Ontario Energy Board
Commission de l'Énergie de l'Ontario

Application for Electricity Distribution Licence

Ontario Energy Board
2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4
Telephone: 1-888-632-6273
Facsimile: (416) 440-7656

Commission de l'Énergie de l'Ontario
2300 rue Yonge
C.P. 2319
Toronto, ON M4P 1E4
Téléphone: 1-888-632-6273
Télécopieur: (416) 440-7656

Application Instructions

1. Purpose of this form

The purpose of this form is to collect information to determine whether the Applicant will be granted a licence to distribute electricity.

2. Structure of the Application Form

This form contains the following sections:
- A General Information;
- B Distribution Facilities Information;
- C Supporting Information
- D Notice and Consent and
- E Acknowledgement

Note: The information in section C16 shall be kept confidential, with the exception of names and positions held of key individuals. All other information filed as part of this application will be considered public. Where the applicant objects to public disclosure of the information, the applicant must follow the Ontario Energy Board's approved Guidelines for Treatment of Filing made in Confidence, effective March19, 2001.

3. Completion Instructions

PRINT CLEARLY or TYPE all information in BLACK. Please send two copies of the completed form and all attachments to:

Board Secretary
Ontario Energy Board
2300 Yonge Street
P.O. Box 2319, 26th Floor
Toronto, ON M4P 1E4

4. Licence Fees:

A non-refundable application fee is required to process your application. Please enclose a cheque or money order made payable to the **ONTARIO ENERGY BOARD**.

Note: If a licence is issued, the Licensee will be required to pay an annual fee of $800.00.

5. Important Information:

As a licenced Electricity Distributor, the licencee may be subject to additional obligations as required by the Independent Electricity System Operator (IESO) and as established under section 70 or section 78 of the *Ontario Energy Board Act, 1998.*

REMARQUE:
Ce document est disponible en français.

OEB App05A - July/05

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For Office Use Only	
Application Number	
Date Received	

A. General information

1. Type of Application

- New licence ☑
- Renewal ☐
- Amendment to an existing Licence ☐

2. Ownership/Operation

Please indicate whether the Application is for:

☑ Ownership and Operation of a distribution system

This application is being made in conjunction with a "MAADs" application to the OEB under s.86 of the Ontario Energy Board Act, 1998, as amended, for the relief necessary to effect the amalgamation of Veridian Connections Inc. (OEB Distributor Licence ED-2002-0503) and Whitby Hydro Electric Corporation (OEB Distributor Licence ED-2002-0571) into a single licensed, rate regulated electricity distributor that will serve over 163,000 customers. As part of the MAADs application, the two consolidating utilities are requesting that the OEB transfer their existing Distributor licences to the new, consolidated distributor (referred to in the MAADs application as "LDC Mergeco").

☐ Ownership of a distribution system only. Please provide the name and licence no., if any, of the operator of the distribution system?

☐ Operation of a distribution system only. Please provide the name and licence no., if any, of the owner of the distribution system?

3. Applicant

Please provide the following information about the Applicant:			
Full Legal Name of Applicant LDC Mergeco (Legal name to be determined)		Ontario Corporation Number, Canadian Corporation Number or Business Registration Number Will be available within thirty days following receipt of OEB approval for the proposed amalgamation.	Date of Formation or Incorporation Within thirty days following receipt of OEB approval for the proposed amalgamation
Business Address: Will be either 55 Taunton Road East, Ajax or 100 Taunton Road East Whitby. A decision on the business address will be available within thirty days following receipt of OEB approval for the proposed amalgamation.			
City see above	Province Ontario	Country Canada	Postal/Zip Code
Phone Number	FAX Number	E-Mail Address (if applicable)	

4. Primary Contact for this Application

Please provide the following information about the Primary Contact for this Application: See Section 4 Attachment			
Mr. ☒ Mrs. ☐ Miss ☐ Ms. ☐ Other: ________	Last Name:	Full First Name:	Initial:
	Position Held:		
Contact Address (if R.R., give Lot, Concession No. and Township)			
City	Province	Country	Postal/Zip Code
Phone Number	FAX Number	E-mail Address (if applicable)	

5. Service Area

Please indicate the location (name of municipality or unorganized territory) of the Applicant's distribution facilities and provide a description of the extent (size, length, coverage) of the distribution facilities involved in this Application. This description will be used for the purpose of stating a service area in which the licensee would be authorized to distribute electricity:

LDC Mergeco's service area will consist of the current service areas of Veridian Connections Inc. ("Veridian LDC", OEB Distributor Licence ED-2002-0503) and Whitby Hydro Electric Corporation ("Whitby LDC", OEB Distributor Licence ED-2002-0571). A copy of Schedule 1 to each of the above distribution licences is attached at Section 5 Attachment. Together, these two schedules denote the distribution service area of LDC Mergeco.

6. Facilities Use

Please indicate whether the distribution facilities are for exclusive use by the Applicant.	Yes	No
	☑	☐

B. Distribution Facilities Information

7. Facilities Type

Please indicate whether the Applicant's distribution facilities are:

☐ New assets to be constructed? Proposed In-service date: ______________________

If Applicant is to be the owner, please attach a statement explaining the financing arrangements.

☑ Existing assets presently owned and/or operated by the Applicant?

LDC Mergeco's distribution facilities will be comprised of the existing assets of Veridian LDC and Whitby LDC.

☐ Existing assets not presently owned and/or operated by the Applicant (ie to be purchased)?

If Applicant is to be the owner please indicate: *LDC Mergeco's distribution facilities will be comprised of the existing assets of Veridian LDC and Whitby LDC.*

a) from whom assets will be purchased:

b) when application for sale has/will be filed with the Board?

☐ Other (please describe):

8. Facilities Purpose

Please indicate the intended purpose(s) of the Applicant's distribution facilities:

- [x] To provide a connection between a generator and a transmission/distribution system.
- [x] To provide a connection between a transmission/distribution system and a load customer or customers.
- [x] To provide a connection between a generator and a load customer or customers.
- [x] To provide distribution services to the general public.
- [ ] Other (please describe):

9. Description of Facilities

Please describe the Applicant's distribution facilities indicating operating voltage(s) (kV), length of distribution line (km), number of substations and approximate total supply capacity (MW):

Veridian LDC is serviced by 10 Hydro One-owned transformer stations and 5 Hydro One-owned distribution substations. Veridian LDC is supplied from 188 sub-transmission and distribution feeders: 29 at 44 kV, 11 at 27.6 kV, 66 at 13.8 kV, 13 at 12.47kV, 6 at 8.32kV and 63 at 4.16 kV. Veridian LDC owns and operates 1 regulator station and 50 municipal substations with a combined transformation capacity of 529.5 MVA of which 3 MVA is provided at 600V, 124.5 MVA is provided at 4.16 kV, 5 MVA is provided at 8.32 kV, 7.5 MVA at 12.47kV, 369.5 MVA at 13.8 kV and 20 MVA at 27.6kV. Power is distributed across 2,634 circuit-length-km of line (4955 conductor-length-km); 1,168 circuit-length-km (1,599 conductor-length-km) of which are installed underground with the remainder 1,466 circuit-length-km (3,356 conductor-length-km) carried on 30,046 Veridian LDC-owned poles.

Whitby LDC is serviced by 3 Hydro One-owned transformer stations (Whitby TS DESN 1, and DESN2 and Thornton TS). Whitby LDC is supplied from 50 sub-transmission and distribution feeders: 13 at 44 kV and 37 at 13.8 kV. Whitby LDC owns and operates 11 municipal substations with combined transformation capacity of 294 MVA and provided at 13.8 kV. Power is distributed across 1,104 circuit-length-km of line (2,118 conductor-length-km); 599 circuit-length-km (827 conductor-length-km) of which are installed underground with the remaining 505circuit-length-km (1,291 conductor-length-km) carried on 8,057 Whitby LDC-owned poles.

10. Location of Facilities

Please indicate whether the distribution facilities will be located on, over or under public streets or highways.	Yes	No
	☑	☐

C. Supporting Information Organizational Information

11. Business Classification

Sole Proprietor	☐
Partnership	☐
Corporation	☑
Other	☐

12. Affiliates of the Applicant

a) Please provide the following information for all Affiliates of the Applicant (attach a copy of 12(a) for each affiliate).

Full Legal Name of Affiliate Company:
Merged Holdco (to be named later) (Merged Holdco will be the holding company of the Applicant), Veridian Energy Inc., Whitby Hydro Energy Services Corporation, Quinte Solar Generation Inc.

Business Address:

City	Province	Country	Postal/Zip Code

Tel. Number	FAX Number	E-Mail Address (if applicable)

Description of Business Activities:

Please see Section 12(a) Attachment.

b) Please attach a Corporate organization chart describing the relationships between the Applicant and its Affiliates and, if applicable, the respective ownership percentages by the Applicant in each Affiliate.
Please see Section 12(b) Attachment

13. Energy Sector Activities

Has the Applicant or an Affiliate undertaken any energy sector activities in Ontario or any other jurisdiction? If yes, please provide the following information for each:	Yes ☑ No ☐
Full Legal Name of Company: Please see Section 13 Attachment	Licence/Registration Number:
Jurisdiction: Ontario (primary) May service clients in other locations	Type of Business Activity (e.g. Generation, Transmission, Distribution):

Technical Capability and Experience Information

14. Business Activities

Please provide a description of the Applicant's business activities:

Electricity distribution in the service areas identified in the distribution licences of Veridian Connections Inc. and Whitby Hydro Electric Corporation. Please see Section 5.

15. Technical Ability

a) Please describe the applicant's technical ability to carry out the activities applied for including the Applicant's specific experience in Ontario and in other jurisdictions.

The Applicant is the distributor that will be created by the consolidation of Veridian LDC and Whitby LDC. These predecessor LDCs of LDC Mergeco have operated as electricity distributors in Ontario for many years, and both hold OEB licences in good standing. LDC Mergeco intends to continue providing reliable and high quality distribution services with employees transferred from its predecessor companies. In respect of the functions identified below, like the utilities which merged to form LDC Mergeco, the Applicant will continue to use its own staffing resources to undertake most of these functions. Where a decision is made to engage an outside vendor or contractor to undertake all or any part of these functions, LDC Mergeco will apply its policy of only engaging duly qualified and experienced vendors and contractors pursuant to its procurement policy.

b) If the Applicant intends to utilize the capability of others by contracting distribution activities, please indicate below which activities and to whom they will be contracted:

☑ Design	Contracted to:
☑ Construction	Contracted to:
☑ Inspection & Maintenance	Contracted to:
☑ Operation	Contracted to:
☑ Customer Connection	Contracted to:
☐ Standard Supply Service	Contracted to:
☑ Metering & Metering Services	Contracted to:
☑ Settlement & Billing	Contracted to:
☐ Other (describe):	Contracted to:

16. Information About Each Key Individual

Mr. ☐ Mrs. ☐ Miss ☐ Ms. ☐ Other: see below	Last Name:	Full First Name:	Initial:
	Position Held:		

Please explain the person's experience in the electrical distribution business and in the energy field in general.

Veridian Connections Inc. - Officers:
Michael Angemeer, President & CEO/ Rob Scarffe, Executive Vice President, Customer Service & Information Technology/ Laurie McLorg, Vice President, Financial Services & CFO/George Armstrong, Vice President, Corporate Services/Peter Petriw, Vice President, Engineering/Adrian Foster, Board Chair/Kevin Ashe, Board Vice Chair
Whitby Hydro Electric Corporation - Officers:
John Sanderson, President & CEO/Ramona Abi-Rashed, Treasurer/Mike Chase, Deputy Treasurer/Susan Reffle, Vice-President

a) Has this person been a proprietor, partner, officer or director of a business that was granted a licence under Part IV or Part V of the *Ontario Energy Board Act, 1998.* Yes ☐ No ☐

If yes, provide business names and licence number(s) and describe the individuals specific related experience.

Please see Section 16 Attachment.

b) Has this person been a proprietor, partner, officer, or director of a business that was registered or licenced under this or any other acts or legislation? Yes ☐ No ☐

If yes, identify the business name, the legislation, licence number(s), date of the licencing or registration and the individual's specific related experience.

Please see Section 16 Attachment.

c) Has this person been a proprietor, partner, officer or director of a business that had a registration or licence of any kind refused, suspended, revoked or cancelled? Yes ☐ No ☐

If yes, please provide company name and describe the situation, including the jurisdiction and type of licence.

Please see Section 16 Attachment.

Note:
Attach a copy of Item 16 for each Key Individual: Officer and Director, Partner or sole Proprietor.

Financial Information

17. Financial Statements

Please attach financial statements of the Applicant for each of the past two fiscal years. This may include audited financial statements, annual reports, prospectuses or other such information. Please see Section 17 Attachment.

Other Information

18. Delivery

Please indicate whether the Applicant's distribution facilities are to be used to deliver electricity to one or more parties other than the Applicant. If yes, please provide the following information:

Yes ☑ No ☐

a) if the purpose of the Applicant's distribution facilities is to provide distribution services to specific generators or load customers rather than the general public (see question #8) please indicate the names of these participants:

Not applicable

b) a summary of the business plans relating to the Applicant's proposed distribution business for the next five years. This should include the following:

- a forecast of annual growth in terms of factors such as the amount of electricity distributed (MW and/or MWH), number of customers served, amount of distribution facilities (lines and/or stations), etc.
- annual pro forma financial statements including forecasts of costs, revenues and project financing indicating the underlying assumptions on which the forecasts are based.

c) estimates of net annual cash flows for subsequent periods to demonstrate financial feasibility and security.

Please see Section 18(c) Attachment.

d) indication of the Applicant's plans to seek Ontario Energy Board approval for electricity distribution rates.

In the MAADs application, the Applicants have indicated that they will be deferring rebasing for a period of 10 years from the completion of the consolidation. During the rebasing deferral period, LDC Mergeco will be applying for approval of rates in a manner applicable to each of the predecessor distributors. More particularly

- the Veridian LDC service areas will be the subject of Price Cap Incentive Rate-Setting rate applications through the rebasing deferral period
- the Whitby LDC service area will be the subject of Annual Incentive Rate-Setting Index rate applications through the rebasing deferral period

19. Proposed Business Transactions

Please provide a brief summary of the expected impact of the proposed business transactions on the Ontario electricity market under the following headings:

a) Facilitate competition and enhance access to transmission/distribution services:

The proposed transaction related to this Application is the consolidation of two existing licensed electricity distributors. The proposed transaction will have no adverse impact on competition, nor will it have an adverse impact on access to distribution services.

b) Improve reliability and quality of supply:

The proposed transaction will have no adverse impact on reliability and quality of supply. Moreover, the consolidation proposed in the MAADs application will create opportunities for the improvement of existing reliability and quality of supply.

c) Promote economic and energy efficiency:

The Applicant anticipates that the proposed transaction will promote economic and energy efficiency. The consolidation of the two existing distributors will create opportunities for improved efficiency in the distribution of electricity in the predecessor distributors' service areas, and more opportunities for the promotion of energy efficiency and conservation in those areas.

20. Electricity Sector Activities

Please indicate whether the Applicant intends to be involved with electricity sector activities in the Ontario market other than distribution and provision of Standard Supply Service?

	Yes	No
Buy or Sell (Wholesale) electricity	☐	☐
Transmit electricity	☐	☐
Retail electricity	☐	☐
Generate electricity	☑	☐

If yes to any of the above:

a) If affiliates have not yet been established, please indicate when this is planned: __________

Please see Section 12.

b) Has the Applicant or an affiliate applied for Ontario Energy Board Licences? If no, when planned? ______________________________ ________	Yes ☐ No ☑

D. Notice and Consent for Ontario Board to Collect Additional Information

AS REQUIRED BY THE FREEDOM OF INFORMATION AND PROTECTION OF INDIVIDUAL PRIVACY ACT

In order to complete or verify the information provided on this form, it may be necessary for the Ontario Energy Board to collect additional information from some or all of the following sources: federal, provincial/state and municipal governments; licensing bodies; banks; professional and industry associations; and former and current employers. **Only information relevant to your application will be collected.**

The public official who can answer questions about the collection of information is:

Board Secretary
Ontario Energy Board
2300 Yonge Street, P.O. Box 2319
Toronto, Ontario M4P 1E4

Note: The issuance of an electricity distribution licence does not guarantee accreditation by the IESO, or connection to a transmission or distribution system.

NOTE: This application must be signed by the proprietor or by at least one partner, officer or director of the organization..

WARNING: It is an offence to knowingly provide false information on this application.

	Yes
I/We consent to the collection of this information as authorized under the *Ontario Energy Board Act, 1998.*	☑
I/We understand that this information will be used to determine whether I am/we are and remain qualified for the licence for which I am/we are applying.	☑

Print Name and Title	Signature of Applicant(s)	Date Signed
John Sanderson President & C.E.O Whitby Hydro Electric Corporation	JSanderson	Nov 2, 2018

E. Acknowledgement of Market Rules, Codes and Conditions

NOTE: This acknowledgement must be signed by the proprietor or by at least one partner, officer or director of the organization.

I understand and acknowledge that, as a licenced electricity distributor, I will be required, unless otherwise exempted:

- To provide non-discriminatory access to all persons wishing to connect to the distribution system.
- To comply with all licence conditions including the provisions of:
  - Affiliate Relationships Code for Electricity Distributors and Transmitters
  - Distribution System Code
  - Retail Settlement Code
  - Standard Supply Service Code
  - Retail Metering Code
  - Market Rules made under section 32 of the *Electricity Act, 1998.*

Print Name and Title	Signature of Applicant(s)	Date Signed
Michael Angemeer President & C.E. O. Veridian Connections Inc.		

Print Name and Title	Signature of Applicant(s)	Date Signed
John Sanderson President & C.E.O. Whitby Hydro Electric Corporation	J Sanderson	Nov 2, 2018

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- To provide non-discriminatory access to all persons wishing to connect to the distribution system.
- To comply with all licence conditions including the provisions of:
  - Affiliate Relationships Code for Electricity Distributors and Transmitters
  - Distribution System Code
  - Retail Settlement Code
  - Standard Supply Service Code
  - Retail Metering Code
  - Market Rules made under section 32 of the *Electricity Act, 1998.*

Print Name and Title	Signature of Applicant(s)	Date Signed
Michael Angemeer President & C.E. O. Veridian Connections Inc.	M. C. Angemeer	Nov. 5, 2018

Print Name and Title	Signature of Applicant(s)	Date Signed
John Sanderson President & C.E.O. Whitby Hydro Electric Corporation		

CHECKLIST

Have You:

1.	Properly and fully completed this form? (Illegible, incomplete or improperly completed forms do not qualify for registration and will be delayed or returned.)	☐
2.	Enclosed a cheque or money order payable to the **ONTARIO ENERGY BOARD** in the amount prescribed?	☐
3.	Attached Section D, the signed "Notice and Consent" form, as specified?	☐
4.	Attached Section E, the "Acknowledgement" form, as specified?	☐
5.	Submitted two copies of the application?	☐

Please send the completed form and all attachments to:

Board Secretary
Ontario Energy Board
2300 Yonge Street
P.O. Box 2319 , 26th Floor
Toronto, ON M4P 1E4

NOTE: You are not required to return the cover page or this checklist to the Ontario Energy Board.

TAB 4

SECTION 4 ATTACHMENT

Primary Contacts for this Application:

Mr. George Armstrong
Vice President, Corporate Services
Veridian Connections Inc.
55 Taunton Road East
Ajax, ON
L1T 3V3
garmstrong@veridian.on.ca
905-427-9870, ext. 2202

Ms. Susan Reffle
Vice President
Whitby Hydro Electric Corporation
100 Taunton Road East, P.O. Box 59
Whitby, ON
L1N 5R8
sreffle@whitbyhydro.on.ca
905-444-1983

TAB 5

SECTION 5 ATTACHMENT

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence.

Index

Service Area Descriptions **Page**

Reference Maps

AJAX/PICKERING SERVICE AREA

The alpha-numeric point numbers below refer to the reference map provided on page 30 of this document.

WESTERN BOUNDARY

1. Point #1 is located at the mouth of the Rouge River. The boundary proceeds in a north-westerly direction along the Rouge River to where it intersects with the straight-line projection of the York-Durham Town Line.

1A. Point # 1A located at the intersection of the Rouge River and the straight-line projection of the York-Durham Town Line. The boundary continues north to point # 2 with the exception of the excursions noted in the tables below. Veridian points 1B to 1H are seven excursions taking in the six registered parcels of land and one streetlight installation as detailed in the following table. These seven excursions are to be included in Veridian's Service Area.

Veridian Point No.	Municipal Address, Town of Markham	Legal Description
1B	7917 Major Mackenzie Drive E	Lot 20, Con. 10, Markham, as in MA80925
1C	9992 York-Durham Town Line	Lot 20, Con. 10, Markham, as in MA80925
1D	11410 York-Durham Town Line	Lot 29, Con. 10, Markham; Lot 30, Con. 10, Markham
1E	11584 York-Durham Town Line	Pt. Lot 31, Con. 10, Markham, Pt. 1, 65R-20217
1F	11290 York-Durham Town Line	Lot 29, Con. 10, Markham, Lot 30, Con. 10, Markham
1G	11350 York-Durham Town Line	Lot 29, Con. 10, Markham, Lot 30, Con. 10, Markham
1H	Streetlight at Major Mackenzie Drive East and York-Durham Town Line	Not applicable

Veridian points 1J to 1K are two excursions taking in the two registered parcels of land as detailed in the following table. These two excursions are to be excluded from Veridian's Service Area.

Veridian Point No.	Municipal Address, City of Pickering	Legal Description
1J	5293 York-Durham Town Line	Pt. Lot 35, Con 9 Pickering, Pt. 1, 40R-18594
1K	5295 York-Durham Town Line	Pt. Lot 35, Con 9 Pickering, Pt. 1, 40R-18594

NORTHERN BOUNDARY

2. Point # 2 is located at the intersection of the York-Durham Town Line and the Uxbridge Pickering Town Line also known as the 10th Concession Road Allowance. The boundary turns easterly and follows in a straight line along this Town Line/Road Allowance to Point #3 with the exception of the excursions noted in the tables below. Veridian points 2A to 2H are eight excursions taking in the eight registered parcels of land as detailed in the following table. These eight excursions are to be included in Veridian's Service Area.

Veridian Point No.	Municipal Address, City of Pickering	Legal Description
2A	132 Uxbridge Pickering Town Line	Part Lot 1, Con. 1 Uxbridge, Pts. 1, 2 & 3, 40R-11119
2B	152 Uxbridge Pickering Town Line	Part Lot 1, Con. 1 Uxbridge as in D526884
2C	160 Uxbridge Pickering Town Line	Part Lot 1, Con. 1 Uxbridge as in D94345
2D	168 Uxbridge Pickering Town Line	Part Lot 1, Con. 1 Uxbridge, as in D528307
2E	174 Uxbridge Pickering Town Line	Part Lots 1 & 2, Con. Uxbridge, as in D160902
2F	176 Uxbridge Pickering Town Line	Pt. Lots 1 & 2, Con 1 Uxbridge, Pts. 1 & 2, 40R-5246
2G	190 Uxbridge Pickering Town Line	Pt. Lots 1, 2, 3, 4 & 5, Con. 1, Uxbridge, Pt. 1, 40R-5742
2H	192 Uxbridge Pickering Town Line	Pt. Lots 1, 2, 3, 4 & 5, Con. 1, Uxbridge, Pt. 1, 40R-5742

Veridian points 2J to 2Q are 8 excursions taking in the 8 registered parcels of land as detailed in the following table. These seven excursions are to be excluded from Veridian's Service Area.

Veridian Point No.	Municipal Address, City of Pickering	Legal Description
2J	1775 Uxbridge Pickering Town Line	Pt. Lot 18, Con 9 Pickering, as in D468835
2K	1935 Uxbridge Pickering Town Line	Pt. Lot 18, Con 9 Pickering, as in D468835
2L	1995 Uxbridge Pickering Town Line	Pt. Lots 15 & 16, Con 9 Pickering, Pts. 1, 2, 4 & 5, 40R-24662

2M	2045 Uxbridge Pickering Town Line	Pt. Lot 15, Con. 9 Pickering
2N	2195 Uxbridge Pickering Town Line	Pt. Lot 14, Con 9 Pickering as in D203854
2O	2265 Uxbridge Pickering Town Line	Pt. of N Pt. Lot 13, Con 9, Pickering as in D430754
2P	2455 Uxbridge Pickering Town Line	Pt. Lot 11, Con 9 Pickering, as in D415868
2Q	5495 Westney Road	Pt. Lot 10, Con 9 Pickering, Pt. 1, 40R-8662

EASTERN BOUNDARY

3. Point # 3 is located at the intersection of Uxbridge Pickering / Town Line and Lakeridge Road. The boundary turns southerly and follows Lakeridge Road to Point #11, with the exception of seven excursions taking in the six registered parcels of land as detailed in the following table: These seven excursions are to be included in Veridian's Service Area.

Veridian Point No.	Municipal Address, Town of Whitby	Legal Description
4	8875 Lakeridge Road	Concession 8, Part Lot 34, 35 and Concession 9, Part Lot 35 and Part of Road Allowance Now RP 40R13254, Part 1 205.57AC
5	8405 Lakeridge Road	Concession 8, Part Lot 34, 35 Now RP 40R7371, Part 1, 56.50AC
6	8195 Lakeridge Road	Concession 8, Part Lot 34, 35.55AC
7	6605 Lakeridge Road	Concession 6, Part Lot 35, 9.47AC
8 and 9	605 Lakeridge Road South	Broken Front Concession, Part Lot 35, Now RP 40R7831, Part 1 Regulator 0.04AC 32.81FR 49.21D
10	715 Halls Road	Broken Front Concession, Part Lot 34, 2.00AC

Veridian points 3A to 3E are five excursions taking in the 4 registered parcels of land and one billboard as detailed in the following table. These five excursions are to be excluded from Veridian's Service Area.

Veridian Point No.	Municipal Address, City of Pickering	Legal Description
3A	5450 Lakeridge Road	Pt. Lot 1, Con 9 Pickering; Pt. N1/2 Lot A, Con. 9, Pickering, as in D464935.
3B	5420 Lakeridge Road	Pt. Lot 1, Con 9 Pickering; Pt. N1/2 Lot A, Con. 9, Pickering, as in D464935.
3C	5240 Lakeridge Road	Pt. Lot 1, Con 9 Pickering; Pt. N1/2 Lot A, Con. 9, Pickering, Pts. 1 & 3, 40R-8746
3D	5150 Lakeridge Road	Pt. S1/2 Lot A, Con 9, Pickering, Pt. 1, 40R-5620
3E	Billboard N of 5240 Lakeridge Road	Not applicable

SOUTHERN BOUNDARY

4. Point # 11 is at Lakeridge Road and Lake Ontario. The boundary turns westerly following the Lake Ontario frontage to Point #1.

BELLEVILLE SERVICE AREA

The alpha-numeric point numbers below refer to the reference map provided on page 31 of this document.

WESTERN BOUNDARY

1. The western boundary of the existing Belleville Service Area starts at point #1 which is located at the Bay of Quinte, 0.1 km west of Avondale Road. The boundary continues parallel to Avondale Road to point #2, with the exception of an additional contiguous parcel extending to the west of Belleville, County of Hastings (476 Dundas Street West - Hastings County Manor).

2. Point #2 is located 0.1 km south of Harder Drive at the north-west corner of 180 Avondale Road. The boundary turns east following the north lot line of 180 and 179 Avondale Road and the south lot line of 67 Harder Drive to point #3.

3. Point #3 is located at the south-east corner of 67 Harder Drive. The boundary then turns north following the west lot line of 44 Glen Road to point #4.

4. Point #4 is located at the north-west corner of 44 Glen Road. The boundary then turns east following the north lot line of 44 and 45 Glen Road and 200 Wright Avenue to point #5.

5. Point #5 is located at the north-east corner of 200 Wright Avenue. The boundary then turns north following the west and north lot lines of 36 Harder Drive and the east lot lines of 62, 64, 66, 68, 72, 76 Kensington Crescent and the west lot lines of 2 and 4 Haslett Court to point #6.

6. Point #6 is located at the north-west corner of 4 Haslett Court. The boundary turns east following the north lot lines of 4, 6, 8 Haslett Court and 8, 10, 12 Wilmot Court to point #7.

7. Point #7 is located at the north-east corner of 12 Wilmot Court. The boundary then turns north following the west lot lines of 19, 21, 23 Benson Court, plus west lot lines of 29, 31, 33, 35, 37, 39, 41, 43, 45 Sherwood Court, plus the west lot lines of 29, 31, 33, 35, 37, 39, 41, 43, 45 Bogart Crescent to Point #8.

8. Point #8 is located at the north-west corner of 45 Bogart Crescent. The boundary then turns east following the north lot lines of 47, 49, 51, 53, 55, 57, 59, 61, 63, 65, 67, 69 Bogart Crescent, crosses Palmer Road and continues east for approximately 0.19km to point #9.

9. Point #9 is located approximately 0.19 km east of Palmer Road. The boundary then turns north at this point following the west lot line of 40 Wilson Avenue and the west lot line of 39 Pepper Avenue for approximately 0.23 km to point #10.

10. Point #10 is located at the south-east corner of 4 Lake Court. The boundary then turns west, following the south lot lines of 4, 6, 8 Lake Court for approximately 0.05 km to point #11.

11. Point #11 is located at the south-west corner of 8 Lake Court. The boundary then turns north following the west lot lines of 10, 12, 14 Lake Court and 337 Moira Street West for approximately 0.16 km to point #12.

12. Point #12 is located at the south lot line of 9 Jeanette Place. The boundary then turns west following the south lot line of 9 and 11 Jeanette Place and 8, 10, 12 Dixie Place for approximately 0.14 km to point #13.

13. Point #13 is located at the south-west corner of 12 Dixie Place. Included in the service area is an excursion which includes the parcel of land at 458 Moira Street W. The boundary then turns north following the west lot lines of 12, 14 and 16 Dixie Place, 135 and 136 Progress Avenue, 291 and 290 College Street West, 16, 18, 20, 22, 24, 26, 28, 30, 32 Beverley Crescent and 1 Robert Drive; then the west lot lines of 129, 126, 124, 122, 120, 118, 116, 114, 112, 110, 108, 106, 104, 102, 100, 98, 96, 94, 92, 90, 88, 86, 84, 82, 80, 78 Tracey Park Drive and 2, 4, 6, 8, 10 Queensboro Court, and north to point #14, located approximately 0.7 km west of Sidney Street at the north edge of Bell Boulevard.

14. Point #14 is located approximately 0.7 km west of Sidney Street at the north edge of Bell Boulevard. The boundary then turns west following the north edge of Bell Boulevard for approximately 0.39 km to point # 15.

15. Point # 15 is located at the south-west corner of a parcel of property addressed as 380 Bell Boulevard and known as Part Lot 32-36, Concession 2 in the City of Quinte West, Hastings County Plan 21-R-24570 parts 1 & 3. The boundary follows the western edge of this parcel of land north to the south edge of Highway # 401 to point # 16.

NORTHERN BOUNDARY

16. Point #16 is located approximately 1.0 km west of Sidney Street at Highway # 401. The boundary turns east following the southern boundary of Highway #401 road allowance for approximately 6.7 km to point #17.

EASTERN BOUNDARY

17. Point #17 is located on the eastern limit of Lot 15, Concession II, former Thurlow Township, at the southerly limit of the Highway #401. The boundary turns south and runs approximately 4.44 km to point #18. Veridian points 17A to 17D are four excursions taking in the 4 registered parcels of land as detailed in the following table. These four excursions are to be excluded from Veridian's Service Area.

Veridian Point No.	Municipal Address, City of Belleville	Legal Description
17A	326 Airport Parkway W	Pt. Lot 15, Con 2 Thurlow, as in QR271589
17B	374 Airport Parkway W	Pt. Lot 15, Con 2 Thurlow, as in QR98635
17C	382 Airport Parkway W	Pt. Lot 15, Con 2 Thurlow, Pt. 1, 21R-11952
17D	150 Antrim Road	Pt. Lots 15 & 16, Con 1, Pts 2 & 3, 21R-1209

18. Point # 18 is located on the easterly limit of Lot 15, Broken Front Concession, former Thurlow Township, at the northerly limit of Highway #2 (Dundas Street East). The boundary turns west and runs approximately 0.68 km to point #19.

19. Point #19 is located on the northerly limit of Highway #2 (Dundas Street East) approximately 0.68km west of point #18. The boundary then turns south and follows the east lot line of 665 Dundas Street East (East Half Lot 13, Broken Front Concession, former Thurlow Township) and runs approximately 0.28 km south to point #20.

SOUTHERN BOUNDARY

20. Point #20 is located on the north shore of the Bay of Quinte at the south-east corner of 665 Dundas Street East. This point is approximately 1.55 km west of Elmwood Drive. The boundary follows the north shore of the Bay of Quinte westward to point #1.

BROCK – BEAVERTON SERVICE AREA

The alpha-numeric point numbers below refer to the reference map provided on page 32 of this document.

WESTERN BOUNDARY

1. The western boundary starts at point # 1, which is located at the intersection of the railway and Concession 5. The boundary follows the railway to point # 2.

2. Point # 2 is 1.5 km from point # 1 along the railway. The boundary turns west, parallel to Main Street West to point # 3.

3. Point # 3 is located on Nine Mile Road, 0.35 km from Main Street West. The boundary continues along Nine Mile Road to point # 4.

4. Point # 4 is located on Nine Mile Road, 0.16 km from Main Street West. The boundary turns west parallel to Main Street West to point # 5.

5. Point # 5 is located 0.13 km from point # 4. The boundary turns north parallel to Nine Mile Road to point # 6.

6. Point # 6 is located 0.11 km from point # 5. The boundary turns west parallel to Main Street West to point # 7.

7. Point # 7 is located 0.2 km from point # 6. The boundary turns north parallel to Nine Mile Road to point # 8.

8. Point # 8 is located 0.07 km from point # 7. The boundary turns and follows Lake Simcoe to point # 9.

9. Point # 9 is located 0.05 km from Harbour Park Crescent. The boundary follows the harbour jetty to point # 10.

10. Point # 10 is located 0.28 km from point # 9. The boundary turns north parallel to the Lake Simcoe Shore to point # 11.

11. Point # 11 is located 0.11 km from point # 10. The boundary turns east to point # 12.

12. Point # 12 is located 0.03 km from the end of Wellington Street on the Lake Simcoe Shore. The boundary follows the lake to point # 13.

NORTHERN BOUNDARY

13. Point # 13 is located on the lakeshore at the continuation of Victoria Street. The boundary turns east to the intersection of Victoria and Morrison Ave. The boundary turns north to follow Morrison Ave. to point # 14.

