its distribution system in accordance with good utility practice and performance standards to ensure reliability and quality of electricity service, on both a short-term and long-term basis."

Together with the Asset Management Plan in the Business Plan, the Reliability Management Plan utilizes statistical evaluation tools to evaluate system reliability by diving into the root causes of electrical interruptions and incorporating operational and capital plans to provide the best overall cost benefit for system reliability.

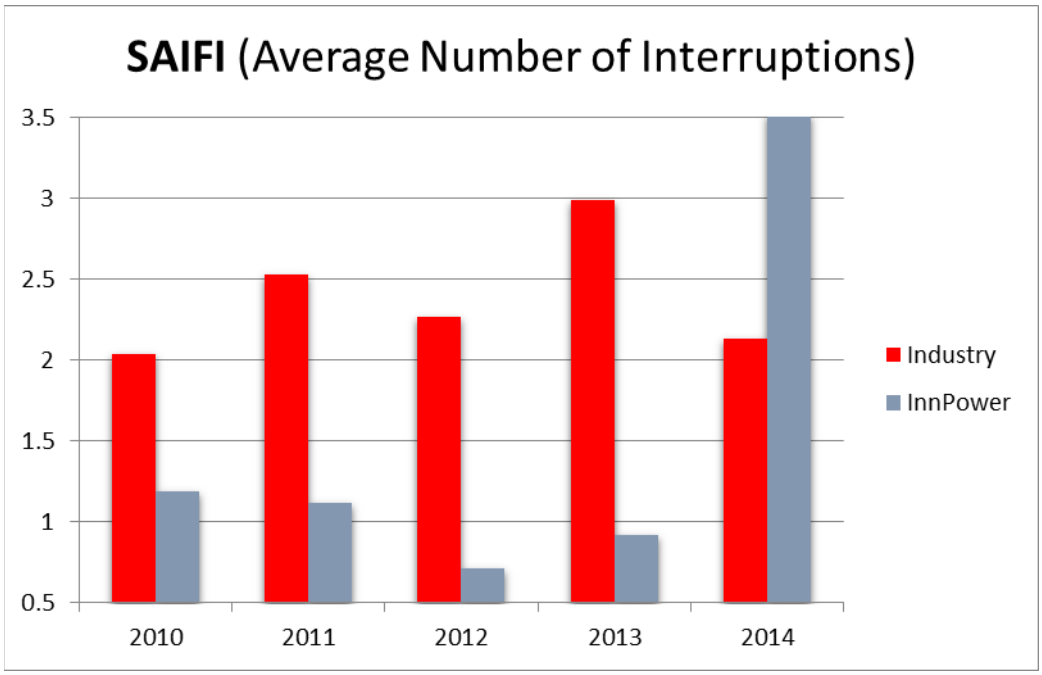
In the charts below we have compared our reliability performance with the industry average on two key metrics: System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).

SAIDI is a measure of how long an average customer in our service territory was out of power (hours) in a given period of time. Based on the comparison below InnPower's performance was better than the industry average from 2010 to 2013 but lower than the average in 2014, which was a result of major storm damage in our service territory. Note: The high industry average in 2013 was a result of the ice storm during the last week in December.

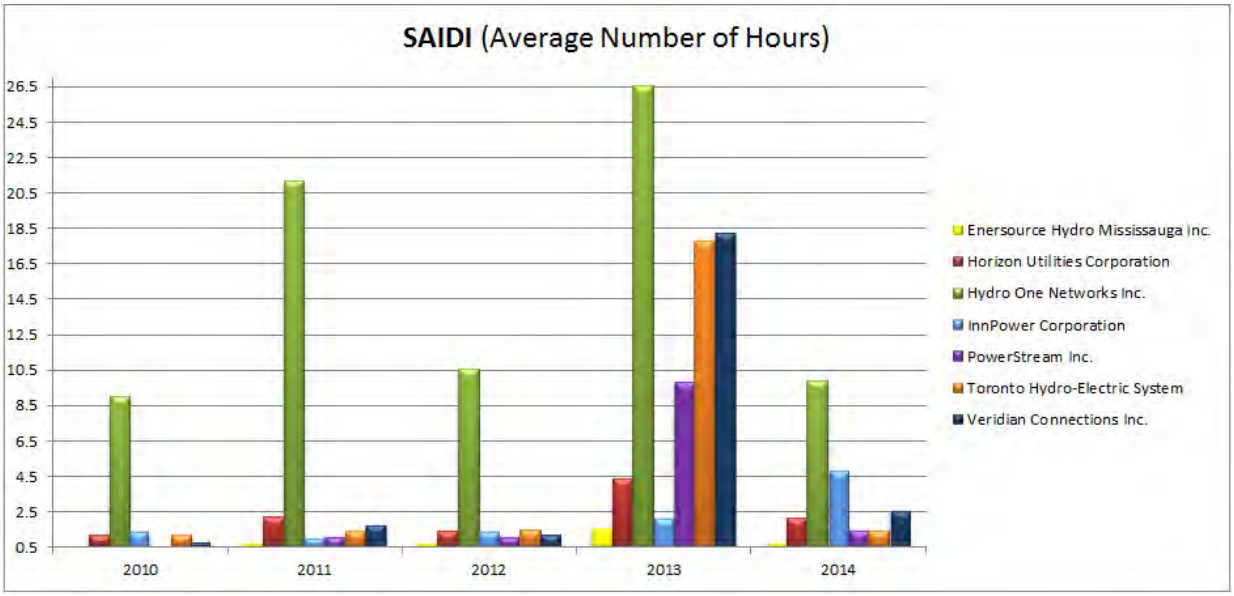


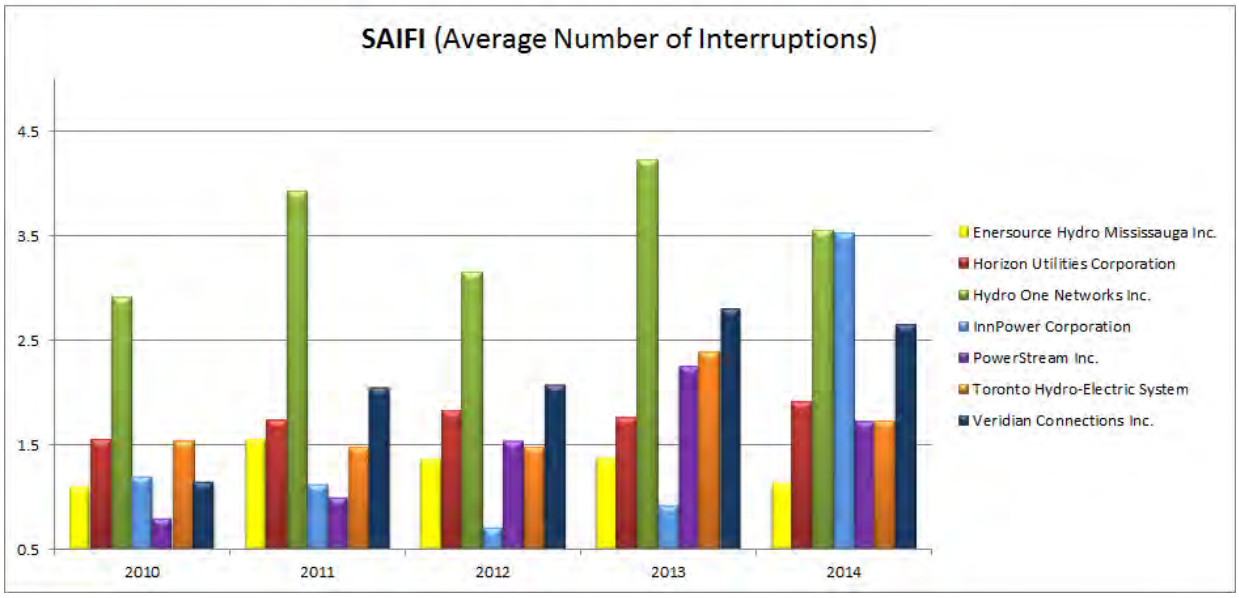
SAIFI is a measure of how many times an average customer in our service territory was out of power in a given period of time. Based on the comparison below InnPower's performance was better the industry average from 2010 to

2013 but lower than the average in 2014, which was a result of major storm damage in our service territory.



InnPower's Performance in comparison to Other LDC's





2014 Performance: InnPower

Innpower Corporation

Outage Frequency by Type



Customer Interruptions	
0 - Unknown/Other	16
1 - Scheduled Outage	4,702
2 - Loss of Supply	6,091
3 - Tree Contacts	6,449
4 - Lightning	1
5 - Defective Equipment	10,807
6 - Adverse Weather	16,709
7 - Adverse Environment	1
8 - Human Element	19
9 - Foreign Interference	11,950
Total	**56,745**

Outage Duration by Type



Customer-hours of Interruptions	
0 - Unknown/Other	32
1 - Scheduled Outage	1,753
2 - Loss of Supply	1,530
3 - Tree Contacts	6,777
4 - Lightning	1
5 - Defective Equipment	31,894
6 - Adverse Weather	20,311
7 - Adverse Environment	3
8 - Human Element	11
9 - Foreign Interference	14,910
Total	**77,221**

Diving into interruption statistics more deeply, an analysis has been developed with regard to the underlying causes of the interruptions in service. These underlying causes have been broken down into the following categories:

1. Adverse Environment
2. Adverse Weather
3. Defective Equipment
4. Foreign Interference
5. Human Element
6. Lightning strike
7. Loss of Supply
8. Scheduled Outage
9. Tree
10. Unknown

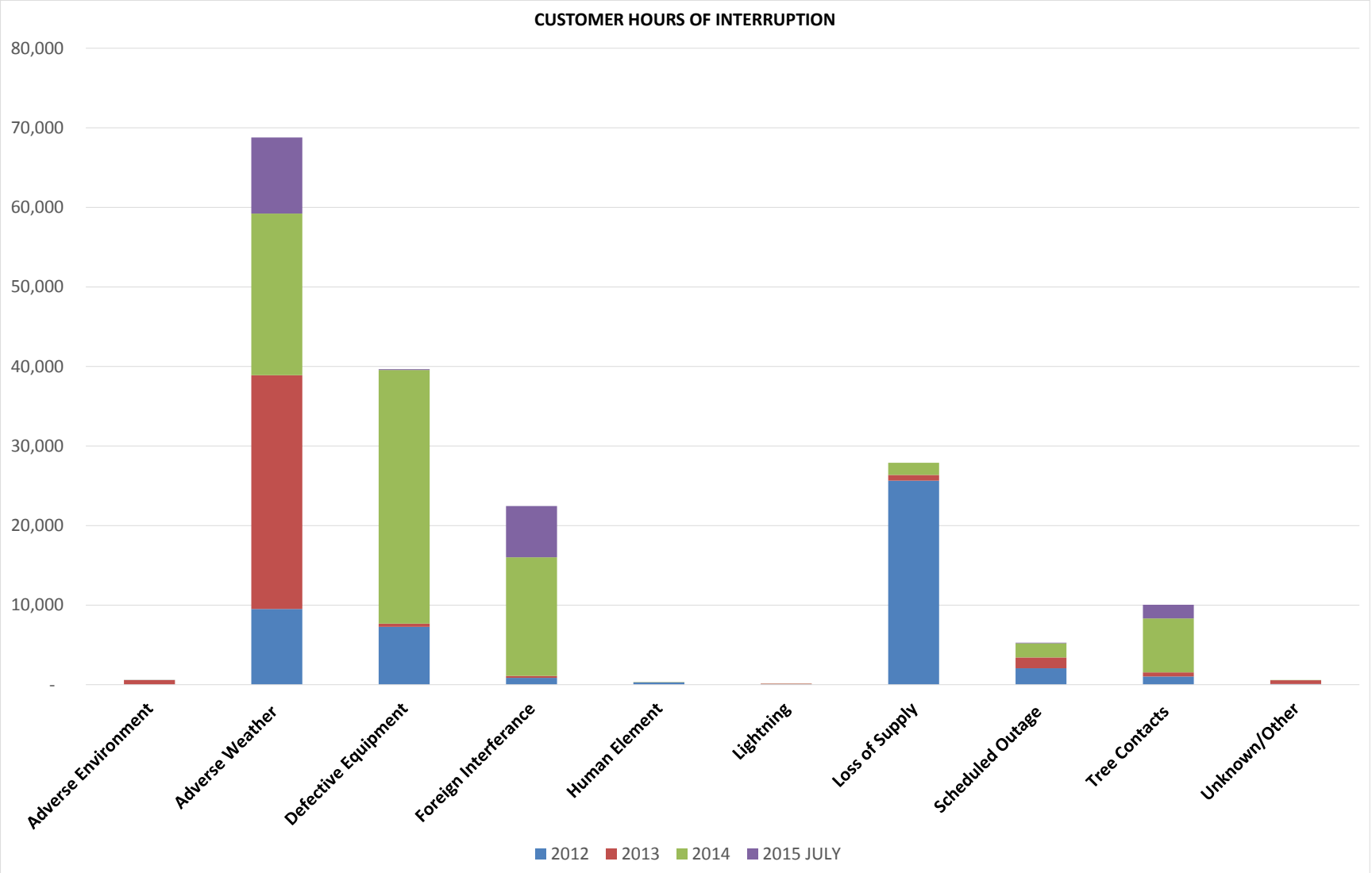
As seen from the InnPower Reliability Chart below, the largest interruption duration cause over the past 3 ½ years was storm related.

Weather mitigation has been accomplished by shortening the tree trimming rotation from a four-year cycle to a three-year cycle. With this schedule, one third of the trees in InnPower's distribution territory that have proximity to power lines will be trimmed. Trees are trimmed by an independent contractor which was chosen through a public tender process.

The InnPower Reliability Chart measures actual customer interruption minutes by category. The second largest cause for interruptions noted in the chart is defective equipment. Although we had a substantial improvement in outages from defective equipment from 2012 to 2013, the transformer loss at the Brian Wilson DS in 2014 resulted in an increase in this metric. The 2012 reason was predominately caused by a G&W Viper Reclosure and arrestor failure at Leonards Beach DS. The reclosure problem was attributed to factory setting error and the arrestor failed atypically. Once repaired, there is no evidence that future trending would occur.

Also in 2014 an outside contractor working on the IBR and 10th Side Road expansion project got into our sub transmission lines and caused a major outage, and earlier this year a para-sailor's gear was entangled in our sub-transmission line that triggered a large outage.

The 13M3 service area has the highest concentration of trees amongst all of the tree trimming cycles. We are continuing to closely monitor the performance of our tree trimming crews to ensure sufficient clearance is maintained to power lines. In 2016 we are planning on engaging our tree contractor to look for and identify danger trees and hazard trees outside the right of way.


CUSTOMER HOURS OF INTERRUPTION
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
Adverse Environment
Adverse Weather
Defective Equipment
Foreign Interferance
Human Element
Lightning
Loss of Supply
Scheduled Outage
Tree Contacts
Unknown/Other
2012
2013
2014
2015 JULY

Appendix 5

InnPower Corporation

Health and Safety Business Plan

Goal

The Joint Health & Safety Committee (JHSC) is compiled of employer and employee representatives who work together to pro-actively improve health and safety in the workplace.

Member Duties

1) Identify sources of danger or hazards.
2) Assist in writing recommendations for improvements to the employer.
3) Obtain certain information from the employer regarding actual or potential hazards.
4) Be consulted about testing methods and strategies.
5) Be present at the beginning of testing, if the member feels their presence is required.
6) Inspect the workplace at least once per month or at least a section of the workplace once a month.
7) Inform the JHSC of actual or potential hazards.
8) Assist in resolving matters when a worker refuses work on the grounds that it endangers health and safety.
9) Review the Health & Safety Policy on an annual basis, revise as necessary.

The H&S Committee Members will make recommendation for funds required to the budget committee for the annual budget. Items that require funding includes, but is not limited to:

- Attendance to E&USA conferences, workshops & annual general meetings.
- Attendance to IAPA or other pertinent safety associations for events.
- General or specialized training required for H&S Committee Members
- Recommendation for funding to facilitate recommended safety training for staff.
- Funds required to facilitate statutory obligations, meetings and staff participation.

Action Plan

This health and safety business plan is the overall strategy for planning and implementation of a health and safety system including the following action plan items:

- Long and short-term health and safety targets and objectives is ZeroQuest. InnPower has won E&USA's President Award for 250,000 no lost time hours in 2005. Another 250,000 hour mile stone was reached in year 2011.
- Project assignment responsibilities are determined at every H&S committee meeting. Target dates for completion are provided and tracked on the minutes of every regular scheduled meeting.
- Anticipated funding requirements for H&S Committee resources shall be provided to the budget committee by mid September of each year. The amount budgeted for the Health and Safety committee in 2015 is $11,800. All other staff training costs are budgeted within departmental human resource training budgets.
- Securing the Bronze Commitment Level was achieved in July 2006.
- Securing the Silver Effort Level was achieved in October 2009.
- Securing the Gold Outcomes Level was achieved in January 2012.
- President's Award for 750,000 no lost time hours in 2014
- Platinum Sustainability Level in 2016
- The Action Plan will be reviewed on an annual basis by the H&S committee to track past performance and to set new targets for subsequent years.

SOUTH GEORGIAN BAY/ MUSKOKA REGION
SCOPING ASSESSMENT OUTCOME REPORT

June 22, 2015



ieso
Independent Electricity System Operator

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4 List of Acronyms 29

South Georgian Bay/Muskoka Study Team

Company
Independent Electricity System Operator
Hydro One Networks Inc. (Transmission)
Hydro One Networks Inc. (Distribution)
InnPower
Lakeland Power
Midland PUC
Newmarket-Tay Power
Orangeville Hydro
Orillia Power
PowerStream
PowerStream COLLUS
Veridian Connections
Wasaga Distribution

1 South Georgian Bay/Muskoka Scoping Assessment Outcome

Scoping Assessment Outcome Report Summary			
Region:	South Georgian Bay/Muskoka		
Start Date	March 23, 2015	**End Date**	June 22, 2015

1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's ("OEB" or "Board") Regional Planning process. The Board endorsed the Planning Process Working Group's Report to the Board in May 2013 and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

The first stage in the regional planning process, the Needs Assessment, was carried out by Hydro One Networks Inc. ("Hydro One") for the South Georgian Bay/Muskoka region. The purpose of the Needs Assessment is to identify if there are any electricity needs in the region requiring regional coordination. The final Needs Assessment report[1] was issued on March 3, 2015 and concluded that some needs in the region may require regional coordination, and these needs should be reviewed further under the IESO-led Scoping Assessment process, which is the second stage in the regional planning process.

The IESO, in collaboration with the Regional Participants, further reviewed the needs identified, in combination with information collected as part of the Needs Screening, and information on potential wires and non-wires alternatives, to assess and determine the best planning approach for the whole or parts of the region: an integrated regional resource plan ("IRRP"), a regional infrastructure plan ("RIP") or that regional coordination is not required and the planning can simply be done between the Transmitter and its customers.

This Scoping Assessment report:

- Defines the sub-regions for needs requiring regional coordination as identified in the Needs Screening report;
- Determines the appropriate regional planning approach and scope for each sub-region with identified needs requiring regional coordination;
- Establishes a Terms of Reference in the case where an IRRP is the recommended approach for the sub-region(s);
- Establishes a working group for each sub-region recommended for an IRRP or a RIP.

2. Team

The Scoping Assessment was carried out with the following Regional Participants:

- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. ("Hydro One Transmission")

[1] The Needs Assessment report for the Southern Georgian Bay/Muskoka Region can be found at http://www.hydroone.com/RegionalPlanning/SGB-Muskoka/Pages/default.aspx

- Hydro One Networks Inc. ("Hydro One Distribution")
- InnPower
- Lakeland Power
- Midland PUC
- Newmarket-Tay Power
- Orangeville Hydro
- Orillia Power
- PowerStream
- PowerStream COLLUS
- Veridian Connections
- Wasaga Distribution

3. Categories of Needs, Analysis and Results

I. Overview of the Region

The South Georgian Bay/ Muskoka region is located in central Ontario and includes all or part of the following Counties and Districts: the County of Simcoe County, County of Dufferin, District of Muskoka, District of Parry Sound and County of Grey. For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries.

The region also includes the following First Nations:

- Henvey Inlet
- Magnetawan
- Shawanaga
- Wasauksing
- Moose Deer Point
- Beausoleil
- Wahta Mohawks
- Chippewas of Rama
- Chippewas of Georgina Island
- Mississaugas of Scugog

The electricity infrastructure supplying the South Georgian Bay/Muskoka region is shown in Figure 1. The region is supplied from 115 kV and 230 kV transmission lines and stations that connect at the Essa transformer station ("TS"). The 500/230 kV auto-transformers at Essa TS provide the major source of supply to the area.

The southern portion of this region is summer-peaking (i.e., electricity demand is highest during the summer months), and is characterized by strong forecast growth, particularly in the Barrie and Innisfil areas. The northern part of the region is winter peaking (i.e., electricity demand is highest during the winter months), and growth is forecast to be more gradual.

Figure 1. South Georgian Bay/Muskoka Region Electricity Infrastructure



NOTE: Region is defined by electricity infrastructure; geographical boundaries are approximate.

II. Needs Identified

Hydro One's Needs Assessment report identified the following needs in the South Georgian Bay Muskoka Region, based on a 10-year demand forecast.