14. Point # 14 is located at the intersection of 9th Street and Morrison Ave. The boundary turns to the east and follows the road allowance for 9th Street to point # 15.

15. Point # 15 is located at the railway on the continuation of the road allowance from 9th Street. The boundary turns north to follow the railway to point # 16.

16. Point # 16 is located 0.19 km along the railway from point # 15. The boundary turns north and runs approximately 220m along the railway to Point # 17.

17. Point # 17 turns east and runs approximately 467m along the north property line of Pollock Avenue to point # 18.

18. Point # 18 turns north along Street 'B' for approximately 255m to point # 19.

19. Point # 19 turns west and runs approximately 119m along the south boundary of Block 56 (Park) to point # 20.

20. Point # 20 turns north and runs approximately 159m along the west boundary of Block 56 (Park) to point # 21.

21. Point # 21 turns east and runs approximately 120m along the north boundary of Block 56 (Park) to point # 22.

22. Point # 22 turns south and runs approximately 128m along the east boundary of Block 56 (Park) to point # 23.

23. Point # 23 turns east and runs approximately 20m along the north boundary of Block 55 (future development Block) to point # 24.

24. Point # 24 turns south and runs approximately 50m along the east boundary of Block 55 (future development block) to point # 25 located on the south side of Street 'F'.

25. Point # 25 turns west and runs approximately 31m along Street 'F' to point # 26.

26. Point # 26 turns south and runs approximately 219m along Street 'B' to point # 27.

27. Point # 27 turns east to point # 28, which is located 0.08 km from Mara Road.

28. Point # 28 turns parallel to Mara Road and runs to point # 29.

29. Point # 29 is located where the boundary intersects the river. The boundary turns east to follow the river to point # 30.

EASTERN BOUNDARY

30. Point # 30 is located 0.76 km from Main Street East. The boundary turns south parallel to James Street to point # 31.

31. Point # 31 is located 0.32 km from James Street and 0.26 km from Main Street. The boundary turns east, parallel to Main Street, to point A.
    A. Point A is located 0.24 km from point # 31. The boundary turns south parallel to James Street to point B.
    B. Point B is located 0.33 km south of point A. The boundary turns southwest to point C.
    C. Point C is located at the river 0.42 km from point B. The boundary turns southwest to point D.
    D. Point D is located 0.43 km from Madill on Simcoe Street. The boundary continues southwest to point E.
    E. Point E is located 0.1 km from point D. The boundary turns south to point F.

SOUTHERN BOUNDARY

F. Point F is located 0.5 km south of point E. The boundary turns west along the road allowance for Concession 5 to point # 1.

BROCK – CANNINGTON SERVICE AREA

The alpha-numeric point numbers below refer to the reference map provided on page 33 of this document.

WESTERN BOUNDARY

1. The western boundary of Cannington starts at point # 1. Point # 1 is located 0.26 km east of Sideline 18A and 0.65 km south of point # 2 (on Cameron Street West).

2. Point # 2 is located 0.35 km west of Albert Street on Cameron Street West. The boundary continues north to point # 3.

3. Point # 3 is located 0.07 km north of point # 2. The boundary turns east parallel to Cameron Street West to point # 4.

4. Point # 4 is located 0.33 km east of point # 3. The boundary turns north parallel to Country Lane to point # 5.

NORTHERN BOUNDARY

5. Point # 5 is located 0.5 km north of point # 4 at the Beaver River. The boundary follows the river east to point # 6.

6. Point # 6 is located 0.1 km north of Riverlea Road and 0.25 km west of Laidlaw Street North. The boundary turns north parallel to Laidlaw Street North to point # 7.

7. Point # 7 is located 0.31 km north of point # 6. The boundary turns east parallel to Cameron Street East to point # 8.

EASTERN BOUNDARY

8. Point # 8 is located 1.34 km east of Laidlaw Street. The boundary turns south parallel to Laidlaw Street North to point # 9.

9. Point # 9 is located 0.56 km south of point # 8. The boundary turns east parallel to Cameron Street East to point # 10.

10. Point # 10 is located 0.16 km east of point # 9. The boundary turns south to point # 11.

11. Point # 11 is located 1.0 km west of Regional Road # 2 on Cameron Street East. The boundary continues south to point # 12.

12. Point # 12 is located 0.05 km south of Cameron Street and 0.03 km west of point # 11. The boundary turns west parallel to Cameron Street East to point # 13.

13. Point # 13 is located 0.42 km west of point # 12. The boundary turns south parallel to Peace Street to point # 14.

14. Point # 14 is located 0.68 km south of point # 13. The boundary turns southwest to point # 15.

15. Point # 15 is located 0.86 km south of Cameron Street East and 0.72 km east of Laidlaw Street South. The boundary turns south parallel to Laidlaw Street South to point # 16.

SOUTHERN BOUNDARY

16. Point # 16 is located 0.12 km south of point # 15. The boundary turns west parallel to Cameron Street East to point # 17.

17. Point # 17 is located 0.89 km west of point # 16. The boundary turns north parallel to Laidlaw Street South to point # 18.

18. Point # 18 is located 0.54 km north of point # 17. The boundary turns west parallel to Cameron Street West to point # 19.

19. Point # 19 is located 0.38 km west of point # 18. The boundary turns southwest to point # 20.

20. Point # 20 is located 0.51 km south of Cameron Street West and 0.46 km east of Sideline 18A. The boundary turns south, parallel to Sideline 18A, to point A. A. Point A is located 0.16 km south of point # 20. The boundary turns west to point # 1.

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence.

BROCK – SUNDERLAND SERVICE AREA

The alpha-numeric point numbers below refer to the reference map provided on page 34 of this document.

WESTERN BOUNDARY

1. Point # 1 is located 0.34 km south of River Street and 0.4 km west of Albert Street. The boundary continues north to point # 2.
2. Point # 2 is located 0.14 km west of Rynard Street, on River Street. The boundary turns west to point # 3.
3. Point # 3 is located 0.08 km west of point # 2 on the north side of River Street. The boundary turns north to point # 4.
4. Point # 4 is located 0.29 km north of point # 3. The boundary turns east to point # 5.
5. Point # 5 is 0.05 km east of point # 4. The boundary turns north to point # 6.
6. Point # 6 is located 0.03 km north of point # 5. The boundary turns east to point # 7.
7. Point # 7 is located 0.02 km east of point # 6. The boundary turns north to point # 8.

NORTHERN BOUNDARY

8. Point # 8 is located 0.15 km north of point # 7. The boundary turns east to point # 9.
9. Point # 9 is located 0.41 km east of point # 8. The boundary turns south to point # 10.
10. Point # 10 is located 0.07 km south of point # 9. The boundary turns east to point # 11.
11. Point # 11 is located 0.69 km east of point # 10. The boundary turns south to point # 12.

EASTERN BOUNDARY

12. Point # 12 is 0.17 km east of Hwy # 12 on Concession 6. The boundary turns east on Concession 6 to point # 13.
13. Point # 13 is 0.33 km east of point # 7 on Concession 6. The boundary turns south to point # 14.
14. Point # 14 is 0.13 km south of point # 13. The boundary turns west to point # 15, parallel to Concession 6.
15. Point # 15 is 0.48 km west of point # 14. The boundary turns south to point # 16, and parallel to Hwy # 12.

SOUTHERN BOUNDARY

16. Point # 16 is 0.6 km south of point # 15. The boundary turns west to point # 17.

17. Point # 17 is 0.02 km north of Thompson Road on Albert Street South. The boundary turns north to point # 18.

18. Point # 18 is on Albert Street South, 0.30 km north of point # 17. The boundary turns southwest to point # 19, running along the northern property lines of the residential lots that front the north side of Rennie Street.

19. Point # 19 is 0.19 km southwest of point # 18 and is located at the north-west corner of the most westerly of the residential lots that front the north side of Rennie Street. The boundary turns south and runs along the western flank of the property, extending across Rennie Street to point # 20.

20. Point # 20 is 0.04 km south of point # 19 and is located on the south side of Rennie Street. The boundary turns west and runs to point # 21, following Rennie Street and then the southern flank of the most southerly residential lot that fronts the west side of Rennie Street.

21. Point # 21 is 0.08 km west of point # 16 and is located at the south-west corner of the most southerly residential lot that fronts the west side of Rennie Street. The boundary turns northwest and runs in an uneven line to point # 22, following the western property lines of the residential lots that front the west side of Rennie Street.

22. Point # 22 is 0.07 km northwest of point # 21 and is located on the western property line of a residential lot that fronts the west side of Rennie Street. The boundary turns west and runs to point # 1.

CLARINGTON – BOWMANVILLE SERVICE AREA

The alpha-numeric point numbers below refer to the reference map provided on page 35 of this document.

WESTERN BOUNDARY

1. The boundary starts at point # 1, on Lake Ontario and follow Waverly Road to point # 2.
2. Point # 2 is 0.17 km south of Hwy # 401 on Waverly Road. The boundary turns west for 0.5 km to point # 3.
3. Point # 3 is 0.05 km south of South Service Road on the extension of Martin Road. The boundary turns north following the extension of Martin Road to the intersection of Martin Road and Hwy # 57 to point # 4.
4. The boundary follows Hwy # 57 north to point # 5 at the intersection of Hwy # 57 and Concession Road # 3.

NORTHERN BOUNDARY

5. The boundary turns east to point # 6 following Concession Road # 3.

EASTERN BOUNDARY

6. Point # 6 is 0.4 km west of Lambs Road on Concession Road # 3. The boundary turns south for 1.05 km to point # 7, and runs parallel to Lambs Road.
7. Point # 7 turns east for 0.4km until it meets Lambs Road at point # 8.
8. Point # 8 turns south and runs along Lambs Road for 0.3 km to point # 9.
9. Point # 9 turns east and runs along the northern property line of 2273 Lambs Road for 100m until it reaches the northeast corner of said property at Point # 10.
10. Point # 10 turns south and runs along the eastern property line of 2273 Lambs Road for 70m until it reaches the southeast corner of said property at Point # 11.
11. Point # 11 turns west and runs along the southern property line of 2273 Lambs Road for 100 m to Point # 12.
12. Point # 12 turns south and runs along Lambs Road for 0.7 km to Point # 13, at the intersection of Lambs Road and Concession Street East.
13. Point # 13 turns west for 0.4 km to Point # 14.
14. Point # 14 turns south for 3.5 km to Point # 15, parallel to Lambs Road.

15. Point # 15 turns east following the property line on Yacht Club Drive for approximately 155m to Point # 16.

16. Point 16 turns south following the property line on Yacht Club Drive for approximately 280m to Point # 17.

SOUTHERN BOUNDARY

17. Point # 17 is 0.4 km west of South Service Road. The boundary follows Lake Ontario to point # 1.

CLARINGTON – NEWCASTLE SERVICE AREA

The alpha-numeric point numbers below refer to the reference map provided on page 36 of this document.

WESTERN BOUNDARY

1. The boundary starts at point # 1 where the continuation of Toronto Street would meet Lake Ontario. The boundary heads north along the road allowance of Toronto Street to point # 2, 1 km west of Mill Street at Hwy # 401.

2. The boundary continues north from this point and follows the road allowance of Rudell Road to point # 3, where Rudell Road terminates north of Given Road, with the exception of an additional contiguous parcel extending to the west of this line approximately opposite Hart Blvd. known as Lot 31, Concession 1 in the former Township of Clarke in Clarington, Part 1, Plan 40R-2074 (St. Francis Elementary School),

3. The boundary continues north from point # 3 to point # 4 north of Hwy # 115.

NORTHERN BOUNDARY

4. Point # 4 is immediately south of the railway track and just northwest of Hwy # 115. The boundary follows the south side of the railway track to point 5. Veridian point 4A is one excursion taking in the registered parcel of land as detailed in the following table. This excursion is to be excluded from Veridian's Service Area.

Veridian Point No.	Municipal Address, Town of Newcastle	Legal Description
4A	2521 Bellwood Drive	Pt. Lot 30, Con 2 Clarke, as in D471130

5. Point # 5 is located at the intersection of the east side of Hwy # 115 and the south side of the railway. The boundary proceeds east following the south side of the railway to point # 6.

6. Point # 6 is located 0.09 km west of Manvers Road on the south side of the railway. The boundary turns north to point # 7, parallel to Manvers Road.

7. Point # 7 is located 0.3 km north of point # 6 and 0.09 km west of Manvers Road. The boundary turns east to point # 8.

8. Point # 8 is located 0.09 km east of Manvers Road and 0.3 km north of point # 9. The boundary turns south, parallel to Manvers Road.

9. Point # 9 is located 0.07 km east of Manvers Road on the south side of the railway. The boundary turns east along the south side of the railway to point # 10.

10. Point # 10 is located 0.11 km west of Arthur Street on the south side of the railway. The boundary turns north parallel to Arthur Street to point # 11.

11. Point # 11 is located 0.3 km north of point # 10 and 0.09 km west of Arthur Street. The boundary turns east at this point to point # 12.

12. Point # 12 is located 0.09 km east of Arthur Street and 0.3 km north of point # 13. The boundary turns south parallel to Arthur Street to point # 13.

13. Point # 13 is located 0.07 km east of Arthur Street on the south side of the railway. The boundary turns east at this point along the south side of the railway to point # 14.

EASTERN BOUNDARY

14. Point # 14 is located at the intersection of the railway and Hwy # 2, on the west side of the railway. The boundary follows the road allowance for Farrow Ave. to point # 15 at Hwy # 401. This excursion is to be included in Veridian's Service Area.

Veridian Point No.	Municipal Address, Town of Newcastle	Legal Description
14A	3742 Hwy 2, Clarke Township	Not available

15. Point # 15 is located at the intersection of Farrow Ave and Hwy # 401. The boundary continues south to point # 16 following the road allowance for Riley Road.

SOUTHERN BOUNDARY

16. Point # 16 is located at the continuation of Riley Road and Lake Ontario. The boundary turns west following the Lake Ontario shore to point # 1.

CLARINGTON – ORONO SERVICE AREA

The alpha-numeric point numbers below refer to the reference map provided on page 37 of this document.

WESTERN BOUNDARY

1. Point #1 is located 0.2 km west of Main Street following the extension of the road allowance of Sommerville Drive. The boundary continues north to point # 2.

2. Point # 2 is located on Princess Street, 0.09 km west of Leigh Street. The boundary continues north to point # 3.

3. Point # 3 is located 0.09 km north of Princess Street and 0.1 km west of Leigh Street. The boundary continues north to point # 4.

4. Point # 4 is located 0.4 km west of Main Street on Station Street. The boundary continues north to point # 5.

5. Point # 5 is located 0.29 km north of the Mill Street and Main Street intersection and 0.18 km west of Main Street. The boundary continues north to point # 6.

6. Point # 6 is located 0.88 km north of the Mill Street and Main Street intersection and 0.18 km west of Main Street.

NORTHERN BOUNDARY

7. The boundary continues east from point # 6 through the north lot line of 5771 Main Street to point # 7. Point # 7 is located on Mill Lane, 0.17 km north of the intersection of Mill Lane and Mill Street. The boundary continues east to point # 8.

8. Point # 8 is located on Mill Street, 0.15 km north of the intersection of Mill Street and Mill Lane. The boundary continues east following the west property line of the Mill Street road allowance to point # 9.

EASTERN BOUNDARY

9. Point # 9 is located at the intersection of Mill Street and Hwy # 115. The boundary turns south along the west property line of Hwy # 115 to point # 10.

SOUTHERN BOUNDARY

10. Point # 10 is located at the end of Sommerville Drive at the west boundary of the road allowance for Hwy # 35/115. The boundary turns west from this point and follows the road allowance for Sommerville Drive to point # 1.

GRAVENHURST SERVICE AREA

The alpha-numeric point numbers below refer to the reference map provided on page 38 of this document.

Beginning at the most northeast corner of the Town of Gravenhurst (the northeast corner of Muskoka County Conc. IX Lot 1), in a clockwise direction, the franchise area limits are an irregular polygon the bounds of which are described as a line:

EASTERN BOUNDARY

The meets and bounds generally begin at the north-east corner of the Town of Gravenhurst but exclude Lot 1, Conc. IX and Lot 1, Conc VIII Muskoka.

1. Beginning at the intersection of the boundary between Lots 1 and 2, Conc. IX Muskoka and the north Muskoka County line, proceeding southerly along the boundary between Lots 1 & 2 (generally parallel to the eastern limit of the Town of Gravenhurst, or the Town of Bracebridge Town Line, being the Muskoka/Draper County Line) to point # 1A at the southeast corner of Lot 1, Conc. VIII, Muskoka;

   At Point #1A turning westerly along the Conc. VIII/Conc. VII boundary and then following an irregular line along the west and south edges of Registered properties known as 1181 and 1188 Campbell's Road, Gravenhurst to Point # 1B at the intersection with the easterly limit of the Town of Gravenhurst;

   At Point #1B turning southerly along the easterly limit of the Town of Gravenhurst to the point where the Town Line turns sharply east (southeast corner of Lot 1, Conc. I, Muskoka County 1 Lot 1);

1.B continuing straight through the preceding point (and not following the Town line) in a straight line southerly along the boundary between the Counties of Ryde and Morrison to the north/south midpoint of Lot 1, Conc. X, Morrison;

SOUTHERN BOUNDARY

2. turning sharply west and continuing in a straight line bisecting Conc. X, Morrison, into north/south halves through Lots 1-13 and into Range East, Morrison, to a point on the boundary between Range West and Range East, Morrison;

3. there making a slight bend northerly and continuing westerly along a line again bisecting Conc. X through Lots 18-25, Conc. X, Morrison to a point immediately west of the boundary between Lots 25 and 26, Conc. X, Morrison;

4. turning sharply northerly along a line just west of the boundary between Lots 25 and 26, through Conc. X to a point midway (north/south) in Conc. XII, Morrison;

WESTERN BOUNDARY

5. there turning westerly and proceeding along a line approximately bisecting Conc. XII, Morrison, to a point on the boundary between Lots 34 and 35, Morrison;

6. turning sharply northerly along the boundary between Lots 34 and 35, Morrison to a point on the Morrison County boundary with Muskoka County;

7. turning sharply westerly and continuing on the south side of the boundary to the intersection of Morrison, Wood, and Muskoka Counties;

8. there turning northerly and following a line along the east side of the boundary between Wood and Muskoka Counties to a point midway in Conc. XVI, Wood;

9. there turning westerly and following a line bisecting Conc. XVI, Wood through Lots H to A to the boundary between Lot A and Lot 1, Conc. XVI, Wood;

10. there turning sharply northerly along a line following the west side of that boundary to the intersection with the allowance between Conc. XV and XVI, Wood;

11. turning sharply westerly along the center of that allowance to a point at the boundary between Lots 3 & 4, Wood;

12. turning sharply northerly along the boundary between Lots 3 & 4, Wood to the boundary between Conc. XII and XIII;

13. there turning sharply westerly and following the boundary between Conc. XII and XIII, Wood to the westerly limit of Lot 8, Wood County, also known as the westerly limit of the Town of Gravenhurst;

14. there turning sharply northerly and following the westerly limit of Lot 8, Wood finishing at the intersection of the easterly limit of Lot 9 Wood and Muskoka Road 169;

15. then turning sharply east and following the southerly limit of Lot 35 Con 14 Muskoka (2246 Muskoka Road 169) to the shore of Lake Muskoka, Point # 16.

NORTHERN BOUNDARY

16. then turning sharply north, then east to strike out across Lake Muskoka following the Gravenhurst/Bracebridge Town Line being an irregular open water route meeting the eastern shore at the northwest corner of Muskoka County Conc. Ix Lot 14, and then a straight line easterly along the line between Conc. IX and X, Muskoka County, returning to the northeast corner of the Town of Muskoka.

PORT HOPE SERVICE AREA

The alpha-numeric point numbers below refer to the reference map provided on page 39 of this document.

WESTERN BOUNDARY

1. The western boundary of the existing Port Hope Service Area starts from point # 1, 1.37 km west of Victoria Street at Lake Ontario.

2. The boundary continues north to point # 2 located at 0.63 km west of Toronto Road on Marsh Road. The boundary continues north to point # 3.

NORTHERN BOUNDARY

3. Point # 3 is located 0.2 km west of Toronto Road at Hwy # 401. The boundary turns east to point # 4.

EASTERN BOUNDARY

4. Point # 4 is located at the intersection of Hamilton Road and Hwy # 401. The boundary turns south following the road allowance for Hamilton Road to point # 5. Veridian point 4A is one excursion taking in the registered parcel of land as detailed in the following table. This excursion is to be included in Veridian's Service Area.

Veridian Point No.	Municipal Address, Town of Port Hope	Legal Description
4A	1699 Hamilton Road	Part Lot 35, Con 1, Hamilton, As in HN7842 except CB53694 south of Service Road

SOUTHERN BOUNDARY

5. Point # 5 is located on the extension of Hamilton Road where it intersects Lake Ontario. The boundary turns west, following the lakeshore to point # 1.

SCUGOG SERVICE AREA

The alpha-numeric point numbers below refer to the reference map provided on page 40 of this document.

Beginning at the most northwest corner of the Veridian's Franchise Service Area, in a clockwise direction, the franchise area limits are an irregular polygon the bounds of which are described as a line:

NORTHERN BOUNDARY

1. Proceeding generally east along Reach Street to the intersection of Simcoe Street where it meets Coulter Street.

2. Continuing along Coulter Street easterly to 44.11531°N by 78.93664°W approximately in the middle of Lake Scugog

EASTERN BOUNDARY

3. Turning shapely south and continuing down the Lake to 44.10069°N by 78.92997°W SOUTHERN BOUNDARY

SOUTHERN BOUNDARY

4. Turning sharply west running parallel with Scugog Street before meeting with Applewood Crescent and continuing west to 44.09829°N latitude by 78.94213° W.

5. There turning to a south south-westerly direction before intersecting with Simcoe Street at Vanedward Drive.

6. There making a sharp turn west for approximately one hundred meters before turning gently south south-westerly again.

7. There meeting with the south east corner of Earl S Cuddy Blvd. heading in a westerly direction for about two hundred meters, then turning slightly to a west south-westerly direction.

8. Continuing to Union Avenue, still heading slightly to a south-westerly direction going east on Victoria Street past Union Avenue.

9. There making a slight bend back to westerly direction at the intersection of Ash Street continuing west to Old Scugog Road.

10. There it continues west to Maple Street. Veridian points 10A to 10E are five excursions taking in the 5 registered parcels of land as detailed in the following table. These five excursions are to be excluded from Veridian's Service Area.

Veridian Point No.	Municipal Address, Town of Port Perry (Scugog)	Legal Description
10A	581 Victoria Street	Lot 46, Plan H50021
10B	583 Victoria Street	Lot 45, Plan H50021

10C	585 Victoria Street	Lot 44, Plan H50021
10D	631 Victoria Street	Lot 130, Plan H50021
10E	635 Victoria Street	Lot 129, Plan H50021

11. Turning sharply north and continuing north on Maple Street to Alma Street. Veridian points 11A to 10D are four excursions taking in the 4 registered parcels of land as detailed in the following table. These four excursions are to be excluded from Veridian's Service Area.

Veridian Point No.	Municipal Address, Town of Port Perry (Scugog)	Legal Description
11A	117 Maple Street	Lot 131, Plan H50021
11B	111 Maple Street	Lot 132, Plan H50021
11C	105 Maple Street	Lot 133, Plan H50021
11D	99 Maple Street	Lot 134, Plan H50021

12. Continuing in a straight-line north to Scugog Street.

13. Turning sharply to the west and continuing to the intersection of Queen Street. Veridian point 13A is one excursion taking in the registered parcel of land as detailed in the following table. This excursion is to be included in Veridian's Service Area.

Veridian Point No.	Municipal Address, Town of Port Perry (Scugog)	Legal Description
13A	1599 Scugog Line 6	Pt. Lots 16 & 17, Con 6 Reach, Pts. 2 & 4, 40R-24422

WESTERN BOUNDARY

14. Turning sharply north and continuing to 44.10160°N by 78.96246°W

15. Turning slightly east north-easterly to the intersection of Old Scugog Road and McDonald Street.

16. Turning sharply north and continuing to the intersection of Old Scugog Road and Reach Road returning to the northwest boundary.

UXBRIDGE SERVICE AREA

The alpha-numeric point numbers below refer to the reference map provided on page 41 of this document.

WESTERN BOUNDARY

1. The western boundary of the existing Uxbridge Service Area starts at point # 1, which is located 0.65 km south of Brock Street West and is in line with the east property line of Center Road. The boundary continues north to point # 2.

2. Point # 2 is located on the northeast corner of 22 South Beech Street. The boundary turns west along the south property lines of 280 and 282 Brock Street West to point # 3.

3. Point # 3 is located on the southeast corner of 282 Brock Street West. The boundary turns north along the west property line of 282 Brock Street West to point # 4.

4. Point # 4 is located on the north side of Brock Street West on the extension of the west property line of 282 Brock Street West. The boundary turns east to point # 5.

5. Point # 5 is located at the intersection of Brock Street West and Center Road. The boundary turns north to point # 6 .

NORTHERN BOUNDARY

6. Point # 6 is located at the center line of the road allowance of Center Road, and in line with the north property line of 49 Center Road. The boundary turns to the east along the north property lines of 237,235,233,231 Maple Street, 56,55 Balsam Street, 24,26,27,25 Pine Street, 8,10,9,7 Latcham Court and continues to point # 7.

7. Point # 7 is located 0.16 km west of Main Street, on the continuation of the north property lines of 8,10,9,7 Latcham Court. The boundary turns north to point # 8.

8. Point # 8 is located 0.16 km west of Main Street. The boundary turns to the east following the north property lines of 214 Main Street and 1,3,5,7 Harvey Street to point # 9.

9. Point # 9 is located at the northeast corner of 7 Harvey Street. The boundary turns to the north along the west property line of 11 Harvey Street to point # 10.

10. Point # 10 is located at the northwest corner of 11 Harvey Street. The boundary turns east to point # 11.

11. Point # 11 is located at the northeast corner of 11 Harvey Street. The boundary turns south to point # 12.

12. Point # 12 is located at the intersection of the east property line of 11 Harvey Street, and the north property line of 15 Harvey Street. The boundary turns east to point # 13.

13. Point # 13 is located 0.2 km east of Main Street. The boundary turns south to point # 14.

14. Point # 14 is located 0.01 km north of the northwest corner of 102 Second Avenue. The boundary turns east to follow the centerline of Barton Lane to point # 15.

EASTERN BOUNDARY

15. Point # 15 is located 0.01 km north of the northeast corner of 31 Remion Crescent. The boundary turns south following the eastern boundaries of 31,29,27,25,23,21,19,17,15,13,11,9 Remion Crescent to point # 16. Veridian points 15A to 15N are fourteen excursions taking in the 14 registered parcels of land as detailed in the following table. These fourteen excursions are to be excluded from Veridian's Service Area.

Veridian Point No.	Municipal Address, Town of Uxbridge	Legal Description
15A	13 Low Blvd	Lot 7, Plan 40M-1937
15B	11 Low Blvd	Lot 6, Plan 40M-1937
15C	9 Low Blvd	Lot 5, Plan 40M-1937
15D	7 Low Blvd	Lot 4, Plan 40M-1937
15E	5 Low Blvd	Lot 3, Plan 40M-1937
15F	3 Low Blvd	Lot 2, Plan 40M-1937
15G	1 Low Blvd	Lot 1, Plan 40M-1937
15H	2 Low Blvd	Lot 14, Plan 40M-1937
15I	4 Low Blvd	Lot 13, Plan 40M-1937
15J	6 Low Blvd	Lot 12, Plan 40M-1937
15K	8 Low Blvd	Lot 11, Plan 40M-1937
15L	10 Low Blvd	Lot 10, Plan 40M-1937
15M	12 Low Blvd	Lot 9, Plan 40M-1937
15N	14 Low Blvd	Lot 8, Plan 40M-1937

16. Point # 16 is located on the southeast corner of 174 Reach Street. The boundary turns west to point # 17.

SOUTHERN BOUNDARY

17. Point # 17 is located 0.2 km south of Bell Street on Main Street. The boundary turns north on Main Street to point # 18.

18. Point # 18 is located 0.1 km south of Bell Street. The boundary turns west to point # 19.

19. Point # 19 is located 0.01 km west of the southeast corner of 166 Water Street. The boundary turns south following the center line of Water Street to point # 20.

20. Point # 20 is located 0.01 km east of the southeast corner of 172 Water Street. The boundary turns west following the south property line of 172 Water Street to point A.

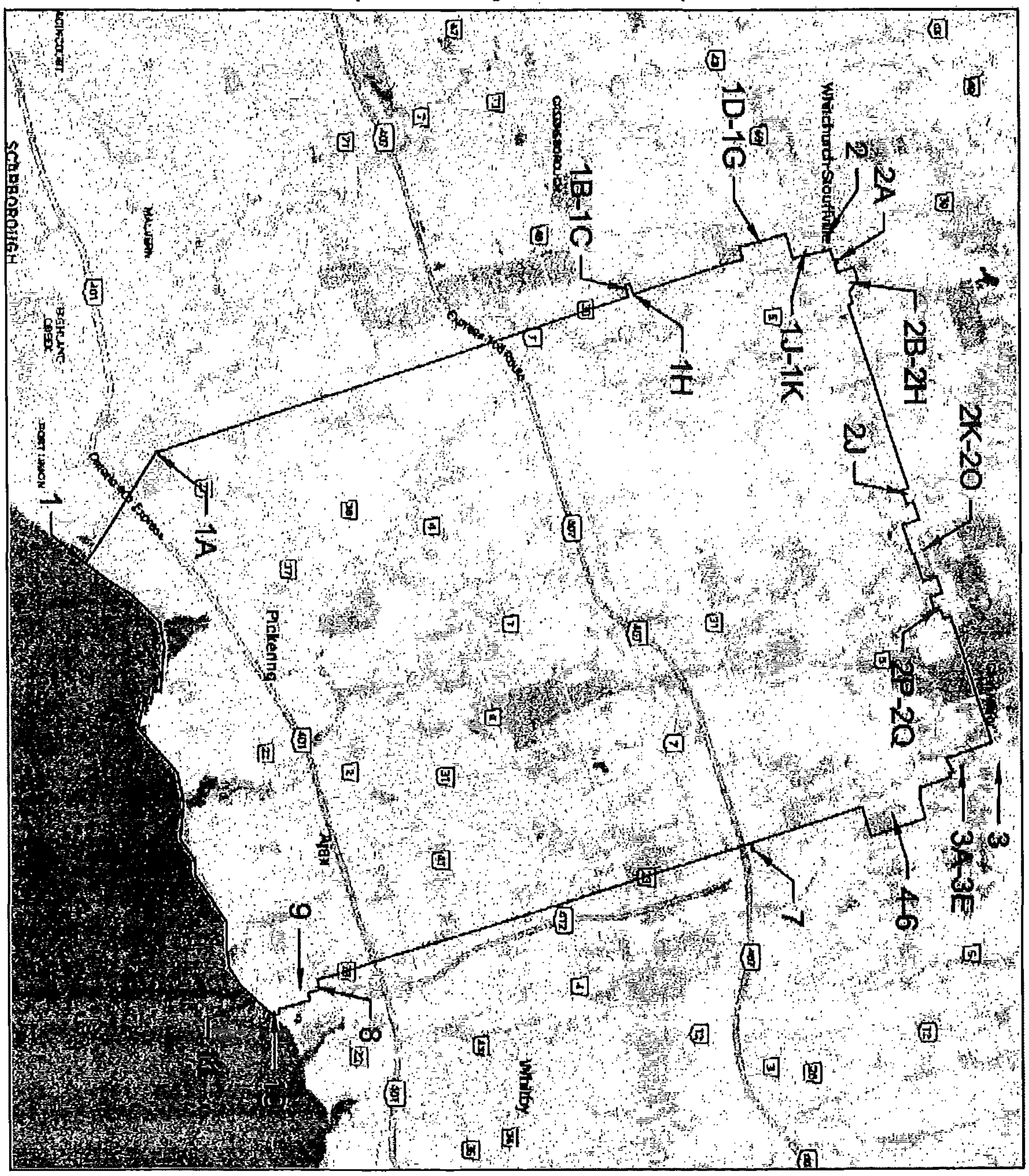
    A. Point A is located at the southwest corner of 188 Water Street. The boundary turns north following the west property lines of 188,170,168 Water Street to point B.

    B. Point B is located at the northwest corner of 168 Water Street. The boundary turns west following the south boundary of 19,20 Joseph Street, 19,20 James Street, 18,20,22 Wilson Street, and 123 Toronto Street South. The boundary continues east to point # 1.

Schedule 1 Definition of Distribution Service Area of Veridian Connections Inc.

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence.

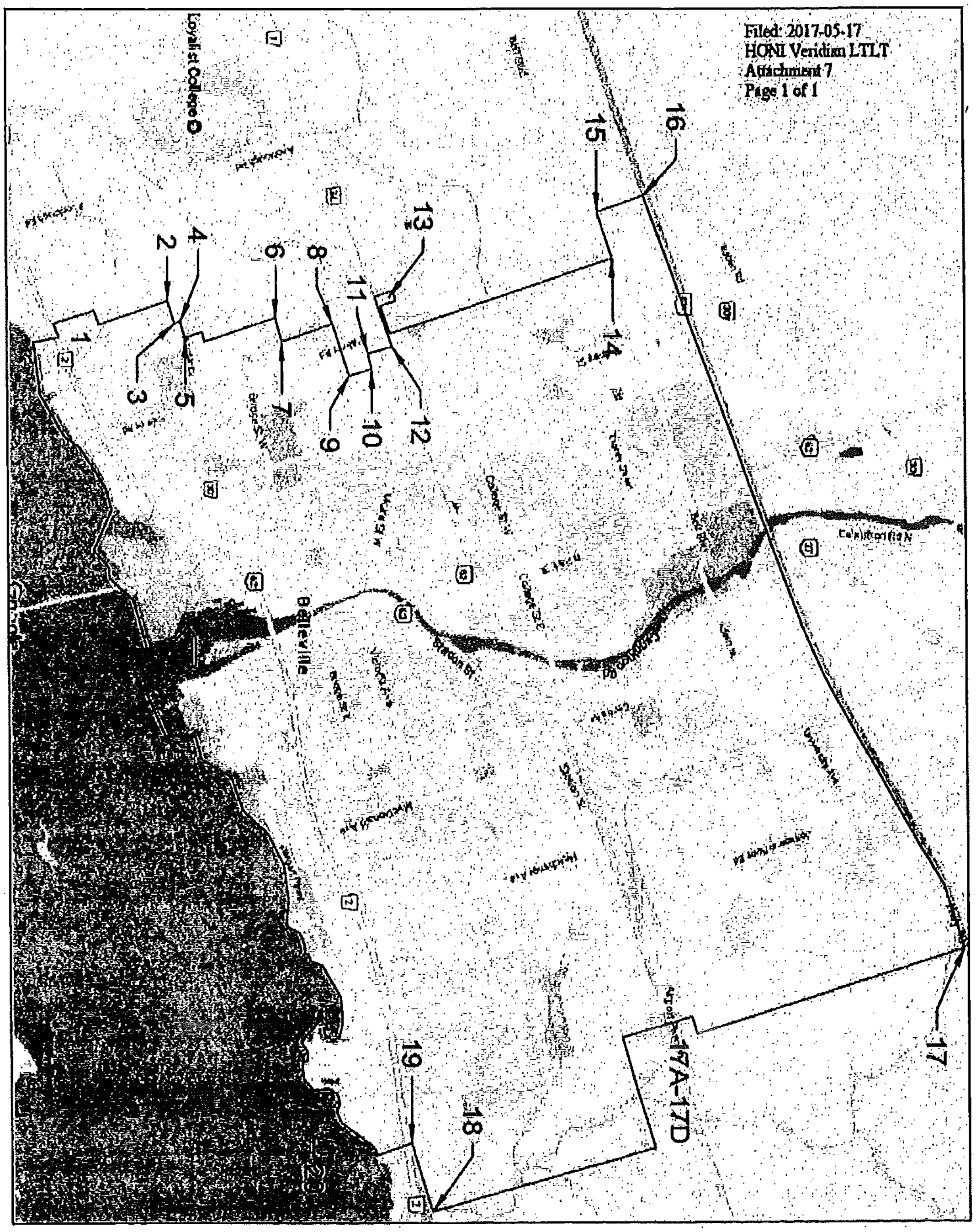
Ajax – Pickering Veridian Territory



Appendix B **Schedule 1 Definition of Distribution Service Area of Veridian Connections Inc.**

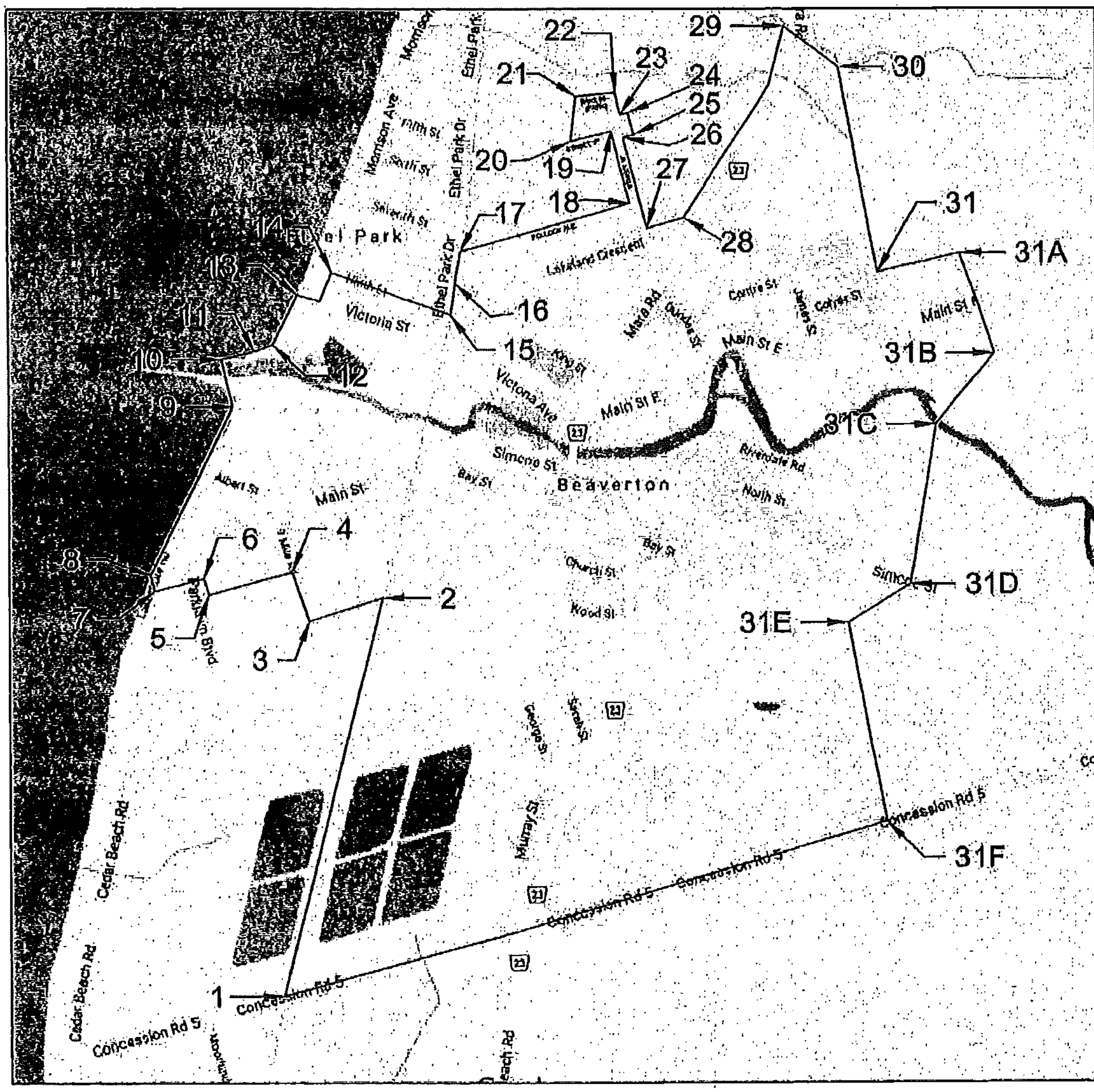
This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence.

Belleville Veridian Territory



This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence.

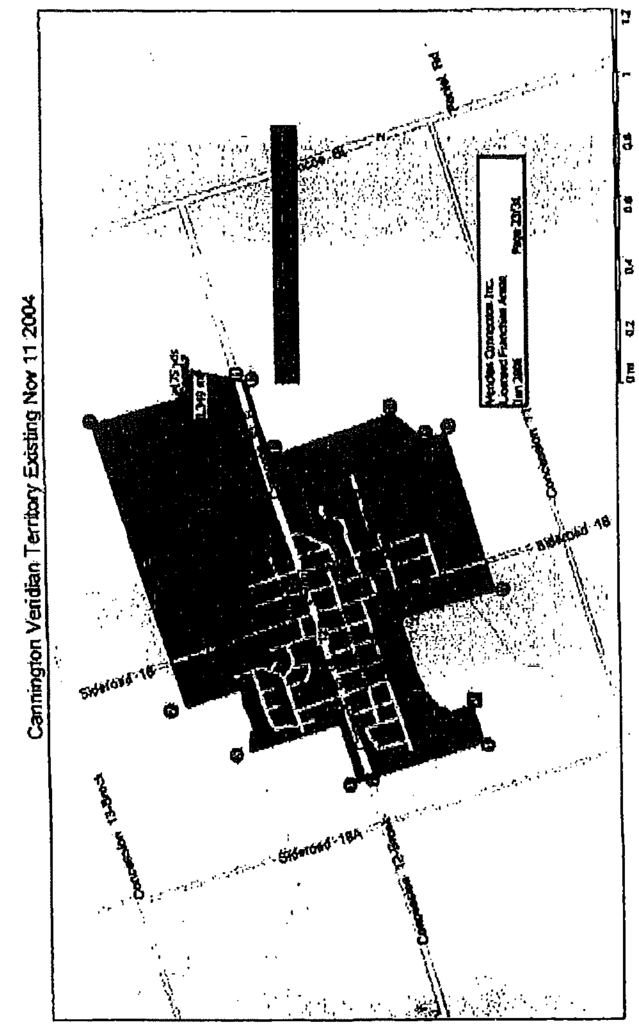
Brock-Beaverton Veridian Territory



Appendix B **Schedule 1 Definition of Distribution Service Area of Veridian Connections Inc.**

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence.

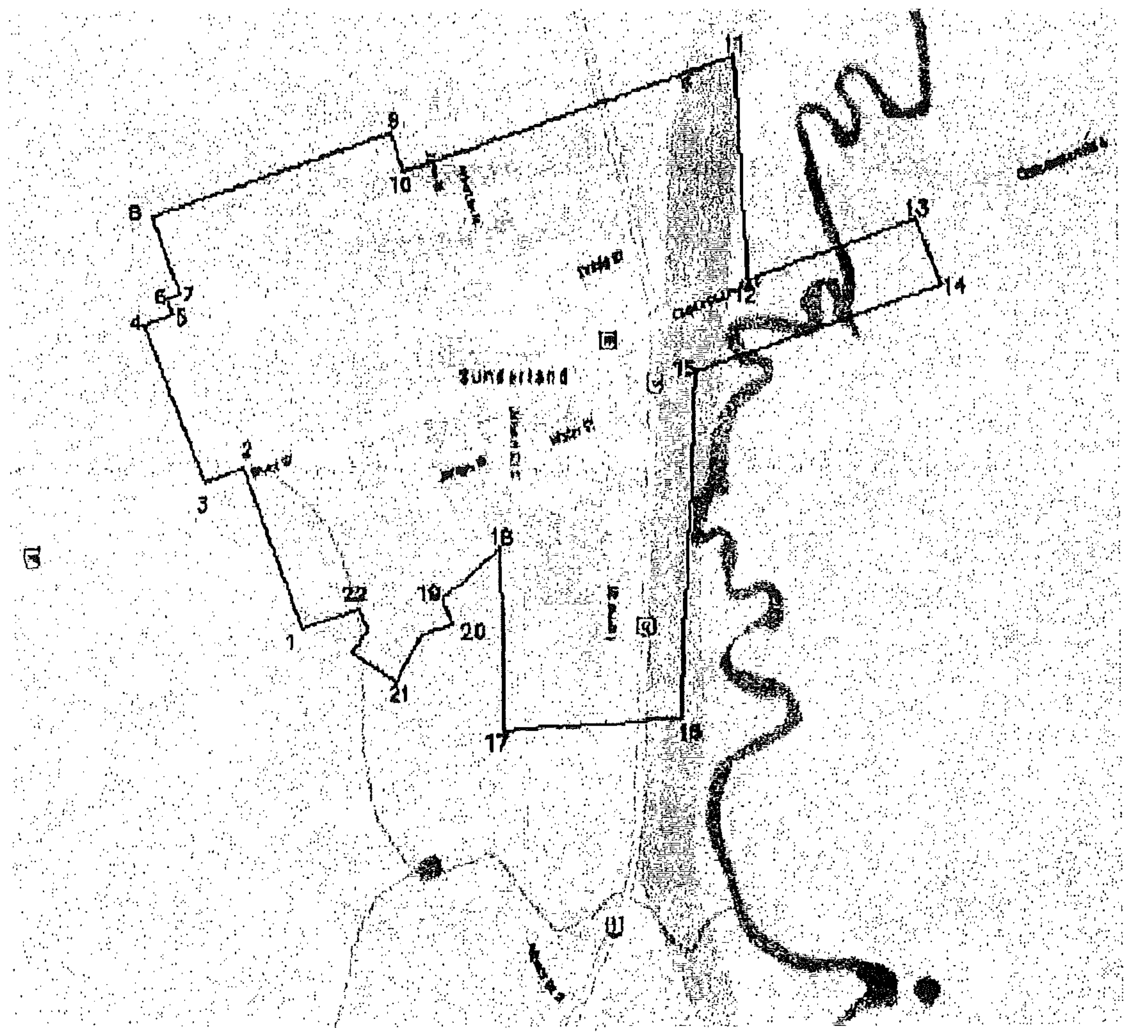
Cannington Veridian Territory



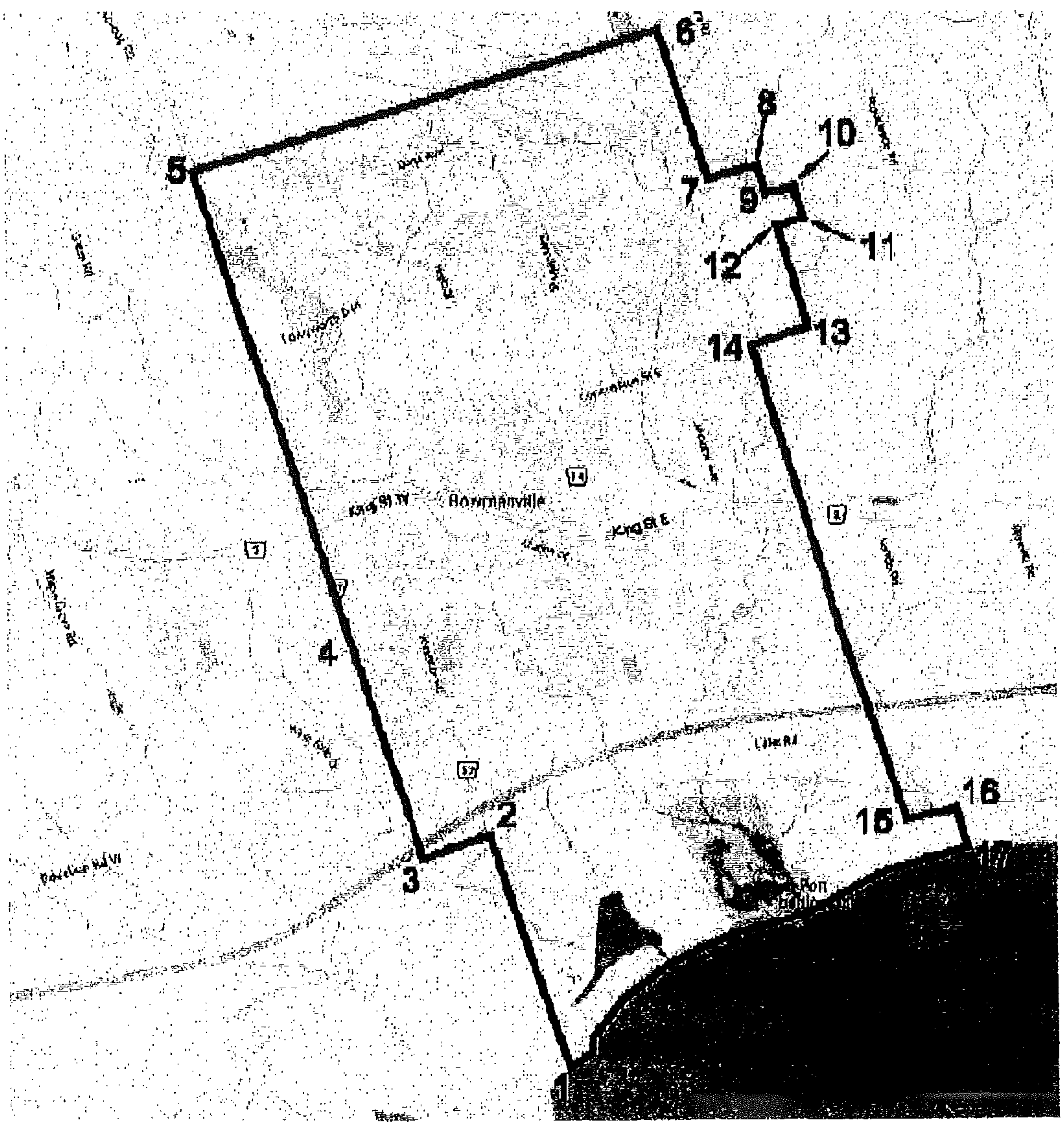
Schedule 1 Definition of Distribution Service Area of Veridian Connections Inc.

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence.

Brock Veridian Territory



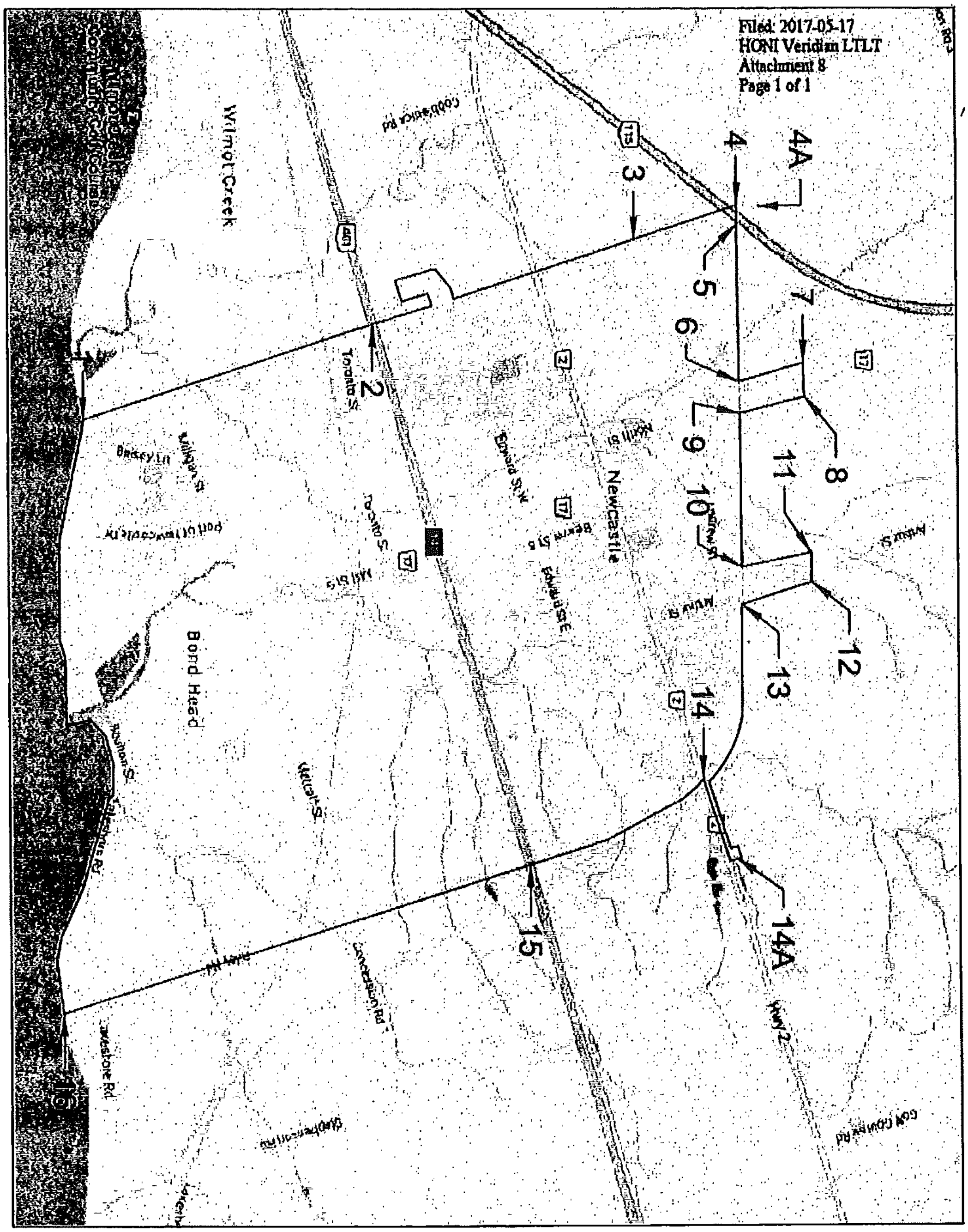
Clarington - Bowmanville Veridian Territory



Appendix B **Schedule 1 Definition of Distribution Service Area of Veridian Connections Inc.**

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence.

Clarington – New Castle Veridian Territory

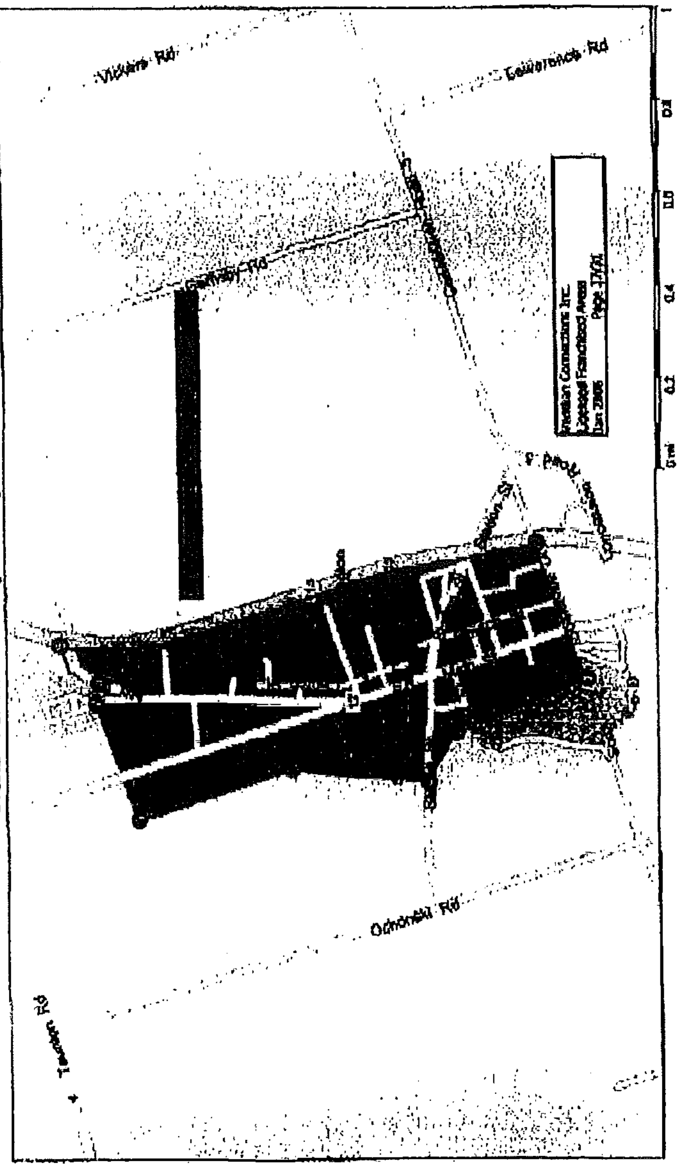


Appendix B **Schedule 1 Definition of Distribution Service Area of Veridian Connections Inc.**

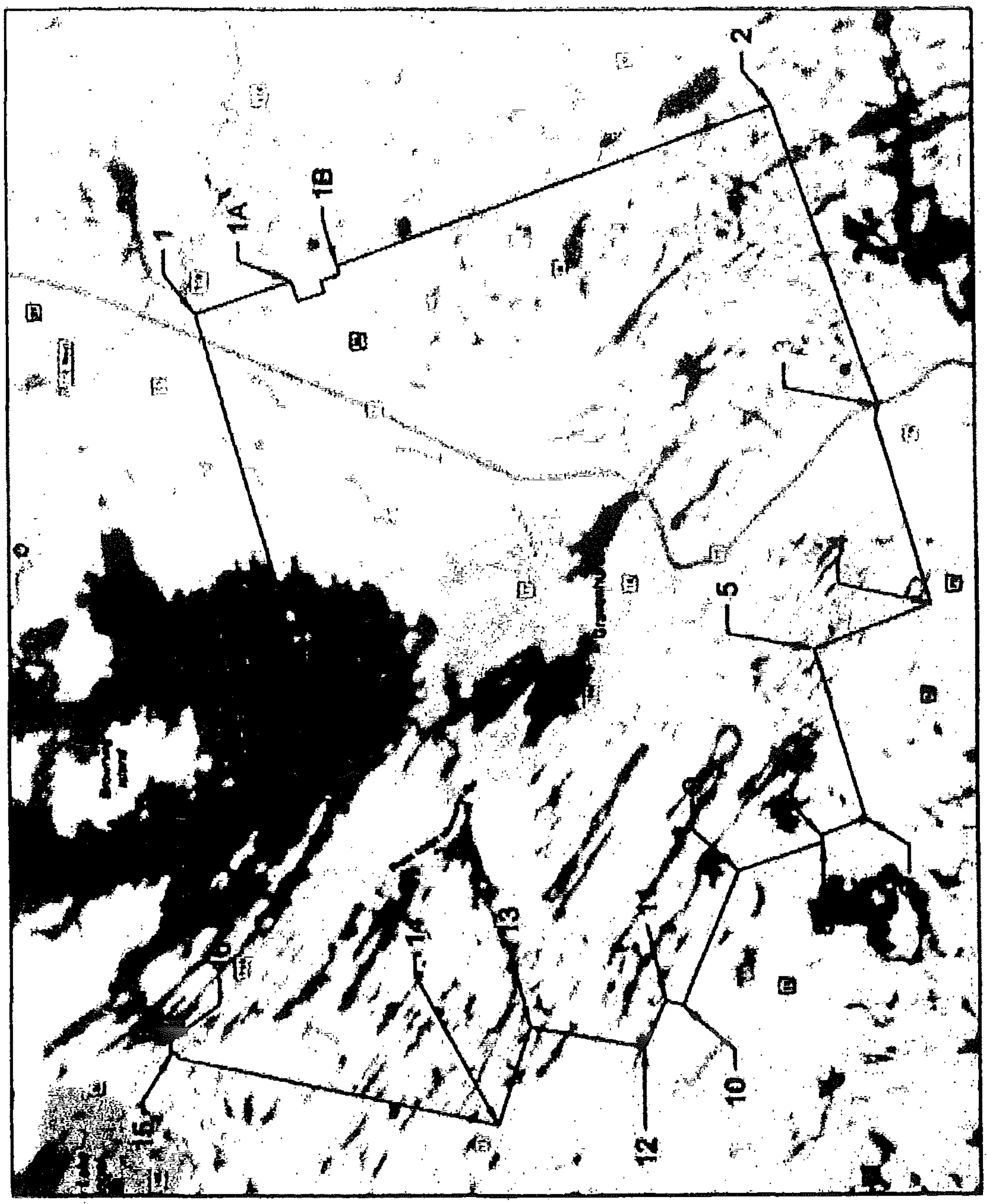
This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence.

Orono Veridian Territory

Orono Veridian Territory Existing Nov 11 2004



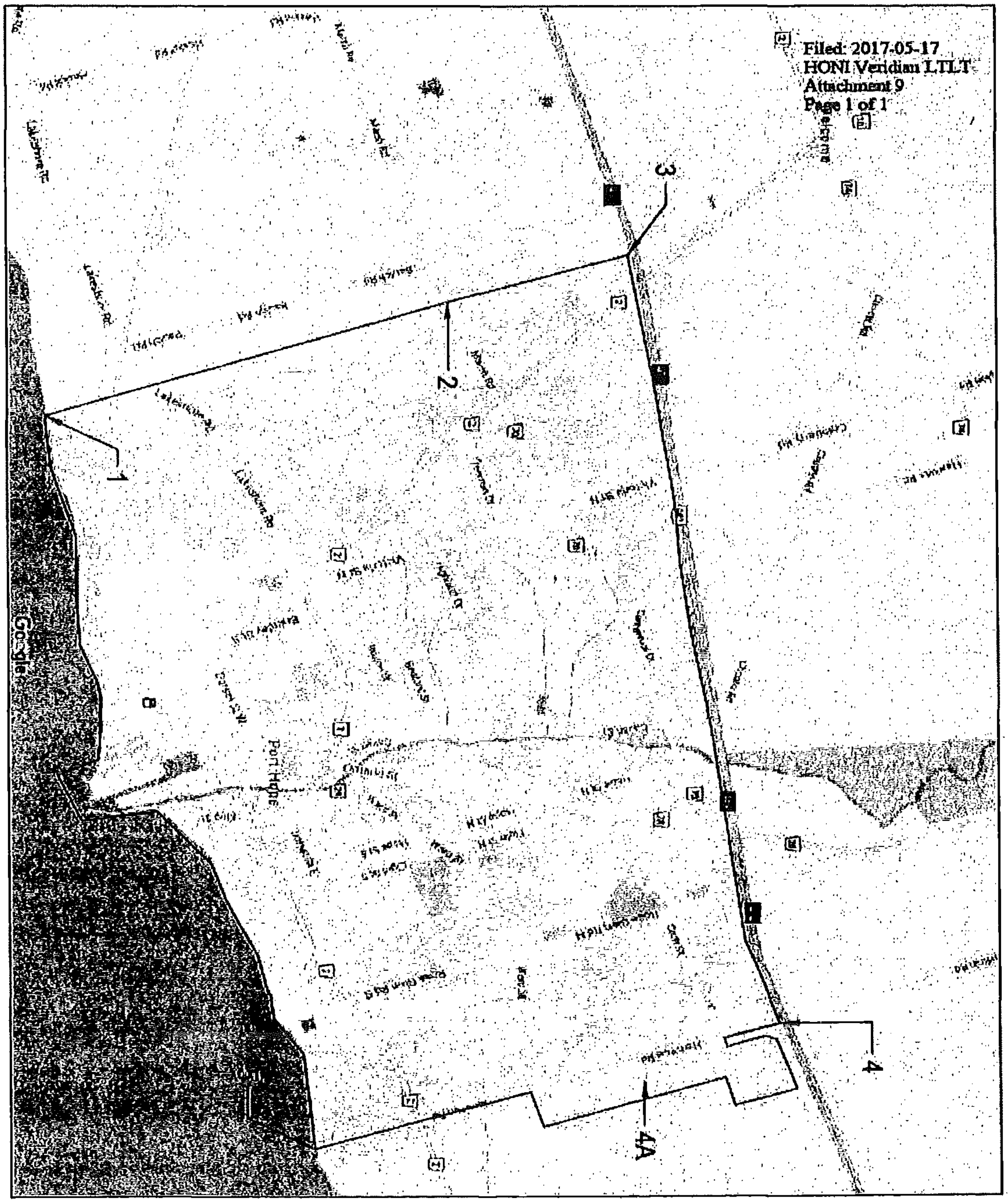
Gravenhurst Veridian Territory



Appendix B **Schedule 1 Definition of Distribution Service Area of Veridian Connections Inc.**

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence.

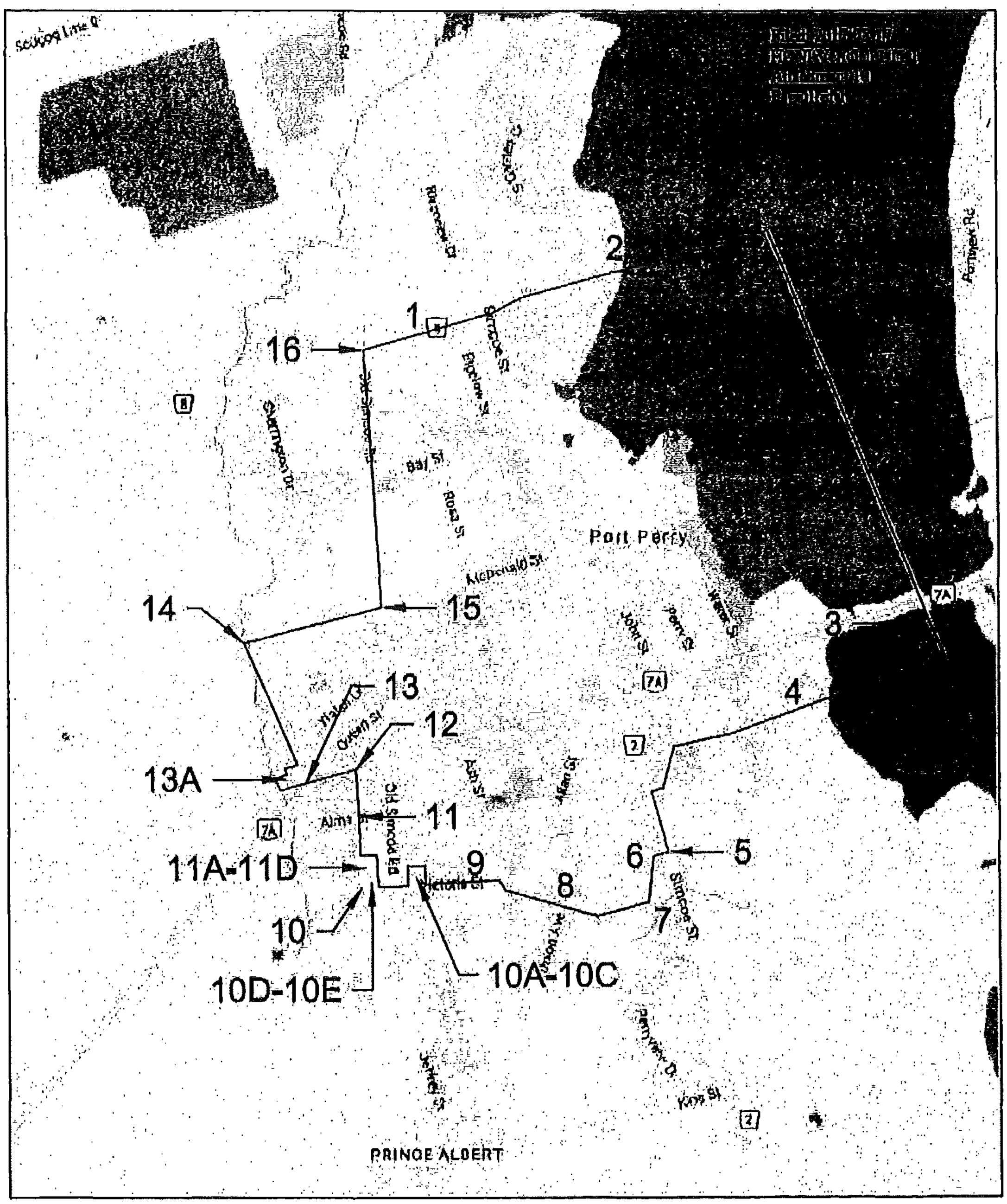
Port Hope Veridian Territory



Appendix B **Schedule 1 Definition of Distribution Service Area of Veridian Connections Inc.**

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence.