115 kV and 230 kV Lines and Auto-Transformers

- The 230/115 kV auto-transformers at Essa TS are expected to exceed their 10-day Long Term Rating (LTR) upon loss of the companion auto-transformer. This need is forecast to arise in the near term for the T1 auto-transformer, and the medium term for T2.
- The 115 kV circuit E3B, which supplies Barrie TS radially from Essa TS, is expected to exceed its Long Term Emergency (LTE) rating upon loss of the companion circuit in the near-term.

115 kV and 230 kV Transmission Stations

The following stations are expected to exceed their normal supply capacity:

Station	Timing of Peak Demand	Timing of Need
Barrie TS	Summer	Today
Muskoka TS	Winter	Near-term
Parry Sound TS	Winter	Today
Midhurst TS	Summer	Medium term, if potential new commercial operations materialize
Minden	Winter	Long term*
Waubaushene	Winter	Long term*

*In the Needs Assessment report, no needs were identified for the Minden and Waubaushene stations based on the 10-year net demand forecast, which includes conservation and demand management ("CDM") and distributed generation ("DG"). Based on the gross load forecast, which does not include CDM or DG, needs were identified within the 10-year horizon. These needs can therefore be expected to appear in the long term (after 10 years) based on net load.

Load Restoration Needs

Potential needs related to restoring loads after a major outage were identified in the Needs Assessment report. This analysis was further developed through the Scoping Assessment Process. Based on this assessment, the following restoration needs were identified:

Circuits	Load Restoration Criterion not met
M6E+M7E	30 min and 4 hours
E8V+E9V	4 hours

In addition, loading on M80/81B and E26/27 is currently around 150 MW. Based on current load transfer capability, load restoration criteria can be met in the near term. However, with load growth, restoration needs may emerge in the longer term. The IESO will monitor growth in the affected areas, and potential future needs will be re-assessed in the next regional planning cycle.

Bulk System Needs

The following needs were identified for the bulk system supplying the Region:

- Excessive post-contingency voltage declines may occur upon losing one of the 500/230 kV auto-transformers at Essa TS when the other is out of service.
- Overloads of 115 kV circuit S2S and the Stayner T1 auto-transformer may results from increased generation in the Bruce area.

Aging Infrastructure / Replacement Plans

The following infrastructure is expected to reach its end-of-life or is the subject of sustainment activities within the study period.

Equipment	Date
Barrie TS—115/44 kV transformers	2018-2020*
Minden TS—230/44 kV transformers and possible rebuild of low-voltage switchyard	2019
Orangeville TS—230-44/27.6 kV transformers and associated low-voltage equipment	2017
M6/7E—ground clearance on several sections to be increased. This may increase the thermal	2015

capability of this line.	
E3/4B	These circuits are about 50-60 years old. Hydro One expects to undertake sustainment work on these facilities within the next 20 years.
Essa TS - 230/115kV Autotransformer (T1)	~2020

* Hydro One identified this need to be addressed by 2018 in the Needs Assessment report. This need may be pushed out to and managed until 2020 to accommodate the lead time of alternatives to address it.

Reliability Needs

Regional Participants identified reliability needs that they would like to see included in the regional planning process. Two types of reliability needs were identified: distribution system reliability concerns related to long 44kV feeders in the northern part of the Region; and a lack of supply redundancy. To the extent that these needs can be coordinated with other regional needs, the Regional Participants agreed to address them as part of the regional planning process.

III. Analysis of Needs and Identification of Sub-Regions

The Regional Participants have discussed the needs in the South Georgian Bay/ Muskoka area and have identified two sub-regions for further study through the regional planning process. The two sub-regions, "Barrie/Innisfil" and "Parry Sound/Muskoka", are shown in Figure 2.

Barrie/Innisfil Sub-Region

Strong electricity demand growth is forecast for the Barrie/Innisfil area, consistent with the provincial *Growth Plan for the Greater Golden Horseshoe, 2006*. This sub-region is summer-peaking, and includes the following infrastructure:

- Stations—Midhurst TS, Barrie TS, Everett TS, Alliston TS
- Transmission circuits—E8/9V, E3/4B, M6/7E (Essa-Midhurst section)
- 230/115 kV auto-transformers at Essa TS

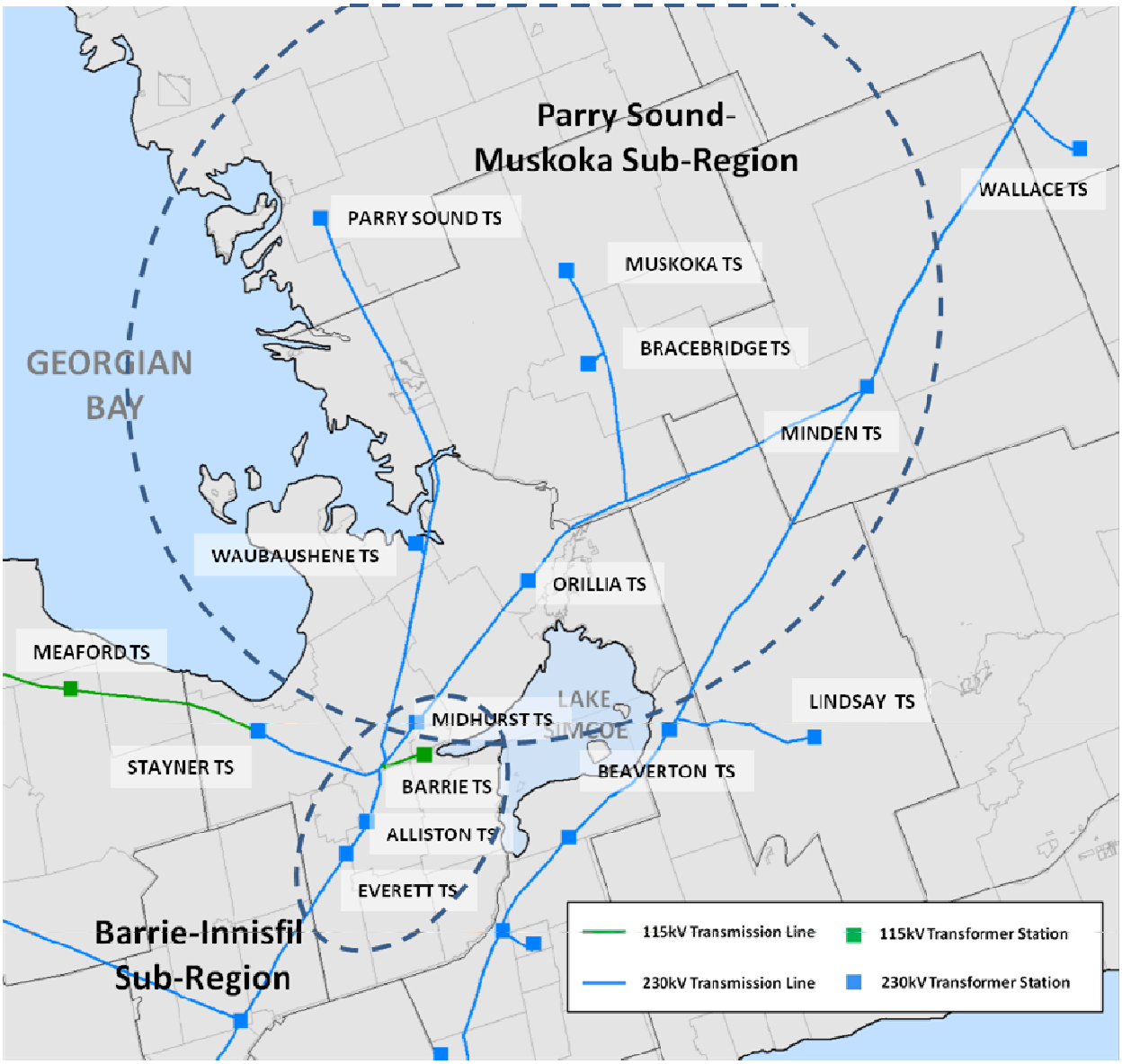
Customers in this sub-region are supplied by PowerStream, InnPower and Hydro One Distribution.

The needs in this sub-region include addressing growth (expressed in the Needs Assessment as overloaded infrastructure at Barrie TS, the E3B circuit, and the Essa 230/115 kV auto-transformers), and meeting load restoration criteria (E8/9V). In addition, with the Barrie TS transformers nearing their end-of-life, the plan for their replacement needs to be coordinated with the above growth-related needs. Options include maintaining Barrie TS as a 115 kV station (like-for-like replacement) or upgrading it to 230 kV, thereby increasing its capacity. The upstream infrastructure supplying the station—the Essa 230/115 kV auto-transformers and the E3/4B transmission line—will also be impacted by this decision and the associated costs and impacts must be considered.

While it is recognized that, with the need to replace Barrie TS equipment, a wires solution will necessarily be part of the plan for this sub-region, the growth-related needs in the area may be met by a combination of wires and non-wires solutions. In addition, the decisions made in this area will have broad impacts, involving multiple local distribution companies ("LDCs") and provincial ratepayers. Therefore, the Regional Participants propose that this sub-region be studied through the IRRP process.

The Barrie TS infrastructure is currently scheduled for replacement in 2018, however the existing equipment can be managed until 2020 if required. Nonetheless, a decision needs to be made as soon as possible in order to allow enough lead time to plan and bring new equipment into service. Therefore, rather than wait for the outcome of the IRRP (which typically takes 18 months), the Terms of Reference for the Barrie/Innisfil IRRP specifies that a decision on the wires component of the integrated solution will be made early in the IRRP process. At that time, wires planning would be initiated through a hand-off letter to the Transmitter.

Figure 2. South Georgian Bay/Muskoka Sub-Regions



NOTE: Region and sub-regions are defined by electricity infrastructure; geographical boundaries are approximate.

Parry Sound/Muskoka Sub-Region

This sub-region is winter-peaking, and is characterized by relatively slow growth. It includes the following infrastructure:

- Stations—Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS, Minden TS
- Transmission circuits—M6/7E, E26/27

Customers in this sub-region are supplied by Hydro One Distribution, Lakeland Power, Midland PUC, Newmarket-Tay Power, Orillia Power, and Veridian Connections.

The needs in this sub-region include:

- Addressing capacity needs at several stations
- Enabling loads to be restored within the timeframes laid out in the ORTAC criteria in the event of a major outage on M6/7E
- Coordinating asset replacement plans at Minden TS with regional needs, as appropriate
- Coordinating solutions to address distribution reliability concerns due to long feeder lengths with regional capacity needs, as appropriate
- Addressing reliability concerns related to a lack of supply redundancy.

With the relatively slow electricity demand growth forecast for this sub-region, the Regional Participants agreed that there may be opportunities for non-wires solutions to defer major capital investment. Therefore, it is proposed that this sub-region be studied through the IRRP process.

Needs to be Addressed through Bulk System Planning

The Essa TS 500/230 kV auto-transformers are bulk system assets that provide the major source of supply to the whole South Georgian Bay/Muskoka Region. Therefore, the Regional Participants agreed that the need associated with these assets be studied by the IESO as part of bulk system planning. Given the importance of this infrastructure to the Region, it was suggested that this planning be conducted in parallel with the IRRPs, and that the IESO involve the Regional Participants in the planning process.

The IESO will also undertake study of the S2S/Stayner auto-transformer issue arising due to increased generation in the Bruce area through the bulk planning process.

Needs to be Addressed through Local Planning

The Regional Participants agreed that the replacement of the Orangeville TS transformer and associated low-voltage equipment does not require regional coordination and can be addressed through local planning involving the transmitter and affected LDC.

4. Conclusion

The Scoping Assessment concludes that:

- An IRRP be undertaken to address the needs in the Barrie/Innisfil sub-region
- An IRRP be undertaken to address the needs in the Parry Sound/Muskoka sub-region
- Additional needs identified in the Needs Assessment will be addressed through other processes as follows:
    - Essa 500/230 kV autotransformers—bulk system planning (IESO), with regular updates

to/ input from the Regional Planning Participants
- S2S/Stayner auto-transformer issue—bulk system planning (IESO)
- Orangeville TS transformer replacement—local planning by transmitter and LDC

The draft Terms of Reference for the Barrie/Innisfil and the Parry Sound/Muskoka IRRPs are attached.

2 Barrie/Innisfil IRRP Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for an Integrated Regional Resource Plan ("IRRP") of the Barrie/Innisfil sub-region.

Based on the potential for demand growth within this sub-region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended.

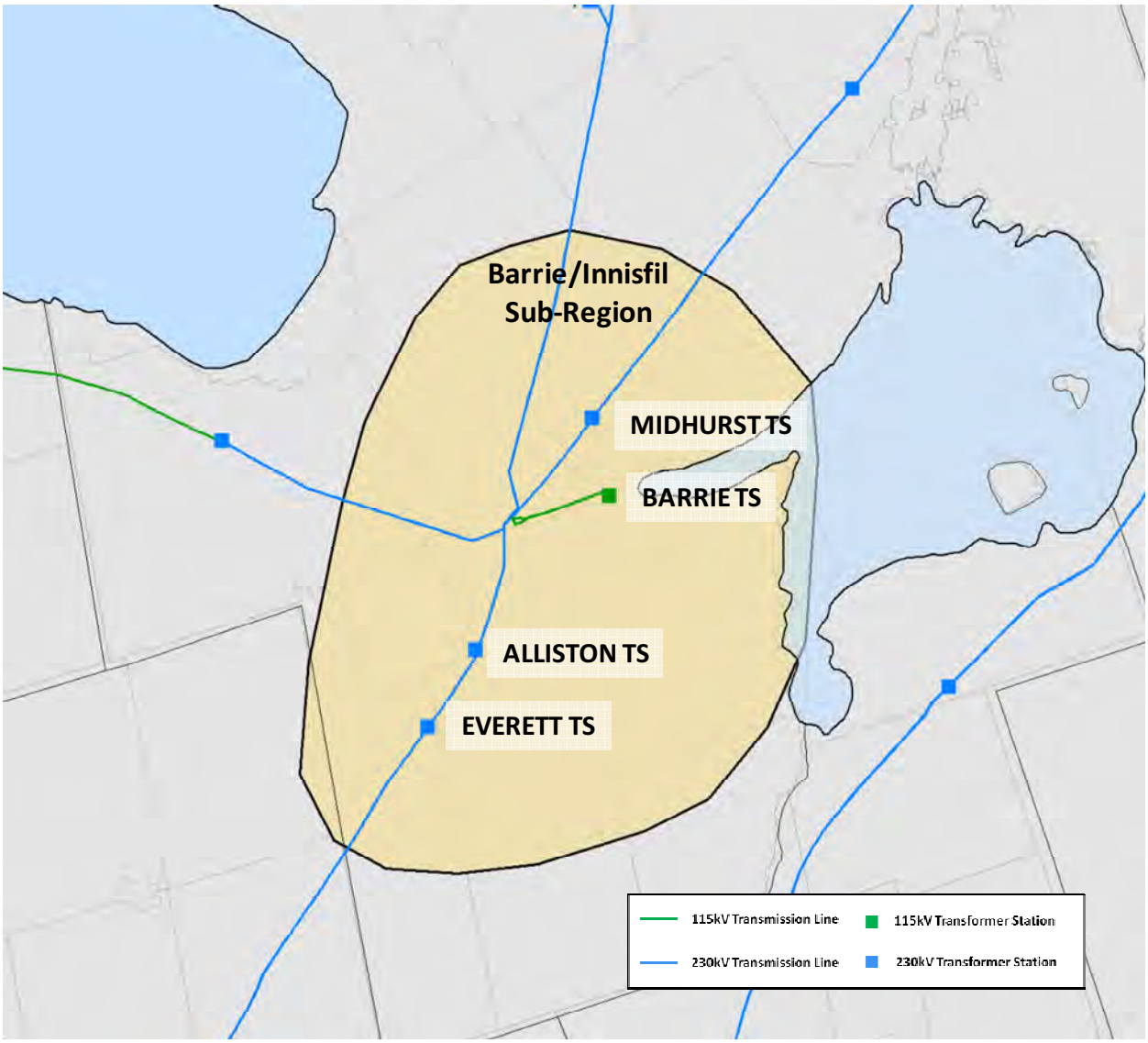
Barrie/Innisfil sub-region

The Barrie/Innisfil sub-region is a summer-peaking region that includes the City of Barrie, the Town of Innisfil, and customers in surrounding municipalities supplied from the Barrie, Midhurst, Everett and Alliston transformer stations (TS). The approximate geographical boundaries of the sub-region are shown in Figure 3.

The sub-region includes all or part of the following municipalities:

- City of Barrie
- Town of Innisfil
- Township of Essa
- Township of Springwater
- Township of Clearview
- Township of Mulmur
- Township of Adjala-Tosorontio
- Town of New Tecumseth
- Town of Bradford West Gwillimbury

Figure 3. Barrie/Innisfil Sub-Region



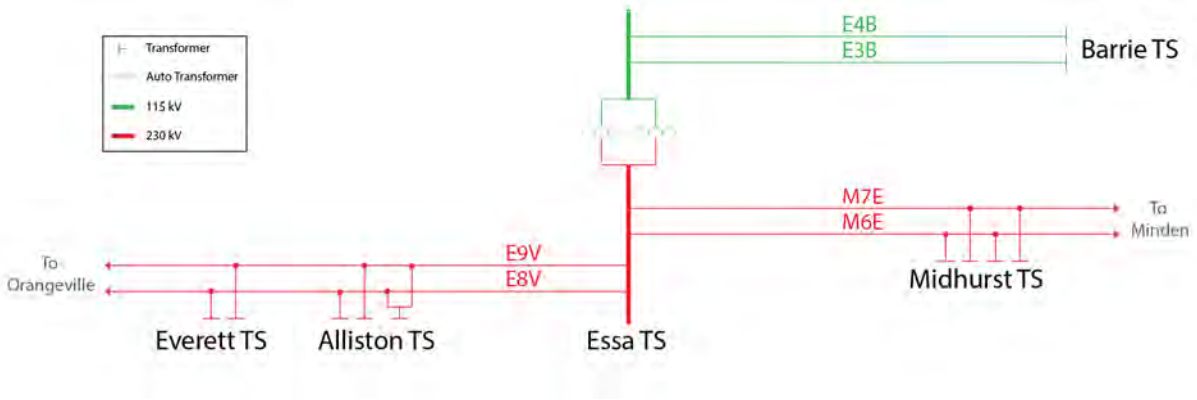
Source: IESO

NOTE: The sub-region is defined by electricity infrastructure; geographical boundaries are approximate.

Barrie/Innisfil Electricity System

The electricity system supplying the Barrie/Innisfil sub-region is shown in Figure 4.

Figure 4. Barrie/Innisfil Electricity System



Source: IESO

Background

Two planning studies have been conducted in the South Simcoe area in the last 12 years.

In November of 2003, a joint utility planning study was initiated between six LDCs in Simcoe County, one large industrial customer and Hydro One Transmission to assess the supply and reliability needs of Simcoe County. The study recommended the implementation of two transmission projects to supply forecast growth in the Meaford/Collingwood and South Simcoe areas: the addition of Everett TS, which came into service in 2007 and the Southern Georgian Bay Transmission Reinforcement, which involved upgrading the Essa-to-Stayner line to 230 kV and installing a 230/115 kV auto-transformer at Stayner TS, came into service in 2009.

In 2010, Hydro One Transmission initiated a regional supply planning study of the South Simcoe area. Together with the Ontario Power Authority (now the Independent Electricity System Operator), PowerStream, Innisfil Power, and Hydro One Distribution, a study report was prepared in 2011 that recommended the installation of low voltage capacitors at Midhurst TS, which was completed in 2012 and for Innisfil Hydro to make a formal request to Hydro One for additional transformation capacity.

2. Objectives

1. To assess the adequacy of electricity supply to customers in the Barrie/Innisfil sub-region over the next 20 years.
2. To coordinate customer-driven electricity needs with major asset renewal needs, and develop a flexible, comprehensive, integrated electricity plan for the Barrie/Innisfil sub-region.
3. To develop an implementation plan, while maintaining flexibility in order to accommodate changes in key assumptions over time.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Barrie/Innisfil sub-region. The plan is a joint initiative involving PowerStream, InnPower, Hydro One Distribution, Hydro

One Transmission, and the IESO, and will incorporate input from community engagement. The plan will integrate forecast electricity demand growth, conservation and demand management ("CDM") in the area with transmission and distribution system capability, end-of-life of major facilities in the area, relevant community plans, other bulk system developments, and Feed-in Tariff ("FIT") and other generation uptake through province-wide programs, and will develop an integrated plan to address needs.

This IRRP will address regional needs in the Barrie/Innisfil area. Specifically, the following existing infrastructure is included in the scope of this study:

- 230/115 kV auto-transformers at Essa TS
- Stations—Midhurst TS, Barrie TS, Everett TS, Alliston TS
- Transmission circuits—E8/9V, E3/4B, M6/7E (Essa-Midhurst section)

The adequacy of the bulk system supplying the area (i.e., the 500/230 kV auto-transformers at Essa TS) is being assessed by the IESO in parallel with this study through a separate bulk system planning process. Results of that study will be shared with the Working Group as they become available.

The Barrie/Innisfil IRRP will:

- Prepare a 20-year electricity demand forecast and establish needs over this timeframe.
- Examine the Load Meeting Capability and reliability of the existing transmission system supplying the Barrie/Innisfil sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices.
- Establish feasible integrated alternatives to address remaining needs, including a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives in order to address the needs of the Barrie/Innisfil sub-region.
- Assess end-of-life needs in the context of longer-term capacity needs and impacts on other connection and network facilities in the area, and hand off the wires component of the integrated solution early in the IRRP process in order to allow enough lead time to address the end-of-life of the Barrie TS transformers
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, environmental and social factors.