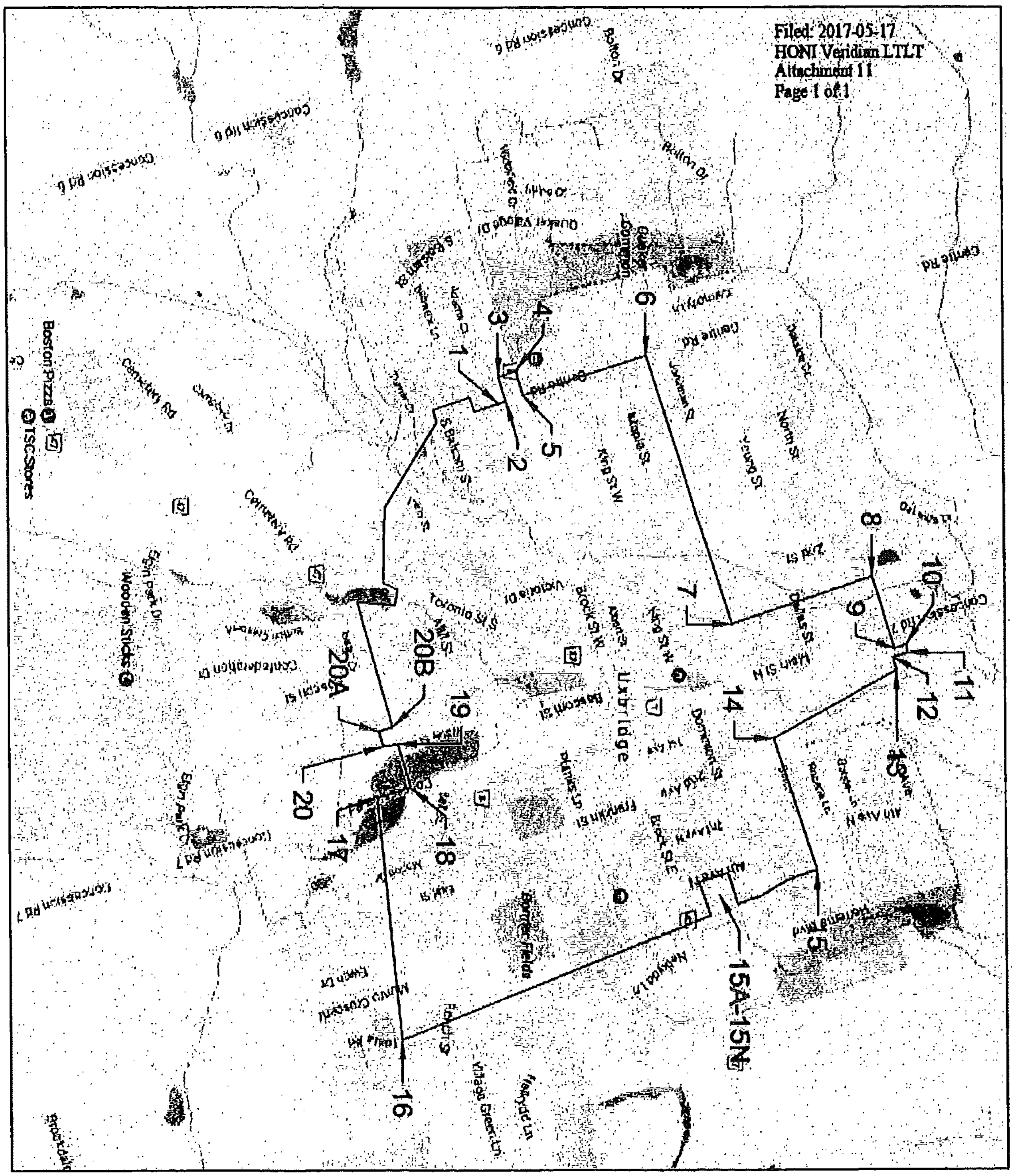
Port Perry (Scugog) Veridian Territory



Appendix B **Schedule 1 Definition of Distribution Service Area of Veridian Connections Inc.**

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence.

Uxbridge Veridian Territory



SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 8.1 of this Licence.

1. The Town of Whitby as at January 1, 1968, except for:

(a) the following lands which are served by Veridian Connections Inc.:

- Broken Front Concession, Part Lot 34, 2.00 AC;
- Broken Front Concession, Part Lot 35, now RP 40R7831, Part 1 Regulator 0.04AC 32.81FR 49.21D;
- Concession 6, Part Lot 35, 9.47AC;
- Concession 8, Part Lot 34, 35.55AC;
- Concession 8, Part Lot 34, 35, now RP 40R7371, Part 1, 56.50 AC;
- Concession 8, Part Lot 34, 35; and
- Concession 9, Part Lot 35 and Part of Road Allowance, now RP 40R13254, Part 1 205.57 AC.

(b) the following lands which are served by Hydro One Networks Inc:

- Concession 9, part lots 21 – 26, and 31 – 33 with civic address numbers 165, 275, 345, 365, 395, 425, 445, 465, 485, 525, 545, 565, 585, 605, 625, 665, 675,1175, 1245, 1375, 1395 on Townline Road West;
- Concession 9, part lot 26 with civic address 995 Ashburn Road North;
- Concession 9, part lot 34 with civic address 9909 Dagmar Road;
- Concession 9, part lot 35 with civic address numbers 9685, 9695, 9885, 9895 on Lake Ridge Road.

TAB 12

Tab A

SECTION 12(a) ATTACHMENT

(1) Merged Holdco

Veridian Connections Inc. is currently wholly owned by Veridian Corporation ("**Veridian Holdco**"). Whitby Hydro Electric Corporation is currently owned by Whitby Hydro Energy Corporation ("**Whitby Holdco**"). Once approval is received for the MAADs Application (EB-2018-0236) Veridian Holdco and Whitby Holdco will merge to form Merged Holdco, the holding company which will wholly own LDC Mergeco. The legal name and business address of LDC Mergeco will be available within 30 days of receiving Board approval for the MAAD's Application.

(2) Veridian Energy Inc. ("VEI")

Historically VEI operated non-rate-regulated business such as water heater and equipment rentals as well as other energy-related services. VEI disposed of its non-regulated water heater and sentinel light operations in 2011. As a result, VEI became dormant in 2011 and has remained inactive since. VEI remains wholly owned by Veridian Holdco.

(3) Quinte Solar Generation Inc. ("QSGI")

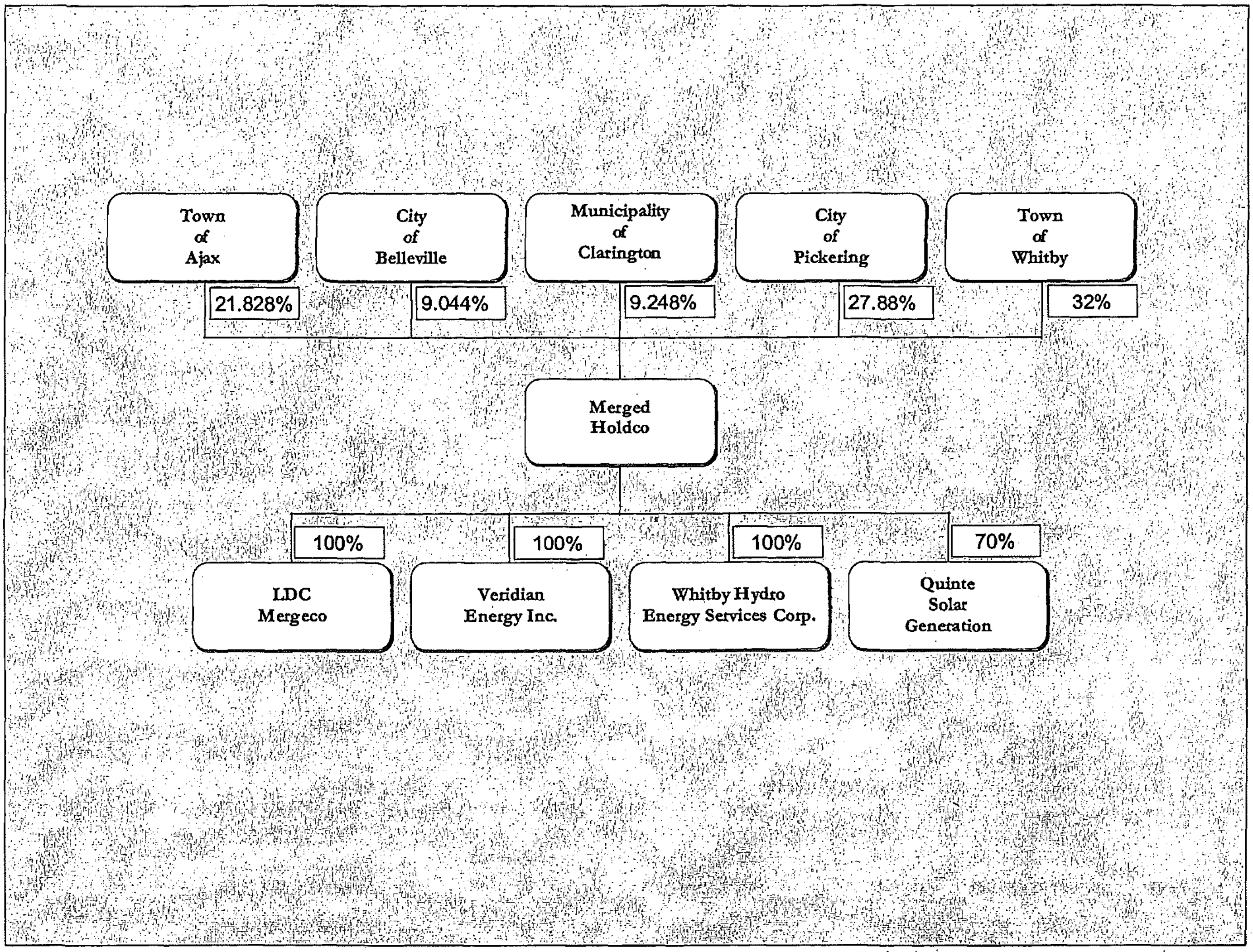
Veridian Holdco has a 70% ownership interest in QSGI. QSGI was incorporated for the purpose of investing in rooftop solar opportunities under the provincial government's various FIT programs. The Corporation of the City of Belleville owns 15% and Solera Sustainable Energies Company Limited owns the remaining 15% of QSGI. QSGI does not have any assets at this time and is maintained as a shell company for future solar investment opportunities.

(4) Whitby Hydro Energy Services Corporation ("WHESC")

WHESC is a wholly-owned subsidiary of Whitby Holdco. WHESC was created when the Ontario electricity market deregulated in 2000. WHESC assists customers from all over Ontario with their energy management and engineering project needs as well as generation, combined heat and power, storage and a range of distribution related services. While licenced to do so (under ES-2013-0257), WHESC does not provide unit sub-metering services.

Tab B

SECTION 12(b) ATTACHMENT


Town of Ajax
21.828%
City of Belleville
9.044%
Municipality of Clarington
9.248%
City of Pickering
27.88%
Town of Whitby
32%
Merged Holdco
100%
LDC Mergeco
100%
Veridian Energy Inc.
100%
Whitby Hydro Energy Services Corp.
70%
Quinte Solar Generation

TAB 13

SECTION 13 ATTACHMENT

Has the Applicant or an Affiliate undertaken any energy sector activities in Ontario or any other jurisdiction? **If yes, please provide the following information for each:** *The Applicant represents the consolidation of Veridian LDC and Whitby LDC. Those consolidating entities and their affiliates are identified below.*	**Yes** ☒
Full Legal Name of Company: *Whitby Hydro Electric Corporation*	**Licence/Registration Number:** *ED-2002-0571*
Jurisdiction: *Ontario*	**Type of Business Activity (e.g. Distribution, Generation):** *Distribution, Generation*
Full Legal Name of Company: *Whitby Hydro Energy Services Corporation*	**Licence/Registration Number:** *ES-2013-0257*
Jurisdiction: *Ontario (primary) May service clients in other locations*	**Type of Business Activity (e.g. Generation, Transmission, Distribution):** *Energy Services*
Full Legal Name of Company: *Veridian Connections Inc.*	**Licence/Registration Number:** *ED-2002-0503*
Jurisdiction: *Ontario*	**Type of Business Activity (e.g. Generation, Transmission, Distribution):** *Distribution, Generation*
Full Legal Name of Company: *Veridian Energy Inc.*	**Licence/Registration Number:** *Not applicable*

Jurisdiction:	Type of Business Activity (e.g. Generation, Transmission, Distribution):
Ontario	*Energy Services (historically – currently inactive)*

TAB 16

SECTION 16 ATTACHMENT

Key Individuals	a) Proprietor, partner, officer or director of business that was granted a licence under Part IV or V of the Ontario Energy Board Act, 1998	b) Proprietor, partner, officer or director of a business that was registered or licenced under this or any other acts of legislation	c) Proprietor, partner, officer or director of a business that had a registration or licence of any kind refused, suspended, revoked or cancelled
Mr. Michael Angemeer *President & CEO* *Veridian Connections Inc.* • *Professional Engineer* • *32 years in the energy sector*	*Current Officer, Veridian Connections Inc.* *Past Officer, Enersource Hydro Mississauga Inc.*	*Current Officer, Veridian Corp.* *Current Officer, Veridian Energy Inc.* *Current Director, 2016 Quinte Hydraulic Generation Inc.* *Past Officer, Enersource Corp.*	*No*
Mr. Rob Scarffe *Executive Vice President, Customer Service & Information Technology* • *18 years in the energy sector*	*Current Officer, Veridian Connections Inc.*	*No*	*No*
Ms. Laurie McLorg *Vice President, Financial Services & CFO* • *CPA* • *23 years in the energy sector*	*Current Officer, Veridian Connections Inc.*	*Current Officer, Veridian Corp.* *Current Officer, Veridian Energy Inc.*	*No*

Mr. George Armstrong *Vice President, Corporate Services* • *C.E.T., B. Comm.* • *33 years in the energy sector*	*Current Officer, Veridian Connections Inc.* *Past Director, First Source Energy Corp.*	*Current Officer, Veridian Corp.* *Past Officer, Veridian Energy Inc.*	*No*
Mr. Peter Petriw *Vice President, Engineering* • *Professional Engineer* • *29 years in the energy sector*	*Current Officer, Veridian Connections Inc.*	*No*	*No*
Mr. John Sanderson *President, C.E.O* *Whitby Hydro Electric Corporation* • *Professional Engineer* • *40 years in the energy industry*	*Current Officer, Whitby Hydro Electric Corporation* *Past Officer and Director, Aurora Hydro Connections Limited*	*Current Officer, Whitby Hydro Energy Services Corporation* *Current Director, Mearie Management Inc.* *Current Director, Peel Mutual Insurance Company*	*No*
Ms. Ramona Abi-Rashed *Treasurer* *Whitby Hydro Electric Corporation* • *CPA* • *32 years in the energy industry*	*Current Officer, Whitby Hydro Electric Corporation*	*Current Officer, Whitby Hydro Energy Services Corporation*	*No*
Mr. Mike Chase *Deputy Treasurer* *Whitby Hydro Electric Corporation* • *MBA, CPA* • *15 years in the energy industry*	*Current Officer, Whitby Hydro Electric Corporation*	*Current Officer, Whitby Hydro Energy Services Corporation*	*No*

Ms. Susan Reffle *Vice-President* *Whitby Hydro Electric Corporation* • *CPA* • *15 years in the energy industry*	*Current Officer, Whitby Hydro Electric Corporation*	*No*	*No*

33289420.1

TAB 17

SECTION 17 ATTACHMENT

Financial Statements of

VERIDIAN CONNECTIONS INC.

Years ended December 31, 2016 and 2015

KPMG LLP
Vaughan Metropolitan Centre
100 New Park Place, Suite 1400
Vaughan ON L4K 0J3
Canada
Tel 905-265-5900
Fax 905-265-6390

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Veridian Connections Inc.

We have audited the accompanying financial statements of Veridian Connections Inc., which comprise the balance sheets as at December 31, 2016 and 2015, the statements of comprehensive income, changes in equity and cash flows for the years then ended, and notes, comprising 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 financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits 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 our 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, we consider 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 in our audits is sufficient and appropriate to provide a basis for our audit opinion.

KPMG LLP, is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity.
KPMG Canada provides services to KPMG LLP.

KPMG

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Veridian Connections Inc. as at December 31, 2016 and 2015, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

April 4, 2017
Vaughan, Canada

VERIDIAN CONNECTIONS INC.

Balance Sheets
(In thousands of dollars)

December 31, 2016 and 2015

	Note	2016	2015
Assets			
Current assets:			
Cash		$ 4,953	$ 6,416
Accounts receivable	2	66,418	57,962
Due from related parties		111	66
Materials and supplies		3,031	2,642
Prepaid expenses		1,202	575
Total current assets		75,715	67,661
Non-current assets:			
Property, plant and equipment	3	239,542	218,159
Intangible assets	4	4,448	4,463
Goodwill		8,746	8,746
Deferred tax assets	7	3,738	6,095
Other assets		161	230
Total non-current assets		256,635	237,693
Total assets		332,350	305,354
Regulatory balances	6	2,530	3,170
Total assets and regulatory balances		$ 334,880	$ 308,524
Liabilities and Shareholder's Equity			
Current liabilities:			
Accounts payable and accrued liabilities	8	$ 44,308	$ 44,053
Due to related parties		42	43
Short-term debt	9	43,588	43,588
Advance payments - construction deposits		629	845
Income taxes payable		123	146
Customer deposits		5,799	5,174
Deferred revenue	10	1,850	1,877
Developer obligations		1,943	1,440
Long-term debt	12	1,514	1,480
Total current liabilities		99,796	98,646
Non-current liabilities:			
Long-term debt	12	94,340	85,753
Deferred contributions	13	18,683	11,543
Employee future benefits	14	2,771	2,616
Unrealized loss on interest rate swaps	22(e)	3,621	3,357
Other liabilities	17(b)	1,212	1,212
Total non-current liabilities		120,627	104,481
Total liabilities		220,423	203,127
Shareholder's equity:			
Share capital	15	69,302	69,302
Contributed capital		23	23
Accumulated other comprehensive loss		(340)	(264)
Retained earnings		35,087	28,683
Total shareholder's equity		104,072	97,744
Total liabilities and equity		324,495	300,871
Regulatory balances	6	10,385	7,653
Contingencies and guarantees	17		
Lease commitments	18		
Total liabilities, equity and regulatory balances		$ 334,880	$ 308,524

See accompanying notes to the financial statements.

On behalf of the Board:

Chair, Board of Directors

Chair
Audit and Risk Management Committee

VERIDIAN CONNECTIONS INC.

Statements of Comprehensive Income
(In thousands of dollars)

Years ended December 31, 2016 and 2015

	Note	2016	2015
Revenue:			
Commodity		$ 338,009	$ 283,052
Commodity cost		(331,487)	(280,564)
		6,522	2,488
Distribution revenue		52,264	51,768
Other income	19	3,348	3,943
		62,134	58,199
Expenses:			
Operating and maintenance	20	9,628	9,253
Administration	20	18,079	17,302
Depreciation and amortization	5	11,350	10,776
		39,057	37,331
		23,077	20,868
Finance income		66	130
Finance costs	12	(4,940)	(5,027)
Unrealized loss on interest rate swaps	22(e)	(264)	(1,466)
		(5,138)	(6,363)
Income before income taxes		17,939	14,505
Income tax expense	7	3,514	3,291
Net income		14,425	11,214
Net movements in regulatory balances, net of tax		(3,372)	(1,465)
Net income after net movements in regulatory balances		11,053	9,749
Other comprehensive loss, net of tax:			
Remeasurements of employee future benefits		(77)	–
Total comprehensive income		$ 10,976	$ 9,749

See accompanying notes to the financial statements.

VERIDIAN CONNECTIONS INC.

Statements of Changes in Equity
(In thousands of dollars)

Years ended December 31, 2016 and 2015

	Note	2016	2015
Share capital		$ 69,302	$ 69,302
Contributed capital		23	23
Accumulated other comprehensive loss		(340)	(264)
		68,985	69,061
Retained earnings, beginning of year		28,683	24,284
Net income after net movements in regulatory balances		11,053	9,749
Dividends paid	16	(4,649)	(5,350)
Retained earnings, end of year		35,087	28,683
Total equity		$ 104,072	$ 97,744

See accompanying notes to the financial statements.

VERIDIAN CONNECTIONS INC.

Statements of Cash Flows
(In thousands of dollars)

Years ended December 31, 2016 and 2015

	Note	2016	2015
Cash provided by (used in):			
Operating activities:			
Net income after net movements in regulatory balances		$ 11,053	$ 9,749
Adjustments:			
Depreciation and amortization	5	12,102	11,497
Amortization of deferred contributions		(318)	(148)
Loss on disposal/retirement of property, plant and equipment		362	373
Employee future benefits		79	101
Unrealized loss on interest rate swaps		264	1,466
Finance income		(66)	(130)
Finance costs		4,940	5,027
Income tax expense		3,514	3,291
Deferred contributions		7,458	5,789
Customer deposits		625	118
Income taxes paid		(1,400)	(1,350)
Income taxes received		221	202
Other assets		69	69
Net movements in regulatory balances		3,372	1,465
		42,275	37,519
Changes in non-cash operating working capital	21	(9,322)	227
Net cash provided by operating activities		32,953	37,746
Financing activities:			
Interest received		66	130
Repayment of long-term debt		(1,379)	(1,586)
Proceeds from long-term debt		10,000	–
Dividends paid	16	(4,649)	(5,350)
Interest paid		(4,934)	(4,994)
Net cash used in financing activities		(896)	(11,800)
Investing activities:			
Additions to property, plant and equipment		(31,821)	(25,853)
Additions to intangible assets		(1,723)	(2,229)
Proceeds from disposal of property, plant and equipment		24	33
Net cash used in investing activities		(33,520)	(28,049)
Decrease in cash		(1,463)	(2,103)
Cash, beginning of year		6,416	8,519
Cash, end of year		$ 4,953	$ 6,416

See accompanying notes to the financial statements.

Veridian Connections Inc. ("VCI" or the "Company") commenced operations on November 1, 1999. It is a wholly owned subsidiary of Veridian Corporation (the "Corporation"). The Company is licensed by the Ontario Energy Board (the "OEB") as an electricity distributor which distributes electricity in the cities of Belleville and Pickering, the towns of Ajax, Gravenhurst, Port Hope and Uxbridge, and the communities of Bowmanville, Newcastle, Orono, Beaverton, Cannington, Sunderland and Port Perry. The Company's registered office is located at 55 Taunton Road East, Ajax, Ontario L1T 3V3.

1. Significant accounting policies:

(a) Basis of presentation:

These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

These financial statements are presented in Canadian dollars, which is the Company's functional currency. The financial statements have been prepared on the historical cost basis, except for employee future benefits and certain financial instruments that are measured at fair value.

(b) Regulated environment:

The Company is an electricity distributor licensed by the OEB. It is regulated by the OEB under authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or setting rates for the transmission and distribution of electricity and the responsibility of ensuring that distribution companies fulfill obligations to connect and service customers.

1. Significant accounting policies (continued):

The Ontario Energy Board Act, 1998 sets out guiding objectives for the OEB:

- To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service;

- To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry;

- To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances;

- *To facilitate the implementation of a smart grid in Ontario; and*

- To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

The Company is responsible for charging its customers the following revenues:

- Commodity revenue - The commodity revenue is pass-through revenue for amounts payable to third parties. This revenue represents the costs of electricity consumed by the customers and passed through to the Independent Electricity System Operator ("IESO"). It also includes global adjustment revenue for non-regulated price plan consumers.

- Wholesale market services ("WMS") revenue - The WMS revenue represents the recovery of wholesale market costs for the IESO to operate the electricity market and maintain the system. This revenue is passed through to the IESO.

- Retail transmission service rate ("RTSR") revenue - The RTSR revenue represents the recovery of costs incurred for transmission of electricity to local distribution networks. This revenue is passed through to operators of transmission facilities.

1. **Significant accounting policies (continued):**

- Electricity distribution revenue - The electricity distribution revenue represents the recovery of costs incurred by VCI in delivering the electricity to its customers.

Electricity distribution rates:

Electricity distribution rates include both fixed monthly rates per customer and variable rates per kWh usage or kW demand. In 2015, the OEB released a policy that for residential electricity customers only, distribution delivery costs will be recovered through a monthly, fixed service charge. The policy set out that the transition to a fully fixed rate would occur over four years beginning in 2016. The fixed rate will increase gradually and the variable rate will decline. These distribution rates are subject to regulation by the OEB.

The OEB regulates electricity rates for distributors through three different rate setting options: Price Cap Incentive Rate-setting, Custom Incentive Rate-setting, and Annual Incentive Rate-setting Index. The Price Cap Incentive Rate-setting method sets a distributor's rates through a formula-based mechanism using a price cap index.

(c) Revenue recognition:

(i) Electricity distribution and sale:

Revenue from the sale of electricity is recognized on an accrual basis driven by cyclical billings based on electricity usage billed at OEB-approved distribution rates. Revenue from the sale of electricity includes an estimate of unbilled revenue accrued in respect of electricity delivered but not yet billed at year end. Unbilled revenue is calculated based on OEB-approved rates for electricity consumption and electricity demand driven by number of days between a customer's last meter reading in the year and December 31, 2016. Actual billed revenue could differ from estimates due to energy demand, weather, line losses and changes in the composition of customer classes.

1. Significant accounting policies (continued):

The difference between the amounts charged to customers, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs billed monthly by the IESO, is recorded as a settlement variance. In accordance with IFRS 14, Regulatory Deferral Accounts ("IFRS 14"), which permits a rate-regulated entity to continue to recognize and measure regulatory deferral account balances in accordance with its previous generally accepted accounting principles ("GAAP"), this settlement variance is presented within regulatory balances on the balance sheets and within net movements in regulatory balances, net of tax on the statements of comprehensive income.

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by the Company in delivering electricity to customers. Distribution revenue also includes revenue related to collection of OEB-approved rate riders.

The carrying amount of accounts receivable is reduced through an allowance for doubtful accounts, if applicable, and all impairment losses are recognized in net income. When the Company considers that there are no realistic prospects of recovery of an account receivable, the relevant amount is determined to be impaired and is written off. If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

(ii) Other income:

Other income, which includes revenue from electricity distribution-related services, is recognized as services are rendered. Capital contributions received from electricity customers to construct or acquire property, plant and equipment ("PP&E") for the purpose of connecting a customer to a network are recorded as deferred contributions and amortized into other income at an equivalent rate to that used for the depreciation of the related PP&E. Government grants and the related performance incentive payments under Conservation and Demand Management ("CDM") programs are recognized as income in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

1. Significant accounting policies (continued):

(iii) Deferred revenue:

Amounts received in advance in relation to the IESO supported CDM initiatives are presented as deferred revenue (note 10).

(d) Rate setting:

The electricity distribution rates of the Company are subject to regulation by the OEB and these rates are based on a revenue requirement that includes a rate of return of 9.36% effective May 1, 2014.

On September 28, 2015, the Company filed a Price Cap Incentive Rate-setting application with the OEB to change distribution rates effective May 1, 2016. The application was approved by the OEB on March 17, 2016.

On November 7, 2016, the Company filed a Price Cap Incentive Rate-setting application with the OEB for May 1, 2017 rates. The OEB decision on this application has not been received at this time.

On January 30, 2014, the IASB issued an interim standard, IFRS 14, to enhance the comparability of financial reporting by entities that are engaged in rate-regulated activities. IFRS 14 describes regulatory deferral account balances as amounts of expense or income that would not be recognized as assets or liabilities in accordance with other standards, but that qualify to be deferred in accordance with this standard because the amount is included, or is expected to be included, by the rate regulator in establishing the price(s) that an entity can charge to customers for rate-regulated goods or services.

1. Significant accounting policies (continued):

The scope of this standard is limited to first-time adopters of IFRS and will remain in force until either repealed or replaced by permanent guidance on rate-regulated accounting from the IASB. The interim standard introduced new presentation requirements and permitted first-time adopters to continue to recognize amounts related to rate regulation in accordance with Chartered Professional Accountants of Canada Handbook Part V - Pre-changeover Accounting Standards (subsequently referred to as "previous Canadian GAAP") requirements and was effective from January 1, 2016, with early application permitted. The Company elected to early adopt IFRS 14 in its 2015 financial statements under IFRS, with a transition date of January 1, 2014 and determined that regulatory balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14 and the accounting principles prescribed by the OEB in the "Accounting Procedures Handbook for Electricity Distributors".

The IASB's comprehensive project on rate-regulated activities is addressing whether IFRSs should require entities operating in rate-regulated environments to recognize assets and liabilities arising from the effects of rate regulation. On December 12, 2016, the IASB staff met with the IASB board members to discuss their preliminary proposals for an accounting model for rate-regulated entities and highlighted the input received from the Accounting Standards Advisory Forum and other stakeholders. This comprehensive project remains ongoing.

The OEB has the general power to include or exclude costs, revenue, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in the timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory balances. The Company's regulatory debit balances represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory credit balances, which represent obligations that are expected to be refunded to customers. The netting of regulatory debit and credit balances is not permitted under IFRS 14.

(e) Cash and cash equivalents:

Cash and cash equivalents are defined as cash and bank term deposits or equivalent financial instruments with original maturities upon issue of less than 90 days.

1. Significant accounting policies (continued):

(f) Materials and supplies:

Materials and supplies, which consists of parts and supplies acquired for internal construction or consumption, are valued at the lower of cost and net realizable value. Cost is determined on a weighted moving average basis.

Any write-downs taken on materials and supplies are reversed if and when net realizable value subsequently recovers. Major spare parts and standby equipment are recorded as part of PP&E and depreciated once they are put into use.

(g) Property, plant and equipment:

PP&E purchased or constructed by the Company are recorded at cost less accumulated depreciation. Costs include contracted services, materials, labour, engineering costs, directly attributable overheads and capitalized borrowing costs during construction when applied. Subsequent costs are capitalized only when it is probable that the future economic benefits associated with the costs will flow to the Company and the costs can be measured reliably. Certain assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers. These contributions are used to connect customers to the Company's network and provide them with ongoing access to the supply of electricity. The contributions are recognized as deferred contributions and amortized into other income over the life of the related asset.

Upon energization of residential subdivision assets, a developer liability is accrued (as per the offer to connect contract) for the amounts payable to the developer for the Company's investment in the subdivision.

(In thousands of dollars)

1. Significant accounting policies (continued):

Depreciation of PP&E is charged to net income on a straight-line basis over their estimated service lives at the following annual rates:

Land rights	2.0%
Buildings	2.0% - 6.7%
Distribution station equipment	1.7% - 4.0%
Transmission and distribution system	1.7% - 10.0%
Meters	4.0% - 6.7%
Office equipment	10.0%
Computer hardware	20.0% - 33.3%
Vehicle fleet	6.7% - 16.7%
Renewable power generation	4.0%

The depreciation method, useful lives, and residual values are reviewed each financial year-end with the effect of any changes in estimate being accounted for on a prospective basis. Estimated useful lives reflect the best estimate and actual lives of assets may vary from estimated useful lives.

Construction in progress comprises PP&E under construction, assets not yet placed into service and pre-construction activities related to specific projects expected to be constructed.

Construction in progress, land rights, major spare parts and standby equipment are not subject to depreciation until these assets are put into service. Land is not depreciated.

Borrowing costs directly attributable to the acquisition, construction or development of qualifying assets that necessarily take a substantial period of time to prepare for their intended use are capitalized, until such time as the assets are substantially ready for their intended use. The weighted average cost of long-term borrowings is used as the capitalization rate. Qualifying assets are considered to be those that take in excess of six months to construct.

1. **Significant accounting policies (continued):**

When portions of the Company's distribution facilities are replaced or relocated, the associated costs less the salvage value of any material returned to materials and supplies are capitalized to the new asset. Depreciation is then recorded at the same rate used for the original asset.

Some of the Company's distribution assets, particularly those located on unowned easements and rights-of-way, may have decommissioning obligations, constructive or otherwise. The majority of the Company's easements and rights-of-way are subject to extension or renewal and are expected to be available for a perpetual duration. As the Company expects to use the majority of its installed assets into perpetuity, no removal date can be determined and consequently no reasonable estimate of the fair value of such asset retirement obligations can be made. If, at some future date, it becomes possible to estimate the fair value cost of removing the assets that the Company is legally or constructively required to remove, a related asset retirement obligation will be recognized at that time. The discounted amount is not material.

Assets are derecognized at their carrying value upon retirement or when no remaining economic benefits are expected from its use. The related gain or loss arising on the disposal or retirement is determined as the difference between the proceeds from sale and the carrying value of the asset and is included in net income for the related fiscal year. The cost of replacing a part of an item of PP&E is recognized as an addition to the carrying amount of the asset and the carrying amount of the replaced part is derecognized. The cost of the day-to-day servicing of PP&E assets is recognized in net income as incurred.

(h) Intangible assets:

Intangible assets separately acquired or internally developed are measured on initial recognition at cost which comprises purchased software, labour, including employee benefits and consulting, engineering, directly attributable overheads and capitalized borrowing costs, if applicable. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses.

Amortization of intangible assets is provided on a straight-line basis over the estimated service lives at the following annual rates:

Application software and intellectual property	33.3%
Internally generated software	20.0%

1. **Significant accounting policies (continued):**

Software in development is not subject to amortization. The above-noted amortization rates apply to assets held within the application software and other intangible asset grouping (note 4). The amortization method, useful lives, and residual values are reviewed each financial year-end with the effect of any changes in estimate being accounted for on a prospective basis. Estimated useful lives reflect the best estimate and actual lives of assets may vary from estimated useful lives.

(i) Goodwill:

Goodwill relates to the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment at each reporting date. Goodwill is measured at cost and is not amortized. Impairment testing for goodwill is always carried out in the context of the cash generating unit ("CGU") as goodwill does not generate cash flows independently of other assets. The Company has determined that goodwill is not impaired.

(j) Impairment of non-financial assets:

The carrying costs of non-financial assets: PP&E, intangible assets and goodwill are reviewed for impairment at each reporting date to determine whether there is any indication of impairment, in which case, the asset's recoverable amount is estimated.

For the regulated business, the carrying costs of most of the Company's non-financial assets are included in rate base (the aggregate of approved investment in PP&E and intangible assets, excluding work in progress, less accumulated depreciation and amortization and unamortized capital contributions from customers, plus an allowance for working capital) where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Impairment is tested at the CGU level, which is the smallest identifiable group of assets that generates independent cash flows. The Company has only one CGU, the regulated business unit. An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its recoverable amount and is recognized in net income.

1. **Significant accounting policies (continued):**

(k) Customer deposits and advance payments:

Customers may be required to post security deposits to obtain electricity or other services. Interest is paid on customer deposits at rates prescribed by the OEB: this is currently interest at Canada's prime business rate less 2%, which was 0.7% per annum as of December 31, 2016. The Company receives advance payments from customers in relation to construction projects and recognizes them as a liability until the projects are completed.