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident peak demand information for the sub-region
    - Historical weather correction, median and extreme conditions
    - Gross peak demand forecast scenarios by sub-region, TS, etc.
    - Coincident peak demand data including transmission-connected customers
    - Identified potential future load customers

- Conservation and Demand Management
    - LDC CDM plans
    - Incorporation of verified LDC results and progression towards OEB targets, and any other CDM programs/opportunities in the area
    - Long-term conservation forecast for LDC customers, based on sub-region's share of the 2013 Long-Term Energy Plan target
    - Conservation potential studies, if available
    - Potential for CDM at transmission-connected customers' facilities

- Local resources
    - Existing local generation, including distributed generation ("DG"), district energy, customer-based generation, Non-Utility Generators and hydroelectric facilities as applicable
    - Existing or committed renewable generation from Feed-in-Tariff ("FIT") and non-FIT procurements
    - Future district energy plans, combined heat and power, energy storage, or other generation proposals

- Relevant local plans, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans and Municipal Energy Plans
    - Municipal Growth Plans

- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria ("ORTAC")
        - Supply capability
        - Load security
        - Load restoration requirements
    - NERC and NPCC reliability criteria, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to customers
    - Other applicable requirements

- Existing system capability
    - Transmission line ratings as per transmitter records
    - System capability as per current IESO PSS/E base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capability
    - Technical and operating characteristics of local generation

- Bulk System considerations to be applied to the existing area network
    - Essa 500/230 kV auto-transformer capability
    - North-South Tie flow assumptions

- End-of-life asset considerations/sustainment plans
    - Transmission assets, in particular Barrie TS transformers
    - Distribution assets

- Other considerations, as applicable

5. Working Group

The core Working Group will consist of planning representative/s from the following organizations:

- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Transmission
- PowerStream
- InnPower
- Hydro One Distribution

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

5. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Working Group is committed to conducting plan-level engagement throughout the development of the Barrie/Innisfil IRRP.

The first step in engagement will consist of meetings with municipalities and First Nation communities within the planning area, First Nation communities who may have an interest in the planning area and the Métis Nation of Ontario to discuss regional planning, the development of the Barrie/Innisfil plan, and integrated solutions.

This will be followed by the establishment of a Local Advisory Committee for local community members to provide input and recommendations throughout the planning process, including information on local priorities and ideas on the design of community engagement strategies. Broad community engagement will be conducted to obtain public input in the development of the plan.

6. Activities, Timeline and Primary Accountability

	Activity	Lead Responsibility	Deliverable(s)	Timeframe
1	**Prepare Terms of Reference considering stakeholder input**	*IESO*	- Finalized Terms of Reference	Q2 2015
2	**Develop the Planning Forecast for the sub-**		- Long-term planning	Q3 2015

	region		forecast scenarios	
	- Establish historical coincident peak demand information	*IESO*		
	- Establish historical weather correction, median and extreme conditions	*IESO*		
	- Establish gross peak demand forecast	*LDCs*		
	- Establish existing, committed and potential DG	*LDCs*		
	- Establish near- and long-term conservation forecasts based on LDC CDM plans and LTEP CDM targets	*IESO*		
	- Develop planning forecast scenarios - including the impacts of CDM, DG and extreme weather conditions	*IESO*		
3	**Provide information on load transfer capabilities under normal and emergency conditions**	*LDCs*	- Load transfer capabilities under normal and emergency conditions	Q3 2015
4	**Provide and review relevant community plans, if applicable**	*LDCs and IESO*	- Relevant community plans	Q3 2015
5	**Complete system studies to identify needs over a twenty-year period** - Obtain PSS/E base case Include bulk system assumptions as identified in Key Assumptions - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels	*IESO, Hydro One Transmission*	- Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q3-Q4 2015
6	**Develop Options and Alternatives**		- Develop flexible planning options for forecast scenarios	Q3-Q4 2015
	Develop conservation options	*IESO and LDCs*		
	Develop local generation options	*IESO and LDCs*		
	Develop transmission (see Action 7 below) and distribution options	*Hydro One Transmission, and LDCs*		
	Develop options involving other electricity initiatives (e.g., smart grid, storage)	*IESO/ LDCs with support as needed*		
	Develop portfolios of integrated alternatives	*All*		
	Technical comparison and evaluation	*All*		
7	**Early Wires Planning**		- Cost, feasibility and reliability performance of potential wires options - Detailed option development	Q3-Q4 2015
	Identify potential wires options to address Barrie TS end-of-life and local capacity needs	*Hydro One Transmission*		
	Provide information on cost, feasibility and reliability performance of identified wires options for the purpose of developing integrated solutions			

	Conduct detailed studies of wires options to ensure in-service date for Barrie TS transformer replacement can be met			
8	**Plan and Undertake Community & Stakeholder Engagement**		- Community and Stakeholder Engagement Plan - Input from local communities	
	- Establish engagement subcommittee of the Working Group (if required)	*All*		Q3 2015
	- Early engagement with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	*All*		Q3-Q4 2015
	- Establish Local Advisory Committee and develop broader community engagement plan with LAC input	*All*		Q3-Q4 2015
	- Develop communications materials	*All*		Q1-Q2 2016
	- Undertake community and stakeholder engagement	*All*		
	- Summarize input and incorporate feedback	*All*		
9	**Hand off Wires Component of Integrated Solution**	*IESO*	- Hand-off letter to Hydro One	Q4 2015
10	**Develop long-term recommendations and implementation plan based on community and stakeholder input**	*IESO*	- Implementation plan - Monitoring activities and identification of decision triggers - Hand-off letters - Procedures for annual review	Q3 2016
11	**Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties**	*IESO*	- IRRP report	Q4 2016

3 Parry Sound/Muskoka IRRP Terms of Reference

1. Introduction and Background

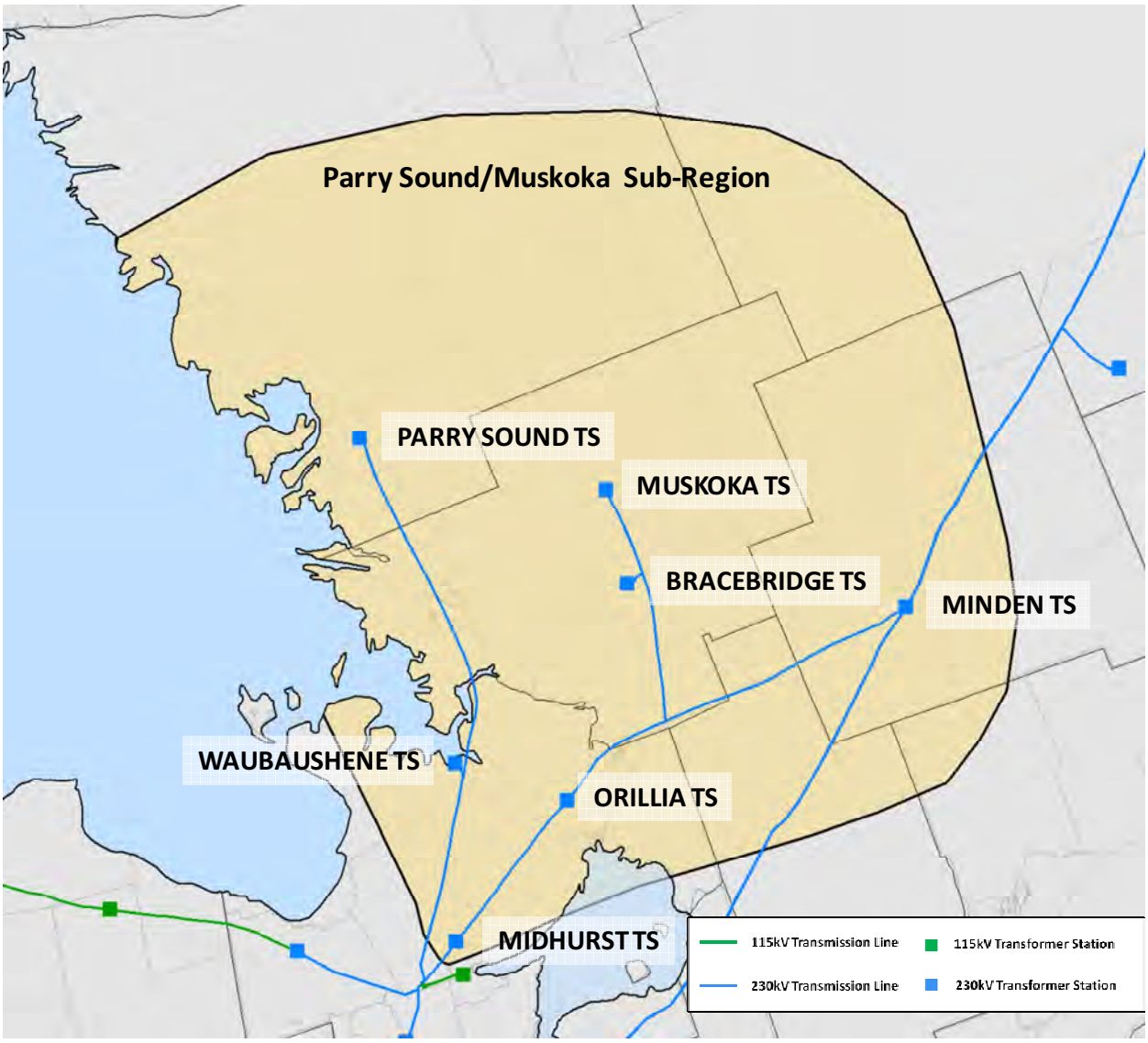
These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for an Integrated Regional Resource Plan ("IRRP") of the Parry Sound/Muskoka sub-region.

Based on the potential for demand growth within this sub-region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended.

Parry Sound/Muskoka sub-region

The Parry Sound/Muskoka sub-region is a winter-peaking region and it roughly encompasses the Districts of Muskoka and Parry Sound. The approximate geographical boundaries of the sub-region are shown in Figure 5.

Figure 5. Parry Sound/Muskoka Sub-Region



Source: IESO

NOTES: (1) The sub-region is defined by electricity infrastructure; geographical boundaries are approximate. (2) Midhurst TS is included in the scope of the Parry Sound/Muskoka IRRP for the purpose of evaluating restoration needs on the Essa-to-Minden transmission line (M6/7E). Supply and transformer station capacity at Midhurst TS are being addressed through the Barrie/Innisfil IRRP, are thus is not in scope for the Parry Sound/Muskoka IRRP.

The sub-region includes all or part of the following municipalities:

- City of Orillia
- Municipality of Highlands East
- Municipality of Magnetawan

- Municipality of McDougall
- Municipality of Whitestone
- Town of Bracebridge
- Town of Gravenhurst
- Town of Huntsville
- Town of Kearney
- Town of Midland
- Town of Parry Sound
- Town of Penetanguishene
- Township of Algonquin Highlands
- Township of Armour
- Township of Carling
- Township of Georgian Bay
- Township of Joly
- Township of Lake of Bays
- Township of McKellar
- Township of McMurrich-Monteith
- Township of Minden Hills
- Township of Muskoka Lakes
- Township of Oro-Medonte
- Township of Perry
- Township of Ramara
- Township of Ryerson
- Township of Seguin
- Township of Severn
- Township of Strong
- Township of Tay
- Township of the Archipelago
- Township of Tiny
- United Townships of Dysart, Dudley, Harcourt, Guilford, Harburn, Bruton, Havelock, Eyre and Clyde
- Village of Burk's Falls
- Village of Sundridge

The Parry Sound/Muskoka sub-region also includes the following First Nations:

- Henvey Inlet
- Magnetawan
- Shawanaga
- Wasauksing

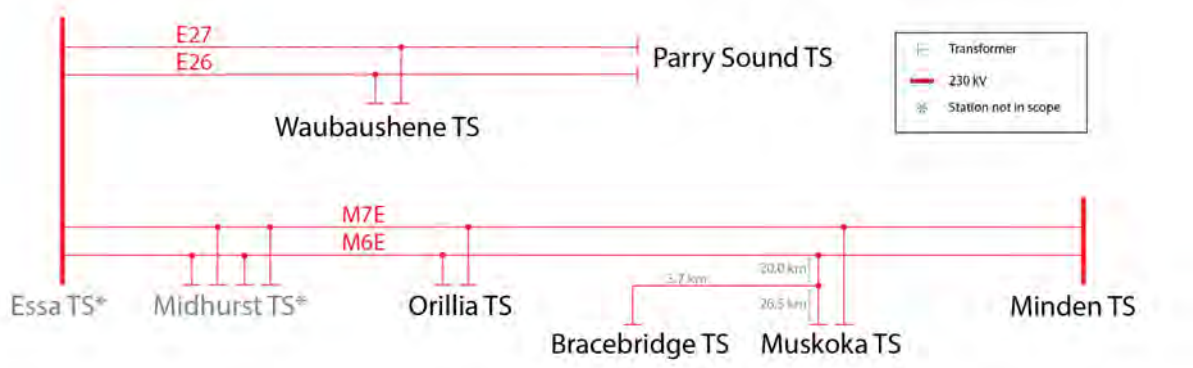
- Moose Deer Point
- Beausoleil
- Wahta Mohawks
- Chippewas of Rama

Engagement on this regional plan may be extended to include additional communities outside of the IRRP area boundaries.

Parry Sound/Muskoka Electricity System

The electricity system supplying the Parry Sound/Muskoka sub-region is shown in Figure 6.

Figure 6. Parry Sound/Muskoka Electricity System



Source: IESO

2. Objectives

1. To assess the adequacy of electricity supply to customers in the Parry Sound/Muskoka sub-region over the next 20 years.
2. To develop a flexible, comprehensive, integrated electricity plan for the Parry Sound/Muskoka sub-region.
3. To develop an implementation plan, while maintaining flexibility in order to accommodate changes in key assumptions over time.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Parry Sound/Muskoka sub-region. The plan is a joint initiative involving Lakeland Power, Midland PUC, Newmarket-Tay Power, Orillia Power, PowerStream, Veridian Connections, Hydro One Distribution, Hydro One Transmission, and the IESO, and will incorporate input from community engagement. The plan will integrate forecast electricity demand growth, conservation and demand management ("CDM") in the area with transmission and distribution system capability, end-of-life of major facilities in the area, relevant community plans, other bulk system developments, and Feed-in Tariff ("FIT") and other

generation uptake through province-wide programs, and will develop an integrated plan to address needs.

This IRRP will address regional needs in the Parry Sound/Muskoka area. Specifically, the following existing infrastructure is included in the scope of this study:

- Stations—Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS, Minden TS
- Transmission circuits—M6/7E, E26/27

The adequacy of the bulk system supplying the area (i.e., the 500/230 kV auto-transformers at Essa TS) is being assessed by the IESO in parallel with this study through a separate bulk system planning process. Results of that study will be shared with the Working Group as they become available.

The Parry Sound/Muskoka IRRP will:

- Prepare a 20-year electricity demand forecast and establish needs over this timeframe
- Examine the Load Meeting Capability and reliability of the existing transmission system supplying the Parry Sound/Muskoka sub-region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices
- Establish feasible integrated alternatives including a mix of CDM, generation, transmission and distribution facilities, and other electricity system initiatives in order to address the needs of the Parry Sound/Muskoka sub-region
- Evaluate options using decision-making criteria including but not limited to: technical feasibility, economics, reliability performance, environmental and social factors

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident peak demand information for the sub-region
    - Historical weather correction, median and extreme conditions
    - Gross peak demand forecast scenarios by sub-region, TS, etc.
    - Coincident peak demand data including transmission-connected customers
    - Identified potential future load customers

- Conservation and Demand Management
    - LDC CDM plans
    - Incorporation of verified LDC results and progression towards OEB targets, and any other CDM programs/opportunities in the area
    - Long-term conservation forecast for LDC customers, based on sub-region's share of the 2013 Long-Term Energy Plan target
    - Conservation potential studies, if available
    - Potential for CDM at transmission-connected customers' facilities

- Local resources
    - Existing local generation, including distributed generation ("DG"), district energy, customer-based generation, Non-Utility Generators and hydroelectric facilities as applicable
    - Existing or committed renewable generation from Feed-in-Tariff ("FIT") and non-FIT procurements
    - Future district energy plans, combined heat and power, energy storage, or other generation proposals

- Relevant local plans, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans and Municipal Energy Plans
    - Municipal Growth Plans

- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria ("ORTAC")
        - Supply capability
        - Load security
        - Load restoration requirements
    - NERC and NPCC reliability criteria, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to customers
    - Other applicable requirements

- Existing system capability
    - Transmission line ratings as per transmitter records
    - System capability as per current IESO PSS/E base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capability
    - Technical and operating characteristics of local generation

- Bulk System considerations to be applied to the existing area network
    - Essa 500/230 kV auto-transformer capability
    - North-South Tie flow assumptions

- End-of-life asset considerations/sustainment plans
    - Transmission assets
    - Distribution assets

- Other considerations, as applicable

5. Working Group

The core Working Group will consist of planning representative/s from the following organizations:

- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Transmission
- Hydro One Distribution
- Lakeland Power
- Midland PUC
- Newmarket-Tay Power
- Orillia Power
- PowerStream
- Veridian Connections

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

5. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Working Group is committed to conducting plan-level engagement throughout the development of the Parry Sound/Muskoka IRRP.

The first step in engagement will consist of meetings with municipalities and First Nation communities within the planning area, First Nation communities who may have an interest in the planning area and the Métis Nation of Ontario to discuss regional planning, the development of the Parry Sound/Muskoka plan, and integrated solutions.

This will be followed by the establishment of a Local Advisory Committee for local community members to provide input and recommendations throughout the planning process, including information on local priorities and ideas on the design of community engagement strategies. Broad community engagement will be conducted to obtain public input in the development of the plan.

6. Activities, Timeline and Primary Accountability

	Activity	Lead Responsibility	Deliverable(s)	Timeframe
1	**Prepare Terms of Reference considering stakeholder input**	*IESO*	- Finalized Terms of Reference	Q2 2015
2	**Develop the Planning Forecast for the sub-region**		- Long-term planning forecast scenarios	Q3 2015
	- Establish historical coincident peak demand information	*IESO*		
	- Establish historical weather correction, median and extreme conditions	*IESO*		

	- Establish gross peak demand forecast for LDC service areas	*LDCs*		
	- Establish existing, committed and potential DG	*LDCs*		
	- Establish near- and long-term conservation forecast based on LDC CDM plans and LTEP target	*IESO*		
	- Develop planning forecast scenarios - including the impacts of CDM, DG and extreme weather conditions	*IESO*		
3	**Provide information on load transfer capabilities under normal and emergency conditions**	*LDCs*	- Load transfer capabilities under normal and emergency conditions	Q3 2015
4	**Provide and review relevant community plans, if applicable**	*LDCs, First Nations and IESO*	- Relevant community plans	Q3 2015
5	**Complete system studies to identify needs** - Obtain PSS/E base case - Include bulk system assumptions as identified in Key Assumptions - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels	*IESO, Hydro One Transmission*	- Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q4 2015
6	**Develop Options and Alternatives**		- Develop flexible planning options for forecast scenarios	Q1 2016
	- Identify solutions requiring immediate implementation and prepare hand-off letters to responsible parties (if applicable)	*IESO*		
	- Develop conservation options	*IESO and LDCs*		
	- Develop local generation options	*IESO and LDCs*		
	- Develop transmission and/or distribution options including maximizing existing infrastructure capability	*IESO, Hydro One Transmission and LDCs*		
	- Develop options involving other electricity initiatives (e.g., smart grid, storage)	*IESO/ LDCs with support as needed*		
	- Develop portfolios of integrated alternatives	*All*		
	- Technical comparison and evaluation	*All*		
7	**Plan and Undertake Community & Stakeholder Engagement**		- Community and Stakeholder Engagement Plan - Input from local communities, First Nation communities, and Métis Nation of Ontario	
	- Establish engagement subcommittee of the Working Group (if required)	*All*		Q3 2015
	- Early engagement with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the	*All*		Q3-Q4 2015

	Métis Nation of Ontario			
	- Establish Local Advisory Committee and First Nations Local Advisory Committee and develop broader community engagement plan with LAC input	*All*		Q4 2015
	- Develop communications materials	*All*		Q1-Q2 2016
	- Undertake community and stakeholder engagement	*All*		
	- Summarize input and incorporate feedback	*All*		
8	**Develop long-term recommendations and implementation plan based on community and stakeholder input**	*IESO*	- Implementation plan - Monitoring activities and identification of decision triggers - Hand-off letters - Procedures for annual review	Q3 2016
9	**Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties**	*IESO*	- IRRP report	Q4 2016

4 List of Acronyms

CDM	Conservation and Demand Management
DG	Distributed Generation
FIT	Feed-in-Tariff
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LAC	Local Advisory Committee
LDC	Local Distribution Company
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
RPP	Regional Planning Process
TS	Transformer Station

Innisfil Hydro Distribution Systems Ltd.

Review of Innisfil Hydro's 2011 Asset Management Plan

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Private and Confidential

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Innisfil Hydro Distribution Systems Ltd.

Review of the 2011 Asset Management Plan

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EXECUTIVE SUMMARY

In preparation for its Cost of Service rate application, Innisfil Hydro Distribution System Ltd. ("Innisfil Hydro") has engaged AESI to review, provide commentary and make recommendations on its 2011 Asset Management Plan. The Asset Management Plan, and requirements, is defined in the Ontario Energy Board's Filing Requirements for Transmission and Distribution Applications, specifically in Chapter 2. AESI has reviewed the Asset Management Plan and provided comments and recommendations based on the defined Ontario Energy Board requirements and on its experience in assisting other Local Distribution Companies to develop their Asset Management Plans.

The existing 2011 Asset Management Plan includes a good narrative of Innisfil Hydro's asset management practices, relevant data and appropriate references to the OEB's Distribution Code. However, the Asset Management Plan should provide additional information regarding maintenance practices and the utility's means and methodology for documenting, reviewing and analyzing inspection and maintenance data in order to identify and prioritize capital expenditures. With regards to capital expenditures, the Asset Management Plan should include a three year forecast (test year plus two subsequent years) of each capital project and estimated expenditures. Further, the Asset Management Plan should explicitly state whether Innisfil Hydro has undertaken any asset condition studies and should include such studies as an appendix to the Asset Management Plan.

Much of the content of the existing Asset Management Plan may be leveraged and included with the framework below, as further discussed within this report.

1. Overview of the Distribution System
2. Asset Management Objectives
3. Approach to Managing Assets
4. Identifying and Prioritizing Projects
5. Capital Budget Items
6. Forecasted Capital Expenditures

1 INTRODUCTION

The Ontario Energy Board ("OEB") has established Filing Requirements for Transmission and Distribution Applications ("Filing Requirements") in which it "Sets out the standards for transmitters and distributors to follow when filing for rate adjustments, leave to construct approvals, and conservation funding." Chapter 2 of the Filing Requirements specifically addresses a Cost of Service ("CoS") rate application for transmission and distribution companies. In June 2011 Chapter 2 was revised and now requires an Asset Management Plan to be included in Exhibit 2 (Rate Base) of the CoS application.

Following are the minimum requirements of an asset management plan, as outlined in Section 2.5.2.2 of Chapter 2:

- The applicant must provide a formal asset management plan, if the applicant has such a plan. If not, an explanation as to why the applicant does not have such a plan must be provided. The applicant must also state whether or not it is planning to have one in place in the future.
- In the absence of an asset management plan, the applicant must provide information outlining its approach to the planning and prioritization of capital projects.
- The applicant must also provide, at minimum, a three year forecast of capital expenditures (Test year plus two subsequent years).
- The applicant must also state whether or not it has undertaken any asset condition studies and, if so, copies of such studies must be filed.

To provide support for its future Ontario Energy Board rate filings Innisfil Hydro Distribution Systems Ltd. ("Innisfil Hydro") has recognized the importance of comprehensive asset management planning to capture and potentially expand on its existing asset management activities. Innisfil Hydro has also recognized that it is now required to have a documented Asset Management Plan as part of its CoS rate application in August 2012. As such, it has developed an Asset Management Plan and has engaged AESI to review, provide commentary and make recommendations on the 2011 Asset Management Plan.

2 OBSERVATIONS AND ASSESSMENT

The assessment of Innisfil Hydro's 2011 Asset Management Plan is presented below and is based on AESI's knowledge and experience with similar Local Distribution Companies ("LDCs") and its understanding of the OEB requirements of an Asset Management Plan.

The existing 2011 Asset Management Plan includes a good narrative of Innisfil Hydro's asset management practices, relevant data and appropriate references to the OEB's Distribution Code. Innisfil's Asset Management Plan presents seven main sections, each of which provides an overview of an asset category; these include overhead lines, underground lines, distribution stations, metering, vehicles, property and equipment. Within each of these sections, the applicable assets and relevant asset management practices are described. For example, the overhead lines section includes a description of vegetation management, infrared thermography, line patrol, pole inspection and testing, protective device inspection, transformer inspection, voltage regulator inspection, capacitor inspection, fault indicator inspection and load balancing. Within these sections, Innisfil Hydro presents general consequences of not remediating deficiencies identified during inspection, providing support for expenditures. The narrative of maintenance practices within these sections, however, should be elaborated to further detail condition-based maintenance[1] activities or other preventive maintenance[2] activities, such as insulator washing, if performed. Innisfil Hydro could also include a brief description of its method of documenting inspection and maintenance data.

Some of the descriptions of asset management practices within the plan include a brief statement about the associated estimated expense that *would* be required but may not indicate whether the expenditure is planned for the bridge year or subsequent years; alternatively, it may state that the cost has been budgeted into a specific account, but does not identify the cost. Further, the asset management plan often states that the cost has not been budgeted for in 2012 (or in subsequent years); it is not clear from this latter statement whether it is required or should be included in forecasts. As such, the existing asset management plan does not adequately address the OEB's requirement to provide a three year forecast of capital expenditures.

[1] Maintenance performed after inspection or other maintenance (e.g. infrared thermography) indicates impending failure or degradation in performance or condition of the asset. Condition-based maintenance serves to eliminate opportunity of breakdowns and reduce deviations from optimum asset performance.
[2] Maintenance performed at predetermined intervals or according to prescribed criteria and intended to reduce the probability of failure.

Also not clearly documented within the plan is a description of how data from these asset management practices is reviewed, analyzed and used for identifying and prioritizing capital expenditures. Therefore, the plan does not adequately address the OEB's requirement to provide information outlining its approach to the planning and prioritization of capital projects.

Lastly, the existing plan does not state whether or not Innisfil has undertaken any asset condition studies; this should be clearly identified within the plan and if such studies have been performed, the results should be included as an appendix to the plan.

3 RECOMMENDATIONS

3.1 General

i. The Asset Management Plan should, as prescribed, include a minimum 3 year forecast of capital expenditures (Test year plus two subsequent years). Chapter 2 (Section 2.5.2.1) identifies capital expenditure information that should be provided on a project specific basis. While this information is required only for capital expenditures over the past five historical years, the bridge year and the test year (note that test year is required in the Asset Management Plan), Innisfil Hydro should consider providing this information for the two years subsequent to the test year.

ii. The Asset Management Plan should clearly state whether or not Innisfil Hydro has undertaken any asset condition studies; if such studies have been performed, Innisfil Hydro should include the results as an appendix to its Asset Management Plan. In AESI's experience, the asset condition studies are those studies performed beyond the routine practices (i.e. inspection and maintenance) to assess asset condition.

iii. As noted above, documentation of maintenance practices within the Asset Management Plan should be elaborated to further detail condition-based maintenance or other preventive maintenance practices, such as insulator washing, as applicable.

iv. Innisfil Hydro should ensure that inspection cycles defined within the Asset Management Plan are consistent with the OEB's minimum inspection requirements.

3.2 Structure

Much, if not all, content in the existing asset management plan could be leveraged to develop a plan that is more aligned, in our experience, with the OEB's expectations and with those Asset Management Plans presented with minimal to no associated interrogatories. The following presents a framework that Innisfil Hydro could adopt for its Asset Management Plan.

1. Overview of the Distribution System

   This section should include a description of the service area, number and type of customers, primary and secondary voltages, conductor/cable lengths, meter types, etc.

2. Asset Management Objectives

   This section should identify Innisfil Hydro's objectives for managing its assets. Typical objectives include, but are not limited to, ensuring customer and employee safety, providing a reliable system while improving reliability indices, accounting for future load growth and ensuring appropriate future supply, etc.

3. Approach to Managing Assets

   Innisfil Hydro could utilize the current format in which it identifies assets and describes inspection and maintenance practices, based on the overhead distribution system, underground distribution system, substations, metering, vehicles, property and equipment. Further, and as noted above, Innisfil Hydro presents the consequences of not remediating deficiencies identified during inspection; this information is well presented and relevant as it relates Innisfil's approach to managing assets to achieving objectives.

4. Identifying and Prioritizing Projects

   Within this section, Innisfil Hydro should describe its approach to identifying projects within the capital budget. In our experience with utilities of Innisfil's size, the approach is informal and essentially encompasses review and analysis of inspection data, maintenance data, system reliability data and regulatory and municipal drivers. The methodology may also comprise analysis of leading indicators of the 'health' of the system, such as load forecasting and system planning. Innisfil Hydro should also describe any risk, cost/benefit or other analysis performed to identify projects for inclusion in the capital budget.

This section should also describe the approach to prioritizing projects and therefore expenditures. For example, projects meeting multiple objectives may be assigned a high priority as compared to a project achieving a single objective. Also as an example, a pole line rebuild may be considered less of a priority than spot pole replacements presenting safety concerns. It should be noted that Innisfil's approach need not be complicated or involve formal risk assessment methods. However, it should be clear in explaining that Innisfil has a process in place in which it reviews system data and considers objectives to determine priorities.

5. Capital Budget Items

This section should explain that the capital budget is developed following the approach to identifying and prioritizing projects, and therefore expenditures; it should also reiterate that spending is prioritized to achieve objectives. Further, a listing and description of key categories, and OEB Uniform System of Account ("USoA") codes within each category, should be included. Examples of categories may include, but are not limited to, buildings and land, stations, underground distribution, overhead distribution, transformers, meters, office equipment, hardware and software, vehicles, tools, etc.

Programs may be defined within the categories. For example, the stations category may include a program for system expansion and a program for replacement or upgrades due to age or condition; similarly, the overhead distribution category may include programs such as relocation of hydro plant due to municipal drivers, replacement or upgrade of plant due to age or condition, and expansion to supply new development. Programs are further itemized to identify projects. Innisfil Hydro should also include a brief description of each program.

Below is an example of what may be presented within this section of the asset management plan.

1. Category: Overhead Distribution

This category includes OEB USoA codes 1830, 1835 and 1855.

1.1. Program: Relocation of Hydro Plant Due to Municipal Drivers

Relocation of overhead plant that is currently situated where road-widening is proposed. Projects within this program are generally non-discretionary and mandated by the Town of Innisfil.

1.2. Program: Replacement or Upgrade Due to Age or Condition

Replacement of overhead assets in poor condition as noted in pole-line inspection records. Also includes replacement and upgrade of open-wire secondary with triplex service wire.

6. Forecasted Capital Expenditures

Projects within capital budget should be identified for the Test Year (the prospective rate year) and subsequent two years. Each capital project should include at least the scope of work (i.e. description of the project), business case (i.e. project justification/reason for completing the project) and project cost.

In addition to the narrative, forecasted capital expenditures should be presented in table format, as has been included in well-documented asset management plans.

Below is an example of what may be presented within this section of the asset management plan. The categories and descriptions are guides and not intended to be all-inclusive.

Project 1: Relocation of Overhead Pole Line on Yonge St. between Victoria St. and Innisfil Beach Rd.

Capital Budget Amount: $102,000.

Project	Total	1830	1835	1840	1845	1850
Project 1	$102,000	$67,000	$12,000	$11,000	$10,000	$2,000

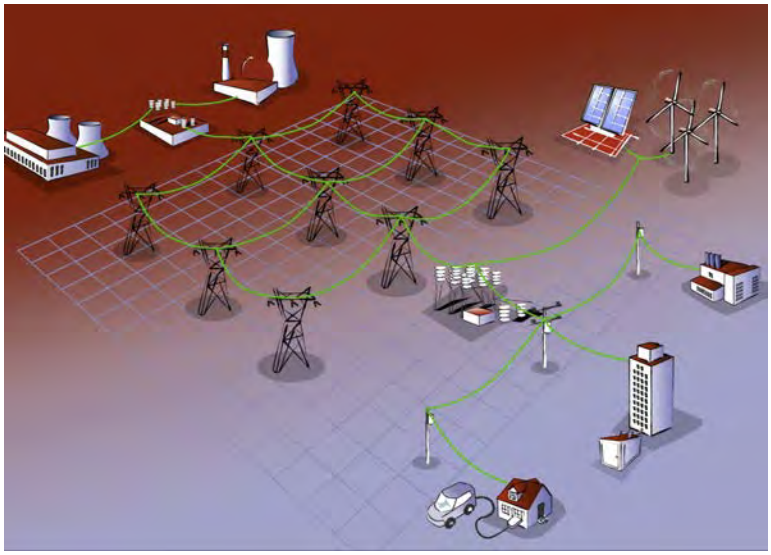
Scope of Work:

Business Case:

Category	Test Year	Test Year + 1	Test Year + 2
Buildings	$ (total)	$ (total)	$ (total)
Land	$ (total)	$ (total)	$ (total)
Stations	$ (total)	$ (total)	$ (total)
Underground Distribution	$ 21,000	$ (total)	$ (total)
Overhead Distribution	$ 79,000	$ (total)	$ (total)
Transformers	$ 2,000	$ (total)	$ (total)
Meters	$ (total)	$ (total)	$ (total)
Total Capital Budget	$ 102,000	$ (sum)	$ (sum)

OEB	Description	Test Year	Test Year + 1	Test Year + 2
1805	Land	$ (total)	$ (total)	$ (total)
1820	Distribution Station Equip.	$ (total)	$ (total)	$ (total)
1830	O/H Poles, Towers, Fixtures	$ 67,000	$ (total)	$ (total)
1835	O/H Conductors, Devices	$12,000	$ (total)	$ (total)
1840	U/G Conduit	$11,000	$ (total)	$ (total)
1845	U/G Conductors, Devices	$10,000	$ (total)	$ (total)
1850	Line Transformers	$2,000	$ (total)	$ (total)
1860	Meters	$ (total)	$ (total)	$ (total)
1920	Computer Hardware	$ (total)	$ (total)	$ (total)
1925	Computer Software	$ (total)	$ (total)	$ (total)
1940	Tools, Shop, Garage Equip.	$ (total)	$ (total)	$ (total)
	Total Capital Expenditures	$102,000	$ (sum)	$ (sum)

Green Energy Act Plan
(Basic Plan)



Revision date: November 9, 2015

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1. Introduction

This document outlines the Green Energy Act Plan for InnPower Corporation (InnPower) on November 9, 2015.

At this time InnPower is filing the basic Green Energy Act (GEA) Plan, as directed by OEB document EB-2009-0397 Distribution System Plans – Filing Under Deemed Conditions of License revised May 17, 2012.

The basic GEA Plan provides information to the Board and interested stakeholders regarding the readiness of InnPower's system to accommodate the connection of renewable generation and the expansion or reinforcement necessary to accommodate renewable generation. In addition, this report provides information with respect to the general condition of the distribution system.

2. Current Assessment of Distribution System

2.1. Distribution System Overview:

InnPower Corporation owns, operates, and maintains a distribution system currently serving approximately 16,000 customers within an area of about 300 square kilometers. The service territory encompasses all of the Town of Innisfil, which includes the communities of South Barrie, Stroud, Alcona, Lefroy, Churchill, Cookstown, Gilford, Sandy Cove, and Big Bay Point. A majority of our customers are located in the above noted urban centers. We also serve a smaller percentage of customers who are farmers.

InnPower's industrial customer base is minimal in comparison to residential customers. We have had significant growth in the area in the past 10 years and expect this trend to continue into the next decade. We predict our customer base to double in the next 8-12 years.

We currently operate our subtransmission system at 44 kV and our three-phase distribution system at 27,600 and 8,320 volts. We own, operate and maintain ten (10) distribution substations. We jointly own, operate, and maintain four (4) private substations; and inspect and maintain seven (7) other customer owned substations.

The average age of our substations is 30 years; of which seven (7) of them were installed and commissioned in the 1960's and 70's. We own, operate, and maintain four (4) subtransmission feeders, 29 distribution feeders, approximately 750 km of both overhead and underground conductors, and 3,285 distribution transformers.

In the past nine (9) years we have designed, installed, and commissioned two (2) distribution substations, namely the Bob Deugo DS and the Belle Ewart DS. We have systematically invested significant capital in upgrading our Distribution Automation (DA), and Supervisory Control and Data Acquisition (SCADA) systems, our IT infrastructure, deploying newer Reclosers and Scada-Mate® switches, SCADA software for use by System Operators, and backend enterprise systems to support the need for better data management and system integration.

In the past few years we have replaced all hydraulic reclosers at five (5) Distribution Stations, namely Leonards Beach, Innisfil, Cedar Point, Lefroy, and Big Bay Point Distribution Stations with vacuum reclosers and microprocessor controls[1]. Our goal is to upgrade the remaining hydraulic reclosers in our distribution system in the near future with vacuum type with advanced electronic controls, as part of our Smart Grid initiative. This initiative will help improve reliability by reducing outage duration while assisting our efforts to track and mitigate momentary interruptions.

InnPower has installed approximately 16,000 residential and commercial electric smart meters, completing our Advanced Metering Infrastructure (AMI) program and implementing TOU billing for all eligible customers by June 2011. We currently use smart meter messages to obtain feedback on our outage management system on meters that could have lost power supply, while continuing to develop internal processes to better utilize smart meter data to further improve our customer experience. Albeit, our AMI meters do not have true 2-way communication, thereby limiting our customers' ability to participate in the CDM Demand Response Programs pertaining to water heaters, pool pumps, peaksaver, etc. We are in the process of reviewing the cost implications for upgrading (1) AMI meters with 2-way communication capability, and (2) our current IT infrastructure (both capital and O&M) to accommodate the system requirements for the implementation of Demand Response programs.

We have worked with our neighbours, Hydro One and PowerStream, on our 15-year future growth plan to establish the possibility of building a 230 kV TS to better serve the growing demand for power.

We are committed to continuing our infrastructure renewal program **to improve customer participation** in reducing energy consumption**, improve system reliability** by reducing outages and outage duration**, improve operational efficiency** by deploying distribution automation and Smart SCADA technology, **improve security and safety** by reducing the vulnerability of the grid to unexpected hazards and promoting a safer system for both workers and the general public, and **promote environmental quality** by allowing customers to purchase cleaner, lower-carbon-emitting generation, and promote a more even deployment of renewable energy sources.

[1] G&W Viper Reclosers with SEL 651R controls

Table 1 - **Circuit length (in meters)**

System Voltage	44 kV	27.6 kV	8.32 kV	TOTAL
Overhead	128,900	100,700	384,800	614,400
Underground	700	69,100	74,400	144,200
<uncategorized>	300	3,600	1,700	5,600
Total	129,900	173,400	460,900	764,200

Table 2 - **Distribution Transformer Count**

System Voltage	44 kV	27.6 kV	8.32 kV	TOTAL
Overhead	0	480	1,680	2,160
Padmount	0	600	525	1125
Total	0	1,080	2,205	3,285

2.2. Embedded Distribution System

Subtransmission: InnPower is embedded into Hydro One Networks Inc.'s (HONI) subtransmission system. We currently own, operate, and maintain four (4) subtransmission feeders[2] from our border connection point, all of which have been identified by HONI to have available capacity to connect FIT or micro-FIT generators.

Distribution: Among our 29 distribution feeders, 28 feeders still have available capacity to connect generators while six other feeders are nearing their capacity for micro-FIT connection. As of this report date, 24 distribution feeders have a total of 2.42 MW of solar generation already connected or pending approval.

[2] Alliston TS 9M1, 9M2, 9M4, and Barrie TS 13M3

Micro FiT Connection Statistics:

No. of Micro-FiTs

Table 3 - No. of Micro-FIT's

STATION	CONNECTED	IN PROGRESS	Grand Total
ALLISTON	66	14	80
BARRIE	7	2	9
EVERETT	4	4	8
Grand Total	**77**	**20**	**103**

Table 4 - KW Listing

STATION	CONNECTED	IN PROGRESS	Grand Total
ALLISTON	609	140	749
BARRIE	63	17.6	80.6
EVERETT	38	31	69
(pending assignment)		60	60
Grand Total	**710**	**248.6**	**958.6**

Table 5 - FIT Summary Table

Station / Feeder	CONNECTED-kW	Pending-kW	TERMINATED	Total - kW
ALLISTON	**609**	**140**	**304.81**	**1053.81**
BOB DEUGO	**40**	**10**	**30**	**80**
F1			10	10
F2	40	10	20	70
BRIAN WILSON	**201.5**	**70**	**117**	**388.5**
F1	72.25	20	30	122.25
F2	66.25		20	86.25
F3	55	40	57	152
F4	8	10	10	28
CEDAR POINT	**45**	**20**	**23**	**88**
F1	10	20	23	53
F2	35			35
INNISFIL	**180**	**10**	**42.95**	**232.95**
F1	50		22.95	72.95
F2	20	10	20	50
F3	110			110
LEFROY	**60**	**20**	**44.36**	**124.36**
F1	20	20	5.76	45.76
F2	20		18.6	38.6
F3	20		20	40
LEONARD BEACH	**2.5**		**27.5**	**30**
F1			7	7
F3	2.5		20.5	23
THORTON	**80**	**10**	**20**	**110**
F1	60	10	10	80
F2	20		10	30
BARRIE	**63**	**17.6**	**79**	**159.6**
BIG BAY POINT	**13**	**17.6**	**20**	**50.6**
F1	3	7.6	10	20.6
F2	10	10	10	30
SANDY COVE	**10**			**10**
F1	10			10
STROUD	**40**		**59**	**99**
F1	10		25	35
F2			10	10
F3	30		24	54
EVERETT	**38**	**31**	**20**	**89**
COOKSTOWN	**38**	**31**	**20**	**89**

F2	28	22	10	60
F4	10	9	10	29
Pending		60		60
Grand Total	**710**	**248.6**	**403.81**	**1362.41**

2.3. Municipal Substations

InnPower has ten (10) substations serving the community. The total design capacity is 75 MVA. The subtransmission system (44 kV) allows for transfer of loads between stations as required.