(l) Employee benefits:

(i) Short-term employee benefits:

The Company provides short-term employee benefits, such as: salaries, employment insurance, short-term compensated absences, health and dental care. These benefits are recognized as the related service is rendered and is measured on an undiscounted basis. Short-term employee benefits are recognized as an expense unless they qualify for capitalization as part of the cost of an item of materials and supplies, PP&E, intangible assets or recoverable projects. A liability is recognized in respect of any unpaid short-term employee benefits for services rendered in the reporting period.

The Company recognizes a current liability for the expected cost of accumulated non-vested sick leave benefits at the end of the reporting period. The assumptions used for estimating the amount of the liability are analogous to those used in the valuation of employee future benefits.

(ii) Defined benefit pension plan:

The Company accounts for its participation in the Ontario Municipal Employees Retirement System ("OMERS"), a multi-employer public sector pension fund, as a defined contribution plan.

1. **Significant accounting policies (continued):**

OMERS plan is a multi-employer defined benefit plan providing pension to employees of municipalities, local boards, public utilities and school boards. It is funded by equal contributions from participating employers and employees, as well as by investment earnings of the plan. Each year, an independent actuary determines the plan's funded status by comparing the actuarial value of invested assets to the estimated present value of all pension benefits that members have earned to date. OMERS does not track its investments by employer and actuarial assumptions are developed based on the entire plan membership on a commingled basis and, therefore, information for individual plans cannot be determined. As a result, the Company accounts for the OMERS plan as a defined contribution plan and contributions to the plan are recognized as an employee benefit expense.

(iii) Employee future benefits:

The Company provides all employees with life insurance benefits, as well as a Health Care Spending Account ("HCSA") for those employees retiring post April 1, 2011 having completed a minimum of 20 years of service with the Company. This benefit is available until age sixty five.

The Company actuarially determines the cost of employee future benefits offered to employees. These unfunded plans are accounted for as defined benefit obligations. The Company applies the projected benefit method, prorated on service and based on management's best estimates and assumptions. Under this method, the projected employee future benefits is deemed to be earned on a pro rata basis over the years of service in the attribution period commencing at date of hire, and ending at the earliest age the employee could retire and qualify for benefits.

Remeasurements of the net benefit liability comprise actuarial gains or losses that are recognized in the balance sheets with a charge or credit to other comprehensive income or loss. Current service costs are allocated to operating, maintenance and administration expenses and to capital and recoverable projects recognized in the balance sheets.

1. Significant accounting policies (continued):

(m) Income taxes:

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

The Company uses the asset and liability method of accounting for the tax effect of temporary differences between the carrying amount and the tax bases of the Company's assets and liabilities. Temporary differences arise when the realization of an asset or the settlement of a liability would give rise to either an increase or decrease in the Company's income taxes payable in the year or a later period.

Deferred tax assets and liabilities are measured using enacted or substantively enacted tax rates at the reporting date, expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the statements of comprehensive income in the year that includes the date of enactment or substantive enactment.

The carrying amount of deferred tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable that the related tax benefits will be realized. Previously unrecognized deferred tax assets are reassessed at each balance sheet date and are recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. A valuation allowance is recorded against a deferred tax asset to the extent that the Company determines that it is probable that a deferred income tax asset will not be realized in the future.

Where the Company expects the deferred taxes to be recovered from or refunded to customers as part of the rate setting process, the deferred income tax assets and liabilities result in regulatory deferral debit balances or credit balances, respectively. Deferred tax assets that are not included in the rate-setting process result in a deferred tax provision that is charged or credited to the statements of comprehensive income.

1. Significant accounting policies (continued):

(n) Provisions and contingencies:

The Company recognizes provisions if, as a result of a past event, there is a present legal or constructive obligation that can be measured reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and, where appropriate, the risks specific to the liability.

The evaluation of the likelihood of the contingent events requires judgment by management as to the probability of exposure to potential gain or loss. Actual results could differ from these estimates.

(o) Use of judgments and estimates:

The preparation of financial statements requires management to make estimates, judgments and assumptions: within reasonable limits of materiality and within the framework of the significant accounting policies, that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenue and expenses during the years. Due to inherent uncertainty involved in making such estimates, actual results reported in future years could differ from those estimates recorded in preparing these financial statements, including changes as a result of future decisions made by the OEB or the Minister of Energy.

Information about assumptions and estimation uncertainties that have a significant risk of resulting in a material adjustment is included in the following financial notes.

(i) Note 1(c)(i) - measurement of unbilled revenue;

(ii) Note 1(g) - environmental and decommissioning liabilities;

(iii) Notes 1(g), (h) - estimation of useful lives of PP&E and intangible assets;

(iv) Note 1(c)(i), (d) and note 6 - recognition and measurement of regulatory balances;

1. **Significant accounting policies (continued):**

   (v) Notes 1(l)(ii)(iii) and note 14 - measurement of employee future benefits: key actuarial assumptions;

   (vi) Note 1(n) - recognition and measurement of provisions and contingencies;

   (vii) Note 1(m) and note 7 - recognition of deferred tax assets - availability of future taxable profit against which tax losses carried forward can be used; and

   (viii) Note 1(c)(i) and note 22(c) - allowance for doubtful accounts.

   Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future periods affected. Estimates and underlying assumptions are reviewed on an ongoing basis and are based on historical experience and other factors that are considered to be relevant.

   (p) Non-derivative financial instruments:

   All non-derivative financial assets are classified as loans and receivables and all non-derivative liabilities are classified as other liabilities. These financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequently, they are measured at amortized costs using the effective interest method less any impairment for the financial assets, as described in note 22(c).

   (q) Derivative financial instruments:

   Derivative financial instruments are measured at their fair value upon initial recognition and on each subsequent reporting date.

   The Company has not elected to apply hedge accounting for its interest rate swap contracts and does not enter into derivative agreements for speculative purposes. Changes in the fair value of the derivatives are recorded each year in the statements of comprehensive income.

1. **Significant accounting policies (continued):**

(r) Capital disclosures:

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis, at reasonable rates, and to deliver the appropriate financial returns. As at December 31, 2016, the Company's definition of capital includes shareholder's equity, short-term debt (including the Corporation shareholders' promissory notes) and long-term debt, less cash and cash equivalents.

During the year, there have been no changes to how the Company assesses its capital structure.

(s) New standards and interpretations not yet adopted:

The IASB issues amendments to standards and interpretations which do not have to be adopted in the current year. The Company is still evaluating the adoption of the following new and revised standards, described below, which the Company anticipates might have an impact on its financial statements or note disclosures:

(i) IFRS 15, Revenue from Contracts with Customers ("IFRS 15"):

In May 2014, the IASB issued IFRS 15. The standard outlines a single comprehensive model for entities to use in accounting for revenues arising from contracts with customers. It supersedes current revenue recognition guidance, including International Accounting Standard ("IAS") 18, Revenues, IAS 11, Construction Contracts and related interpretations. The new revenue model applies to all contracts with customers, except those that are within the scope of other IFRSs, such as leases, insurance contracts and financial instruments. IFRS 15 specifies how and when the entity should recognize revenue and additional disclosure requirements. The new standard is effective for annual periods beginning on or after January 1, 2018. The Company intends to adopt IFRS 15 and the clarifications in its financial statements for the annual period beginning on January 1, 2018. The Company does not expect the standard to have a material impact on the financial statements.

1. Significant accounting policies (continued):

(ii) IFRS 9, Financial Instruments ("IFRS 9"):

The IASB published the final version of IFRS 9 in July 2014. The final version of IFRS 9 brings together the classification and measurement, impairment and hedge accounting to replace IAS 39, Financial Instruments: Recognition and Measurement. IFRS 9 is built on a logical, single classification and measurement approach for financial assets that reflects the business model in which they are managed and their cash flow characteristics. IFRS 9 has an expected credit loss model for a timely recognition of loan losses and is a single model that is applicable to all financial instruments subject to impairment accounting. It also includes an improved hedge accounting model to better link the economics of risk management with its accounting treatment. IFRS 9 is effective for annual periods beginning on or after January 1, 2018. The Company intends to adopt IFRS 9 in its financial statements for the annual period beginning on January 1, 2018. The Company does not expect the standard to have a material impact on the financial statements.

(iii) IFRS 16, Leases ("IFRS 16"):

The IASB published IFRS 16 in January 2016. It replaces the previous leases standard, IAS 17, Leases, and related interpretations. IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases. It eliminates the current dual accounting model for lessees, which distinguishes between on-balance sheet finance leases and off-balance sheet operating leases. Instead, there is a single, on-balance sheet accounting model that is similar to current finance lease accounting. IFRS 16 is effective from January 1, 2019. A company can choose to apply IFRS 16 before that date but only if it also applies IFRS 15. The Company intends to early adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2018. The Company does not expect the standard to have a material impact on the financial statements.

(In thousands of dollars)

2. Accounts receivable:

	2016	2015
Energy revenue	$ 29,497	$ 19,513
Unbilled revenue	33,740	34,781
Project expenditures recoverable	3,275	3,522
Pole rentals and other	976	1,216
	67,488	59,032
Less allowance for doubtful accounts	1,070	1,070
	$ 66,418	$ 57,962

Unbilled revenue represents amounts for which the Company has a contractual right to receive cash through future billings and are unbilled at the period end. Unbilled revenue is considered current with no allowance for doubtful accounts.

(In thousands of dollars)

3. Property, plant and equipment:

December 31, 2016:

	December 31, 2015	Additions/ depreciation	Disposals/ retirements	December 31, 2016
Cost				
Land	$ 1,777	$ –	$ –	$ 1,777
Land rights	392	3	–	395
Buildings	16,530	801	–	17,331
Distribution station equipment	25,217	2,801	–	28,018
Transmission and distribution system	158,885	23,380	(333)	181,932
Meters	13,855	1,154	(142)	14,867
Office equipment	1,276	132	–	1,408
Computer hardware	1,540	839	–	2,379
Vehicle fleet	5,118	549	(54)	5,613
Renewable power generation	767	(8)	–	759
Construction in progress	10,362	2,322	–	12,684
	235,719	31,973	(529)	267,163
Accumulated depreciation				
Land rights	22	11	–	33
Buildings	2,330	1,120	–	3,450
Distribution station equipment	1,637	907	–	2,544
Transmission and distribution system	9,261	5,524	(61)	14,724
Meters	2,433	1,297	(36)	3,694
Office equipment	388	208	–	596
Computer hardware	719	384	–	1,103
Vehicle fleet	713	719	(45)	1,387
Renewable power generation	57	33	–	90
	17,560	10,203	(142)	27,621
	$ 218,159	$ 21,770	$ (387)	$ 239,542

(In thousands of dollars)

3. **Property, plant and equipment (continued):**

December 31, 2015:

	December 31, 2014	Additions/ depreciation	Disposals/ retirements	December 31, 2015
Cost				
Land	$ 1,777	$ –	$ –	$ 1,777
Land rights	385	7	–	392
Buildings	15,945	585	–	16,530
Distribution station equipment	23,109	2,108	–	25,217
Transmission and distribution system	138,593	20,662	(370)	158,885
Meters	13,148	804	(97)	13,855
Office equipment	1,207	69	–	1,276
Computer hardware	1,365	175	–	1,540
Vehicle fleet	3,820	1,298	–	5,118
Renewable power generation	630	137	–	767
Construction in progress	9,556	806	–	10,362
	209,535	26,651	(467)	235,719
Accumulated depreciation				
Land rights	11	11	–	22
Buildings	1,154	1,176	–	2,330
Distribution station equipment	785	852	–	1,637
Transmission and distribution system	4,371	4,934	(44)	9,261
Meters	1,203	1,247	(17)	2,433
Office equipment	191	197	–	388
Computer hardware	425	294	–	719
Vehicle fleet	35	678	–	713
Renewable power generation	27	30	–	57
	8,202	9,419	(61)	17,560
	$ 201,333	$ 17,232	$ (406)	$ 218,159

During the year, borrowing costs of $313 (2015 - $254) were capitalized to PP&E and credited to finance costs. Weighted average cost of short-term debt with a maturity date of November 1, 2039 and long-term borrowings is used for capitalizing borrowing costs as part of PP&E with an average rate of 3.94% (2015 - 4.00%).

Additions to construction in progress are net of transfers to other PP&E categories.

(In thousands of dollars)

4. Intangible assets:

December 31, 2016:

	December 31, 2015	Additions/ amortization	Disposals/ retirements	December 31, 2016
Cost				
Application software and other	$ 7,431	$ 1,825	$ –	$ 9,256
Construction in progress related to application software and other	126	58	–	184
Capital contributions	1,212	–	–	1,212
	8,769	1,883	–	10,652
Accumulated amortization				
Application software and other	4,306	1,898	–	6,204
	$ 4,463	$ (15)	$ –	$ 4,448

December 31, 2015:

	December 31, 2014	Additions/ amortization	Disposals/ retirements	December 31, 2015
Cost				
Application software and other	$ 5,654	$ 1,777	$ –	$ 7,431
Construction in progress related to application software and other	9	117	–	126
Capital contributions	1,212	–	–	1,212
	6,875	1,894	–	8,769
Accumulated amortization				
Application software and other	2,229	2,077	–	4,306
	$ 4,646	$ (183)	$ –	$ 4,463

No borrowing costs were capitalized on intangible assets under development in 2016 or 2015.

(In thousands of dollars)

4. Intangible assets (continued):

Application software and other includes externally acquired, as well as internally generated computer software. The remaining amortization period is between 1 and 5 years.

5. Depreciation and amortization:

	2016	2015
Total depreciation and amortization expense	$ 12,102	$ 11,497
Allocated to:		
Depreciation/amortization of vehicle fleet included in operating and maintenance expenses	719	678
Depreciation/amortization of assets in non-regulated utility operations included in other income	33	43
	752	721
Depreciation and amortization expense	$ 11,350	$ 10,776

6. Regulatory balances:

Regulatory balances can arise out of the rate-making process. Specifically, the following regulatory treatments have resulted in accounting treatments that differ from IFRS for enterprises operating in a non-regulated environment and regulated entities that did not adopt IFRS 14:

(i) The Company records the difference between the borrowing costs capitalization rate prescribed by the OEB and the weighted average cost of borrowings rate used to capitalize PP&E under IFRS. This amount is recognized as a regulatory debit or credit balance to be recovered or paid respectively to the customers through future rates;

(ii) The Company records regulatory debit balances arising from derecognition of assets under IFRS. These amounts will be sought for disposition through the next cost of service rebasing application and recovered from customers through future rates;

(iii) The Company records deferred tax assets and a corresponding regulatory tax liability, as the recovery from, or refund to, customers is expected to be included in future distribution rates for its regulated business activities;

VERIDIAN CONNECTIONS INC.

Notes to the Financial Statements (continued)
(In thousands of dollars)

Years ended December 31, 2016 and 2015

6. Regulatory balances (continued):

(iv) The Company has deferred certain retail settlement variances which comprise the variances between amounts charged by the Company to customers based on regulated rates and wholesale rates incurred for the cost of electricity service; and

(v) The Company has deferred costs related to: IFRS implementation, lost revenue adjustment mechanism costs, and OEB assessment costs.

Debit balances comprise of the following:

	January 1, 2016	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2016	Remaining recovery/ reversal period (years)
Approved settlement variances (a)	$ 1,371	$ 5	$ (1,287)	$ –	$ 89	1 year
One-time IFRS conversion costs (b)	473	6	–	–	479	Note 1
Extraordinary costs related to ice storm restoration (d)	205	–	(205)	–	–	
IFRS transitional adjustments (e)	852	267	–	–	1,119	Note 1
Other (f)	269	574	–	–	843	Note 1
	$ 3,170	$ 852	$ (1,492)	$ –	$ 2,530	

	January 1, 2015	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2015	Remaining recovery/ reversal period (years)
Approved settlement variances (a)	$ 821	$ 2,830	$ (2,280)	$ –	$ 1,371	1 year
Future settlement variances (a)	2,633	–	–	(2,633)	–	Note 3
One-time IFRS conversion costs (b)	469	4	–	–	473	Note 1
Stranded meters (c)	1,457	–	–	(1,457)	–	Note 3
Extraordinary costs related to ice storm restoration (d)	728	7	(530)	–	205	1 year
IFRS transitional adjustments (e)	494	358	–	–	852	Note 1
Other (f)	162	107	–	–	269	Note 1
	$ 6,764	$ 3,306	$ (2,810)	$ (4,090)	$ 3,170	

(In thousands of dollars)

6. Regulatory balances (continued):

Credit balances comprise of the following:

	January 1, 2016	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2016	Remaining recovery/ reversal period (years)
Future settlement variances (a)	$ 2,646	$ 5,162	$ –	$ –	$ 7,808	Note 1
Stranded meters (c)	18	–	–	–	18	Note 1
Other (f)	47	1	–	–	48	Note 1
Deferred taxes (g)	4,942	(2,431)	–	–	2,511	Note 2
	$ 7,653	$ 2,732	$ –	$ –	$ 10,385	

	January 1, 2015	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2015	Remaining recovery/ reversal period (years)
Future settlement variances (a)	$ –	$ 2,448	$ 2,831	$ (2,633)	$ 2,646	Note 1
Approved IFRS transitional adjustments (e)	3,049	–	(3,049)	–	–	
Stranded meters (c)	–	(4)	1,479	(1,457)	18	Note 1
Other (f)	40	25	(18)	–	47	Note 1
Deferred taxes (g)	6,694	(1,752)	–	–	4,942	Note 2
	$ 9,783	$ 717	$ 1,243	$ (4,090)	$ 7,653	

Note 1 The Company intends to seek recovery or refund in future rate applications to the OEB.

Note 2 The Company will not seek disposition of the balance since it will be reversed through timing differences in the recognition of deferred tax assets.

Note 3 These balances have been reclassified to regulatory credit balances.

The balances arising in the period column are new additions (for both debits and credits). The recovery/reversal column are amounts: collected or refunded through rate riders, disposition of OEB-approved regulatory balances, or other transactions which reduces existing regulatory balances. The other movements column consists of impairment (if the OEB disallowed certain amounts), carrying cost adjustments, and reclassification between the regulatory debit and credit balances. There is no impairment recorded for the years ended December 31, 2016 and December 31, 2015.

6. Regulatory balances (continued):

Regulatory balances descriptions:

(a) Settlement variances:

The amounts include the variances between the amount charged by the IESO for the operation of the markets and grid, as well as various wholesale market settlement charges and transmission charges, as compared to the amount billed to consumers based on the OEB-approved rates. This amount also includes variances between the amounts charged by Hydro One Networks Inc. ("Hydro One") for low voltage services and the amount billed to consumers based on the OEB-approved rates. Also included are retail cost variances, being the differences between the revenue charged to retailers and the retail services costs associated with providing the retail services.

In 2015, the OEB approved the disposition of the Company's retail settlement variance accounts as at December 31, 2013.

(b) One-time IFRS conversion costs:

In accordance with an OEB directive, a deferral account has been established for the one-time administrative costs during transition to IFRS. These amounts will be sought for disposition in the Company's first cost of service rebasing application under IFRS.

(c) Stranded meters:

These amounts are related to the provincial government's directive for licensed distributors to install smart meters for specific customer classes and represent the net book value of stranded meter assets arising from the Company's smart metering program.

In 2014, the OEB approved the Company's request for recovery of these regulatory balances through a rate rider with a one-year term.

This rate rider expired April 30, 2015 with the balance to be refunded in a future rate application to the OEB.

6. Regulatory balances (continued):

(d) Extraordinary costs related to ice storm restoration:

In December 2013, the Company recorded deferred power restoration costs related to a severe ice storm as a regulatory balance for disposition to be sought in the future.

On February 19, 2015, the OEB approved the Company's application for recovery of these costs through a rate rider which ended February 28, 2016.

(e) IFRS transitional adjustments:

Approved amounts:

In 2012, the Company began recording regulatory credit balances arising from changes in estimates of useful lives of PP&E and increases in operating expenses resulting from changes in estimation and allocation of overheads.

In 2014, the OEB approved the Company's request for refund of the amount of $6,278 to ratepayers through a rate rider with a one-year term. This rate rider expired April 30, 2015.

Future amounts:

Commencing in 2014, the Company has recorded regulatory debit balances arising from derecognition of assets under IFRS and capitalized borrowing costs difference between weighted average long-term borrowing costs under IFRS and OEB guidelines. These amounts will be sought for disposition in the Company's first cost of service rebasing application under IFRS.

(f) Other:

These amounts relate to the deferral of costs related to lost revenue adjustment mechanism costs, renewable generation connection funding adder, OEB assessment costs and other regulatory balances.

(g) Deferred taxes:

This regulatory credit balance includes both deferred tax amounts reclassified under IFRS 14 and expected future electricity distribution rate reduction for customers arising from timing difference in the recognition of deferred tax assets.

(In thousands of dollars)

6. Regulatory balances (continued):

The amounts reclassified under IFRS 14 include the deferred tax liability related to regulatory balances $626 as at December 31, 2016 (2015 - $399).

The deferred tax amount related to the expected future electricity distribution rate reduction for customers was $1,885 as at December 31, 2016 (2015 - $4,543).

7. Income taxes:

The provision for income taxes differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and effective tax rates is provided as follows:

	2016	2015
Income before income taxes	$ 17,939	$ 14,505
Federal and Ontario statutory income tax rate	26.50%	26.50%
Provision for income taxes at statutory rate	$ 4,754	$ 3,844
Increase (decrease) resulting from:		
Temporary differences expected to be recovered from customers	(1,857)	(1,373)
Other miscellaneous	(1,814)	(932)
Income taxes recorded in regulatory balances movements	2,431	1,752
Income tax expense	$ 3,514	$ 3,291
Allocated:		
Current	$ 1,156	$ 1,407
Deferred	(73)	132
Income taxes recorded in regulatory balances movements	2,431	1,752
Total income tax expense	$ 3,514	$ 3,291

(In thousands of dollars)

7. Income taxes (continued):

Deferred tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. The tax effects of these differences are as follows:

	2016	2015
Deferred tax assets:		
Property, plant and equipment and intangible assets	$ 500	$ 2,977
Employee future benefits	999	943
Sick leave liability	352	352
Unrealized loss on interest rate swaps	960	889
Deferred revenue, contingent liability and others	927	934
	3,738	6,095
Deferred tax liabilities:		
Regulatory balances	626	399
Moved to regulatory deferral account credit balances	(626)	(399)
	–	–
Deferred tax assets	$ 3,738	$ 6,095

8. Accounts payable and accrued liabilities:

	2016	2015
Power bill accrual	$ 28,896	$ 26,803
Customer credit balances	3,783	6,357
Other accounts payable and accrued liabilities	11,629	10,893
	$ 44,308	$ 44,053

9. Credit facilities and short-term debt:

Credit facilities:

As at December 31, 2016, the Company had the following external credit facilities with a Canadian chartered bank (the "Bank"):

(a) Uncommitted revolving demand credit facility. The facility at all times is required to be no greater than $30,000 with a letter of credit ("L/C") carve-out availability;

(b) Committed reducing term facility with a credit limit of $40,999 and amortization term of 30 years with an optional exit strategy at 10 years, 15 years, 20 years and 25 years (note 12); and

(c) Committed or demand revolver facility (note 12) with a combined total no greater than $70,000 at all times.

The financial covenants to the above facilities require a funded debt to capitalization ratio of no greater than 0.60:1, and maintain a debt service coverage ratio of not less than 1.20:1. The financial covenants are tested on a consolidated basis. The Corporation and the Company have been in compliance with all the covenants.

As at December 31, 2016, nil was drawn out of facility (a); $39,653 was outstanding out of facility (b) and $25,000 was outstanding out of facility (c) above (note 12). To cover the risk of fluctuating interest rates, facility (b) was structured with interest rate swap agreement with the Bank, effectively converting the obligations into a fixed interest rate loan of approximately 3.715%.

The Company utilized (a) for: $807 to issue an irrevocable L/C in favour of the IESO; and $100 to issue an irrevocable L/C in favour of the Ministry of Environment.

The IESO requires all purchasers of electricity in Ontario to provide security to mitigate the risk of their default based on their expected purchases from the IESO administered spot market. The IESO could draw on the L/C if the Company defaults on its payment.

The Ministry of Environment requires security to ensure adequate funds are available, to effect suitable remedial action, if an event occurs resulting in a health and safety hazard to any person, or the natural environment.

9. Credit facilities and short-term debt (continued):

Short-term debt:

As at December 31, 2016, the Company had $43,588 notes payable to the Corporation's shareholders with the maturity date of November 1, 2039, at a rate equal to the OEB-deemed long-term debt rate less 30-basis-points. The noteholders have a right to demand repayment of this note (in whole or in part) at any time upon six months prior written notice to the Company provided that a duly enacted resolution or by-law is passed by the noteholders certifying that the funds are required for municipal purposes. As the Company does not have any unconditional right to defer settlement of this liability for at least twelve months after the reporting period, the notes are classified as a short-term debt.

10. Deferred revenue:

Deferred revenue represents the balance at year end of unearned revenue from funding received from the IESO to deliver CDM programs. On February 3, 2011, the Company entered into an agreement to deliver these CDM programs. These programs were to cover the period from January 1, 2011 to December 31, 2014. The agreement was amended on November 14, 2014, and was extended until December 31, 2015. All programs are fully funded and paid in advance by the IESO. Amounts received but not yet spent are presented on the balance sheets under current liabilities as deferred revenue.

A new agreement was entered with the IESO on December 16, 2014 and on June 8, 2015, whereby the IESO conditionally approved a CDM plan that was jointly submitted by the Company and Whitby Hydro Electric Corporation to deliver CDM programs covering the period from January 1, 2015 to December 31, 2020.

In accordance with the funding model that was approved in the Joint CDM Plan, all programs to be delivered under the IESO agreement are expected to be fully funded and paid by the IESO. The IESO is invoiced monthly for the costs incurred on various CDM programs. The Company received some initial funding from the IESO for the delivery of CDM programs under the energy conservation agreement. Amounts received but not yet spent are presented on the balance sheets under current liabilities as deferred revenue.

11. Related party transactions:

The Company provides electricity and services to the Corporation's shareholders, the Town of Ajax, the Municipality of Clarington, the City of Pickering and the City of Belleville (collectively, the "shareholders"). Electrical energy is sold to the Corporation's shareholders at the same prices and terms as other electricity customers consuming equivalent amounts of electricity.

The electricity and services amounts charged by the Company to the Corporation's shareholders for the year ended December 31, 2016 was $8,889 (2015 - $8,276). As at December 31, 2016, accounts receivable include $716 (2015 - $1,028) due from the Corporation's shareholders.

Finance costs includes interest of $1,948 (2015 - $1,948) on the notes payable to the Corporation's shareholders and $1,466 (2015 - $1,498) on the notes payable to the Corporation.

The Company paid $429 (2015 - $435) in property taxes to the Corporation's shareholders.

The Company paid $2,010 (2015 - $1,734) in compensation to the Company's key management personnel, comprising of the senior management team and members of the Board of Directors. The compensation includes salaries, performance pay, taxable benefits and OMERS contributions.

The Company declared and paid a dividend of $4,649 (2015 - $5,350) to the Corporation.

The Company has renewable generation projects and holds interest in the following joint operation:

Claremont Community Centre Solar:

The Company, Queen Street Solar Co-Operative Corporation and Solera Sustainable Energies Company Limited entered into a joint operation agreement with an equity interest of 39%, 51% and 10%, respectively, to build, own, operate and maintain a solar generation project at Claremont Community Centre owned by the City of Pickering, located at 4941 Old Brock Road, Pickering, Ontario L1V 7E2. This project is approved under the Feed-in Tariff government program.

(In thousands of dollars)

11. Related party transactions (continued):

In 2016, the Corporation financed the above project for an amount of $264 for a 15-year term at an interest rate of 5.00%. An amount of $101 (net of repayments) is included in the Company's long-term debt as at December 31, 2016 (note 12). The funding provided by the Corporation was in the same proportion as the equity interest: VCI 39%, Queen Street Solar Co-Operative Corporation 51% and Solera Sustainable Energies Company Limited 10%.

12. Long-term debt:

	2016	2015
Notes payable to the Corporation, maturing on December 9, 2024, at a rate of 4.77%	$ 15,000	$ 15,000
Notes payable to the Corporation, maturing on December 17, 2039, at a rate equal to the OEB-deemed long-term debt rate, less 30-basis-points	16,100	16,800
Loan payable to the Corporation, maturing on September 1, 2031, at a rate of 5%	101	–
Long-term debt from the Bank, maturing on March 2, 2045 (note 9)	39,653	40,433
Long-term debt from the Bank, repayable no later than December 28, 2019 (note 9)	25,000	15,000
	95,854	87,233
Less current portion	1,514	1,480
	$ 94,340	$ 85,753

Scheduled principal repayments for the next five years and thereafter as of December 31, 2016:

2017	$ 1,514
2018	1,545
2019	26,577
2020	1,610
2021	1,645
Thereafter	62,963
	95,854
Less current portion	1,514
	$ 94,340

(In thousands of dollars)

12. Long-term debt (continued):

Scheduled principal repayments for the next five years and thereafter as of December 31, 2015:

2016	$ 1,480
2017	1,509
2018	1,540
2019	16,571
2020	1,605
Thereafter	64,528
	87,233
Less current portion	1,480
	$ 85,753

Scheduled interest payments for the next five years and thereafter as of December 31, 2016:

2017	$ 5,094
2018	5,032
2019	4,968
2020	4,689
2021	4,624
Thereafter	60,610
	$ 85,017

Expected weighted average borrowing costs:

2017	3.66%
2018	3.65%
2019	3.65%
2020	3.48%
2021	4.28%

(In thousands of dollars)

12. Long-term debt (continued):

Finance costs related to short-term and long-term debt comprise:

	2016	2015
Interest on:		
Notes payable and loans	$ 5,186	$ 5,238
Customer deposits and other	67	43
	5,253	5,281
Less capitalized borrowing costs	313	254
	$ 4,940	$ 5,027

13. Deferred contributions:

Deferred contributions are the capital contributions received from electricity customers, which have not yet been recognized into other income.

The continuity of deferred contributions is as follows:

	2016	2015
Deferred contributions, beginning of year	$ 11,543	$ 5,903
Contributions received	7,458	5,828
Contributions amortized as other income	(318)	(188)
Deferred contributions, end of year	$ 18,683	$ 11,543

Customer contributions for the acquisition or construction of PP&E are considered to be deferred contributions and are recognized over the useful lives of the related assets as other income.

(In thousands of dollars)

14. Employee benefits:

(a) Pensions:

During 2016, the Company made contributions totalling $2,187 (2015 - $2,078) to OMERS.

(b) Employee future benefits:

The Company pays certain benefits on behalf of its retired employees and recognizes these post-retirement costs in the period in which the employees render the services.

Information about the Company's non-contributory defined benefit plan to fund life insurance, health and dental care benefits and a retiree HCSA, is as follows:

	2016	2015
Accrued benefit liability recognized, January 1	$ 2,616	$ 2,514
Current service costs	74	72
Interest expense on accrued benefit obligation	100	101
Benefit payments	(96)	(71)
Remeasurements recognized in other comprehensive income	77	–
Accrued benefit liability, December 31	$ 2,771	$ 2,616

The amounts presented are based upon an actuarial valuation performed as at December 31, 2014 with a measurement date of January 1, 2014. The next valuation is expected to be performed for the year ending December 31, 2017.

The main actuarial assumptions employed for the valuations are as follows:

(i) General inflation:

Future general inflation levels, as measured by changes in the Consumer Price Index, are assumed at 2.00% for future years.

(ii) Interest (discount) rate:

Amounts were determined using an annual discount rate of 3.90% (2015 - 4.10%).

(In thousands of dollars)

14. Employee benefits (continued):

(iii) Salary levels:

Future general salary and wage levels were assumed to increase at 3.60% (2015 - 3.60%) per annum.

(iv) Health and dental care:

The health and dental care cost increases are 6.31% and 4.60% (2015 - 6.66% and 4.60%), respectively.

(c) Risks associated with the plan:

Significant actuarial assumptions related to discount rates, future health and dental costs, mortality rates, retirement age, and utilization rate of the HCSA etc. may affect the valuation of expected accrued benefit liability.

15. Share capital:

	2016		2015	
	Number of shares	Amount	Number of shares	Amount
Authorized:				
Unlimited common shares				
Issued	15,000	$ 69,302	15,000	$ 69,302

16. Dividends:

The Company's current dividend policy states:

(a) the base annual dividend to the Corporation be set at $4,600 from 2012 to 2017;

(b) the base dividend would be increased or decreased depending upon:

(i) decrease/increase in debt to capitalization ratio of 60%;

(ii) net income projected to be higher/lower than budget; or

(iii) capital expenditure projected to be lower/higher than budget.

(c) the Company's Board of Directors should determine annually if earnings from renewable generation be used to supplement the base dividend.

During 2016, the Board of Directors of the Company declared and paid dividends totalling $4,649 (2015 - $5,350) to the Corporation.

17. Contingencies and guarantees:

(a) Insurance claims:

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. MEARIE provides general liability insurance to member electric utilities. MEARIE also provides vehicle and property insurance to the Company.

Insurance premiums charged to each member electric utility consist of a levy per $1 of service revenue subject to a credit or surcharge based on each electric utility's claims experience. The maximum coverage is $24,000 per occurrence for liability insurance, $15,000 for vehicle insurance, and $98,685 for property insurance; plus $10,000 excess coverage on top of the regular liability and vehicle coverage.

(In thousands of dollars)

17. Contingencies and guarantees (continued):

(b) Contractual obligation - Hydro One Networks Inc.:

The Company is party to a connection and cost recovery agreement with Hydro One related to the construction by Hydro One of a transformer station designated to meet the Company's anticipated electricity load growth. Construction of the project was completed during 2007 and the Company connected to the transformer station during 2008.

To the extent that the cost of the project is not recoverable from future transformation connection revenues, the Company is obligated to pay a capital contribution equal to the difference between these revenues and the construction costs allocated to the Company. The construction costs allocated to the Company for the project are $9,975.

The Company has recorded a liability and a corresponding intangible asset for $1,212 as at December 31, 2016 (2015 - $1,212), based on management's best estimate of the future transformation connection revenue shortfall. Hydro One is expected to perform a true-up based on actual load at the end of the tenth and fifteenth anniversaries of the in-service date.

(c) General claims:

From time to time, the Company is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's financial position and results of operations or cash flows.

18. Lease commitments:

Future minimum lease payment obligations under operating leases are as follows:

2017	$ 41
2018	41
2019	33
2020	32
2021	33
Thereafter	60
	$ 240

(In thousands of dollars)

19. Other income (loss):

	2016	2015
Third party revenue (a)	$ 562	$ 1,237
Late payment charges	510	493
Customer charges (b)	1,843	1,974
Pole rentals	484	484
Disposal of PP&E	(362)	(373)
Foreign exchange	(7)	(20)
Amortization of deferred contributions	318	148
	$ 3,348	$ 3,943

(a) Mainly includes revenue for CDM incentives related to 2011-14 programs received from IESO.

(b) Includes reconnection/disconnection, collection and change of occupancy charges from customers.

20. Operating, maintenance and administration expenses:

	Operating and maintenance		Administration	
	2016	2015	2016	2015
Salaries and benefits	$ 5,819	$ 5,656	$ 11,221	$ 10,490
External services	2,778	2,585	2,787	2,409
Materials and supplies	140	139	1	5
Vehicle	494	534	45	43
Other	397	339	4,025	4,355
	$ 9,628	$ 9,253	$ 18,079	$ 17,302

(In thousands of dollars)

21. Statements of cash flows:

Changes in non-cash operating working capital provided by (used in) includes the following:

	2016	2015
Accounts receivable	$ (8,456)	$ 697
Related parties	(46)	(37)
Materials and supplies	(389)	(275)
Prepaid expenses	(627)	389
Accounts payable and accrued liabilities	(64)	(399)
Advance payments - construction deposits	(216)	(284)
Deferred revenue	(27)	601
Developer obligations	503	(465)
	$ (9,322)	$ 227

22. Financial instruments and risk management:

(a) Market risk:

Market risk refers primarily to risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk due to the flow-through nature of energy purchases and costs. All variances due to timing of customer billing or regulated pricing are recorded in retail settlement variance accounts and are recovered from or returned to customers in accordance with regulatory directives. The foreign exchange risk is considered not material and is limited to U.S. dollar cash and cash equivalents holdings of $132 (2015 - $77) as at December 31, 2016.

(b) Interest rate risk:

The Company enters into fixed interest rate long-term debt agreements to minimize cash flow and interest rate fluctuation exposure. In February 2015, a $40,999, 30-year fixed rate term loan was arranged from the Bank to blend and extend a $30,000 loan and a $15,000 loan. The Company entered into interest rate swap derivative agreements with the Bank to exchange interest rate cash flows. Under these agreements, the Company and the Bank have the periodic exchange of payments without exchanging the notional principal amount on which the payments are based. This effectively provided the Company with fixed rate loans, which reduces the impact of fluctuating interest rates on long-term debt. The Company does not enter into any such financial instrument for speculative purposes.

22. Financial instruments and risk management (continued):

(c) Credit risk:

Financial assets create credit risk that a counterparty will fail to discharge an obligation, causing a financial loss. The Company's distribution revenue is earned on a broad base of customers. As a result, the Company did not earn a significant amount of revenue from any individual customer. As at December 31, 2016, there were no significant balances of accounts receivable due from any single customer.

The Company manages counterparty credit risk through various techniques, including limiting total exposure levels with individual counterparties consistent with the Company's policies and monitoring the financial condition of counterparties.

Management believes that the credit risk of accounts receivable is limited due to the following reasons:

(i) There is a broad base of customers with no one customer that accounts for revenue or an accounts receivable balance in excess of 10% of the respective balance.

(ii) The Company, as permitted by the OEB's Retail Settlement and Distribution System Code, may obtain a security deposit or L/C from customers to mitigate risk of payment default.

(iii) The percentage of accounts receivable that is outstanding more than 90 days is approximately 1.36% (2015 - 1.59%) of the total net outstanding balance.

(iv) The Company includes an amount of accounts receivable write-offs within net income for rate-setting purposes.

(In thousands of dollars)

22. Financial instruments and risk management (continued):

Pursuant to their respective terms, accounts receivable are aged as follows as at December 31:

	2016	2015
Total accounts receivable	$ 67,488	$ 59,034
Less allowance for doubtful accounts	1,070	1,070
Total accounts receivable, net	$ 66,418	$ 57,964
Of which:		
Unbilled revenue	$ 33,740	$ 34,781
Outstanding 1 day but not more than 30 days	30,654	21,995
Outstanding 31 days but not more than 60 days	1,788	982
Outstanding 61 days but not more than 90 days	399	355
Outstanding 91 days but not more than 120 days	439	412
Outstanding more than 120 days	468	509
	67,488	59,034
Less allowance for doubtful accounts	1,070	1,070
	$ 66,418	$ 57,964

(d) Liquidity risk:

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Short-term liquidity is provided through cash and cash equivalents on hand and funds from operations. Short-term liquidity is expected to be sufficient to fund normal operating requirements. The liquidity risks associated with financial commitments are as follows:

Financial commitments as of December 31, 2016:

	Due within one year	Due between one and five years	Due past five years
Financial liabilities:			
Accounts payable and accrued liabilities	$ 44,308	$ –	$ –
Short-term debt (note 9)	43,588	–	–
Long-term debt	1,514	31,376	62,964
Lease commitments	41	139	60

(In thousands of dollars)

22. Financial instruments and risk management (continued):

Financial commitments as of December 31, 2015:

	Due within one year	Due between one and five years	Due past five years
Financial liabilities:			
Accounts payable and accrued liabilities	$ 44,053	$ –	$ –
Short-term debt (note 9)	43,588	–	–
Long-term debt	1,480	21,225	64,528
Lease commitments	34	26	62

(e) Fair values:

The Company included $3,621 of unrealized loss (2015 - $3,357) in its financial statements. This is the fair value of the interest rate swap derivative which represents the amount that the Company would have paid to unwind its position as at December 31, 2016. This unrealized loss is not expected to affect cash as the Company intends to hold the financial instrument until its maturity.

Fair value measurements recognized in the statements of comprehensive income are categorized using a fair value hierarchy that reflects the significance of inputs used in determining the fair values.

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

The interest rate swap derivatives are all Level 2 as at December 31, 2016.

There were no transfers between levels during the year.

(In thousands of dollars)

22. Financial instruments and risk management (continued):

The carrying amounts of all financial instruments, except the following: short-term debt with a maturity date of November 1, 2039, and long-term debt; approximate fair values due to the immediate or short-term maturity of these financial instruments. The estimated fair values of the loans payable, including related party loans, are as follows:

	2016	2015
Fair value	$ 145,530	$ 124,062
Carrying value (notes 9 and 12)	139,442	130,821

(f) Capital management:

The Company considers its capital structure to consist of shareholder's equity, short-term debt, long-term debt, less cash and cash equivalents. The Company's capital structure was as follows:

	2016	2015
Cash	$ (4,953)	$ (6,416)
Short-term debt	43,588	43,588
Long-term debt	95,854	87,233
	139,442	130,821
Share capital	69,302	69,302
Retained earnings	35,087	28,683
Contributed capital	23	23
Accumulated other comprehensive loss	(340)	(264)
	104,072	97,744
Total capital	$ 238,561	$ 222,149

23. Comparative information:

Certain comparative information has been reclassified to conform with the financial statement presentation adopted in the current year.

Financial Statements of

VERIDIAN CONNECTIONS INC.

Years ended December 31, 2017 and 2016

KPMG LLP
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Vaughan ON L4K 0J3
Canada
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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Veridian Connections Inc.

We have audited the accompanying financial statements of Veridian Connections Inc., which comprise the balance sheets as at December 31, 2017 and 2016, the statements of comprehensive income, changes in equity and cash flows for the years then ended, and notes, comprising 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 financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits 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 our 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, we consider 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 in our audits is sufficient and appropriate to provide a basis for our audit opinion.

KPMG LLP, is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity.
KPMG Canada provides services to KPMG LLP.

KPMG

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Veridian Connections Inc. as at December 31, 2017 and 2016, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

April 5, 2018
Vaughan, Canada

VERIDIAN CONNECTIONS INC.

Balance Sheets
(In thousands of dollars)

December 31, 2017 and 2016

	Note	2017	2016
Assets			
Current assets:			
Cash		$ 9,363	$ 4,953
Accounts receivable	2	52,068	66,418
Due from related parties	12	176	111
Materials and supplies		3,020	3,031
Prepaid expenses		1,280	1,202
Total current assets		65,907	75,715
Non-current assets:			
Property, plant and equipment	3, 22	256,503	239,542
Intangible assets	4, 22	4,131	4,448
Goodwill		8,746	8,746
Deferred tax assets	7	854	3,738
Other assets		92	161
Total non-current assets		270,326	256,635
Total assets		336,233	332,350
Regulatory balances	6	2,852	2,530
Total assets and regulatory balances		$ 339,085	$ 334,880
Liabilities and Shareholder's Equity			
Current liabilities:			
Accounts payable and accrued liabilities	8	$ 41,314	$ 44,308
Due to related parties	12	43	42
Short-term debt	9	43,588	43,588
Income taxes payable		83	123
Deferred revenue	10	1,767	1,850
Deposits and developer obligations	11	8,671	8,371
Long-term debt	13	1,545	1,514
Total current liabilities		97,011	99,796
Non-current liabilities:			
Long-term debt	13	92,795	94,340
Deferred contributions	14	23,311	18,683
Employee future benefits	15	2,891	2,771
Unrealized loss on interest rate swaps	23(e)	1,992	3,621
Other liabilities	18(b)	1,212	1,212
Total non-current liabilities		122,201	120,627
Total liabilities		219,212	220,423
Shareholder's equity:			
Share capital	16	69,302	69,302
Contributed capital		23	23
Accumulated other comprehensive loss		(316)	(340)
Retained earnings		41,122	35,087
Total shareholder's equity		110,131	104,072
Total liabilities and equity		329,343	324,495
Regulatory balances	6	9,742	10,385
Contingencies and guarantees	18		
Lease commitments	19		
Total liabilities, equity and regulatory balances		$ 339,085	$ 334,880

See accompanying notes to the financial statements.

On behalf of the Board:

Chair, Board of Directors

Chair, Audit and Risk Management Committee

VERIDIAN CONNECTIONS INC.

Statements of Comprehensive Income
(In thousands of dollars)

Years ended December 31, 2017 and 2016

	Note	2017	2016
Revenue:			
Commodity		$ 280,206	$ 338,009
Commodity cost		(277,975)	(331,487)
		2,231	6,522
Distribution revenue		52,225	52,264
Other income	20	2,822	3,348
		57,278	62,134
Expenses:			
Operating and maintenance	21	9,634	9,628
Administration	21	18,582	18,079
Depreciation and amortization	5	12,003	11,350
		40,219	39,057
		17,059	23,077
Finance income		132	66
Finance costs	13	(5,045)	(4,940)
Unrealized gain (loss) on interest rate swaps	23(e)	1,629	(264)
		(3,284)	(5,138)
Income before income taxes		13,775	17,939
Income tax expense	7	3,698	3,514
Net income		10,077	14,425
Net movements in regulatory balances, net of tax:	6		
Net movements in regulatory balances		(1,242)	(5,803)
Income tax on net movements in regulatory balances		2,207	2,431
		965	(3,372)
Net income after net movements in regulatory balances		11,042	11,053
Other comprehensive income (loss), net of tax:			
Remeasurements of employee future benefits		24	(77)
Total comprehensive income		$ 11,066	$ 10,976

See accompanying notes to the financial statements.

VERIDIAN CONNECTIONS INC.

Statements of Changes in Equity
(In thousands of dollars)

Years ended December 31, 2017 and 2016

	Note	2017	2016
Share capital		$ 69,302	$ 69,302
Contributed capital		23	23
Accumulated other comprehensive loss		(316)	(340)
		69,009	68,985
Retained earnings, beginning of year		35,087	28,683
Net income after net movements in regulatory balances		11,042	11,053
Dividends paid	17	(5,007)	(4,649)
Retained earnings, end of year		41,122	35,087
Total equity		$ 110,131	$ 104,072

See accompanying notes to the financial statements.

VERIDIAN CONNECTIONS INC.

Statements of Cash Flows
(In thousands of dollars)

Years ended December 31, 2017 and 2016

	Note	2017	2016
Cash provided by (used in):			
Operating activities:			
Net income after net movements in regulatory balances		$ 11,042	$ 11,053
Adjustments:			
Depreciation and amortization	5	12,797	12,102
Amortization of deferred contributions		(458)	(318)
Loss on disposal/retirement of property, plant and equipment		194	362
Employee future benefits		144	79
Unrealized loss (gain) on interest rate swaps		(1,629)	264
Finance income		(132)	(66)
Finance costs		5,045	4,940
Income tax expense		3,698	3,514
Deferred contributions		5,086	7,458
Customer deposits		(296)	625
Income taxes paid		(1,075)	(1,400)
Income taxes received		222	221
Other assets		69	69
Net movements in regulatory balances		(965)	3,372
		33,742	42,275
Changes in non-cash operating working capital	22	13,203	(9,322)
Net cash provided by operating activities		46,945	32,953
Financing activities:			
Interest received		132	66
Repayment of long-term debt		(1,514)	(1,379)
Proceeds from long-term debt		–	10,000
Dividends paid	17	(5,007)	(4,649)
Interest paid		(4,841)	(4,934)
Net cash used in financing activities		(11,230)	(896)
Investing activities:			
Additions to property, plant and equipment	22	(29,746)	(31,821)
Additions to intangible assets	22	(1,625)	(1,723)
Proceeds from disposal of property, plant and equipment		66	24
Net cash used in investing activities		(31,305)	(33,520)
Increase (decrease) in cash		4,410	(1,463)
Cash, beginning of year		4,953	6,416
Cash, end of year		$ 9,363	$ 4,953

See accompanying notes to the financial statements.

Veridian Connections Inc. ("VCI" or the "Company") commenced operations on November 1, 1999. It is a wholly owned subsidiary of Veridian Corporation (the "Corporation"). The Company is licensed by the Ontario Energy Board (the "OEB") as an electricity distributor which distributes electricity in the cities of Belleville and Pickering, the towns of Ajax, Gravenhurst, Port Hope and Uxbridge, and the communities of Bowmanville, Newcastle, Orono, Beaverton, Cannington, Sunderland and Port Perry. The Company's registered office is located at 55 Taunton Road East, Ajax, Ontario L1T 3V3.

1. Significant accounting policies:

(a) Basis of presentation:

These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

These financial statements are presented in Canadian dollars, which is the Company's functional currency. The financial statements have been prepared on the historical cost basis, except for employee future benefits and certain financial instruments that are measured at fair value.

(b) Regulated environment:

The Company is an electricity distributor licensed by the OEB. It is regulated by the OEB under authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or setting rates for the transmission and distribution of electricity and the responsibility of ensuring that distribution companies fulfill obligations to connect and service customers.

1. Significant accounting policies (continued):

The Ontario Energy Board Act, 1998 sets out guiding objectives for the OEB:

- To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service;
- To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry;
- To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances;
- To facilitate the implementation of a smart grid in Ontario; and
- To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

The Company is responsible for charging its customers the following revenues:

- Commodity revenue - The commodity revenue is pass-through revenue for amounts payable to third parties. This revenue represents the costs of electricity consumed by the customers and passed through to the Independent Electricity System Operator ("IESO"). It also includes global adjustment revenue for non-regulated price plan consumers.
- Wholesale market services ("WMS") revenue - The WMS revenue represents the recovery of wholesale market costs for the IESO to operate the electricity market and maintain the system. This revenue is passed through to the IESO.
- Retail transmission service rate ("RTSR") revenue - The RTSR revenue represents the recovery of costs incurred for transmission of electricity to local distribution networks. This revenue is passed through to operators of transmission facilities.

1. **Significant accounting policies (continued):**

- Electricity distribution revenue - The electricity distribution revenue represents the recovery of costs incurred by VCI in delivering the electricity to its customers.

Electricity distribution rates:

Electricity distribution rates include both fixed monthly rates per customer and variable rates per kWh usage or kW demand. In 2015, the OEB released a policy that for residential electricity customers only, distribution delivery costs will be recovered through a monthly, fixed service charge. The policy set out that the transition to a fully fixed rate would occur over four years beginning in 2016. The fixed rate will increase gradually and the variable rate will decline. These distribution rates are subject to regulation by the OEB.

The OEB regulates electricity rates for distributors through three different rate setting options: Price Cap Incentive Rate-setting, Custom Incentive Rate-setting, and Annual Incentive Rate-setting Index. The Price Cap Incentive Rate-setting method sets a distributor's rates through a formula-based mechanism using a price cap index.

(c) Revenue recognition:

(i) Electricity distribution and sale:

Revenue from the sale of electricity is recognized on an accrual basis driven by cyclical billings based on electricity usage billed at OEB-approved distribution rates. Revenue from the sale of electricity includes an estimate of unbilled revenue accrued in respect of electricity delivered but not yet billed at year end. Unbilled revenue is calculated based on OEB-approved rates for electricity consumption and electricity demand driven by number of days between a customer's last meter reading in the year and December 31. Actual billed revenue could differ from estimates due to energy demand, weather, line losses and changes in the composition of customer classes.

1. Significant accounting policies (continued):

The difference between the amounts charged to customers, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs billed monthly by the IESO, is recorded as a settlement variance. In accordance with IFRS 14, Regulatory Deferral Accounts ("IFRS 14"), which permits a rate-regulated entity to continue to recognize and measure regulatory deferral account balances in accordance with its previous generally accepted accounting principles ("GAAP"), this settlement variance is presented within regulatory balances on the balance sheets and within net movements in regulatory balances, net of tax on the statements of comprehensive income.

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by the Company in delivering electricity to customers. Distribution revenue also includes revenue related to collection of OEB-approved rate riders.

The carrying amount of accounts receivable is reduced through an allowance for doubtful accounts, if applicable, and all impairment losses are recognized in net income. When the Company considers that there are no realistic prospects of recovery of an account receivable, the relevant amount is determined to be impaired and is written off. If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

(ii) Other income:

Other income, which includes revenue from electricity distribution-related services, is recognized as services are rendered. Capital contributions received from electricity customers to construct or acquire property, plant and equipment ("PP&E") for the purpose of connecting a customer to a network are recorded as deferred contributions and amortized into other income at an equivalent rate to that used for the depreciation of the related PP&E. Government grants and the related performance incentive payments under Conservation and Demand Management ("CDM") programs are recognized as income in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

1. Significant accounting policies (continued):

(iii) Deferred revenue:

Amounts received in advance in relation to the IESO supported CDM initiatives are presented as deferred revenue (note 10).

(d) Rate setting:

The electricity distribution rates of the Company are subject to regulation by the OEB and these rates are based on a revenue requirement that includes a rate of return of 9.36% effective May 1, 2014.

On November 7, 2016, the Company filed a Price Cap Incentive Rate-setting application with the OEB to change distribution rates effective May 1, 2017. The application was approved by the OEB on March 30, 2017.

On October 16, 2017, the Company filed a Price Cap Incentive Rate-setting application with the OEB for May 1, 2018 rates. The application was approved and the OEB decision released on March 22, 2018.

On January 30, 2014, the IASB issued an interim standard, IFRS 14, to enhance the comparability of financial reporting by entities that are engaged in rate-regulated activities. IFRS 14 describes regulatory deferral account balances as amounts of expense or income that would not be recognized as assets or liabilities in accordance with other standards, but that qualify to be deferred in accordance with this standard because the amount is included, or is expected to be included, by the rate regulator in establishing the price(s) that an entity can charge to customers for rate-regulated goods or services.

1. Significant accounting policies (continued):

The scope of this standard is limited to first-time adopters of IFRS and will remain in force until either repealed or replaced by permanent guidance on rate-regulated accounting from the IASB. The interim standard introduced new presentation requirements and permitted first-time adopters to continue to recognize amounts related to rate regulation in accordance with Chartered Professional Accountants of Canada Handbook Part V - Pre-changeover Accounting Standards (subsequently referred to as "previous Canadian GAAP") requirements and was effective from January 1, 2016, with early application permitted. The Company elected to early adopt IFRS 14 in its 2015 financial statements under IFRS, with a transition date of January 1, 2014 and determined that regulatory balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14 and the accounting principles prescribed by the OEB in the "Accounting Procedures Handbook for Electricity Distributors".

The IASB's comprehensive project on rate-regulated activities is addressing whether IFRS should require entities operating in rate-regulated environments to recognize assets and liabilities arising from the effects of rate regulation. On December 13 and 14, 2017, the IASB staff informed the IASB board members about the key messages received from members of the IASB Consultative Group for Rate Regulation at the meeting held on October 26, 2017. The IASB staff also provided an update of the proposed timetable for developing the next consultative document for the project.

On February 22, 2018, the IASB tentatively decided: (i) the accounting model will use as its unit of account the individual timing differences that create the incremental rights and obligations arising from the regulatory agreement; (ii) the present regulatory right to charge a rate increased by an amount as a result of past events meets the definition of an asset; and (iii) the present regulatory obligation to provide goods or services at a rate reduced by an amount as a result of past events meets the definition of a liability. This comprehensive project remains ongoing.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in the timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory balances. The Company's regulatory debit balances represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory credit balances, which represent obligations that are expected to be refunded to customers. The netting of regulatory debit and credit balances is not permitted under IFRS 14.

1. **Significant accounting policies (continued):**

(e) Cash and cash equivalents:

Cash and cash equivalents are defined as cash and bank term deposits or equivalent financial instruments with original maturities upon issue of less than 90 days.

(f) Materials and supplies:

Materials and supplies, which consists of parts and supplies acquired for internal construction or consumption, are valued at the lower of cost and net realizable value. Cost is determined on a weighted moving average basis.

Any write-downs taken on materials and supplies are reversed if and when net realizable value subsequently recovers. Major spare parts and standby equipment are recorded as part of PP&E and depreciated once they are available for use.

(g) Property, plant and equipment:

PP&E purchased or constructed by the Company are recorded at cost less accumulated depreciation. Costs include contracted services, materials, labour, engineering costs, directly attributable overheads and capitalized borrowing costs during construction when applied. Subsequent costs are capitalized only when it is probable that the future economic benefits associated with the costs will flow to the Company and the costs can be measured reliably. Certain assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers. These contributions are used to connect customers to the Company's network and provide them with ongoing access to the supply of electricity. The contributions are recognized as deferred contributions and amortized into other income over the life of the related asset.

Upon energization of residential subdivision assets, a developer liability is accrued (as per the offer to connect contract) for the amounts payable to the developer for the Company's investment in the subdivision.

(In thousands of dollars)

1. Significant accounting policies (continued):

Depreciation of PP&E is charged to net income on a straight-line basis over their estimated service lives at the following annual rates:

Land rights	2.0%
Buildings	2.0% - 6.7%
Distribution station equipment	1.7% - 4.0%
Transmission and distribution system	1.7% - 10.0%
Meters	4.0% - 6.7%
Office equipment	10.0%
Computer hardware	20.0% - 33.3%
Vehicle fleet	6.7% - 16.7%
Renewable power generation	4.0%

The depreciation method, useful lives, and residual values are reviewed each financial year-end with the effect of any changes in estimate being accounted for on a prospective basis. Estimated useful lives reflect the best estimate and actual lives of assets may vary from estimated useful lives.

Construction in progress comprises PP&E under construction, assets not yet placed into service and pre-construction activities related to specific projects expected to be constructed.

Construction in progress, land rights, major spare parts and standby equipment are not subject to depreciation until these assets are available for use. Land is not depreciated.

Borrowing costs directly attributable to the acquisition, construction or development of qualifying assets that necessarily take a substantial period of time to prepare for their intended use are capitalized, until such time as the assets are substantially ready for their intended use. The weighted average cost of long-term borrowings is used as the capitalization rate. Qualifying assets are considered to be those that take in excess of six months to construct.

1. **Significant accounting policies (continued):**

When portions of the Company's distribution facilities are replaced or relocated, the associated costs less the salvage value of any material returned to materials and supplies are capitalized to the new asset. Depreciation is then recorded at the same rate used for the original asset.

Some of the Company's distribution assets, particularly those located on unowned easements and rights-of-way, may have decommissioning obligations, constructive or otherwise. The majority of the Company's easements and rights-of-way are subject to extension or renewal and are expected to be available for a perpetual duration. As the Company expects to use the majority of its installed assets into perpetuity, no removal date can be determined and consequently no reasonable estimate of the fair value of such asset retirement obligations can be made. If, at some future date, it becomes possible to estimate the fair value cost of removing the assets that the Company is legally or constructively required to remove, a related asset retirement obligation will be recognized at that time. The discounted amount is not material.

Assets are derecognized at their carrying value upon retirement or when no remaining economic benefits are expected from its use. The related gain or loss arising on the disposal or retirement is determined as the difference between the proceeds from sale and the carrying value of the asset and is included in net income for the related fiscal year. The cost of replacing a part of an item of PP&E is recognized as an addition to the carrying amount of the asset and the carrying amount of the replaced part is derecognized. The cost of the day-to-day servicing of PP&E assets is recognized in net income as incurred.

(h) Intangible assets:

Intangible assets acquired, or internally developed, are recognized initially at cost and comprised of purchased software, labour, consulting costs, directly attributable overheads and capitalized borrowing costs, if applicable. Intangible assets qualifying for capitalized borrowing costs are considered to be those assets that take in excess of six months to develop. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses.

1. **Significant accounting policies (continued):**

Amortization of intangible assets is provided on a straight-line basis over the estimated service lives at the following annual rates:

Application software and intellectual property	33.3%
Internally generated software	20.0%

Software in development is not subject to amortization. The above-noted amortization rates apply to assets held within the application software and other intangible asset grouping (note 4). The amortization method, useful lives, and residual values are reviewed each financial year-end with the effect of any changes in estimate being accounted for on a prospective basis. Estimated useful lives reflect the best estimate and actual lives of assets may vary from estimated useful lives.

(i) Goodwill:

Goodwill relates to the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment at each reporting date. Goodwill is measured at cost and is not amortized. Impairment testing for goodwill is always carried out in the context of the cash generating unit ("CGU") as goodwill does not generate cash flows independently of other assets. The Company has determined that goodwill is not impaired.

(j) Impairment of non-financial assets:

The carrying costs of non-financial assets: PP&E, intangible assets and goodwill are reviewed for impairment at each reporting date to determine whether there is any indication of impairment, in which case, the asset's recoverable amount is estimated.

For the regulated business, the carrying costs of most of the Company's non-financial assets are included in rate base (the aggregate of approved investment in PP&E and intangible assets, excluding work in progress, less accumulated depreciation and amortization and unamortized capital contributions from customers, plus an allowance for working capital) where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

1. **Significant accounting policies (continued):**

Impairment is tested at the CGU level, which is the smallest identifiable group of assets that generates independent cash flows. The Company has only one CGU, the regulated business unit. An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its recoverable amount and is recognized in net income.

(k) Customer deposits and advance payments:

Customers may be required to post security deposits to obtain electricity or other services. Interest is paid on customer deposits at rates prescribed by the OEB: this is currently interest at Canada's prime business rate less 2%, which was 1.2% per annum as of December 31, 2017. The Company receives advance payments from customers in relation to construction projects and recognizes them as a liability until the projects are completed.

(l) Employee benefits:

(i) Short-term employee benefits:

The Company provides short-term employee benefits, such as: salaries, employment insurance, short-term compensated absences, health and dental care. These benefits are recognized as the related service is rendered and is measured on an undiscounted basis. Short-term employee benefits are recognized as an expense unless they qualify for capitalization as part of the cost of an item of materials and supplies, PP&E, intangible assets or recoverable projects. A liability is recognized in respect of any unpaid short-term employee benefits for services rendered in the reporting periods.

The Company recognizes a current liability for the expected cost of accumulated non-vested sick leave benefits at the end of the reporting period. The assumptions used for estimating the amount of the liability are analogous to those used in the valuation of employee future benefits.

(ii) Defined benefit pension plan:

The Company accounts for its participation in the Ontario Municipal Employees Retirement System ("OMERS"), a multi-employer public sector pension fund, as a defined contribution plan.

1. **Significant accounting policies (continued):**

OMERS plan is a multi-employer defined benefit plan providing pension to employees of municipalities, local boards, public utilities and school boards. It is funded by equal contributions from participating employers and employees, as well as by investment earnings of the plan. Each year, an independent actuary determines the plan's funded status by comparing the actuarial value of invested assets to the estimated present value of all pension benefits that members have earned to date. OMERS does not track its investments by employer and actuarial assumptions are developed based on the entire plan membership on a commingled basis and, therefore, information for individual plans cannot be determined. As a result, the Company accounts for the OMERS plan as a defined contribution plan and contributions to the plan are recognized as an employee benefit expense.

(iii) Employee future benefits:

The Company provides all employees with life insurance benefits, as well as a Health Care Spending Account ("HCSA") for those employees retiring post April 1, 2011 having completed a minimum of 20 years of service with the Company. This benefit is available until age sixty five.

The Company actuarially determines the cost of employee future benefits offered to employees. These unfunded plans are accounted for as defined benefit obligations. The Company applies the projected benefit method, prorated on service and based on management's best estimates and assumptions. Under this method, the projected employee future benefits is deemed to be earned on a pro rata basis over the years of service in the attribution period commencing at date of hire, and ending at the earliest age the employee could retire and qualify for benefits.

Remeasurements of the net benefit liability comprise actuarial gains or losses that are recognized in the balance sheets with a credit or charge to other comprehensive income or loss. Current service costs are allocated to operating, maintenance and administration expenses and to capital recognized in the balance sheets.

1. Significant accounting policies (continued):

(m) Income taxes:

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

The Company uses the asset and liability method of accounting for the tax effect of temporary differences between the carrying amount and the tax bases of the Company's assets and liabilities. Temporary differences arise when the realization of an asset or the settlement of a liability would give rise to either an increase or decrease in the Company's income taxes payable in the year or a later period.

Deferred tax assets and liabilities are measured using enacted or substantively enacted tax rates at the reporting date, expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the statements of comprehensive income in the year that includes the date of enactment or substantive enactment.

The carrying amount of deferred tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable that the related tax benefits will be realized. Previously unrecognized deferred tax assets are reassessed at each balance sheet date and are recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. A valuation allowance is recorded against a deferred tax asset to the extent that the Company determines that it is probable that a deferred income tax asset will not be realized in the future.

Where the Company expects the deferred taxes to be recovered from or refunded to customers as part of the rate setting process, the deferred income tax assets and liabilities result in regulatory deferral debit balances or credit balances, respectively. Deferred tax assets that are not included in the rate-setting process result in a deferred tax provision that is charged or credited to the statements of comprehensive income.

1. Significant accounting policies (continued):

(n) Provisions and contingencies:

The Company recognizes provisions if, as a result of a past event, there is a present legal or constructive obligation that can be measured reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and, where appropriate, the risks specific to the liability.

The evaluation of the likelihood of the contingent events requires judgment by management as to the probability of exposure to potential gain or loss. Actual results could differ from these estimates.

(o) Use of judgments and estimates:

The preparation of financial statements requires management to make estimates, judgments and assumptions: within reasonable limits of materiality and within the framework of the significant accounting policies, that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the years. Due to inherent uncertainty involved in making such estimates, actual results reported in future years could differ from those estimates recorded in preparing these financial statements, including changes as a result of future decisions made by the OEB or the Minister of Energy.

Information about assumptions and estimation uncertainties that have a significant risk of resulting in a material adjustment is included in the following financial notes.

(i) Note 1(c)(i) - measurement of unbilled revenue;

(ii) Note 1(g) - environmental and decommissioning liabilities;

(iii) Notes 1(g), (h) - estimation of useful lives of PP&E and intangible assets;

(iv) Note 1(c)(i), (d) and note 6 - recognition and measurement of regulatory balances;

1. **Significant accounting policies (continued):**

(v) Notes 1(l)(ii)(iii) and note 15 - measurement of employee future benefits: key actuarial assumptions;

(vi) Note 1(n) - recognition and measurement of provisions and contingencies;

(vii) Note 1(m) and note 7 - recognition of deferred tax assets - availability of future taxable profit against which deductible temporary differences and tax losses carried forward can and be used; and

(viii) Note 1(c)(i) and note 23(c) - allowance for doubtful accounts.

Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future periods affected. Estimates and underlying assumptions are reviewed on an ongoing basis and are based on historical experience and other factors that are considered to be relevant.

(p) Non-derivative financial instruments:

All non-derivative financial assets are classified as loans and receivables and all non-derivative liabilities are classified as other liabilities. These financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequently, they are measured at amortized costs using the effective interest method less any impairment for the financial assets, as described in note 23(c).

(q) Derivative financial instruments:

Derivative financial instruments are measured at their fair value upon initial recognition and on each subsequent reporting date.

The Company has not elected to apply hedge accounting for its interest rate swap contracts and does not enter into derivative agreements for speculative purposes. Changes in the fair value of the derivatives are recorded each year in the statements of comprehensive income.

1. Significant accounting policies (continued):

(r) Capital disclosures:

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis, at reasonable rates, and to deliver the appropriate financial returns. As at December 31, 2017, the Company's definition of capital includes shareholder's equity, short-term debt (including the Corporation shareholders' promissory notes) and long-term debt, less cash and cash equivalents.

During the year, there have been no changes to how the Company assesses its capital structure.

(s) New standards and interpretations not yet adopted:

The IASB issues new standards, amendments and interpretations which do not have to be adopted in the current year. The Company continues to analyze these standards and interpretations, described below, which the Company anticipates might have an impact on its financial statements or note disclosures:

(i) IFRS 15, Revenue from Contracts with Customers ("IFRS 15"):

In May 2014, the IASB issued IFRS 15. The standard outlines a single comprehensive model for entities to use in accounting for revenues arising from contracts with customers. It supersedes current revenue recognition guidance, including International Accounting Standard ("IAS") 18, Revenue, IAS 11, Construction Contracts and related interpretations. The new revenue model applies to all contracts with customers, except those that are within the scope of other IFRS, such as leases, insurance contracts and financial instruments. IFRS 15 specifies how and when the entity should recognize revenue and additional disclosure requirements. The new standard is effective for annual periods beginning on or after January 1, 2018. The Company has completed its assessment of revenue streams and adopted IFRS 15 on January 1, 2018 using the modified retrospective approach, recognizing the cumulative effect of applying the new standard, with no restatement of comparative periods presented. Commodity pass-through revenue and distribution revenue account for the majority of the Company's revenues and IFRS 15 does not have a material impact on the financial statements.

1. Significant accounting policies (continued):

(ii) IFRS 9, Financial Instruments ("IFRS 9"):

The IASB published the final version of IFRS 9 in July 2014. The final version of IFRS 9 brings together the classification and measurement, impairment and hedge accounting to replace IAS 39, Financial Instruments - Recognition and Measurement. IFRS 9 is built on a logical, single classification and measurement approach for financial assets that reflects the business model in which they are managed and their cash flow characteristics. IFRS 9 has an expected credit loss model for a timely recognition of loan losses and is a single model that is applicable to all financial instruments subject to impairment accounting. It also includes an improved hedge accounting model to better link the economics of risk management with its accounting treatment. IFRS 9 is effective for annual periods beginning on or after January 1, 2018. The Company completed its assessment of IFRS 9 and adopted IFRS 9 on January 1, 2018. IFRS 9 does not have a material impact on the financial statements.