Table 6 - **Feeder Data**

SUBSTATION	LOCATION	SIZE	OWNER	FEEDER #	Volt	Vintage
BIG BAY POINT DS	709 13th Line	5,000 KVA	InnPower	F1 & F2	44/8.32 KV	1971
BOB DEUGO DS	2033 Commerce Park Drive	10,000 KVA	InnPower	F1 & F2	44/27.6 kV	2006
BRIAN WILSON DS	1434 Innisfil Beach Road	20,000 KVA	InnPower	F1, F2, F3 & F4	44/27.6 kV	1991 2014
Belle Ewart DS	1214 20th Sideroad	10,000 KVA	InnPower	F1 & F2	44/27.6 kV	2014
CEDAR POINT DS	733 6th Line	5,000 KVA	InnPower	F1 & F2	44/8.32 kV	1976
INNISFIL DS	2255 Highway #89	5,000 KVA	InnPower	F1, F2 & F3	44/8.32 kV	1978
LEFROY DS	1495 Killarney Beach Road	5,000 KVA	InnPower	F1, F2 & F3	44/8.32 kV	1967
LEONARDS BEACH DS	2895 25th Sideroad	5,000 KVA	InnPower	F1 & F2	44/8.32 kV	1974

SANDY COVE DS	1104 Lockhart Road	5,000 KVA	InnPower	F1 & F3	44/8.32 kV	1975
STROUD DS	2135 Lockhart Road	5,000 KVA	InnPower	F1, F2 & F3	44/8.32 kV	1969

Table 7 - Hydro One owned Distribution Stations

COOKSTOWN WEST DS	Victoria St. Cookstown, West of Cty.Rd. 27	7,000 KVA	Hydro One	F2 & F4	44/8.32 kV	--
THORNTON DS	Innisfil Beach Rd. East of Cty.Rd. 27	5,000 KVA	Hydro One	F1 & F2	44/8.32 kV	--

Note: All transformers are connected as Delta-Primary and Wye-Secondary.

2.4. Station Metering and Monitoring

We have installed and commissioned station monitoring equipment and systems on all ten (10) of our substations, while eight (8) have smart SCADA equipment installed and functional, as noted in the table below. Our intent is to add remote sensing and switching capability with Smart Grid Self-healing properties to the remaining two (2) stations. *We currently do not monitor private substations.*

Table 8 – **Smart SCADA Status of IPC DS**

STATION	Station Monitoring Capability	Smart SCADA Status
BIG BAY POINT DS	YES	Fully Functional
BOB DEUGO DS	YES	Fully Functional
BELLE EWART DS	YES	Fully Functional
BRIAN WILSON DS	YES	Fully Functional
CEDAR POINT DS	YES	Fully Functional
INNISFIL DS	YES	Fully Functional
LEFROY DS	YES	Fully Functional
LEONARDS BEACH DS	YES	Fully Functional
SANDY COVE DS	YES	NEEDS UPGRADE
STROUD DS	YES	NEEDS UPGRADE

We are currently engaging with other public utilities to share costs.

- Communication infrastructure
    - We currently use an unlicensed frequency band for our SCADA system and have experienced significant signal interference. In an effort to improve reliability of our communication network we are working on replacing/upgrading all our communication equipment to use the dedicated utility frequency band that has been allotted for the management of the electric grid by Industry Canada. We are planning on completing this upgrade in fiscal 2015, which will require significant investment in capital and O&M.
    - As part of the SCADA upgrade we replaced the older vintage OPTOMUX protocol equipment with newer technology devices, while quality testing our existing DNP3 communication equipment to ensure long term reliable operation.
    - This new technology gives us the capability to monitor and control DG units, which in turn allows us the opportunity to consider a higher number of DG connection requests.
    - The installation of the new SCADA system and monitoring devices will improve our ability to obtain real time system information at various locations of our distribution system, which in turn will enable us to better determine circuit response to load and other operating conditions. This will further assist us in the evaluation of DG connection requests.
    - For the continuous improvement and maintenance of the above projects it will be necessary for us to expand our technical support team by adding ONE new position in the near future.

2.5. Feeder Capacities to Connect Generation

At InnPower we follow the guidelines stipulated by Hydro One in their document: Distributed Generation Technical Interconnection Requirements – Interconnections at Voltages 50kV and below; DT-10-015 Rev 3, 2013. In this section Hydro One stipulates the acceptable generation limits for three-phase and single-phase generators for DG facilities interconnected to HONI Distribution feeders. We use the same guidelines for our system. In addition, we use other industry recognized standards and procedures in determining connectability of DG's to our system; including IEEE 1547, which is the "Standard for Interconnecting Distributed Resources With Electric Power System", and calculations based on feeder specific load calculations. We have a design threshold to limit connected DG power to 50% of our calculated average

minimum load of each feeder, which is determined to be 15% of the average maximum load on the respective feeder.

Distribution System

Distribution: Among our 29 distribution feeders, 28 feeders still have available capacity to connect generators, while six feeders are nearing their capacity for micro-FIT connection.

Subtransmission System

As noted earlier in this report, InnPower is embedded into Hydro One Networks Inc.'s (HONI) subtransmission system, and we currently own, operate, and maintain four (4) subtransmission feeders from our boarder connection point, all of which have been identified by HONI to have available capacity to connect FIT or micro-FIT generators as noted below.

Table 9 - IPC Feeder Capacity Status for DG Connectivity -Subtransmission

Feeder	TS	Voltage	Rating	Available DG Capacity
9M1	Alliston	44 kV	600 amps	27.5MW
9M2	Alliston	44 kV	600 amps	29.75MW
9M4	Alliston	44 kV	600 amps	29MW
13M3	Barrie	44 kV	600 amps	28.5MW

Note: Above capacity data was calculated on 09-Nov-2015 using Hydro One's Capacity Evaluation Tool. Please see Appendix section for screen shots of calculation.

2.6. Challenges related to our distribution system:

Currently we are facing capacity limitations on seven (7) distribution feeders. One feeder has already reached its maximum capacity for DG connectivity while six (6) other feeders are nearing their maximum capacity. Over the next two to three years we are anticipating DG connection requests to amount to 1-2.5 MW in total. It is very likely that our aging infrastructure would need to be upgraded to accommodate the anticipated DG connection

applications. However, an accurate estimate of the extent of system upgrades and associated costs are better determined after the specific feeders on which these DG units will be connected are identified. In the interim, as we continue to expand our in-house technical capabilities to conduct substation and feeder based studies, and implement communication and SCADA system upgrades, it is imperative that we have the opportunity to employ an additional technician in the near future to adequately support these efforts.

One of the other challenges we face in our distribution system pertains to the sharing of the distribution infrastructure with other LDC's. We currently have four (4) feeders that are based out of two separate HONI owned stations, namely Thornton DS and Cookstown DS. Since two separate LDC's are operating out of the same substation it poses logistical problems. These arrangements pose unique challenges when working on micro-FIT and FIT projects.

Table 10 - HONI owned DS with IPC feeders

Station Name	Bus Name	Feeder Name	Voltage (kV)	Thermal Capacity (MW)	Upstream TS	Upstream TS Feeder
Cookstown West DS	Total	F1, F2*, F3, F4*	8.32	4.8	Everett TS	M6
Thornton DS	Total	F1*, F2*, F3	8.32	3.3	Alliston TS	M4

* Feeders owned by IPC

Long Term Load Transfer (LTLT) Customers

IPC supplies power to 95 Hydro One LTLT customers via three IPC feeders[3]. These feeders supply power to the following LTLT customers: 61 metered customers, 33 flat rate customers, and 1 micro-FIT customer; these are HONI customers who are supplied power through our distribution infrastructure. We do not have any InnPower customers who are fed off HONI distribution infrastructure.

We are currently engaging with HONI to transfer these customers over to us.

2.7. Identification of Expenditures

As stated above seven of our distribution feeders have DG connectivity concerns and therefore, if we are to continue to offer our customers the opportunity to connect their renewable power

[3] Cookstown F4, and Thornton F1 and F2

generators to our grid we would need to implement a variety of infrastructure upgrade projects to accommodate their generators. In late 2015, InnPower undertook an effort to calculate remaining connectivity capacity and the final report (pending) will be supplied as an addendum to this report (expected to be published in December 2015)

3. Planned Development of the Distribution Systems to Accommodate Generation Connections

3.1 Existing and Pending Renewable Generation Projects:

Pending the release of the Consultant report in December 2015 on InnPower's generation connectivity capability, InnPower will issue as an addendum to this report a detailed outline of the projects that would enable more renewable generation connections to its grid.

MicroFIT Summary

Installed, approved and forecasted Projects by Year

YEAR	2010-2014	2015	2016	2017	2018	2019
Forecast	N/A	12	15	18	21	24
Actual	82*					

*as of November 13, 2014

Breakdown of MicroFIT Applications (as of Nov 13, 2014)

Total Connected	77
In Progress	6
Application Terminated	46
Total Applications	129
MicroFIT Connected or In Progress	960 kW

FIT Summary

Installed, approved and forecasted Projects by Year

YEAR	2010-2015	2016	2017	2018	2019	2020
Forecast	7	5	5	2	2	2
Actual	7*					

*as of Nov 9, 2015

2016-2019 FIT forecast contingent on OPA approval of FIT projects

Breakdown of FIT Applications (as of November 13, 2014)

Total Connected 7
In CIA Process 0
Pending CIA Process 0
Total Applications 10
Cancelled 3
FIT Connected or In Progress 1.463 MW

Connected FIT Projects

S.NO	Project Name	Size (kW)	TS	DS	Phase
1	Wardlaw Poultry Farm	150	9M6	Cookstown F4	Three Phase
2	Innisfil Self Storage	225	13M3	Stroud F1	Three Phase
3	Brubacher Solar	216	9M4	Thornton F2	Three Phase
4	Herbets Boots	65	9M1	Bob Deugo F1	Three Phase
5	Nantry Schores	250	9M1	Brian Wilson F2	Three Phase
6	Robtrans	57	9M1	Bob Deugo F1	Single Phase
7	Home Hardware	500	9M2	*(Connected to 9M2)*	Three Phase

4. Smart Grid Development

Continuing from our earlier investment in Smart Grid technology with the installation and commissioning of approximately 15,000 meters as part of the AMI project, we have recently

invested time and resources for the upgrading of our SCADA system, installation and commissioning of a new Outage Management System (OMS), replacing, upgrading, and/or maintaining substation Remote Terminal Units (RTU's), SCADA switches, and Reclosers.

During the last quarter of 2015 (currently in progress) InnPower will be installing control buildings and monitoring equipment at several locations on our distribution system, installing fault current indicators with SCADA communication, and replacing our radio communication network (scheduled for completion in Q4-2015) to further enhance our system reliability, resiliency, and efficiency. With the move to the new office, InnPower commissioned a control room for grid monitoring and outage management.

Benefits:

- The new SCADA system has improved visibility and has helped with quicker outage restoration.
    - The new SCADA system is configured with remote accessibility, allowing greater functionality.
- Installing advanced Fault Current Indicators with communication capability reduces the time taken to locate our faults and helps reduce outage restoration times and overall reliability.

Impacts on Distributed Generation:

- Power quality and reliability- For sensitive equipment (computer equipment, manufacturing process equipment) or in the event where a power outage could seriously impact a business, DG can be used to improve power quality and reliability.

- Security - A DG system can provide added security by maintaining power to critical operating areas which would otherwise be affected by utility power outages.

- Environment - Many DG installations reduce total emission levels by using energy resources more efficiently, replacing heating and water heating fossil fuel combustion emissions and in some cases displacing more damaging central plant emissions.

- Other – DG's further help with avoiding future expansions of transmission and distribution networks in their respective areas.

- The implementation of Substation and Distribution Automation is expected to reduce the number of sustained outages and thereby decreasing the downtime of DG units that would have otherwise been dropped from the grid.

- The ability to track momentary outages by installing advanced microprocessor controlled automatic interrupting devices will provide intelligent data on momentary outages that would help LDC's implement proactive solutions to eliminate sustained outages.

- Our new communication infrastructure will enable real time monitoring of our subtransmission and distribution system, further helping operator assisted restoration efforts, and thereby reducing downtime.

- The installation of smart meters has enabled us to harvest accurate load data to help us optimize DG connection capacity on our feeders.

5. Summary

The GEA Plan has been prepared to illustrate the ability to accommodate renewable generation. Through the plan the existing capacity has been outlined and with the impending release of the Consultant report on the investment requirements to enable more renewable energy connections a list of investment projects will be identified and issued as an addendum to this report shortly.

In order for InnPower to continue to accommodate DG connection requests, given our current system limitations, we would need to follow through starting in 2016 with infrastructure upgrade that will likely be required to enhance DG connectivity.

Should additional supporting documentation be required IPC will be glad to provide such as required.

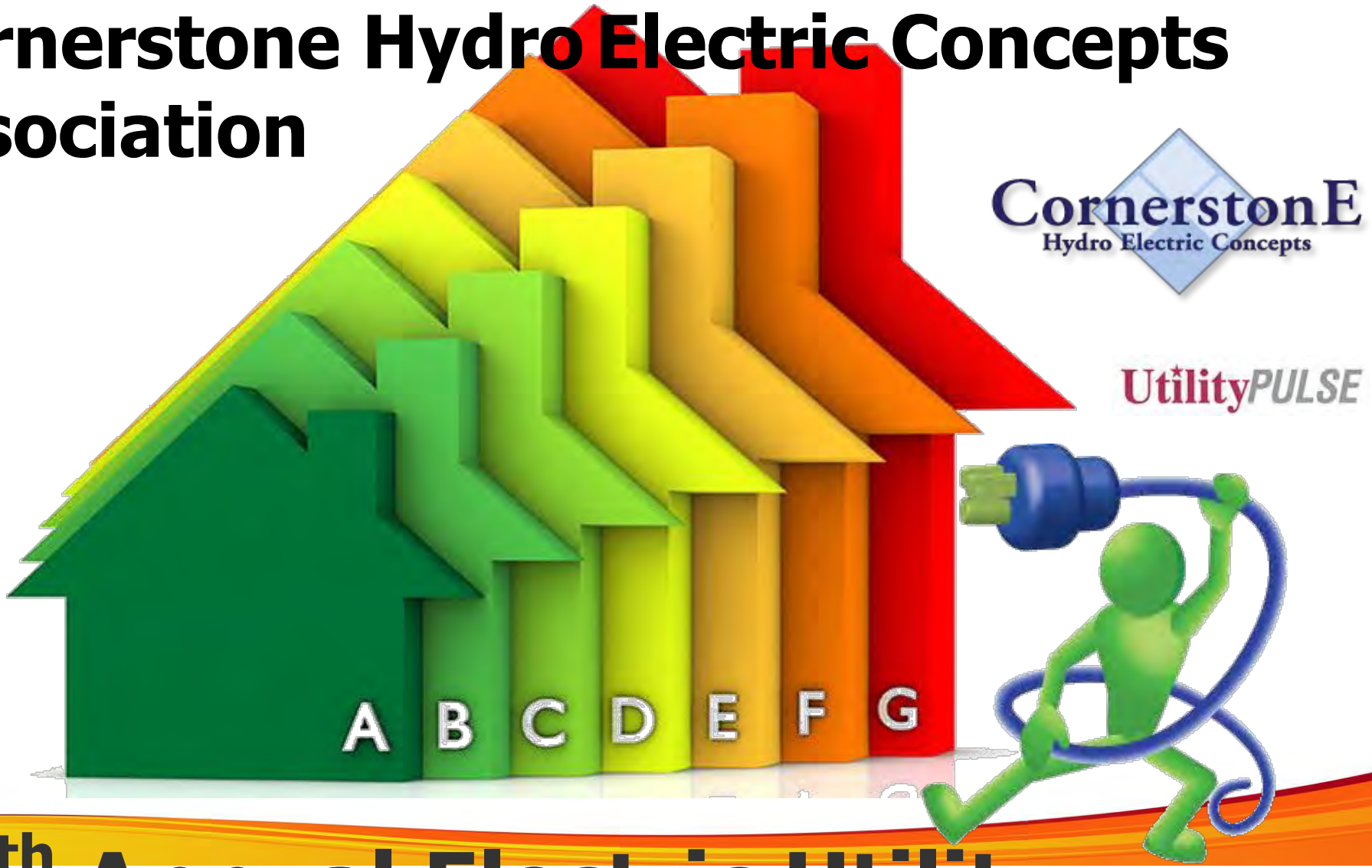
END OF REPORT

Appendix

Service Territory



Cornerstone Hydro Electric Concepts Association



15th Annual Electric Utility Customer Satisfaction Survey

The purpose of this report is to profile the connection between CHEC Group 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.

This is privileged and confidential material and no part may be used outside of Cornerstone Hydro Electric Concepts Association without written permission from UtilityPULSE, the electric utility survey division of Simul Corporation.



All comments and questions should be addressed to:

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

Executive summary

"Putting the Consumer First" was part of the title of the *Report of the Ontario Distribution Sector Review Panel.* Its findings and recommendations add an additional level of challenges and opportunities. While the Report challenges the structural nature and efficiency of LDCs in Ontario, the "customer" remains focused on their own needs and expectations. The customer is primarily concerned about their overall costs for their electricity rather than the costs of the individual components of producing, transmitting, distributing and regulating electricity.

For the past 15 years, the only constant Ontario LDCs and their customers have faced is constant change. With topics such as SMART Meters, SMART Grid, green energy, infrastructure renewal, coupled with the recommendations from the Ontario Distribution Sector Review Panel, it is easy to predict that change will continue – for many years to come. One of the challenges for utilities today is to determine how to educate, empower and engage their residential and small business customers. The goal for utilities is to cut through the fog of fear, misinformation and confusion that exists amongst its customers, regarding a myriad of subjects, while retaining a very high level of trust, respect and credibility.

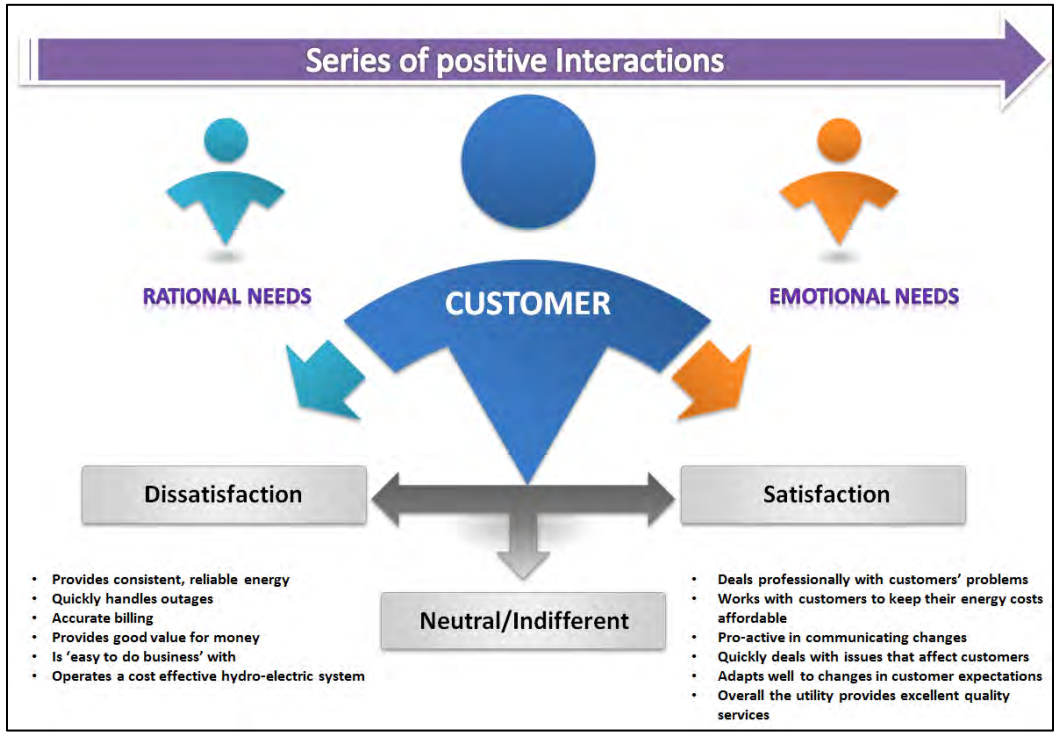




Trust and credibility are the foundational building blocks for ensuring that customers have both their rational and emotional requirements

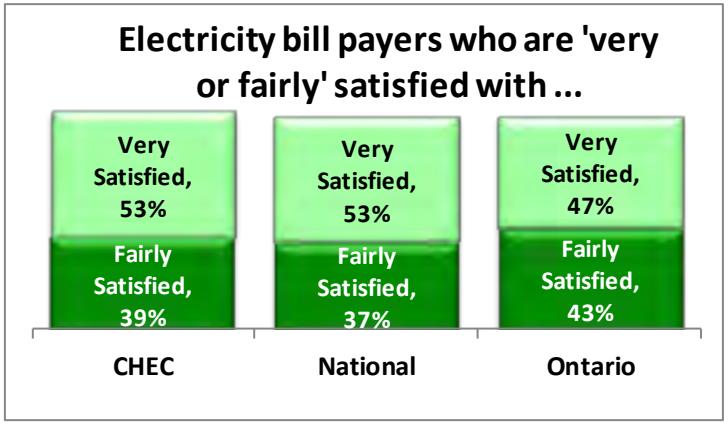
fulfilled. The attributes which help an LDC to be seen as trusted and highly credible are: knowledge, integrity, involvement and trust. On demonstrating Credibility and Trust, CHEC Group has done well. Overall, CHEC Group 87% [Ontario 82%; National 82%].

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 old adage, “You cannot command respect, you have to earn respect” is a lesson that aptly describes the loyalty effect with customers. Many people mistakenly think doing a good job will lead to loyalty; that a satisfied customer equals a loyal customer. Customers have expectations of their electric utility that go far beyond “keeping the lights on”, “billing me properly”, and “restoring power quickly”.