(iii) IFRS 16, Leases ("IFRS 16"):

The IASB published IFRS 16 in January 2016. It replaces the previous leases standard, IAS 17, Leases, and related interpretations. IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases. It eliminates the current dual accounting model for lessees, which distinguishes between on-balance sheet finance leases and off-balance sheet operating leases. IFRS 16 introduces 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 low value. IFRS 16 is effective from January 1, 2019. A company can choose to apply IFRS 16 before that date but only if it also applies IFRS 15. The Company completed its assessment of operating leases and early adopted IFRS 16 on January 1, 2018. IFRS 16 does not have a material impact on the financial statements.

(iv) IFRIC 23, Uncertainty over Income Tax Treatments:

On June 7, 2017, the IASB issued IFRIC Interpretation 23, Uncertainty over Income Tax Treatments. The Interpretation provides guidance on the accounting for current and deferred tax liabilities and assets in circumstances in which there is uncertainty over income tax treatments. The Interpretation is applicable for annual periods beginning on or after January 1, 2019. Earlier application is permitted.

(In thousands of dollars)

1. **Significant accounting policies (continued):**

The Interpretation requires an entity to contemplate whether uncertain tax treatments should be considered separately, or together as a group, based on which approach provides better predictions of the resolution. It also requires an entity to determine if it is probable that the tax authorities will accept the uncertain tax treatment; and if it is not probable that the uncertain tax treatment will be accepted, measure the tax uncertainty based on the most likely amount or expected value, depending on whichever method better predicts the resolution of the uncertainty.

The Company intends to adopt the Interpretation in its financial statements for the annual period beginning on January 1, 2019. The extent of the impact of adoption of the Interpretation has not yet been determined.

2. **Accounts receivable:**

	2017	2016
Energy revenue	$ 21,065	$ 29,497
Unbilled revenue	29,880	33,740
Project expenditures recoverable	1,352	3,275
Pole rentals and other	841	976
	53,138	67,488
Less allowance for doubtful accounts	1,070	1,070
	$ 52,068	$ 66,418

Unbilled revenue represents amounts for which the Company has a contractual right to receive cash through future billings and are unbilled at the period end. Unbilled revenue is considered current with no allowance for doubtful accounts.

(In thousands of dollars)

3. Property, plant and equipment:

December 31, 2017:

	December 31, 2016	Additions/ depreciation	Disposals/ retirements	December 31, 2017
Cost				
Land	$ 1,777	$ –	$ –	$ 1,777
Land rights	395	9	–	404
Buildings	17,110	185	–	17,295
Distribution station equipment	28,018	1,311	–	29,329
Transmission and distribution system	182,153	20,257	(230)	202,180
Meters	14,867	1,022	(85)	15,804
Office equipment	1,408	45	–	1,453
Computer hardware	2,379	687	–	3,066
Vehicle fleet	6,032	1,760	33	7,825
Renewable power generation	759	–	–	759
Construction in progress	12,684	2,987	–	15,671
	267,582	28,263	(282)	295,563
Accumulated depreciation				
Land rights	33	11	–	44
Buildings	3,434	1,134	–	4,568
Distribution station equipment	2,544	956	–	3,500
Transmission and distribution system	14,740	6,085	(55)	20,770
Meters	3,694	1,346	(28)	5,012
Office equipment	596	216	–	812
Computer hardware	1,103	500	–	1,603
Vehicle fleet	1,806	761	61	2,628
Renewable power generation	90	33	–	123
	28,040	11,042	(22)	39,060
	$ 239,542	$ 17,221	$ (260)	$ 256,503

(In thousands of dollars)

3. **Property, plant and equipment (continued):**

December 31, 2016:

	December 31, 2015	Additions/ depreciation	Disposals/ retirements	December 31, 2016
Cost				
Land	$ 1,777	$ –	$ –	$ 1,777
Land rights	392	3	–	395
Buildings	16,360	750	–	17,110
Distribution station equipment	25,217	2,801	–	28,018
Transmission and distribution system	159,055	23,431	(333)	182,153
Meters	13,855	1,154	(142)	14,867
Office equipment	1,276	132	–	1,408
Computer hardware	1,540	839	–	2,379
Vehicle fleet	5,118	968	(54)	6,032
Renewable power generation	767	(8)	–	759
Construction in progress	10,362	2,322	–	12,684
	235,719	32,392	(529)	267,582
Accumulated depreciation				
Land rights	22	11	–	33
Buildings	2,320	1,114	–	3,434
Distribution station equipment	1,637	907	–	2,544
Transmission and distribution system	9,271	5,530	(61)	14,740
Meters	2,433	1,297	(36)	3,694
Office equipment	388	208	–	596
Computer hardware	719	384	–	1,103
Vehicle fleet	713	1,138	(45)	1,806
Renewable power generation	57	33	–	90
	17,560	10,622	(142)	28,040
	$ 218,159	$ 21,770	$ (387)	$ 239,542

During the year, borrowing costs of $309 (2016 - $313) were capitalized to PP&E and credited to finance costs. Weighted average cost of short-term debt with a maturity date of November 1, 2039 and long-term borrowings is used for capitalizing borrowing costs as part of PP&E with an average rate of 3.80% (2016 - 3.94%).

Additions to construction in progress are net of transfers to other PP&E categories.

(In thousands of dollars)

4. **Intangible assets:**

December 31, 2017:

	December 31, 2016	Additions/ amortization	Disposals/ retirements	December 31, 2017
Cost				
Application software and other	$ 9,256	$ 1,473	$ –	$ 10,729
Construction in progress related to application software and other	184	(35)	–	149
Capital contributions	1,212	–	–	1,212
	10,652	1,438	–	12,090
Accumulated amortization				
Application software and other	6,204	1,755	–	7,959
	$ 4,448	$ (317)	$ –	$ 4,131

December 31, 2016:

	December 31, 2015	Additions/ amortization	Disposals/ retirements	December 31, 2016
Cost				
Application software and other	$ 7,431	$ 1,825	$ –	$ 9,256
Construction in progress related to application software and other	126	58	–	184
Capital contributions	1,212	–	–	1,212
	8,769	1,883	–	10,652
Accumulated amortization				
Application software and other	4,306	1,898	–	6,204
	$ 4,463	$ (15)	$ –	$ 4,448

No borrowing costs were capitalized on intangible assets under development in 2017 or 2016.

(In thousands of dollars)

4. Intangible assets (continued):

Application software and other includes externally acquired, as well as internally generated computer software. The remaining amortization period is between 1 and 5 years.

5. Depreciation and amortization:

	2017	2016
Total depreciation and amortization expense	$ 12,797	$ 12,102
Allocated to:		
Depreciation/amortization of vehicle fleet included in operating and maintenance expenses	761	719
Depreciation/amortization of assets in non-regulated utility operations included in other income	33	33
	794	752
Depreciation and amortization expense	$ 12,003	$ 11,350

6. Regulatory balances:

Regulatory balances can arise out of the rate-making process. Specifically, the following regulatory treatments have resulted in accounting treatments that differ from IFRS for enterprises operating in a non-regulated environment and regulated entities that did not adopt IFRS 14:

(i) The Company records the difference between the borrowing costs capitalization rate prescribed by the OEB and the weighted average cost of borrowings rate used to capitalize PP&E under IFRS. This amount is recognized as a regulatory debit or credit balance to be recovered or paid respectively to the customers through future rates;

(ii) The Company records regulatory debit balances arising from derecognition of assets under IFRS. These amounts will be sought for disposition through the next cost of service rebasing application and recovered from customers through future rates;

(iii) The Company records deferred tax assets and a corresponding regulatory tax liability, as the recovery from, or refund to, customers is expected to be included in future distribution rates for its regulated business activities;

(In thousands of dollars)

6. Regulatory balances (continued):

(iv) The Company has deferred certain retail settlement variances which comprise the variances between amounts charged by the Company to customers based on regulated rates and wholesale rates incurred for the cost of electricity service; and

(v) The Company has deferred costs related to: IFRS implementation, lost revenue adjustment mechanism costs, and OEB assessment costs.

Debit balances comprise of the following:

	January 1, 2017	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2017	Remaining recovery/ reversal period (years)
Approved settlement variances (a)	$ 89	$ –	$ –	$ (89)	$ –	Note 3
One-time IFRS conversion costs (b)	479	5	–	–	484	Note 1
IFRS transitional adjustments (e)	1,119	156	–	–	1,275	Note 1
Other (f)	843	819	(521)	(48)	1,093	Note 1, 3
	$ 2,530	$ 980	$ (521)	$ (137)	$ 2,852	

	January 1, 2016	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2016	Remaining recovery/ reversal period (years)
Approved settlement variances (a)	$ 1,371	$ 5	$ (1,287)	$ –	$ 89	1 year
One-time IFRS conversion costs (b)	473	6	–	–	479	Note 1
Extraordinary costs related to ice storm restoration (d)	205	–	(205)	–	–	
IFRS transitional adjustments (e)	852	267	–	–	1,119	Note 1
Other (f)	269	574	–	–	843	Note 1
	$ 3,170	$ 852	$ (1,492)	$ –	$ 2,530	

(In thousands of dollars)

6. Regulatory balances (continued):

Credit balances comprise of the following:

	January 1, 2017	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2017	Remaining recovery/ reversal period (years)
Future settlement variances (a)	$ 7,808	$ 1,968	$ (726)	$ –	$ 9,050	Note 1
Approved settlement variances (a)	–	85	373	(89)	369	1 year
Stranded meters (c)	18	1	–	–	19	Note 1
Other (f)	48	–	–	(48)	–	Note 1
Deferred taxes (g)	2,511	(2,207)	–	–	304	Note 2
	$ 10,385	$ (153)	$ (353)	$ (137)	$ 9,742	

	January 1, 2016	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2016	Remaining recovery/ reversal period (years)
Future settlement variances (a)	$ 2,646	$ 5,162	$ –	$ –	$ 7,808	Note 1
Stranded meters (c)	18	–	–	–	18	Note 1
Other (f)	47	1	–	–	48	Note 1
Deferred taxes (g)	4,942	(2,431)	–	–	2,511	Note 2
	$ 7,653	$ 2,732	$ –	$ –	$ 10,385	

Note 1 The Company intends to seek recovery or refund in future rate applications to the OEB.

Note 2 The Company will not seek disposition of the balance since it will be reversed through timing differences in the recognition of deferred tax assets.

Note 3 These balances have been reclassified to regulatory credit balances.

The balances arising in the period column are new additions (for both debits and credits). The recovery/reversal column are amounts: collected or refunded through rate riders, disposition of OEB-approved regulatory balances, or other transactions which reduces existing regulatory balances. The other movements column consists of impairment (if the OEB disallowed certain amounts), carrying cost adjustments, and reclassification between the regulatory debit and credit balances. There is no impairment recorded for the years ended December 31, 2017 and December 31, 2016.

6. Regulatory balances (continued):

Regulatory balances descriptions:

(a) Settlement variances:

The amounts include the variances between the amount charged by the IESO for the operation of the markets and grid, as well as various wholesale market settlement charges and transmission charges, as compared to the amount billed to consumers based on the OEB-approved rates. This amount also includes variances between the amounts charged by Hydro One Networks Inc. ("Hydro One") for low voltage services and the amount billed to consumers based on the OEB-approved rates. Also included are retail cost variances, being the differences between the revenue charged to retailers and the retail services costs associated with providing the retail services.

In 2017, the OEB approved the disposition of the Company's retail settlement variance accounts as at December 31, 2015.

(b) One-time IFRS conversion costs:

In accordance with an OEB directive, a deferral account has been established for the one-time administrative costs during transition to IFRS. These amounts will be sought for disposition in the Company's first cost of service rebasing application under IFRS.

(c) Stranded meters:

These amounts are related to the provincial government's directive for licensed distributors to install smart meters for specific customer classes and represent the net book value of stranded meter assets arising from the Company's smart metering program.

In 2014, the OEB approved the Company's request for recovery of these regulatory balances through a rate rider with a one-year term.

This rate rider expired April 30, 2015 with the balance to be refunded in a future rate application to the OEB.

6. Regulatory balances (continued):

(d) Extraordinary costs related to ice storm restoration:

In December 2013, the Company recorded deferred power restoration costs related to a severe ice storm as a regulatory balance for disposition to be sought in the future.

On February 19, 2015, the OEB approved the Company's application for recovery of these costs through a rate rider which ended February 28, 2016.

(e) IFRS transitional adjustments:

Commencing in 2014, the Company has recorded regulatory debit balances arising from derecognition of assets under IFRS and capitalized borrowing costs difference between weighted average long-term borrowing costs under IFRS and OEB guidelines. These amounts will be sought for disposition in the Company's first cost of service rebasing application under IFRS.

(f) Other:

These amounts relate to the deferral of costs related to lost revenue adjustment mechanism costs, renewable generation connection funding adder, OEB assessment costs and other regulatory balances.

(g) Deferred taxes:

This regulatory credit balance includes both deferred tax amounts reclassified under IFRS 14 and expected future electricity distribution rate increase or reduction for customers arising from timing difference in the recognition of deferred tax assets.

The amounts reclassified under IFRS 14 include the deferred tax liability related to regulatory balances of $906 as at December 31, 2017 (2016 - $626).

The deferred tax amount related to the expected future electricity distribution rate increase for customers was $602 as at December 31, 2017 (2016 – rate reduction $1,885).

(In thousands of dollars)

7. Income taxes:

The provision for income taxes differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and effective tax rates is provided as follows:

	2017	2016
Income before income taxes	$ 13,776	$ 17,939
Federal and Ontario statutory income tax rate	26.50%	26.50%
Provision for income taxes at statutory rate	$ 3,651	$ 4,754
Increase (decrease) resulting from:		
Temporary differences expected to be recovered from customers	(1,812)	(1,857)
Over provided in prior years	(219)	(167)
Other miscellaneous	(129)	(1,647)
Income taxes recorded in regulatory balances movements	2,207	2,431
Income tax expense	$ 3,698	$ 3,514
Allocated:		
Current	$ 813	$ 1,156
Deferred (recovery)	678	(73)
Income taxes recorded in regulatory balances movements	2,207	2,431
Total income tax expense	$ 3,698	$ 3,514

(In thousands of dollars)

7. Income taxes (continued):

Deferred tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. The tax effects of these differences are as follows:

	2017	2016
Deferred tax assets:		
Property, plant and equipment and intangible assets (a)	$ (1,979)	$ 500
Employee future benefits	1,042	999
Sick leave liability	358	352
Unrealized loss on interest rate swaps	528	960
Deferred revenue, contingent liability and others	905	927
	854	3,738
Deferred tax liabilities:		
Regulatory balances	906	626
Moved to regulatory deferral account credit balances	(906)	(626)
	–	–
Deferred tax assets	$ 854	$ 3,738

(a) Taxable temporary difference, book value is more than tax value.

8. Accounts payable and accrued liabilities:

	2017	2016
Power bill accrual	$ 23,207	$ 28,896
Customer credit balances	7,698	3,783
Other accounts payable and accrued liabilities	10,409	11,629
	$ 41,314	$ 44,308

9. Credit facilities and short-term debt:

Credit facilities:

As at December 31, 2017, the Company had the following external credit facilities with a Canadian chartered bank (the "Bank"):

(a) Uncommitted revolving demand credit facility. The facility at all times is required to be no greater than $30,000 with a letter of credit ("L/C") carve-out availability;

(b) Committed reducing term facility with a credit limit of $40,999 and amortization term of 30 years with an optional exit strategy at 10 years, 15 years, 20 years and 25 years (note 13); and

(c) Committed or demand revolver facility (note 13) with a combined total no greater than $70,000 at all times.

The financial covenants to the above facilities require a funded debt to capitalization ratio of no greater than 0.60:1, and maintain a debt service coverage ratio of not less than 1.20:1. The financial covenants are tested on a consolidated basis. The Corporation and the Company have been in compliance with all the covenants.

As at December 31, 2017, nil was drawn out of facility (a); $38,844 was outstanding out of facility (b) and $25,000 was outstanding out of facility (c) above (note 13). To cover the risk of fluctuating interest rates, facility (b) was structured with interest rate swap agreement with the Bank, effectively converting the obligations into a fixed interest rate loan of approximately 3.715%.

The Company utilized (a) for: $807 to issue an irrevocable L/C in favour of the IESO; and $100 to issue an irrevocable L/C in favour of the Ministry of Environment.

The IESO requires all purchasers of electricity in Ontario to provide security to mitigate the risk of their default based on their expected purchases from the IESO administered spot market. The IESO could draw on the L/C if the Company defaults on its payment.

The Ministry of Environment requires security to ensure adequate funds are available, to effect suitable remedial action, if an event occurs resulting in a health and safety hazard to any person, or the natural environment.

9. Credit facilities and short-term debt (continued):

Short-term debt:

As at December 31, 2017, the Company had $43,588 in notes payable to the Corporation's shareholders with the maturity date of November 1, 2039, at a rate equal to the OEB-deemed long-term debt rate less 30-basis-points. The noteholders have a right to demand repayment of this note (in whole or in part) at any time upon six months prior written notice to the Company provided that a duly enacted resolution or by-law is passed by the noteholders certifying that the funds are required for municipal purposes. As the Company does not have any unconditional right to defer settlement of this liability for at least twelve months after the reporting period, the notes are classified as a short-term debt.

10. Deferred revenue:

Deferred revenue represents the balance at year end of unearned revenue from funding received from the IESO to deliver CDM programs.

An agreement was entered with the IESO on December 16, 2014 and on June 8, 2015, whereby the IESO conditionally approved a CDM plan that was jointly submitted by the Company and Whitby Hydro Electric Corporation to deliver CDM programs covering the period from January 1, 2015 to December 31, 2020. This CDM plan was most recently updated on April 18, 2017 and conditionally approved by the IESO on May 12, 2017.

In accordance with the funding model that was approved in the Joint CDM Plan, all programs to be delivered under the IESO agreement are expected to be fully funded and paid by the IESO. The IESO is invoiced monthly for the costs incurred on various CDM programs. The Company received some initial funding from the IESO for the delivery of CDM programs under the energy conservation agreement. Amounts received but not yet spent are presented on the balance sheets under current liabilities as deferred revenue.

(In thousands of dollars)

11. Deposits and developer obligations:

	2017	2016
Advance payments - construction deposits	$ 348	$ 629
Customer deposits	5,503	5,799
Developer obligations	2,820	1,943
Deposits and developer obligations	$ 8,671	$ 8,371

12. Related party transactions:

The Company provides electricity and services to the Corporation's shareholders, the Town of Ajax, the Municipality of Clarington, the City of Pickering and the City of Belleville (collectively, the "shareholders"). Electrical energy is sold to the Corporation's shareholders at the same prices and terms as other electricity customers consuming equivalent amounts of electricity.

The electricity and services amounts charged by the Company to the Corporation's shareholders for the year ended December 31, 2017 was $9,169 (2016 - $8,889).

As at December 31, 2017, accounts receivable includes $959 (2016 - $716) due from the Corporation's shareholders.

Finance costs includes interest of $1,948 (2016 - $1,948) on the notes payable to the Corporation's shareholders and $1,435 (2016 - $1,466) on the notes payable to the Corporation.

The Company paid $408 (2016 - $439) in property taxes to the Corporation's shareholders.

The Company paid $2,131 (2016 - $2,010) in compensation to the Company's key management personnel, comprising of the senior management team and members of the Board of Directors. The compensation includes salaries, performance pay, taxable benefits and OMERS contributions.

The Company purchases or supplies administrative and management services from and to the Corporation. Charges for these services are recorded at exchange amounts established and agreed to by the related parties.

The Company recovered $185 (2016 - $181) for administrative and management services provided to the Corporation.

12. Related party transactions (continued):

The Company has $176 (2016 - $111) of current receivables related to services rendered, without interest or terms of repayment from the Corporation and $43 (2016 - $42) is owed to the Corporation related to interest accrued on the Corporation promissory notes.

The Company declared and paid a dividend of $5,007 (2016 - $4,649) to the Corporation.

The Company has renewable generation projects and holds interest in the following joint operation:

Claremont Community Centre Solar:

The Company, Queen Street Solar Co-Operative Corporation and Solera Sustainable Energies Company Limited entered into a joint operation agreement with an equity interest of 39%, 51% and 10%, respectively, to build, own, operate and maintain a solar generation project at Claremont Community Centre owned by the City of Pickering, located at 4941 Old Brock Road, Pickering, Ontario L1V 7E2. This project is approved under the Feed-in Tariff government program.

In 2016, the Corporation financed the above project for an amount of $264 for a 15-year term at an interest rate of 5.00%. An amount of $96 (net of repayments and intercompany funding) is included in the Company's long-term debt as at December 31, 2017 (note 13). The funding provided by the Corporation was in the same proportion as the equity interest: VCI 39%, Queen Street Solar Co-Operative Corporation 51% and Solera Sustainable Energies Company Limited 10%.

(In thousands of dollars)

13. Long-term debt:

	2017	2016
Notes payable to the Corporation, maturing on December 9, 2024, at a rate of 4.77%	$ 15,000	$ 15,000
Notes payable to the Corporation, maturing on December 17, 2039, at a rate equal to the OEB-deemed long-term debt rate, less 30-basis-points	15,400	16,100
Loan payable to the Corporation, maturing on September 1, 2031, at a rate of 5.00%	96	101
Long-term debt from the Bank, maturing on March 2, 2045 (note 9)	38,844	39,653
Long-term debt from the Bank, repayable no later than December 28, 2019 (note 9)	25,000	25,000
	94,340	95,854
Less current portion	1,545	1,514
	$ 92,795	$ 94,340

Scheduled principal repayments for the next five years and thereafter as of December 31, 2017:

2018	$ 1,545
2019	26,577
2020	1,610
2021	1,645
2022	1,680
Thereafter	61,283
	94,340
Less current portion	1,545
	$ 92,795

(In thousands of dollars)

13. Long-term debt (continued):

Scheduled principal repayments for the next five years and thereafter as of December 31, 2016:

2017	$ 1,514
2018	1,545
2019	26,577
2020	1,610
2021	1,645
Thereafter	62,963
	95,854
Less current portion	1,514
	$ 94,340

Scheduled interest payments for the next five years and thereafter as of December 31, 2017:

2018	$ 5,221
2019	5,158
2020	4,689
2021	4,624
2022	4,557
Thereafter	56,053
	$ 80,302

Expected weighted average borrowing costs:

2018	3.79%
2019	3.78%
2020	3.48%
2021	4.28%
2022	4.28%

(In thousands of dollars)

13. Long-term debt (continued):

Finance costs related to short-term and long-term debt comprises:

	2017	2016
Interest on:		
Notes payable and loans	$ 5,304	$ 5,186
Customer deposits and other	50	67
	5,354	5,253
Less capitalized borrowing costs	309	313
	$ 5,045	$ 4,940

14. Deferred contributions:

Deferred contributions are the capital contributions received from electricity customers, which have not yet been recognized into other income.

The continuity of deferred contributions is as follows:

	2017	2016
Deferred contributions, beginning of year	$ 18,683	$ 11,543
Contributions received	5,086	7,458
Contributions amortized as other income	(458)	(318)
Deferred contributions, end of year	$ 23,311	$ 18,683

Customer contributions for the acquisition or construction of PP&E are considered to be deferred contributions and amortized over the useful lives of the related assets as other income.

(In thousands of dollars)

15. *Employee future benefits:*

(a) Pensions:

During 2017, the Company made contributions totalling $2,200 (2016 - $2,187) to OMERS.

(b) Post-retirement benefits other than pensions:

The Company pays certain benefits on behalf of its retired employees and recognizes these post-retirement costs in the period in which the employees render the services.

Information about the Company's non-contributory defined benefit plan to fund life insurance, health and dental care benefits and a retiree HCSA, is as follows:

	2017	2016
Accrued benefit liability recognized, January 1	$ 2,771	$ 2,616
Current service costs	78	74
Past service costs	80	–
Interest costs	105	100
Benefit payments	(119)	(96)
Remeasurements recognized in other comprehensive income	(24)	77
Accrued benefit liability, December 31	$ 2,891	$ 2,771

The amounts presented are based upon an actuarial valuation performed as at December 31, 2017. The next valuation is expected to be performed for the year ending December 31, 2020.

The main actuarial assumptions employed for the valuations are as follows:

(i) General inflation:

Future general inflation levels, as measured by changes in the Consumer Price Index, are assumed at 2.00% for future years.

(ii) Interest (discount) rate:

Amounts were determined using an annual discount rate of 3.50% (2016 - 3.90%).

(In thousands of dollars)

15. Employee future benefits (continued):

(iii) Salary levels:

Future general salary and wage levels were assumed to increase at 3.20% (2016 - 3.60%) per annum.

(iv) Health and dental care:

The health and dental care cost increases are 6.20% and 4.50% (2016 - 6.31% and 4.60%), respectively.

(c) Risks associated with the plan:

Significant actuarial assumptions related to discount rates, future health and dental costs, mortality rates, retirement age, and utilization rate of the HCSA etc. may affect the valuation of expected accrued benefit liability.

16. Share capital:

	2017		2016	
	Number of shares	Amount	Number of shares	Amount
Authorized:				
Unlimited common shares				
Issued	15,000	$ 69,302	15,000	$ 69,302

17. Dividends:

The Company's current dividend policy states:

(a) a base annual dividend to the Corporation be set at $4,600 from 2012 to 2017;

(b) the base dividend would be increased or decreased depending upon:

(i) decrease/increase in debt to capitalization ratio of 60%;

(ii) net income projected to be higher/lower than budget; or

(iii) capital expenditure projected to be lower/higher than budget.

(c) the Company's Board of Directors should determine annually if earnings from renewable generation be used to supplement the base dividend.

During 2017, the Board of Directors of the Company declared and paid dividends totalling $5,007 (2016 - $4,649) to the Corporation.

18. Contingencies and guarantees:

(a) Insurance claims:

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. MEARIE provides general liability insurance to member electric utilities. MEARIE also provides vehicle and property insurance to the Company.

Insurance premiums charged to each member electric utility consist of a levy per $1 of service revenue subject to a credit or surcharge based on each electric utility's claims experience. The maximum coverage is $30,000 per occurrence for liability insurance, $21,000 for vehicle insurance, and $119,736 for property insurance; plus $10,000 excess coverage on top of the regular liability and vehicle coverage.

(In thousands of dollars)

18. Contingencies and guarantees (continued):

(b) Contractual obligation - Hydro One Networks Inc.:

The Company is party to a connection and cost recovery agreement with Hydro One related to the construction by Hydro One of a transformer station designated to meet the Company's anticipated electricity load growth. Construction of the project was completed during 2007 and the Company connected to the transformer station during 2008.

To the extent that the cost of the project is not recoverable from future transformation connection revenues, the Company is obligated to pay a capital contribution equal to the difference between these revenues and the construction costs allocated to the Company. The construction costs allocated to the Company for the project are $9,975.

The Company has recorded a liability and a corresponding intangible asset for $1,212 as at December 31, 2017 (2016 - $1,212), based on management's best estimate of the future transformation connection revenues shortfall. Hydro One is expected to perform a true-up based on actual load at the end of the tenth and fifteenth anniversaries of the in-service date.

(c) General claims:

From time to time, the Company is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's financial position and results of operations or cash flows.

19. Lease commitments:

Future minimum lease payment obligations under operating leases are as follows:

2018	$ 41
2019	33
2020	32
2021	24
2022	2
Thereafter	58
	$ 190

(In thousands of dollars)

20. Other income (loss):

	2017	2016
Late payment charges	$ 413	$ 510
Customer charges (a)	1,102	1,843
Pole rentals	490	484
Disposal of PP&E	(194)	(362)
Foreign exchange gain (loss)	3	(7)
Amortization of deferred contributions	458	318
Miscellaneous revenue	550	562
	$ 2,822	$ 3,348

(a) Includes reconnection/disconnection, collection and change of occupancy charges from customers.

21. Operating, maintenance and administration expenses:

	Operating and maintenance		Administration	
	2017	2016	2017	2016
Salaries and benefits	$ 5,586	$ 5,819	$ 10,983	$ 11,221
External services	2,977	2,778	3,055	2,787
Materials and supplies	208	140	–	–
Vehicle	539	494	49	45
Other	324	397	4,495	4,026
	$ 9,634	$ 9,628	$ 18,582	$ 18,079

VERIDIAN CONNECTIONS INC.

Notes to the Financial Statements (continued)
(In thousands of dollars)

Years ended December 31, 2017 and 2016

22. Statements of cash flows:

Changes in non-cash operating working capital provided by (used in) includes the following:

	2017	2016
Accounts receivable	$ 14,350	$ (8,456)
Related parties	(66)	(46)
Materials and supplies	11	(389)
Prepaid expenses	(78)	(627)
Accounts payable and accrued liabilities	(1,527)	(64)
Advance payments - construction deposits	(281)	(216)
Deferred revenue	(83)	(27)
Developer obligations	877	503
	$ 13,203	$ (9,322)

Reconciliation between the amount presented on the statements of cash flows and total additions to property, plant and equipment and intangible assets:

	2017	2016
Purchase of PP&E, cash basis	$ 29,746	$ 31,821
Net change in accruals related to PP&E	(1,483)	571
Total additions to PP&E	$ 28,263	$ 32,392
Purchase of intangible assets, cash basis	$ 1,625	$ 1,723
Net change in accruals related to intangible assets	(187)	160
Total additions to intangible assets	$ 1,438	$ 1,883

23. Financial instruments and risk management:

(a) Market risk:

Market risk refers primarily to risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk due to the flow-through nature of energy purchases and costs. All variances due to timing of customer billing or regulated pricing are recorded in retail settlement variance accounts and are recovered from or returned to customers in accordance with regulatory directives. The foreign exchange risk is considered not material and is limited to U.S. dollar cash and cash equivalents holdings of $204 (2016 - $132) as at December 31, 2017.

(b) Interest rate risk:

The Company enters into fixed interest rate long-term debt agreements to minimize cash flow and interest rate fluctuation exposure. In February 2015, a $40,999, 30-year fixed rate term loan was arranged from the Bank to blend and extend a $30,000 loan and a $15,000 loan. The Company entered into interest rate swap derivative agreements with the Bank to exchange interest rate cash flows. Under these agreements, the Company and the Bank have the periodic exchange of payments without exchanging the notional principal amount on which the payments are based. This effectively provided the Company with fixed rate loans, which reduces the impact of fluctuating interest rates on long-term debt. The Company does not enter into any such financial instrument for speculative purposes.

(c) Credit risk:

Financial assets create credit risk that a counterparty will fail to discharge an obligation, causing a financial loss. The Company's distribution revenue is earned on a broad base of customers. As a result, the Company did not earn a significant amount of revenue from any individual customer. As at December 31, 2017, there were no significant balances of accounts receivable due from any single customer.

The Company manages counterparty credit risk through various techniques, including limiting total exposure levels with individual counterparties consistent with the Company's policies and monitoring the financial condition of counterparties.

(In thousands of dollars)

23. Financial instruments and risk management (continued):

Management believes that the credit risk of accounts receivable is limited due to the following reasons:

(i) There is a broad base of customers with no one customer that accounts for revenue or an accounts receivable balance in excess of 10% of the respective balance.

(ii) The Company, as permitted by the OEB's Retail Settlement and Distribution System Code, may obtain a security deposit or L/C from customers to mitigate risk of payment default.

(iii) The percentage of accounts receivable that is outstanding more than 90 days is approximately 0.92% (2016 - 1.36%) of the total net outstanding balance.

(iv) The Company includes an amount of accounts receivable write-offs within net income for rate-setting purposes.

Pursuant to their respective terms, accounts receivable are aged as follows as at December 31:

	2017	2016
Total accounts receivable	$ 53,138	$ 67,488
Less allowance for doubtful accounts	1,070	1,070
Total accounts receivable, net	$ 52,068	$ 66,418
Of which:		
Unbilled revenue	$ 29,880	$ 33,740
Outstanding 1 day but not more than 30 days	21,495	30,654
Outstanding 31 days but not more than 60 days	1,007	1,788
Outstanding 61 days but not more than 90 days	275	399
Outstanding 91 days but not more than 120 days	209	439
Outstanding more than 120 days	272	468
	53,138	67,488
Less allowance for doubtful accounts	1,070	1,070
	$ 52,068	$ 66,418

(In thousands of dollars)

23. Financial instruments and risk management (continued):

(d) Liquidity risk:

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Short-term liquidity is provided through cash and cash equivalents on hand and funds from operations. Short-term liquidity is expected to be sufficient to fund normal operating requirements. The liquidity risks associated with financial commitments are as follows:

Financial commitments as of December 31, 2017:

	Due within one year	Due between one and five years	Due past five years
Financial liabilities:			
Accounts payable and accrued liabilities	$ 41,314	$ –	$ –
Short-term debt (note 9)	43,588	–	–
Long-term debt	1,545	31,512	61,283
Lease commitments	41	91	58

Financial commitments as of December 31, 2016:

	Due within one year	Due between one and five years	Due past five years
Financial liabilities:			
Accounts payable and accrued liabilities	$ 44,308	$ –	$ –
Short-term debt (note 9)	43,588	–	–
Long-term debt	1,514	31,376	62,964
Lease commitments	41	139	60

(In thousands of dollars)

23. Financial instruments and risk management (continued):

(e) Fair values:

The Company included $1,992 of unrealized loss (2016 - $3,621) in its financial statements. This is the fair value of the interest rate swap derivative which represents the amount that the Company would have paid to unwind its position as at December 31, 2017. This unrealized loss is not expected to affect cash as the Company intends to hold the financial instrument until its maturity.

Fair value measurements recognized in the statements of comprehensive income are categorized using a fair value hierarchy that reflects the significance of inputs used in determining the fair values.

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

The interest rate swap derivatives are all Level 2 as at December 31, 2017.

There were no transfers between levels during the year.