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

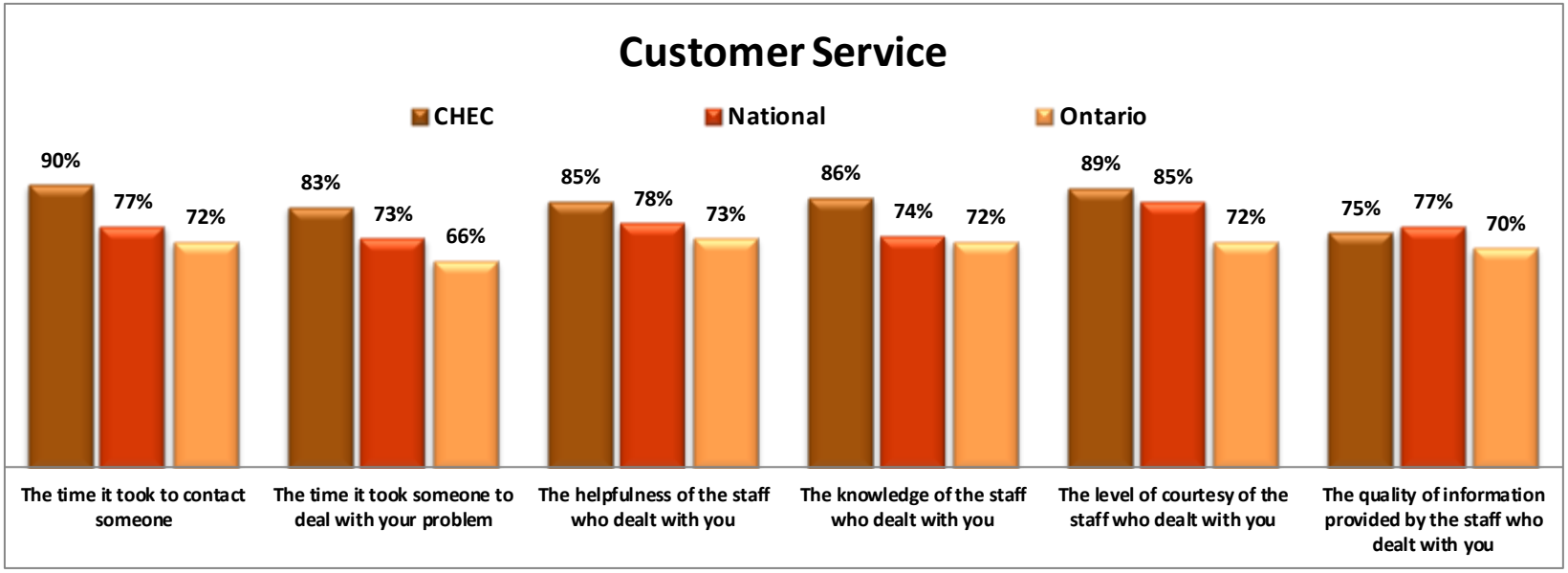
Satisfaction alone does not make a customer loyal; a willingness to commit and advocate for a company along with satisfaction identifies the three basic customer attitudes which underpin loyalty profiles. While satisfaction is an important component of loyalty, the loyalty definition needs to incorporate more attitudinal and emotive components.



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

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

Customers have needs and expectations AND they will have problems. How those problems are dealt with are “proof points” which will validate or invalidate their perceptions. Customer problems are far more diverse than they have ever been, thereby, causing customer service to change in response to those problems and needs. Given the increase in fragmentation of customer type and customer problems, the need for building a customer-centric culture in line with customers’ needs, preferences and expectations is important when customer satisfaction is important to the organization.



Base: total respondents who contacted the utility



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 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 that cause the most concern with customers.

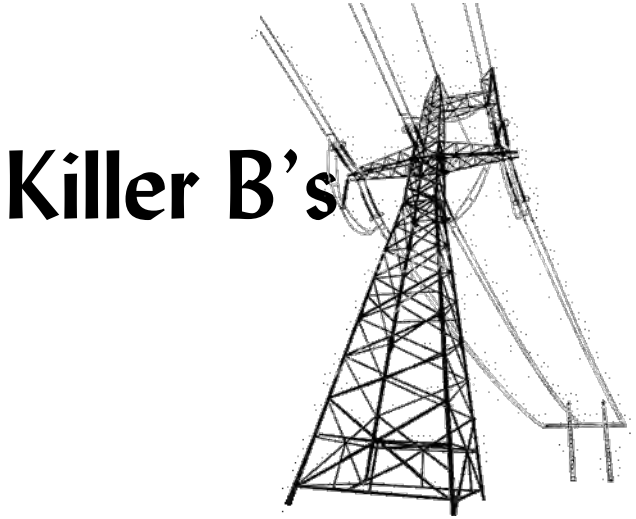
Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months			
	CHEC	National	Ontario
2013	36%	41%	35%
2012	-	44%	46%
2011	-	43%	43%
2010	-	45%	41%

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
2013	10%	8%	10%
2012	-	12%	13%
2011	-	10%	16%
2010	-	10%	12%

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





What do customers think about electricity costs?

There is a correlation between ability to pay and satisfaction with higher earners reporting the highest levels of initial satisfaction with their utility. It is also true that emotional connectivity, i.e. loyalty, also plays a role about what customers think about costs. Out of all the Ontario survey respondents this year, only 17% of Secure customers vs 43% of At Risk customers report that they sometimes or often worry about paying their electricity bill.

Is paying for electricity a worry or major problem …			
	CHEC	**National**	**Ontario**
Not really a worry	67%	70%	66%
Sometimes I worry	24%	18%	21%
Often it is a major problem	4%	8%	11%
Depends	3%	2%	1%

Base: total respondents



Customer Experience Performance rating (CEPr)

New for 2013 is the Customer Experience Performance rating (CEPr). Every touch point with customers on the phone, website or in-person influences what customers think and feel about the organization.



Customer Experience Performance rating (CEPr)			
	CHEC	National	Ontario
CEPr: all respondents	87%	83%	83%
CEPr: respondents *who have* contacted their utility	83%	79%	77%
CEPr: respondents *who have not* contacted their utility	88%	84%	85%

Base: total respondents



The key is handling every individual element of an interaction with a customer so that he/she feels good at the end of the whole interaction and the utility achieves its business objectives.

While an excellent transaction today creates a positive experience today, the perception created is that future transactions will be excellent too, which is how you want your customers to feel. Of course, a negative transaction creates the perception that future transactions will be negative.



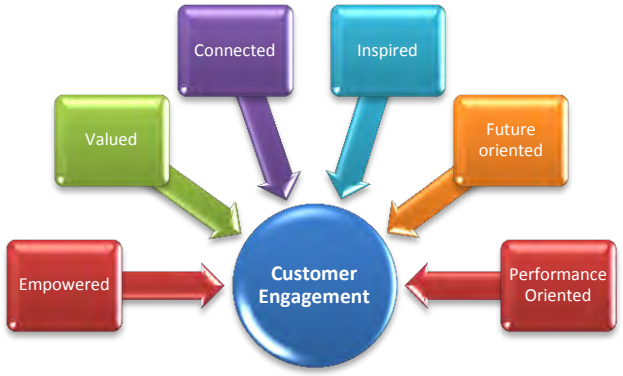
Customer Engagement Index (CEI)

UtilityPULSE has been researching this topic for the past 2 years and we have found that there are 4 basic types of definitions associated with the term called “customer engagement”. Here are the basic types:

1- Participation in programs or service offerings
2- Pro-active “reach-out” to customers
3- Customer loyalty
4- How customers think, feel and act towards the organization that serves them.

Drawing from our 25+ years of experience working with enterprises in both the private and public domains, we believe that basic types 1 & 2 are too simplistic and tend to be an efficiency measurement. Whereas types 3 & 4 are more valuable to the organization especially when a key corporate goal is to create an operationally effective place to do business with – essentially an effectiveness and outcomes oriented measurement.

Engagement is how customers think, feel and act towards the organization. As such, ensuring that customers respond in a positive way requires that they are rationally satisfied with the services provided AND emotionally connected to your LDC and its brand. The more frequently and consistently an organization's products and services can connect with a customer, especially on an emotional level, the stronger and deeper the customer becomes engaged with the organization. The six dimensions of an outcome based definition of customer engagement are: empowered, valued, connected, inspired, future oriented and performance oriented.





Utility Customer Engagement Index (CEI)			
	CHEC	**National**	**Ontario**
CEI	86%	81%	81%

Base: total respondents

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 for influencing satisfaction and affinity levels with their utility.



CHEC's UtilityPULSE Report Card®

Performance

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

Base: total respondents

Corporate Image

Organizations today, are always under scrutiny and have to consider the reality AND perception of their image. Increasingly, organizations have realized that the management of a strong positive image with various stakeholders can be beneficial.

Attributes strongly linked to a hydro utility's image			
	CHEC	National	Ontario
Is a respected company in the community	89%	83%	84%
Maintains high standards of business ethics	88%	81%	81%
A leader in promoting energy conservation	85%	80%	80%
Keeps its promises to customers and the community	88%	81%	82%
Beyond providing jobs and paying taxes, is socially responsible	86%	79%	79%
Is a trusted and trustworthy company	89%	83%	83%
Adapts well to changes in customer expectations	80%	74%	73%
Is 'easy to do business with'	88%	82%	81%
Overall the utility provides excellent quality services	87%	85%	83%
Operates a cost effective hydro-electric system	79%	72%	68%

Base: total respondents with an opinion



Supplemental Insights

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

SMART Meters & SMART Grid



Do economic incentives have an impact on resource consumption patterns? *77% agree strongly or somewhat that Time-of-Use billing has changed the way in which they consume electricity on a day-to-day basis. [Base: Ontario LDC respondents]*

SMART metering is also a key element of SMART grid technology. This year's survey probed around the concept of SMART grid, its importance and support towards working with neighbouring utilities. It is clear that the need for education is immense. 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 LDCs
I have a fairly good understanding of what it is and how it might benefit homes and businesses	7%
I have a basic understanding of what it is and how it might work	17%
I've heard of the term, but don't know much about it	33%
I have not heard of the term	42%
Don't know	1%

Base: An aggregate of respondents from 2013 participating LDCs

Importance of pursuing implementation of the SMART Grid	
	Ontario LDCs
Very important	23%
Somewhat important	30%
Neither important or unimportant	9%
Somewhat unimportant	5%
Unimportant	10%
Don't know	23%

Base: An aggregate of respondents from 2013 participating LDCs

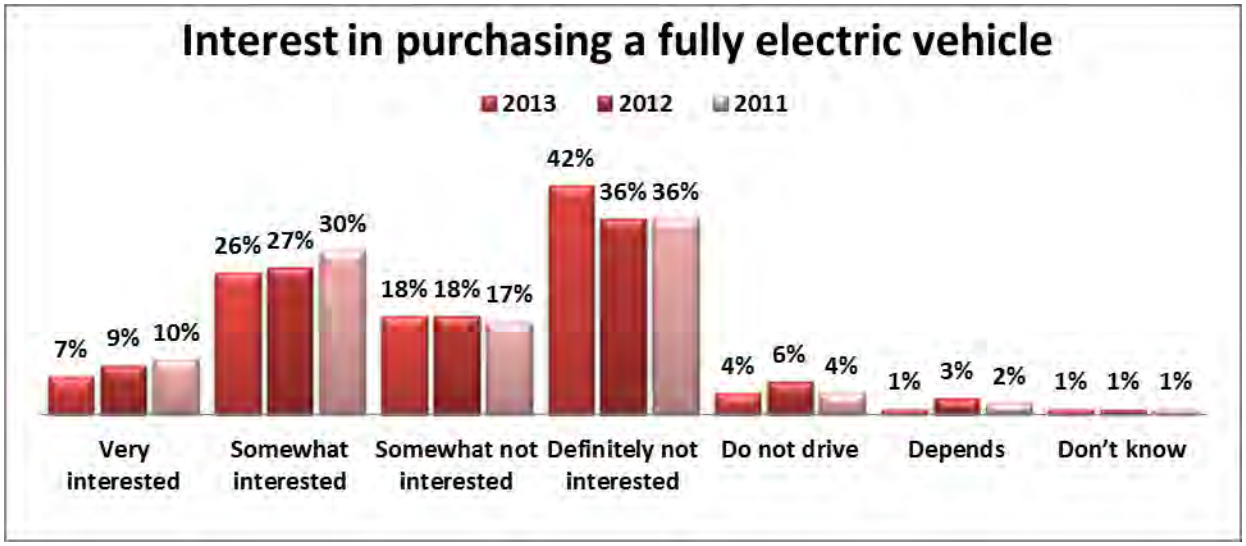
Support towards working with neighbouring utilities on SMART Grid initiatives	
	Ontario LDCs
Very supportive	38%
Somewhat supportive	37%
Neither supportive or unsupportive	4%
Somewhat unsupportive	2%
Unsupportive	6%
Don't know	12%

Base: An aggregate of respondents from 2013 participating LDCs



Purchasing an Electric Vehicle

Looking at age demographics, 22% of older respondents (55+) versus 47% of respondents aged 35-54 and 43% aged 18-34 are in favor of EVs replacing conventional cars.





Base: total respondents in the Ontario Benchmark survey



Energy Conservation & Efficiency

Improving energy efficiency does not mean that customers have to give up or forgo activities to save energy. Rather, new technologies and more effective behaviour will actually allow customers to do more, improving their living conditions rather than reducing their comfort. 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. During the survey interview process, we asked *"what are the 1 or 2 barriers for creating higher levels of energy efficiency?"* 21% identified "costs involved in making equipment/appliance changes", and 12% identified "lack of knowledge or lack of information". Respondents were asked: *"What will you be doing to conserve energy?"*

Efforts to conserve energy				
Ontario LDCs	**Yes**	**No**	**Already Done**	**Don't Know**
Install energy-efficient light bulbs or lighting equipment	20%	10%	69%	1%
Install timers on lights or equipment	15%	49%	35%	2%
Shift use of electricity to lower cost periods	21%	19%	57%	3%
Install window blinds or awnings	15%	26%	58%	1%
Install a programmable thermostat	15%	20%	63%	2%
Have an energy expert conduct an energy audit	9%	70%	18%	3%
Removing old refrigerator or freezer for free	14%	45%	37%	4%
Join the peaksaverPLUS™ program	18%	48%	21%	13%
Replacing furnace with a high efficiency model	13%	36%	48%	3%
Replacing air-conditioner with a high efficiency model	16%	39%	41%	4%
Use a coupon to purchase qualified energy saving products	33%	42%	21%	4%

Base: An aggregate of respondents from 2013 participating LDCs



E-care and E-billing

For any service provider including electric utilities, using the Internet for online customer care and electronic billing involves a number of interrelated requirements, including a customer's ability to: sign up for and change their services using the internet, find answers to their questions online about their accounts, learn about products, services and topics, i.e., green energy, electricity pricing, etc. It is about giving control to the customer.



83% of CHEC Group respondents have access to the internet and 14% have accessed their utility's website in the last six months.

Consumers will eventually adopt electronic billing and online customer care as many industries/companies begin providing consumer bills online, and critical mass is reached.



Using the internet for billing		
	Ontario LDCs	**CHEC**
I am already receiving my hydro bill electronically	10%	4%
I use on-line banking and will definitely be requesting that my bill be sent electronically	11%	11%
I use on-line banking but prefer to have paper statements	30%	35%
I prefer to have the paper copy of my bills	23%	26%
I don't use on-line banking	17%	22%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

Social Media



Social media is evolving at an incredible pace. Importantly, it seems to represent a shift in how people discover, read and share news, information and content. Respondents of this year's survey were asked *"how likely they would use social media such as twitter®, facebook® (and others) as a resource for energy efficiency tips or to help manage your electricity use"…*

Likelihood of using Social Media				
	CHEC	**Ontario LDCs**	**Ontario LDCs Age Group:18-34**	**Ontario LDCs Age Group: 55+**
Very likely	4%	6%	10%	3%
Somewhat likely	7%	11%	17%	6%
Not likely	22%	20%	24%	17%
Not likely at all	64%	61%	48%	68%
Don't have social media account	2%	2%	0%	4%
Don't know	0%	1%	0%	1%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility



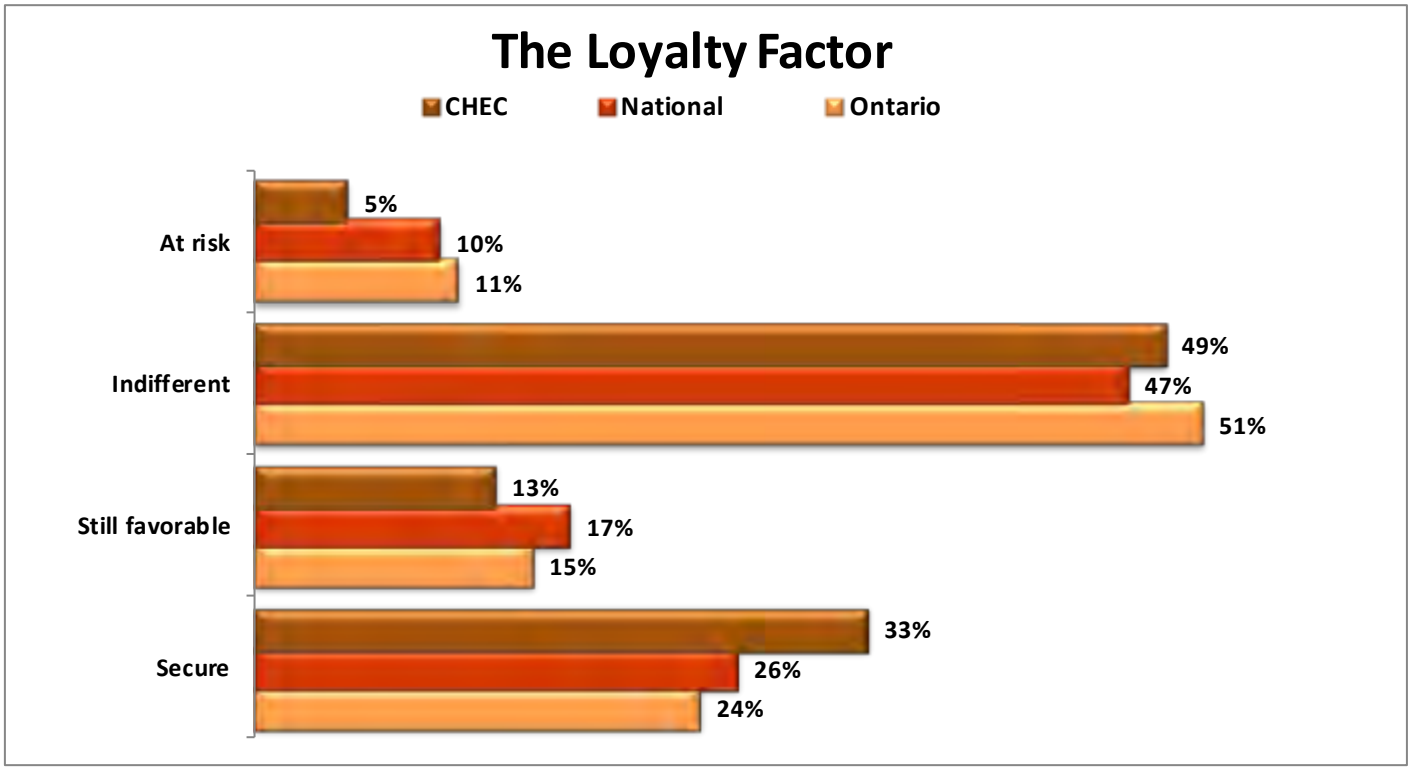
Customer Affinity

Private industry often equates customer loyalty with basic customer retention. If a customer continues to do business with a company, that customer is, by definition, considered to be loyal. If this definition

were applied to many companies in the utility industry, all customers would automatically be considered loyal. As such, measuring customer loyalty would appear to be unnecessary.

Natural monopolies (like LDCs) are not really different in what they should measure except that trying to determine which customers are “loyal” or “at risk” is not about a customer’s future behaviour but more about their “attitudinal” loyalty (are they advocates?).





Base: total respondents

Customer Loyalty Groups				
	Secure	Favorable	Indifferent	At Risk
		CHEC		
2013	33%	13%	49%	5%
2012	-	-	-	-
2011	-	-	-	-
2010	-	-	-	-

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



Electricity customers' loyalty – Is a company that you would like to continue to do business with				
CHEC	**2013**	**2012**	**2011**	**2010**
Top 2 boxes: 'Definitely + Probably' would continue	85%	-	-	-

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



Electricity customers' loyalty – is a company that you would recommend to a friend or colleague				
CHEC	**2013**	**2012**	**2011**	**2010**
Top 2 boxes: 'Definitely + Probably' would recommend	78%	-	-	-

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

Every LDC has a brand and a brand image, while that image can be affected by events in the industry beyond the control of the LDC, the reality is there is a cost benefit to improving the customer experience, generating higher levels of customer engagement and growing the numbers of Favourable and Secure customers. Providing consistent reliable energy while being seen as 'easy to do business with', along with providing information and support for customers to use electricity more efficiently are core components of a successful relationship with customers.



Marketing – Communications			
	CHEC	National	Ontario
Topics that require more pro-active communication			
Cost of electricity is reasonable when compared to other utilities	69%	66%	61%
Works with customers to keep their energy costs affordable	73%	66%	65%
Adapts well to changes in customer expectations	80%	74%	73%
Operates a cost effective hydro-electric system	79%	72%	68%
Provides good value for money	76%	71%	68%
Topics that your utility scores very well on			
Is a trusted and trustworthy company	89%	83%	83%
Respected company in the community	89%	83%	84%
Accurate billing	88%	85%	86%
Overall the utility provides excellent quality services	87%	85%	83%
Provides consistent, reliable energy	91%	90%	90%

Base: total respondents with an opinion

UtilityPULSE is the only enterprise with multiple year customer trend data that appears on the List of Presenters and Submitters in the *Report of the Ontario Distribution Sector Review Panel.* With 14 years of data (15 now that the 2013 survey has been completed), we know that LDCs in Ontario have made excellent progress in the way(s) in which customers are cared for and served – despite the massive amounts of change that have taken place during that same timeframe.

We've often been asked: "What does it take to be seen as having great customer service?" Our answer continues to be "have genuine empathy for customers". If you and your fellow employees don't have it, then your organization will not achieve the highest levels of customer engagement and affinity as may be possible. This requires CHEC Group to ensure that it is truly embracing the strategic intent of being "customer centric" AND it requires the establishment of a corporate culture that supports both customer and employee engagement.



We recommend having meaningful two-way dialogue with employees (and others) to leverage the results from your 2013 customer satisfaction survey derived from speaking with 632 CHEC Group customers [April 10 - April 23, 2013]. After-all, people can't care about the things that they don't know about.

Sid Ridgley
Simul/UtilityPULSE
Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com
June, 2013

Simul

UtilityPULSE

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 fifteen 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 L: Financial Services Agreement InnServices

Contract/Agreement Review Form

The review document is required to be included with all contracts/agreements as per Finance Policy section 5.2.

Requestor Wade Morris **Date** April 15/16

Legal review

Not required ☐

Name of Lawyer GWG

Date April/March 2016

Finance review

Signature

Date 4/18/16

Requestor comments

Finance comments

- Used the w/ww billing contract deseaped from GWG. A review of the contract done by GWG.

Contract Archiving (Please indicate the following to assist finance with archiving the contract)

Company:	InnServices	(name of contractor/partner)
Department:	Admin	(O&M, IT, Customer Service, Interco, Admin, Metering, etc)
Category:	Financial Services	(what is the contract for? ie. Lawn maintenance)
Start Date:	Aug 24/15	(MM/DD/YY)
End date:	Dec 31/20	(MM/DD/YY)

FINANCIAL SERVICES AGREEMENT

THIS AGREEMENT made in duplicate this 15th day of April, 2016.

BETWEEN:

INNSERVICES UTILITIES INC.
("InnServices")

OF THE FIRST PART

- and –

INNPOWER CORPORATION
("Contractor" or "InnPower")

OF THE SECOND PART

WHEREAS InnServices Utilities Inc. deems it appropriate to engage the services of the Contractor to provide its general accounting and payroll administration functions for vendors and employees of InnServices effective as of August 24, 2015; and

AND WHEREAS the Contractor currently provides InnServices billing for and on behalf of InnServices;

AND WHEREAS it is the intent of this Agreement that the Contractor shall be fully reimbursed and compensated by InnServices in accordance with the terms of this Agreement for all of its actual costs and expenses incurred in providing the Services as provided herein;

AND WHEREAS the InnServices Board authorized the transaction and arrangement contemplated in this Agreement on November 16, 2015;

AND WHEREAS the InnPower Board authorized the transaction and arrangement contemplated in this Agreement on November 16, 2015.

NOW THEREFORE IN CONSIDERATION OF THE MUTUAL COVENANTS AND AGREEMENTS CONTAINED HEREIN AND SUBJECT TO THE TERMS AND CONDITIONS HEREINAFTER SET OUT, THE PARTIES HEREBY AGREE AS FOLLOWS:

1.0 Interpretation

1.1 Definitions

In this Agreement the following terms shall have the meaning ascribed to them:

(a) **"Business Day"** means any day other than Saturday or Sunday or a statutory holiday so recognized by the Province of Ontario;

(b) **"Change Order"** means the document executed by the Parties confirming their agreement to undertake a change to the Services or related matters pursuant to a Change Order Request;

(c) **"Change Order Request"** means a request by either Party for a modification, amendment or addition to the Services ("Change") and a draft of the Change prepared by the Contractor and set out in a Change Order Request form;

(d) **"Contractor"** refers to InnPower Corporation;

(e) **"Contractor Data"** means all information, of whatever nature and type and in all formats, of the Contractor used to provide the Services, and in respect of which the Contractor has a proprietary interest. Contractor Data is deemed to be Contractor Proprietary and Confidential Information;

(f) **"Contractor Proprietary and Confidential Information"** means any personal information, data, materials, and other information of InnPower which is used, delivered or disclosed to InnServices and marked or otherwise identified to InnServices as proprietary or confidential at the time of such use, delivery or disclosure. It also includes data, materials, or other information provided to InnServices on a confidential or non-disclosure basis pursuant to a specific provision of this Agreement. Notwithstanding the foregoing, all personal information, cost, pricing and other financial information shall be deemed to be Contractor Proprietary and Confidential Information whether or not specifically identified as such;

(g) **"Contractor Equipment"** means the computer equipment, including all peripherals, attachments, lines and cabling and applicable documentation, owned or leased by the Contractor, and used to perform the Services;

(h) **"Contractor Software"** means those computer programs in object code or source code and including microcode not embedded in a circuit element, and all applicable documentation and media, used by the Contractor to perform the Services and in respect of which the Contractor has an interest as owner or licensee.

(i) **"Current Technology"** means the Contractor Equipment, and Contractor Software resident in the Contractor Equipment, as of the Effective Date;

(j) **"Dedicated Employees"** means employees of InnPower that were specifically hired or assigned by InnPower to assist InnPower in the performance of the Services, and whose time at work is primarily (75% of the employees' time) used to perform the Services;

(k) **"Effective Date"** means the date on which the Contractor commences the performance of Services under this Agreement, namely, August 24, 2015;

(l) **"Hourly Billing Rate"** means the effective hourly rate for billing purposes under this Agreement, as amended from time to time, for each of InnPower's employees working on various aspects of the Services. It shall include, without limitation, charges for overhead, payroll burden, including computers and equipment used by InnPower for the Services with a view to fully reimburse and compensate InnPower for the provision of such Services. This rate is subject to upward adjustments from time to time, in InnPower's sole discretion, to respond to changes in InnPower's costs of providing the Services over the Term of this Agreement;

(m) **"InnPower's Service Levels and Performance Standards"** means the target level of dedicated and non-dedicated personnel, equipment and other resources

("Service Levels"), together with the applicable performance standards for the foregoing, that are deemed appropriate or sufficient by the Contractor, in its sole discretion, for the performance of the Services in accordance with the Contractor's own internal practices for the same or similar functions;

(n) **"InnServices"** refers to InnServices Utilities Inc.

(o) **"InnServices Data"** means all information of whatever nature and type and in all formats, of InnServices or InnService's vendors or employees that is provided or made available to InnPower for the performance of the Services, and in respect of which InnServices has a proprietary interest. InnServices Data does not include Contractor Data.

(p) **"Parties"** means InnServices and the Contractor, and "Party" means one of them as the context requires;

(q) **"Schedule"** means the schedule to this Agreement described in Article 2.0;

(r) **"Services"** means the general accounting and payroll administration services to be provided the Contractor described in Schedule A, as the scope of such services may be changed from time to time by Change Order executed by both parties, and any particular work products, deliverables, documents and reports (collectively the "Deliverables") that InnPower may in its sole discretion decide to furnish to InnServices in relation to the Services;

(s) **"Standards"** refers to International Financial Reporting Standards; and

(t) **"Taxes"** means any applicable sales taxes levied or assessed by any governmental authority with respect to the Services.

1.2 ***Currency***

Unless otherwise stated in this Agreement, all dollar amounts shall be Canadian dollars.

1.3 ***Accounting Terms***

Unless otherwise stated in this Agreement, all accounting terms shall be interpreted in accordance with International Financial Reporting Standards.

2.0 Schedules

2.1 The Schedule appended to and forming part of this Agreement are described in subsection 2.2 hereof. In the event of any inconsistency or conflict between the terms and conditions of this Agreement and any Schedule, the terms and conditions shall prevail.

2.2 The Schedules to this Agreement are as follows:

Schedule A: Description of Services

2.3 The Schedules may be changed from time to time by Change Order.

3.0 Financial Services

3.1 Appointment and Acceptance

InnServices appoints the Contractor to perform the Services described in the Schedule A (Description of Services) as the exclusive Service "Provider" for the duration of the initial Term and any renewal thereof. The Services shall be performed in accordance with InnPower's Service Levels and Performance Standards, as the standards may be changed from time to time by Change Order, and otherwise in accordance with all terms and conditions of this Agreement. The Contractor accepts the appointment for the compensation described in Article 4.0 and all other consideration received under this Agreement.

4.0 Compensation and Payment

4.1 As consideration for the provision of Services under this Agreement, InnServices shall pay the Contractor fees for the Services, and any other amount payable pursuant to this Agreement (collectively "the Fees"), calculated on a time and material basis. Fees shall be computed on the basis of the Hourly Billing Rates or as otherwise provided herein, plus an administrative charge equal to 1% of such Fees plus HST, each month. All time expended on performing the Services, including all services, functions and responsibilities that are inherent, incidental, necessary or customarily provided as part of the Services, shall be chargeable, whether it is expended on the Contractor's premises, at InnService's premises, or elsewhere. Chargeable time also includes, but is not limited to, time expended by clerical staff to prepare such documents as reports or other Deliverables, if any.

4.2 The Contractor shall be reimbursed at cost, plus an administrative charge of 1%, for all reasonable expenses the Contractor incurs properly in connection with the Services, including applicable sales and value added taxes (herein "Reimbursable Expenses"). Reimbursable Expenses, including applicable sales and value added taxes, are additional to the Fees calculated on a time basis. Reimbursable Expenses include, but are not limited to:

- Vehicle use charges;
- Travelling and living expenses;
- Acquisition and/or leasing costs and/or licensing fees related to newly acquired Contractor Software or Contractor Equipment deemed by the Contractor to be necessary for the provision of the Services, provided the cost thereof has been first approved in writing by InnServices;
- Long-distance telephone and communication charges;
- Leasing Costs of existing Contractor Equipment used to perform the Services;
- Licensing Fees related to existing Contractor Software used to perform the Services;
- Postage and special or express delivery charges;
- Overtime premiums;
- Employee severance or termination costs of Dedicated Employees in the event of termination of this Agreement for any reason by either Party before the expiration of the Term, provided InnPower has been unable to reassign such Dedicated Employee(s) to other employment within its organization despite its reasonable efforts;

- Overhead costs to maintain office from which to provide Services;
- Supplies, equipment and any other material costs;
- Cost of any requisite insurance that Contractor must maintain in excess of the Contractor's usual coverage;

4.3 InnServices shall pay Fees and Taxes within thirty (30) days of the invoice date, with the first such invoice to be submitted by the Contractor no earlier than the first day of the first calendar month following the commencement of Services.

4.4 Unless otherwise specified, the Contractor shall obtain and pay for all necessary permits, licenses, certificates and inspections required for the execution of the Services, and the related costs shall be reimbursable to the Contractor at costs plus an administrative charge of 1%.

4.5 All payments shall be made in Canadian currency. On past due charges and late payments the Contractor may impose a late payment charge equal to the lesser of 1.0 percent (1%) per month or the maximum rate permitted by law.

4.6 InnServices shall be responsible for payment of the HST and any other sales and other commodity or similar taxes imposed or levied in respect of the charges payable to the Contractor, other than any tax on the income of the Contractor. The applicable HST or other tax payable by InnServices shall be separately described on each invoice.

5.0 Changes to the Services

5.1 Quarterly Contract Administrative Meetings

InnServices or the Contractor may request from the other Party a quarterly review of the performance of the Services and each Party's obligations under this Agreement, and to review any potential changes to the Services.

6.0 Change Control

6.1 Where InnPower considers it advisable, in its sole discretion, the following changes to Services or other circumstances under the Agreement shall only be implemented after each of the Parties has executed a Change Order:

(i) additions to the description of Services in Schedule A (Description of Services) pursuant to a request by InnServices for new or out-of-scope Services;

(ii) modifications to the Service Level requirements from the Service Levels customarily provided by InnPower for similar services, functions and responsibilities for its own internal purposes;

6.2 Either Party may submit a Change Order Request to the other Party at any time. The Change Order Request shall be submitted in writing and signed by the Party. The Change Order Request shall contain sufficient detailed information concerning the requested Change, including any impact on Services, Service Levels, cost of Service delivery and Contractor compensation, for the other Party to undertake an informed assessment and decision in regard to the request. A draft of the Change will be set out in a Change Order Request form prepared by the Contractor.

6.3 The Receiving Party shall use all reasonable commercial efforts to respond to the Change Order request within the requested time period. A response shall be in writing and may include a request for additional information, for modifications to be made to the Change request, or the decision to reject or accept the requested change.

6.4 An accepted Change Order Request shall act as a direction to the Parties to complete and sign a formal Change Order implementing the Change Order request.

6.5 The Parties shall not implement the proposed change until a Change Order is fully executed including any applicable new or amended contract terms and conditions. Unless otherwise agreed, neither Party shall be responsible for the costs of the other Party in relation to the preparation or evaluation of Change Order request.

6.6 Proposed changes to this Agreement, other than those set out above, shall be undertaken solely by means of a written amendments to this Agreement.

7.0 Technology Change

7.1 The Parties anticipate that either the Contractor's or InnService's information technology requirements will change over the term of this Agreement. The Current Technology may require additions to, enhancement or other modification to accommodate any new or enhanced Customer requirements from time to time. To this end, either Party may request the provision of additional or substituted technology more advanced than the Current Technology by Change Order. The resultant Change Order shall reflect any consequential changes to the Services, including Service Levels, compensation payable to the Contractor and any other changes to this Agreement.

8.0 Contractor Responsibilities, Warranty and Disclaimer

8.1 In undertaking the Services, the Contractor shall:

(a) perform the Services in accordance with the provisions of this Agreement. The Services shall be performed conscientiously, by qualified and competent Services personnel, lawfully, in a good and professional manner and in adherence to the Contractor's Service Levels and Performance Standards; and,

(b) ensure that its security practices with respect to InnServices Data adhere to the same standards of care practiced by the Contractor currently with respect to the Contractor's own data of a similar type or nature; and,

(c) provide skilful and efficient supervision of its employees engaged in the performance of the Services it provides to InnServices and InnService's vendors and employees.

8.2 Notwithstanding the above, the Contractor shall not be responsible or otherwise liable for any wrongful access to, use or disclosure of InnServices Data:

(a) caused by any failure or deficiency of InnServices in its treatment of InnServices Data, including any failure by InnServices to adhere to the confidentiality standards and practices of the Contractor under this Agreement;

(b) demonstrated by the Contractor to be in the public domain; and

(c) required by law to be disclosed. The Contractor shall give InnServices prompt notice of such requirement for disclosure and permit InnServices to undertake any available appeal procedures to maintain the confidentiality of InnServices Data.

8.3 The Contractor warrants that it shall perform its Services in a professional and workman-like manner.

9.0 Compliance with Laws

9.1 The Contractor shall ensure that its employees, agents and subcontractors comply with all applicable laws, statutes, ordinances, by-laws and regulations of all applicable governmental authorities, as well as InnServices' own by-laws and policies, provided InnServices has previously provided the Contractor with all of its own applicable by-laws and policies on a timely basis.

10.0 Terms and Termination

Term of Agreement

10.1 Subject to earlier termination in accordance with the terms and conditions hereunder, the term of this Agreement and the provision of Services shall commence on August 24, 2015 and continue until December 31, 2020 ("Initial Term"). The Parties may renew this Agreement thereafter on such terms and conditions as agreed between the Parties, provided that any such renewal has been agreed to, in writing, at least three (3) months prior to the end of the Initial Term or any subsequent term.

10.2 In the event that an agreement between the Parties on the renewal of this Agreement cannot be reached within the time period prescribed in Article 10.1, this Agreement shall terminate at the end of the then current term subject to an additional transitional period of six (6) months, at InnService's option, for transfer of the Services to InnServices or another service provider. The Contractor will cooperate with InnServices by providing the transitional assistance services described in Article 10.5.

Subsequent Agreements

10.3 The Parties agree to enter into negotiations twelve (12) months prior to the end of the term of this Agreement to facilitate the transfer of the financial services back to InnServices or to negotiate a new agreement for the Services.

Termination for Cause

10.4 (a) In the event that either Party commits a breach of one or more of its material duties or obligations under this Agreement ("Material Breach"), which Material Breach shall not have been cured within twenty (20) Business Days from notice in writing advising of said Material Breach ("Cure Period"), the Party not in breach may terminate this Agreement, forthwith, for cause by giving written notice to the Party in Material Breach.

(b) Without limiting the generality of the foregoing, each of the following specific events shall be deemed to be a Material Breach by the Contractor granting InnServices the right to terminate this Agreement pursuant to Article 10.4(a):

(i) the Contractor is adjudged bankrupt, commits or threatens to commit an act of bankruptcy, makes a general assignment for the benefit of its creditors, becomes insolvent, or otherwise commences action for its winding up, reorganization, liquidation, or dissolution under any applicable law;

(ii) Contractor is in breach of the Confidentiality of Customer Data provision of this Agreement;

(iii) failure by the Contractor to perform its obligations under the Agreement as required or on a timely basis; and

(iv) breach of a condition of the Agreement by the Contractor.

(c) Without limiting the generality of the foregoing, each of the following specific events shall be deemed to be a Material Breach by InnServices granting the Contractor the right to terminate this Agreement pursuant to Article 10.4(a):

(i) InnServices is adjudged bankrupt, commits or threatens to commit an act of bankruptcy, makes a general assignment for the benefit of its creditors, becomes insolvent, or otherwise commences action for its winding up, reorganization, liquidation, or dissolution under any applicable law;

(ii) InnServices is in breach of the Confidentiality of Contractor Proprietary and Confidential Information provision of this Agreement; and

(iii) InnServices fails, without valid cause, to pay any amount owing to the Contractor within five (5) Business Days following written notice by the Contractor to InnServices that such amount is overdue.

(d) Upon termination of this Agreement for Material Breach all responsibilities and liabilities of the Parties to each other shall cease on the specified date of termination, except only any liability which accrued before the termination became effective and for for damages that may be assessed against the Party in Material Breach and for those responsibilities of each Party to the other with respect to the Termination Assistance provisions of this Agreement.

(e) On the termination of this Agreement for any reason, all payments required to be made to the Contractor by InnServices hereunder, shall be due and payable immediately.

10.5 Termination Assistance

(a) The Parties acknowledge the need for an orderly transfer of the Services to InnServices or another service provider on the termination of this Agreement. By notice in writing InnServices may require the Contractor to perform the Pre-termination Assistance Services and Post-Termination Assistance Services set out below.

(b) Pre-termination Assistance Services shall be provided by the Contractor during a period of up to three (3) months prior to the termination of this Agreement. Pre-termination Assistance Services include, but are not limited to:

(i) Notifying outside vendors of procedures to be followed during the transfer of Services to InnServices or a new service provider;

(ii) Reviewing Service Level requirements with InnServices or a new Services provider;

(iii) Providing procedural orientation to new operations staff;

(iv) Preparing a transition plan setting forth the respective tasks to be accomplished in connection with the orderly transition to InnServices or a new Services provider,

(v) Granting InnServices or a new Services provider a perpetual, non-transferable, non-exclusive license for the use of Contractor Software after the termination of this Agreement at the Contractor's then current license fees and other charges for the same;

(vi) Assisting InnServices or new Services provider in acquiring any necessary rights to third party software or documentation used by the Contractor for the provision of Services; and,

(vii) Assisting InnServices or new Services provider in engaging any third party services utilized by the Contractor to perform the Services.

(c) Post-termination Assistance Services shall be provided by the Contractor during a period of up to six (6) months following the termination of this Agreement. During this period the Contractor shall provide consulting services to InnServices or the new service provider as requested. The Contractor shall be paid its then current Hourly Billing Rates on a time and material basis for such services.

11.0 Ownership and Transfer of InnServices Data

11.1 In the event this Agreement is terminated or expires, the Parties agree that the Contractor will deliver to InnServices all InnServices Data and financial records within InnPower's possession that were created by InnPower in the performance of the Services, whether in paper or in electronic format, unless otherwise directed in writing by InnServices.

12.0 Indemnification

12.1 Contractor Indemnification

(a) The Contractor shall indemnify, defend, and hold harmless InnServices and its directors, officers, employees, servants, agents, successors, and assigns from any and all losses arising from or in connection with any claims of infringement made against InnServices for any patent, copyright, trade-mark, service mark, trade name, or other proprietary rights in regard to Contractor Software, Contractor Equipment or any other products or materials provided by the Contractor in the provision of Services; provided,

however, the Contractor shall not have any liability with respect to any claim based upon InnServices's modification of any such item or InnServices's combination, operation, or use of such item with an item or program not furnished by the Contractor.

(b) The Contractor agrees to indemnify, defend, and hold harmless InnServices, its directors, officers, employees, servants, agents, successors and assigns from and against any and all losses in connection with claims made by third parties against InnServices arising out the use or occupation, if any, of InnServices' premises by the Contractor or out of any acts or omissions of the Contractor in the performance of Services or the observance of its obligations under this Agreement.

12.2 InnServices Indemnification

(a) InnServices shall indemnify, defend, and hold harmless the Contractor, and its directors, officers, employees, agents, successors, and assigns from any and all losses arising from or in connection with any claims of infringement made against the Contractor for any patent, copyright, trade-mark, service mark, trade name, or similar proprietary rights in regard to InnServices Data, software, equipment or any other InnServices products or materials used in the provision of Services; provided, however, InnServices shall not have any liability with respect to any claim based upon the Contractor's modification of any such item or the Contractor's combination, operation, or use of such item with an item or program not furnished by InnServices.

(b) InnServices agrees to indemnify, defend, and hold harmless the Contractor, its directors, officers, employees, servants, agents, successors and assigns from and against any and all losses in connection with claims made by third parties against the Contractor, arising out of any acts or omissions of InnServices in the performance of its obligations under this Agreement.

12.3 Exclusive Remedy

The indemnities described above are the exclusive indemnities provided by each Party to the other under this Agreement. The indemnities shall not apply unless the Party against whom the claims are made provides the indemnifying Party with prompt written notice of such claim, grants the indemnifying Party authority to defend or settle the claims and provides all reasonable assistance to the indemnifying Party in defending or settling the claim.

13.0 Force Majeure

(a) Neither party shall be responsible for any delay or failure to perform its obligations under this Agreement where such delay or failure is due to fire, flood, explosion, war, embargo, governmental action, labour disruptionAct of Public Authority, Act of God, or to any other cause beyond its control, except labour disruption.

(b) In the event Force Majeure occurs, the party who is delayed or fails to perform shall give prompt notice to the other party and shall take all reasonable steps to eliminate the cause.

(c) Should the Force Majeure event last for longer than thirty (30) days, InnServices may terminate this Agreement by notice to the Contractor without further liability, expense or cost of any kind.

14.0 Insurance

14.1 General Liability

The Contractor shall effect prior to the commencement of the Services, and shall maintain and keep in force during the carrying out of the Contractor's Services under this Agreement, Comprehensive General Liability Insurance, naming InnServices as an additional insured, protecting both the Contractor and InnServices against claims for contractual liability, personal injury, bodily injury, death, property damage, or other third party or public liability claims arising from any accident or occurrence in respect of such services performed by the Contractor, in an amount not less than TEN MILLION DOLLARS ($10,000,000.00) in respect of any one accident or occurrence.

14.2 Automobile Liability

The Contractor shall effect prior to commencement of the Services, and shall maintain and keep in force during the carrying out of the Services, automobile liability insurance. Such policy shall protect the Contractor against all liability arising out of the use of owned and non-owned automobiles. The limits of the liability under this insurance policy shall be no less than TWO MILLION DOLLARS ($2,000,000.00) per occurrence.

15.0 Workers' Compensation

The Contractor shall obtain, maintain and pay for during the term of this Agreement Workers' Compensation insurance coverage covering all employees engaged in providing the Services.

16.0 Terms and Policies

16.1 The Contractor shall effect, and shall keep in force during the carrying out of its Services, naming jointly the Contractor and InnServices, any other form of insurance as InnServices may from time to time reasonably require.

16.2 In the event that InnServices requests that the amount of coverage be increased under any policy of insurance required to be effected under this section, the Contractor shall endeavour forthwith to obtain such increased coverage and InnServices shall pay for any additional cost thereof with written notice.

16.3 Any policies required to be effected by the Contractor shall, where available, contain a cross-liability and severability of interest clause.

16.4 The Contractor shall pay all premiums and costs of all insurance required to be effected by the Contractor under any provision of this Agreement, and shall, prior to commencing the Services, furnish to InnServices, upon request, a certificate of insurance and, where applicable, any renewal Agreement and other documents sufficient to show and establish accurately at all times the current status of policies in force, and in particular shall submit to InnServices, upon request, not later than fifteen (15) days before the expiration of every current policy evidence of the renewal of the policy or the issuance of a replacement policy and of the payment of all premiums due

for the renewal or replacement, and shall promptly notify InnServices of any cancellation or intended cancellation by any insurer of any policy or any circumstances known to the Contractor materially affecting its coverage. The Contractor should advise InnServices of any insurance carrier change but does not require prior approval to change carriers.

16.5 If the Contractor defaults on any of its obligations under this Agreement regarding insurance, InnServices may, but is not obliged to, place any insurance at the cost and expense of the Contractor, or pay any arrears of premium, and any expense incurred by InnServices, including deductible payments, shall be reimbursed to it by the Contractor on demand without prejudice to any other rights and remedies of InnServices under this Agreement.

17.0 Entire Agreement

17.1 This Agreement constitutes the entire Agreement between the Parties with respect to the subject matter hereof, and supersedes all previous agreements, arrangements, representations or understandings between the Parties whether written or oral, express or implied, in connection with, or incidental to, the Services.

18.0 Financial Audit

18.1 Authorized InnService officials may periodically inspect all relevant books, records, documents, and other information of the Contractor that strictly pertain to the Services for the purpose of evaluating the financial integrity and compliance of the Contractor, and the Services provided hereunder, to the terms and conditions of this Agreement and to the law. The Contractor shall grant authorized officials access to such books and records on a confidential basis, upon request and at all reasonable times upon at least seventy-two (72) hours' notice in writing to the Contractor, at the Contractor's premises or such other Contractor locations where such books, records or other information may be located.

19.0 Relationship of the Parties

19.1 (a) The Contractor expressly acknowledges that it is an independent contractor and no agency, partnership or employer-employee relationship is intended or created by this Agreement.

(b) The Contractor shall be solely responsible for all matters relating to statutory deduction of all taxes, employment insurance and Canada Pension and all licenses and permits which may be or become required to perform its services.

(c) The Contractor shall be solely responsible for all matters relating to leave, remuneration, Workers' Compensation, insurance premiums, discipline, and the health and safety of its own employees, agents and subcontractors.

20.0 Workplace Safety and Insurance Act

20.1 The Contractor shall furnish evidence of compliance with all requirements of the *Workplace Safety and Insurance Act, 1997*, S.O. 1997, c. 16, as amended, and its regulations passed thereunder. Such evidence shall include a certificate of good standing issued prior to commencement of the services under this Agreement.

21.0 Taxes

21.1 Unless otherwise stated, InnServices shall pay all applicable provincial and federal government sales taxes, known at the commencement of this Agreement, with respect to the Services carried out by the Contractor for InnServices under this Agreement.

22.0 Representations and Warranties

22.1 The Contractor warrants and represents to InnServices that:

(a) The Contractor is duly incorporated and has the legal authority to enter into this Agreement, provide the Services and undertake all obligations and responsibilities of the Contractor described hereunder. This Agreement has been duly authorized by all necessary corporate action by the Contractor and is a valid and binding obligation of each party, enforceable against it in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency and other legislation affecting creditors' rights generally;

(b) it shall perform, or cause to be performed, the Services and all other Contractor obligations under this Agreement honestly, in good faith, exercising reasonable skill, care and diligence, using personnel having a level of competence commensurate with the requirements, in accordance with the terms and conditions of this Agreement; and

(c) it shall comply with all applicable laws, statutes, ordinances, by-laws and regulations (collectively, "legislation") of all applicable governmental authorities.

22.2 InnServices warrants and represents to the Contractor that it is duly incorporated and has the legal authority to enter into this Agreement and undertake all of InnServices' obligations and responsibilities described hereunder. This Agreement has been duly authorized by all necessary corporate action and is a valid and binding obligation of InnServices, enforceable against it in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency and other legislation affecting creditors' rights generally.

22.3 Except as expressly stated in this Article 22.0, all representations and warranties, express or implied, by operation of law or otherwise are hereby excluded. Except as expressly stated herein, InnPower disclaims any and all express, implied or statutory warranties, including without limitation any implied warranties of merchantability or fitness for a particular purpose.

23.0 Dispute Resolution

23.1 (a) In the event of a dispute arising between InnServices and the Contractor in regard to the Services, the rights and duties of the Parties, or any other matter arising out of or connected with this Agreement (herein "Dispute"), both parties agree to use all reasonable efforts to resolve the Dispute, promptly and in a good faith manner by negotiation.

(b) In the event the Parties are unable to resolve the Dispute within twenty (20) Business Days from when the Dispute first arose, either Party may by written notice to the other Party submit the matter to a Dispute Resolution Committee made up of a maximum of three mutually agreeable members drawn from either party or externally selected. This informal Dispute Resolution Committee will convene a meeting and attempt to resolve the matter within fourteen (14) Business Days thereafter. If the Dispute Resolution Committee cannot resolve the Dispute within five (5) Business Days thereafter, either Party may by notice in writing to the other Party direct the matter to arbitration pursuant to the clause below.

(c) The arbitration shall be undertaken before a single arbitrator jointly appointed by the Parties. Upon appointment of the arbitrator, each Party shall forthwith submit its argument in writing and make oral argument should the arbitrator so require. The arbitrator shall make his or her decision and so advise the Parties in writing within sixty (60) days from the completion of the argument and hearing, if any. In so doing, the arbitrator shall be restricted to construing the terms of this Agreement. The arbitration award cannot under any circumstances exceed the remedies available under this Agreement. Each Party will bear its own costs of the arbitration and share equally the costs of the arbitrator, unless the arbitrator in its discretion, and pursuant to representations by the Parties, awards some or all of the costs of the arbitration to one of the Parties. The decision of the arbitrator shall be final and binding on both Parties. Any award by the arbitrator may be filed in court and enforced as a judgment of the court. All documents created in the course of or for the purposes of the mediation and arbitration, including the arbitration award, shall be kept completely confidential and shall not be disclosed by the Parties to any other party (excluding their respective counsel and advisors) without the prior written consent of the other Party. The dispute resolution committee and arbitration proceedings shall be undertaken in a location determined by the committee or the arbitrator, as applicable. The arbitration shall be governed by the arbitration rules and procedures of the then current *Arbitration Act* of Ontario.

23.2 Notwithstanding Articles 23.1 and 23.2, neither Party is precluded from seeking from a court of competent jurisdiction interim relief, including injunctive relief, when the subject matter of the Dispute may require.

24.0 Notice

24.1 Any notice required or permitted to be given under this Agreement may be given personally or by prepaid first class mail (in which case receipt shall be deemed to have occurred five (5) clear days after the mailing thereof) or via facsimile (in which case receipt shall be deemed to have occurred one day after transmission). Notice to the parties shall be delivered at the following address or fax numbers:

InnServices: InnServices Utilities Inc.
2101 Innisfil Beach Road
Innisfil, ON, L9S 1A1

Fax: 705-436-7120

Contractor: InnPower Corporation
7251 Yonge Street
Innisfil, ON, L9S 0J3

Fax: 705-431-5901

In the case of InnServices, the Notice shall be directed to the attention of the President and Chief Executive Officer. In the case of the Contractor, the Notices shall be addressed to the Vice-President of Corporate Services.

25.0 Confidentiality of InnServices Data

25.1 The Contractor shall not at any time before, during or after the completion of the Services, access, use or disclose any InnServices Data, or copies, notes and records reflecting such InnServices Data, for any purpose other than the purpose for which it was provided hereunder, without the prior written consent of InnServices. InnServices Data shall not be reproduced in any form except as required by the Contractor to perform its obligations under this Agreement. Any such reproduction shall remain the property of InnServices. To this end, the Contractor shall use all reasonable means to keep InnServices Data to which it has access confidential. It shall not access, use or disclose InnServices Data, other than to provide the Service hereunder. Notwithstanding the above, the Contractor shall not be responsible or otherwise liable for wrongful access to, use or disclosure of InnServices Data demonstrated by the Contractor to be in the public domain; or required by law to be disclosed.

26.0 Confidentiality of Contractor Proprietary and Confidential Information

26.1 InnServices shall use all reasonable means to maintain the confidentiality of Contractor Proprietary and Confidential Information. It shall not access, use or disclose Contractor Proprietary and Confidential Information for any purpose other than the purpose for which it was provided by InnPower hereunder, without the prior written consent of InnPower. Such Confidential Information shall not be reproduced by InnServices in any format, except as required by InnServices to perform its obligations under this Agreement. Any such reproduction shall remain the property of the Contractor. Notwithstanding the above, InnServices shall not be responsible or otherwise liable for wrongful access to, use or disclosure of Contractor Proprietary and Confidential Information that was known or independently developed by InnServices prior to its disclosure; demonstrated by InnServices to be lawfully in the public domain through no wrongful act of InnServices; or required to be disclosed pursuant to a legal order, provided that InnServices shall give the Contractor prompt notice of such requirement for disclosure and permit the Contractor to undertake any available appeal procedures to limit or reverse the order.

27.0 Intellectual Property

27.1 All right, title, and interest (including all rights of copyright) to all preexisting ideas, concepts, know-how, data-processing techniques, software, documentation, diagrams, schematics or blueprints provided by the Contractor under this Agreement shall reside exclusively with the Contractor. The Contractor grants to InnServices a non-exclusive, royalty-free license to use the same solely in support of the delivery of Services. InnServices may not otherwise use, copy, or disclose any of such ideas, concepts,

know-how, data-processing techniques, software, documentation, diagrams schematics or blueprints without the prior written consent of the Contractor.

27.2 All right, title, and interest (including all rights of copyright) to all ideas, concepts, know-how, data-processing techniques, software, documentation, diagrams, schematics or blueprints developed by Contractor personnel alone under this Agreement shall reside exclusively with the Contractor. The Contractor grants to InnServices a non-exclusive, royalty-free license to use the same solely in support of the delivery of Services. InnServices may not otherwise use, copy, or disclose any of such ideas, concepts, know-how, data-processing techniques, software, documentation, diagrams schematics or blueprints without the prior written consent of the Contractor.

27.3 All right, title, and interest (including all rights of copyright) to all ideas, concepts, know-how, data-processing techniques, software, documentation, diagrams, schematics or blueprints developed jointly by Contractor and Customer personnel under this Agreement shall be jointly owned by the Parties as tenants in common. Each Party shall have the unrestricted right to, and to authorize others to, use, produce, reproduce, transfer, convey, publish, license, commercially exploit, develop derivative works based upon, and otherwise deal with the same and to enforce such participant's intellectual property rights against third parties, without the consent of the other Party.

28.0 Liability

28.1 Subject to subsection 28.2, the liability of the Contractor to InnServices in damages for any breach of this Agreement, regardless of the basis of the claim, including, without limitation, any claim in tort or of fundamental breach of contract, shall be direct damages only in an amount not to exceed two (2) months of Fees. In no event shall either Party be liable to the other Party for indirect, incidental, special, or consequential damages, or damages for or lost profits or revenues relating to the Services or any breach of this Agreement, even if it has been informed of the possibility thereof.

28.2 The limitation on damages described in Article 28.1 shall not apply to:

(a) claims for bodily injury, death, or damage to real property or tangible personal property for which the Contractor or any of its subcontractors is responsible; or

(b) Contractor indemnities described in Articles 12.2(a) and 12.2(b).

29.0 Further Assistance

29.1 The Contractor and InnServices agree that each of them shall and will, upon reasonable request of the other, make, do, execute, or cause to be made, done or executed, all such further and other lawful acts, deeds, things, devices and assurances whatsoever necessary to give effect to this Agreement.

30.0 Severability

30.1 In the event that any of the terms, conditions or provisions contained in this Agreement shall be determined invalid, unlawful or unenforceable to any extent, such terms, conditions, or provisions shall be severed from the remaining terms, conditions and provisions, which shall continue to be valid to the fullest extent permitted by law.

31.0 Waiver

31.1 The failure by either Party to insist in one or more instances upon the performance by the other Party of any term or terms of this Agreement shall not be construed as a waiver of future performance of any such term or terms and the obligation of the other Party with respect to such a future performance shall continue in full force and effect.

32.0 Survival

32.1 Those provisions of this Agreement, which by their terms, are intended to survive, or which must survive in order to give effect to continuing obligations of the Parties, shall survive the termination of this Agreement. Without restricting the generality of the foregoing, the Parties agree that the following provisions shall survive termination of the Agreement: Articles 10.5, 11.1, 12,1, 12.2, 25, 26, 27 and 28.

33.0 General

33.1 The Agreement and the Services shall be governed under and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable thereto.

33.2 Words used in the Agreement importing the singular number or the one gender only, include more persons, parties or things of the same kind than one, and females as well as males and the converse.

33.3 This Agreement constitutes the entire agreement between the Parties and can only be changed by mutual agreement in writing signed by the Parties.

33.4 The Contractor shall not subcontract or assign its obligation or rights under this Agreement without the written consent of InnServices, which will not be unreasonably withheld. InnServices may assign this Agreement or any of its rights or obligations hereunder to its parent company, or to an affiliate as that term is defined in the *Ontario Business Corporation Act,* upon notice in writing to the Contractor.

33.5 This Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and permitted assigns.

IN WITNESS WHEREOF the Parties have executed this Agreement by their proper officers and the individual parties have hereunto set their hands and seals, at the times and places indicated:

SIGNED AND SEALED)
)
This 15th day of April) Per: _____
) Andy Campbell, President & CEO
)
)
2016, at Innisfil) Per: _____
) Jason Reynar, Chair
Province of Ontario)

INNSERVICES UTILITIES INC.

SIGNED AND SEALED	)	INNPOWER CORPORATION
	)	
This 15th day of April	)	Per: _____
	)	Wade Morris, Acting President & CEO
	)	
	)	
2016, at Innisfil	)	Per: _____
	)	Jason Reynar, Chair
Province of Ontario	)	

SCHEDULE A

Description of the Services

The Contractor will provide general accounting, financial reporting and employee payroll administration services, including record-keeping, for the following functions: accounts payable, accounts receivable, payroll, treasury, together with such other financial services as may be mutually agreed to by the Parties, as more particularly described in Schedule A (Description of Services), all in accordance with generally accepted accounting principles and International Financial Reporting Standards. For greater certainty, the description in this Schedule A is deemed to include all services, functions and responsibilities that are inherent, necessary or customarily provided as part of the services described in this Schedule A or which are reasonably required for the proper performance of such services.

InnServices has appointed the Chief Financial Officer of InnPower as the Chief Financial Officer for InnServices. The Chief Financial Officer is to perform all regulatory and fiduciary responsibilities as an Officer of InnServices.

SCHEDULE "A"

CFO

- Responsible for complete, accurate and timely financial statements for the President, Board of Directors, auditors, financial institutions, management team, and other regulatory bodies in accordance with Financial Reporting requirements of the CICA Handbook.
- Develop and coordinate the preparation of corporate operating and capital budgets and forecasts. Oversee and monitor the administration of the approved budgets. Oversee financial related audits of the Corporation's financial and accounting processes in consultation with external auditors and implementation of recommendations from audits.
- Develop, review and authorize departmental policies and procedures for the accounting and financial procedures to ensure appropriate accounting principles, practices and Corporate goals.
- Responsible for safeguarding of the financial records.
- Responsible for the Treasury functions for the Corporations as required such as banking and lending relations, short and long term financing agreements and cash management.
- Respond to inquiries from the public, staff, businesses, government and other regulatory bodies with regard to corporate financials/accounting/taxation matters.
- Establish and maintain appropriate internal control safeguards. Review, evaluate and recommend internal financial controls.
- Oversee and authorize payment of invoices per Financial Policies and Procedures.
- Approve and coordinate changes and improvements in automated financial and accounting information systems to ensure maximum abilities are realized.
- Review and provide financial management perspective on all contracts into which the Corporations are evaluating.
- Execute deeds, transfer, assignments, contracts and obligations on behalf of the Board of Directors.

Financial Analyst

- Organize and draft the monthly, quarterly and annual financial statements for review, in accordance with Financial Reporting requirements of the CICA Handbook.
- Assist the CFO with the preparation for the annual audit.
- Prepare the monthly reconciliation of financial records, resolving discrepancies through analysis.
- Prepare monthly inventory analysis.
- Assist in the preparation of reports/analysis for various departments as required.
- Assist with government agency reporting and communication to ensure filing compliance with tax and regulatory requirements.

- Compile and prepare monthly financial reports, conduct research and prepare supporting analysis for management review and to support departmental goals.
- Process the additions, dispositions, capital contributions and depreciation within the general ledger and sub ledger and prepare the Capital Asset continuity schedules.
- Assist the CFO with the preparation of the annual and strategic budgets.
- Develop, construct, update and maintain reports for multiple departments, effectively utilizing various databases and reporting software.

Payroll

- Manage all aspects of payroll function, including setting up new hires, requesting ROEs, updating employee rate/salary changes, etc., by liaising with appropriate parties. Administrator for Penny time reporting software.
- Prepare various reports on employment data as requested or needed by management or staff, such as vacation, sick days, leave of absences, benefits or compensation costs and statistics and forecasts and performance evaluation.
- Process bi-weekly payroll, including payroll-related updates in Great Plains and Penny.
- Process bi-weekly payroll and human resources information within Ceridian InSync software package, including reconciliation with Great Plains.
- Prepare monthly payroll remittances, i.e. pension, WSIB, Union dues, etc.

IT

- Network administration including backup, security management, user account management, e-mail systems, internet access, office systems and applications support, phone systems and security systems.
- Implement, maintain and support the network and computing infrastructure including network switches, firewalls, network appliances, cabling and connections.
- Support and maintain physical and virtual servers, printers and desktop hardware, software and applications.
- Coordinate, and implement network security measures in order to protect data, software, and hardware.
- Implement, document and provide training where applicable for new hardware and software to ensure optimal deployment of resources.
- Liaise with third party hardware and software support personnel as required.
- Maintain adequate on-site and off-site backups.

Purchasing

- Purchasing functions as they may relate or be required pertaining to the administration of all of the above services.