The carrying amounts of all financial instruments, except the following: short-term debt with a maturity date of November 1, 2039, and long-term debt; approximate fair values due to the immediate or short-term maturity of these financial instruments. The estimated fair values of the loans payable, including related party loans, are as follows:

	2017	2016
Fair value	$ 137,908	$ 145,530
Carrying value (notes 9 and 13)	137,928	139,442

(In thousands of dollars)

23. Financial instruments and risk management (continued):

(f) Capital management:

The Company considers its capital structure to consist of shareholder's equity, short-term debt, long-term debt, less cash and cash equivalents. The Company's capital structure was as follows:

	2017	2016
Cash	$ (9,363)	$ (4,953)
Short-term debt	43,588	43,588
Long-term debt	94,340	95,854
	137,928	139,442
Share capital	69,302	69,302
Retained earnings	41,122	35,087
Contributed capital	23	23
Accumulated other comprehensive loss	(316)	(340)
	110,131	104,072
Total capital	$ 238,696	$ 238,561

24. Comparative information:

Certain comparative information has been reclassified to conform with the financial statement presentation adopted in the current year.

Financial Statements of

WHITBY HYDRO ELECTRIC CORPORATION

Years ended December 31, 2016
(Expressed in thousands of dollars)

KPMG LLP
Commerce Place
21 King Street West, Suite 700
Hamilton Ontario L8P 4W7
Canada
Telephone (905) 523-8200
Fax (905) 523-2222

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Whitby Hydro Electric Corporation

We have audited the accompanying financial statements of Whitby Hydro Electric Corporation ("the Entity"), which comprise the statement of financial position as at December 31, 2016, the statements of comprehensive income, changes in equity and cash flows for the year then, and notes, comprising 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 financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our 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, we consider 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.

KPMG

We believe that the audit evidence we have obtained in our audit 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 Whitby Hydro Electric Corporation as at December 31, 2016, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

April 6, 2017
Hamilton, Canada

WHITBY HYDRO ELECTRIC CORPORATION

Statement of Financial Position
December 31, 2016
(In thousands of dollars)

	Note		2016		2015
Assets					
Current assets					
Cash and cash equivalents	5	$	735	$	3,072
Accounts receivable	6		10,707		7,971
Due from related parties	20		411		343
Unbilled revenue			13,173		12,908
Materials and supplies	7		1,143		1,083
Prepaid expenses			79		88
Total current assets			26,248		25,465
Non-current assets					
Property, plant and equipment	8		90,601		84,288
Intangible assets	9		458		543
Deferred tax assets	10		400		733
Total non-current assets			91,459		85,564
Total assets			117,707		111,029
Regulatory balances	11		4,348		6,201
Total assets and regulatory balances		$	122,055	$	117,230

	Note		2016		2015
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities	12	$	14,323	$	12,717
Income taxes payable			248		470
Due to related parties	20		5,544		3,433
Long-term debt due within one year	13		400		400
Customer deposits			2,007		1,619
Total current liabilities			22,522		18,639
Non-current liabilities					
Customer deposits			219		141
Long-term debt	13		31,938		32,338
Deferred revenue			13,652		11,543
Total non-current liabilities			45,809		44,022
Total liabilities			68,331		62,661
Equity					
Share capital	14		29,494		29,494
Retained earnings			19,162		18,199
Total equity			48,656		47,693
Total liabilities and equity			116,987		110,354
Regulatory balances	11		5,068		6,876
Total liabilities, equity and regulatory balances		$	122,055	$	117,230

See accompanying notes to the financial statements.

On behalf of the Board:

Director

Director

WHITBY HYDRO ELECTRIC CORPORATION

Statement of Comprehensive Income
Year ended December 31, 2016, with comparative information for 2015
(In thousands of dollars)

	Note	2016	2015
Revenue			
Distribution revenue		$ 19,845	$ 21,951
Other	15	1,895	2,038
		21,740	23,989
Sale of energy		119,091	105,607
Total revenue		140,831	129,596
Operating expenses			
Operations and maintenance		5,500	5,463
Administration expense		6,974	6,276
Depreciation and amortization		4,677	4,442
	16	17,151	16,181
Cost of power purchased		116,492	105,367
Total expenses		133,643	121,548
Income from operating activities		7,188	8,048
Finance income	17	-	(3)
Finance costs	17	2,188	2,159
Income before income taxes		5,000	5,892
Income tax expense	10	1,316	1,248
Net income for the year		3,684	4,644
Net movement in regulatory balances, net of tax	11		
Net movement in regulatory balances		(377)	(1,191)
Income tax on net movement in regulatory balances		333	287
		(44)	(904)
Net income for the year and net movement in regulatory balances, which is comprehensive income		$ 3,640	$ 3,740

See accompanying notes to the financial statements.

WHITBY HYDRO ELECTRIC CORPORATION

Statement of Changes in Equity
Year ended December 31, 2016, with comparative information for 2015
(in thousands of dollars)

	Share capital	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance at January 1, 2016	$ 29,494	$ 18,199	$ -	$ 47,693
Net income and net movement in regulatory balances	-	3,640	-	3,640
Dividends	-	(2,677)	-	(2,677)
Balance at December 31, 2016	$ 29,494	$ 19,162	$ -	$ 48,656
Balance at January 1, 2015	$ 29,494	$ 16,979	$ -	$ 46,473
Net income and net movement in regulatory balances	-	3,740	-	3,740
Dividends	-	(2,520)	-	(2,520)
Balance at December 31, 2015	$ 29,494	$ 18,199	$ -	$ 47,693

See accompanying notes to the financial statements.

WHITBY HYDRO ELECTRIC CORPORATION

Statement of Cash Flows
Year ended December 31, 2016, with comparative information for 2015
(In thousands of dollars)

	2016	2015
Operating activities		
Net income and net movement in regulatory balances	$ 3,640	$ 3,740
Adjustments for:		
Depreciation and amortization	4,677	4,442
Amortization of deferred revenue	(849)	(946)
Losses on disposal of property, plant and equipment	86	193
Net finance costs	2,188	2,156
Income tax expense	1,316	1,248
Contributions received from customers	2,962	8,890
Change in non-cash operating working capital:		
Accounts receivable	(2,736)	(2)
Due to/from related parties	2,043	(1,513)
Unbilled revenue	(265)	(909)
Materials and supplies	(60)	(83)
Prepaid expenses	9	2
Accounts payable and accrued liabilities	1,606	536
Customer deposits	466	35
	15,083	17,790
Net change in regulatory balances	44	904
Income tax paid	(1,275)	(489)
Income tax received	69	637
Interest paid	(2,190)	(2,159)
Interest received		3
Net cash from operating activities	11,731	16,686
Investing activities		
Purchase of property, plant and equipment	(10,926)	(15,251)
Purchase of intangible assets	(65)	(142)
Net cash used by investing activities	(10,991)	(15,393)
Financing activities		
Dividends paid	(2,677)	(2,520)
Repayment of long-term debt	(400)	(400)
Net cash used by financing activities	(3,077)	(2,920)
Change in cash and cash equivalents	(2,337)	(1,627)
Cash and cash equivalents, beginning of year	3,072	4,699
Cash and cash equivalents, end of year	$ 735	$ 3,072

See accompanying notes to the financial statements.

1. Reporting entity

Whitby Hydro Electric Corporation (the "Corporation") is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Corporation is located in the Town of Whitby of the Region of Durham. The address of the Corporation's registered office is 100 Taunton Rd. East, Whitby Hydro, Ontario.

The Corporation delivers electricity and related energy services to residential and commercial customers in Whitby. The Corporation is wholly owned by Whitby Hydro Energy Corporation and the ultimate parent company is the Corporation on the Town of Whitby.

The financial statements are for the Corporation as at and for the year ended December 31, 2016.

2. Basis of presentation

(a) Statement of compliance

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The financial statements were approved by the Board of Directors on April 6, 2017.

(b) Basis of measurement

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand.

(d) Use of estimates and judgments

(i) Assumptions and estimation uncertainty

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

2. Basis of presentation (continued)

(d) Use of estimates and judgments (continued)

(i) Assumptions and estimation uncertainty (continued)

Information about assumptions and estimation uncertainties that have a significant risk of resulting in material adjustment is included in the following notes:

(i) Note 3(b) – measurement of unbilled revenue
(ii) Notes 8, 9, – estimation of useful lives of its property, plant and equipment and intangible assets
(iii) Note 11 – recognition and measurement of regulatory balances
(iv) Note 18 – recognition and measurement of provisions and contingencies

(ii) Judgments

Information about judgments made in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in the following notes:

(i) Note 19 – leases: whether an arrangement contains a lease

(e) Rate regulation

The Corporation is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the *Ontario Energy Board Act, 1998.* Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as the Corporation, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

The Corporation is required to bill certain customers for the debt retirement charge set by the province. The Corporation may file to recover uncollected debt retirement charges from Ontario Electricity Financial Corporation ("OEFC") once each year.

2. Basis of presentation (continued)

(e) Rate regulation (continued)

Rate setting

(i) Distribution revenue

For the distribution revenue, the Corporation files a "Cost of Service" ("COS") rate application with the OEB approximately every five years. The COS filing timeline may be extended if the Corporation is able to maintain good reliability and operations under the existing approved rate structure, and has either received approval by the OEB for such a deferral or has elected to follow the Annual Incentive Rate Setting Index ("Annual IR Index") approach. The COS rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholder's equity required to support the Corporation's business. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and interveners and rates are approved based upon this review, including any revisions resulting from that review.

In the intervening years an Incentive Rate Mechanism ("IRM") or an Annual IR Index application is filed. Both of these annual applications result in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year's rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "stretch factor" determined by the relative efficiency of an electricity distributor. The only difference in the rate calculations under each type of annual application is the "stretch factor" applied. An annual IR Index is applicable if an LDC anticipates a cost of service deferral for multiple years.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

The Corporation last filed a COS application in January 2010 for rates effective May 1, 2010. The Corporation has filed an Annual IR Index application annually since 2011. The GDP IPI-FDD for 2016 is 2.10%, the Corporation's productivity factor is (0.0) % and the stretch factor is 0.3%, resulting in a net adjustment of 1.8% to the previous year's rates.

2. Basis of presentation (continued)

(e) Rate regulation (continued)

Rate setting

(ii) Electricity rates

The OEB sets electricity prices for low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity. The Corporation is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

The OEB issued a new distribution rate design for residential electricity customers which will be phased in over a four year period commencing January 2016. Under this new policy, electricity distributors will structure residential rates so that all of the distribution charge will be collected through a fully fixed monthly charge instead of the current fixed and variable charge.

3. Significant accounting policies

The accounting policies set out below have been applied consistently in all years presented in these financial statements:

(a) Financial instruments

All financial assets are classified as loans and receivables and all financial liabilities are classified as other liabilities. These financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets as described in note 3(f). The Corporation does not enter into derivative instruments.

Hedge accounting has not been used in the preparation of these financial statements.

Cash equivalents include short-term investments with maturities of three months or less when purchased.

(b) Revenue recognition

Sale and distribution of electricity

Revenue from the sale and distribution of electricity is recognized as the electricity is delivered to customers on the basis of cyclical meter readings and estimated customer usage since the last meter reading date to the end of the year. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

3. Significant accounting policies (continued)

(b) Revenue recognition (continued)

Sale and distribution of electricity (continued)

Customer billings for debt retirement charges are recorded on a net basis as the Corporation is acting as an agent for this billing stream.

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered or contract milestones are achieved. Amounts received in advance of these milestones are presented as deferred revenue.

Certain customers and developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. Cash contributions are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Government grants and the related performance incentive payments under CDM programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

(c) Materials and supplies

Materials and supplies, the majority of which are consumed by the Corporation in the provision of its services, are valued at the lower of cost and net realizable value, with cost being determined on a weighted average cost basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition.

Net realizable value is the estimated selling price in the ordinary course of business, less estimated selling expenses.

(d) Property, plant and equipment

Items of property, plant and equipment ("PP&E") used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date, less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labour, overhead costs, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

(In thousands of dollars)

3. Significant accounting policies (continued)

(d) Property, plant and equipment (continued)

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Corporation's borrowings. Qualifying assets are considered to be those that take in excess of 12 months to construct.

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item and is included in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically. The Corporation has concluded it does not have any legal or constructive obligation to remove PP&E.

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

The estimated useful lives are as follows:

Buildings & fixtures	10-50 years
Distribution lines	25-60 years
Distribution transformers	40 years
Distribution meters	30 years
Smart meters	12 years
Electricity generation equipment	20 years
General office equipment	10 years
Computer equipment	3-5 years
Major tools	10 years

3. Significant accounting policies (continued)

(e) Intangible assets

Intangible assets used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date, less accumulated amortization. All other intangible assets are measured at cost.

Computer software that is acquired or developed by the Corporation after January 1, 2014, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization.

Payments to obtain rights to access land ("land rights") are classified as intangible assets. These include payments made for easements, right of access and right of use over land for which the Corporation does not hold title. Land rights are measured at cost less accumulated amortization.

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

	Useful life
Computer software	5 years
Land rights	Indefinite

(f) Impairment

(i) Financial assets measured at amortized cost

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss is calculated as the difference between an asset's carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Interest on the impaired assets continues to be recognized through the unwinding of the discount. Losses are recognized in profit or loss. An impairment loss is reversed through profit or loss if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

3. **Significant accounting policies (continued)**

(f) Impairment (continued)

(ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than materials and supplies and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

For other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(g) Customer deposits

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid on customer deposits.

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

(h) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

3. Significant accounting policies (continued)

(i) Regulatory balances

Regulatory asset balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory liability balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory asset balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

The probability of recovery of the regulatory asset balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB, etc. Any resulting impairment loss is recognized in profit or loss in the year incurred.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory liability balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The liability balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

(j) Leased assets

Leases, where the terms cause the Corporation to assume substantially all the risks and rewards of ownership, are classified as finance leases. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

All other leases are classified as operating leases and the leased assets are not recognized on the Corporation's statement of financial position. Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease.

3. Significant accounting policies (continued)

(k) Finance income and finance costs

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash and cash equivalents.

Finance costs comprise interest expense on borrowings. Finance costs are recognized in profit or loss unless they are capitalized as part of the cost of qualifying assets.

(l) Income taxes

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the "Tax Acts"). Under the *Electricity Act*, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the *Electricity Act*, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes. Payments in lieu of taxes are referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

(m) Income taxes

Deferred tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

(In thousands of dollars)

4. Future changes in accounting policy and disclosures

The Corporation is evaluating the adoption of the following new and revised standards along with any subsequent amendments.

Revenue Recognition

The IASB has issued IFRS 15, Revenue from Contracts with Customers ("IFRS 15"). IFRS 15 replaces IAS 11 Construction Contracts, IAS 18 Revenue and various interpretations and establishes principles regarding the nature, amount, timing and uncertainty of revenue arising from contracts with customers. The standard requires entities to recognize revenue for the transfer of goods or services to customers measured at the amounts an entity expects to be entitled to in exchange for those goods or services. IFRS 15 is effective for annual periods beginning on or after January 1, 2018. The Corporation is assessing the impact of IFRS 15 on its results of operations, financial position and disclosures.

Financial Instruments

In July 2014, the IASB issued a new standard, IFRS 9 Financial Instruments, which will replace IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 is effective for periods beginning on or after January 1, 2018 and must be applied retrospectively. The Corporation is assessing the impact of IFRS 9 on its results of operations, financial position, and disclosures.

Leases

In January 2016, the IASB issued IFRS 16 to establish principles for the recognition, measurement, presentation and disclosures of leases, with the objective of ensuring that lessees and lessors provide relevant information that faithfully represents those transactions. IFRS 16 replaces IAS17 and it is effective for annual periods beginning on or after January 1, 2019. The Corporation is assessing the impact of IFRS 16 on its results of operations, financial position and disclosures.

5. Cash and cash equivalents

	2016	2015
Bank balances	$ 735	$ 3,072
Cash and cash equivalents	$ 735	$ 3,072

(In thousands of dollars)

6. Accounts receivable

		2016		2015
Trade receivables	$	9,632	$	7,501
Other trade receivables – WHESC		-		12
Other trade receivables		414		571
Billable work		1,095		415
		11,141		8,499
Less allowance for doubtful accounts		(434)		(528)
	$	10,707	$	7,971

7. Materials and supplies

No amounts written down due to obsolescence in 2016 (2015 – $6).

8. Property, plant and equipment

	Land and buildings	Distribution equipment	Other fixed assets	Construction -in-progress	Total
Cost or deemed cost					
Balance at January 1, 2016	$ 15,077	$ 73,313	$ 2,526	$ 1,234	$ 92,150
Additions	962	9,451	285	228	10,926
Transfers	-	1,088	-	(1,088)	-
Disposals/retirements	-	(496)	-	-	(496)
Balance at December 31, 2016	$ 16,039	$ 83,356	$ 2,811	$ 374	$ 102,580
Balance at January 1, 2015	$ 15,100	$ 58,496	$ 2,095	$ 1,583	$ 77,274
Additions	72	13,683	431	1,065	15,251
Transfers	-	1,414	-	(1,414)	-
Disposals/retirements	(95)	(280)	-	-	(375)
Balance at December 31, 2015	$ 15,077	$ 73,313	$ 2,526	$ 1,234	$ 92,150
Accumulated depreciation					
Balance at January 1, 2016	$ (763)	$ (6,495)	$ (604)	$ -	$ (7,862)
Depreciation	(446)	(3,765)	(316)	-	(4,527)
Disposals/retirements	-	410	-	-	410
Balance at December 31, 2016	$ (1,209)	$ (9,850)	$ (920)	$ -	$ (11,979)
Balance at January 1, 2015	$ (368)	$ (3,112)	$ (275)	$ -	$ (3,755)
Depreciation	(435)	(3,524)	(329)	-	(4,288)
Disposals/retirements	40	141	-	-	181
Balance at December 31, 2015	$ (763)	$ (6,495)	$ (604)	$ -	$ (7,862)
Carrying amounts					
At December 31, 2016	$ 14,830	$ 73,506	$ 1,891	$ 374	$ 90,601
At December 31, 2015	$ 14,314	$ 66,818	$ 1,922	$ 1,234	$ 84,288

During the year, no borrowing costs were capitalized as part of the cost of property, plant and equipment (2015 – $nil).

(In thousands of dollars)

9. Intangible assets

		Computer software		Land rights		Total
Cost or deemed cost						
Balance at January 1, 2016	$	949	$	11	$	960
Additions (disposals)		76		(11)		65
Balance at December 31, 2016	$	1,025	$	-	$	1,025
Balance at January 1, 2015	$	807	$	11	$	818
Additions		142		-		142
Balance at December 31, 2015	$	949	$	11	$	960
Accumulated amortization						
Balance at January 1, 2016	$	(418)	$	-	$	(418)
Amortization		(149)		-		(149)
Balance at December 31, 2016	$	(567)	$	-	$	(567)
Balance at January 1, 2015	$	(264)	$	-	$	(264)
Amortization		(153)		-		(153)
Balance at December 31, 2015	$	(417)	$	-	$	(417)
Carrying amounts						
At December 31, 2016	$	458	$	-	$	458
At December 31, 2015	$	532	$	11	$	543

10. Income tax expense

Current tax expense

		2016		2015
Current year	$	908	$	960
Adjustment for prior years		75		-
	$	983	$	960

Deferred tax expense

		2016		2015
Origination and reversal of temporary differences	$	332	$	288

(In thousands of dollars)

10. Income tax expense (continued)

Reconciliation of effective tax rate

	2016	2015
Income before taxes	$ 5,000	$ 5,892
Canada and Ontario statutory income tax rates	26.5%	26.5%
Expected tax provision on income at statutory rates	1,325	1,562
Increase (decrease) in income taxes resulting from:		
Permanent differences	2	3
Tax on regulatory timing differences	(11)	(317)
Income tax expense	$ 1,316	$ 1,248

Significant components of the Corporation's deferred tax balances

	2016	2015
Deferred tax assets (liabilities):		
Property, plant and equipment	$ 61	$ 383
Cumulative eligible capital	130	123
Other reserves	(108)	(17)
Timing differences on regulatory assets and liabilities	317	244
	$ 400	$ 733

(In thousands of dollars)

WHITBY HYDRO ELECTRIC CORPORATION

11. Regulatory balances

Regulatory deferral account debit balances		January 1, 2016		Additions		Recovery/ reversal		December 31, 2016	Remaining recovery/ reversal years
Deferred meter costs	$	980	$	(103)	$	-	$	877	2
Group 1 deferred accounts		3,681		501		(2,537)		1,645	2
Retail services variances		526		71		-		597	2
Other regulatory assets		751		327		-		1,078	2
Regulatory recovery account		-		(40)		47		7	2
Future income tax		263		144		(263)		144	N/A
	$	6,201	$	900	$	(2,752)	$	4,348	

Regulatory deferral account debit balances		January 1, 2015		Additions		Recovery/ reversal		December 31, 2015	Remaining years
Deferred meter costs	$	1,090	$	(110)	$	-	$	980	3
Group 1 deferred accounts		2,837		844		-		3,681	3
Retail services variances		455		71		-		526	3
Other regulatory assets		519		232		-		751	3
Future income tax		271		263		(271)		263	N/A
	$	5,172	$	1,300	$	(271)	$	6,201	

Regulatory deferral account credit balances		January 1, 2016		Additions		Recovery/ reversal		December 31, 2016	Remaining years
Group 1 deferred accounts	$	2,446	$	1,217	$	(382)	$	3,282	2
Regulatory recovery account		215		-		(215)		-	0
Other regulatory liabilities		3,218		14		(1,991)		1,241	1
Future income taxes		997		545		(997)		545	N/A
	$	6,876	$	1,776	$	(3,585)	$	5,068	

Regulatory deferral account credit balances		January 1, 2015		Additions		Recovery/ reversal		December 31, 2015	Remaining years
Group 1 deferred accounts	$	708	$	1,738	$	-	$	2,446	3
Regulatory recovery account		925		-		(710)		215	1
Other regulatory liabilities		2,018		1,201		-		3,218	2
Future income taxes		1,292		997		(1,292)		997	N/A
	$	4,943	$	3,936	$	(2,002)	$	6,876	

11. Regulatory balances (continued)

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using estimates of future consumption of electricity by the Corporation's customers. Future consumption is impacted by various factors including the economy and weather. The Corporation has received approval from the OEB to establish its regulatory balances.

Deferred meter costs arose as a result of the Ontario Governments' initiative - the Provincial Smart Meter Program. The current deferred balance represents the residual net book value of stranded meters. The Corporation is required to address the balance during its next COS rate application but may request the OEB consider them as part of a stand-alone application.

Group 1 deferral accounts represent retail settlement variances between purchase costs and amounts billed to customers. Settlement to clear these amounts is done through an application to the OEB is done on an annual basis when the audited balances exceed an OEB standard threshold test. The Corporation received approval from the OEB to recover an amount of $1,890 effective January 1, 2016. At the beginning of 2016, the Corporation moved the approved account balance to the regulatory recovery account for recovery over the one year period ending December 31, 2016.

The retailer service variance captures the difference between revenue collected and the associated costs to support retailer activities and transactions. These balances are settled as part of the COS rate process or may be considered in a stand-alone application.

Other regulatory assets include the lost revenue adjustment variance of $828. This account captures the difference between the results of actual verified impacts of authorized CDM program activities and the level of CDM program activities included in the Corporation's 2011 load forecast. Incremental costs incurred to prepare and complete the transition to IFRS accounting represent $205, while the remaining amount is primarily related to an OEB assessment cost variance. These balances must be settled during a COS rate application process but lost revenue may also be settled as part of the annual rate setting process.

The OEB requires the Corporation to estimate its income taxes when it files a COS application to set its rates. As a result, the Corporation has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be recovered from/paid back to its customers. This balance will fluctuate as the Corporation's deferred tax balance fluctuates.

The regulatory recovery account is comprised primarily of Group 1 deferral accounts which have been previously approved for disposition by the OEB. Rate riders related to these balances have expired. The 2016 balance represents a credit of $50 related to Shared Tax Savings which have been approved for deferral plus a small residual balance for the difference between approved balances and rate rider amounts.

(In thousands of dollars)

14. Share capital

		2016		2015
Authorized:				
Unlimited number of common shares				
Issued:				
165 common shares	$	29,494	$	29,494

Dividends

The holders of the common shares are entitled to receive dividends as declared from time to time.

The Corporation paid dividends in the year of $2,677 (2015 – $2,520).

15. Other revenue

		2016		2015
Contributions received from customers	$	853	$	945
Late payment charges		368		381
Collection and other service charges		368		338
Pole and other rental income		135		137
Conservation and Demand Management performance bonus, revenues		40		53
Miscellaneous		131		184
	$	1,895	$	2,038

16. Operating expenses

		2016		2015
Service agreement contract expense	$	9,442	$	9,046
Depreciation and amortization		4,677		4,442
Contract/consulting/service fees		1,975		1,435
Salaries, wages and benefits		694		807
Community relations		106		105
Losses on disposal of property, plant and equipment		86		193
Other		171		153
	$	17,151	$	16,181

(In thousands of dollars)

17. Finance income and costs

		2016		2015
Finance income				
Interest income on bank deposits	$	-	$	(3)
Finance costs				
Interest expense on long-term debt		2,153		2,146
Interest expense on customer deposits		12		13
Other		23		-
		2,188		2,159
Net finance costs recognized in profit or loss	$	2,188	$	2,156

18. Commitments and contingencies

General Liability Insurance

The Corporation maintains appropriate types and levels of insurance with major insurers. With respect to liability insurance, the Corporation is a member of the Municipal Electricity Association Reciprocal Insurance Exchange ("MEARIE"). 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. MEARIE is licensed to provide general liability insurance to its members. All members of the pool could potentially be subjected to an assessment for losses experiences by the pool for the years in which they were members on a pro-rata basis on the total of their respective service revenues. It is anticipated that should such an assessment occur it would be funded over a period of up to 5 years. As at December 31, 2016, no such assessments have been made.

Contractual Obligations

The Corporation is party to a connection and cost recovery agreement with Hydro One Networks Inc. ("Hydro One") related to the construction by Hydro One of a transformer station designated to meet the Corporation's anticipated load growth. Construction of the project was completed during 2007 and the Corporation connected to the transformer station in November 2007.

To the extent that the cost of the project is not recoverable from future transformer connection revenues, the Corporation is obliged to pay a capital contribution equal to the difference between these revenues and the construction costs allocated to the Corporation. Hydro One performs a true-up based on actual load on a periodic basis. There is currently no revenue shortfall owing by the Corporation based on the most recent true-up. Any estimated short fall in the future would be recorded as a liability and a corresponding intangible asset when determined.

General

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

(In thousands of dollars)

19. Operating leases

The Corporation is committed to lease agreements for various vehicles and equipment.

The future minimum non-cancellable annual lease payments are as follows:

		2016		2015
Less than one year	$	332	$	227
Between one and five years		1,657		880
More than five years		111		69
	$	2,100	$	1,176

During the year ended December 31, 2016 an expense of $176 (2015 – $145) was recognized in net income in respect of operating leases.

20. Related party transactions

(a) Parent and ultimate controlling party

The Parent of both the Corporation and Whitby Hydro Services Corporation is Whitby Hydro Energy Corporation, which in turn is wholly-owned by the ultimate controlling party, the Corporation of the Town of Whitby ("Town of Whitby"). The Town produces consolidated financial statements that are available for public use.

(b) Outstanding balances due from related parties

		2016		2015
Town of Whitby	$	398	$	331
Whitby Hydro Energy Services		13		12
	$	411	$	343

Outstanding balances due to related parties

		2016		2015
Whitby Hydro Energy Services	$	5,544	$	3,433
Town of Whitby		28,338		28,338
	$	33,882	$	31,771

Transactions between Whitby Hydro Energy Corporation, Whitby Hydro Electric Corporation, and the Whitby Hydro Energy Services Corporation are pursuant to an annual agreement and recorded at the exchange amount.

(In thousands of dollars)

20. Related party transactions

(c) Transactions with Town of Whitby

The Corporation had the following significant transactions with the Town of Whitby, a government entity:

The Corporation delivers electricity to the Town of Whitby throughout the year for the electricity needs of the Town and its related organizations. Electricity delivery charges are at prices and under terms approved by the OEB.

The Corporation pays interest expense on outstanding promissory notes. Included in Operation, maintenance, and administration expense are fees remitted to the Town for providing fleet maintenance services on an ongoing basis in order for the Corporation to maintain its fleet.

		2016		2015
Revenue				
Energy and distribution	$	4,175	$	4,219
Expenses				
Interest	$	2,000	$	2,000
Operation, maintenance and administration		994		335
	$	2,994	$	2,335

(d) Key management personnel

The key management personnel of the Corporation have been defined as members of its board of directors and executive management team members. The compensation paid or payable is as follows:

		2016		2015
Directors' fees	$	135	$	148
Salaries and other short-term benefits		216		260
	$	351	$	408

21. Financial instruments and risk management

Fair value disclosure

The carrying values of cash and cash equivalents, accounts receivable, unbilled revenue, due from/to related parties and accounts payable and accrued liabilities approximate fair value because of the short maturity of these instruments. The carrying value of customer deposits and the notes payable due to the Town both approximate fair value because the amounts are payable upon demand.

The fair value of the Infrastructure Ontario long-term debt at December 31, 2016 is $4,031 (2015 - $4,452). 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 interest rate used to calculate fair value at December 31, 2016 was 3.25% (2015 – 3.17%).

Financial risks

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

(a) Credit risk

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the Town of Whitby. No single customer accounts for a balance in excess of 5.4% of total accounts receivable.

The carrying amount of accounts receivable is reduced through the use of an allowance for impairment and the amount of the related impairment loss is recognized in profit or loss. Subsequent recoveries of receivables previously provisioned are credited to profit or loss. The balance of the allowance for impairment at December 31, 2016 is $434 (2015 – $528).

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2016, approximately $675 (2015 – $728) is considered over 60 days past due. The Corporation has just over 42 thousand customers, the majority of whom are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2016, the Corporation holds security deposits in the amount of $2,228 (2015 – $1,760).

21. Financial instruments and risk management (continued)

Financial risks (continued)

(b) Market risk

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

A 1% increase in the interest rate at December 31, 2016 would have increased interest expense on the long-term debt by $319 (2015 – $323), assuming all other variables remain constant. A 1% decrease in the interest rate would have an equal but opposite effect.

(c) Liquidity risk

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $5,000 revolving credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. As at December 31, 2016, $520 had been drawn under the Corporation's $5,000 credit facility.

The Corporation also has a bilateral facility for $6,900 (2015 – $6,900) for the purpose of issuing letters of credit to support the prudential requirements of the IESO.

The majority of accounts payable, as reported on the statement of financial position, are due within 30 days.

(d) Capital disclosures

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

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2016, shareholder's equity amounts to $49,733 (2015 – $47,693) and long-term debt amounts to $31,938 (2015 – $32,338).

22. Comparative figures

The financial statements have been reclassified, where applicable, to conform to the presentation used in the current year.

Financial Statements of

WHITBY HYDRO ELECTRIC CORPORATION

Year ended December 31, 2017
(Expressed in thousands of dollars)

KPMG

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Whitby Hydro Electric Corporation

We have audited the accompanying financial statements of Whitby Hydro Electric Corporation ("the Entity"), which comprise the statement of financial position as at December 31, 2017, the statements of comprehensive income, changes in equity and cash flows for the year then, and notes, comprising 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 financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our 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, we consider 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.

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity. KPMG Canada provides services to KPMG LLP.

We believe that the audit evidence we have obtained in our audit 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 Whitby Hydro Electric Corporation as at December 31, 2017, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Hamilton, Canada
April 13, 2018

WHITBY HYDRO ELECTRIC CORPORATION

Statement of Financial Position
December 31, 2017
(In thousands of dollars)

	Note		2017		2016
Assets					
Current assets					
Cash and cash equivalents	5	$	2,785	$	735
Accounts receivable	6		9,177		10,707
Due from related parties	20		395		411
Unbilled revenue			9,530		13,173
Materials and supplies	7		1,152		1,143
Income tax receivable			291		-
Prepaid expenses			80		79
Total current assets			23,410		26,248
Non-current assets					
Property, plant and equipment	8		96,290		90,601
Intangible assets	9		253		458
Deferred tax assets	10		121		508
Total non-current assets			96,664		91,567
Total assets			120,074		117,815
Regulatory balances	11		5,646		4,348
Total assets and regulatory balances		$	125,720	$	122,163

	Note	2017	2016
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	12	$ 13,671	$ 14,323
Due to related parties	20	7,858	5,544
Long-term debt due within one year	13	400	400
Customer deposits		2,352	2,007
Income taxes payable		-	248
Total current liabilities		24,281	22,522
Non-current liabilities			
Customer deposits		146	219
Long-term debt	13	31,538	31,938
Deferred revenue		14,430	13,652
Deferred tax liabilities	10	531	108
Total non-current liabilities		46,645	45,917
Total liabilities		70,926	68,439
Equity			
Share capital	14	29,494	29,494
Retained earnings		20,957	19,162
Total equity		50,451	48,656
Total liabilities and equity		121,377	117,095
Regulatory balances	11	4,343	5,068
Total liabilities, equity and regulatory balances		$ 125,720	$ 122,163

See accompanying notes to the financial statements.

On behalf of the Board:

_____________ Director _____________ Director

WHITBY HYDRO ELECTRIC CORPORATION

Statement of Comprehensive Income
Year ended December 31, 2017, with comparative information for 2016
(In thousands of dollars)

	Note	2017	2016
Revenue			
Distribution revenue		$ 21,865	$ 19,846
Other	15	1,856	1,895
		23,721	21,740
Sale of energy		100,554	119,091
Total revenue		124,275	140,831
Operating expenses			
Operations and maintenance		5,527	5,500
Administration expense		7,575	6,974
Depreciation and amortization		4,784	4,677
	16	17,886	17,151
Cost of power purchased		100,712	116,492
Total expenses		118,598	133,643
Income from operating activities		5,677	7,188
Net finance costs	17	2,141	2,188
Income before income taxes		3,536	5,000
Income taxes			
Current	10	433	983
Future	10	811	333
		1,244	1,316
Net income for the year		2,292	3,684
Net movement in regulatory balances, net of tax	11		
Net movement in regulatory balances		1,212	(377)
Income tax on net movement in regulatory balances		811	333
		2,023	(44)
Net income for the year and net movement in regulatory balances, which is comprehensive income		$ 4,315	$ 3,640

See accompanying notes to the financial statements.

WHITBY HYDRO ELECTRIC CORPORATION

Statement of Changes in Equity
Year ended December 31, 2017, with comparative information for 2016
(In thousands of dollars)

	Share capital	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance at January 1, 2017	$ 29,494	$ 19,162	$ -	$ 48,656
Net income and net movement in regulatory balances	-	4,315	-	4,315
Dividends	-	(2,520)	-	(2,520)
Balance at December 31, 2017	$ 29,494	$ 20,957	$ -	$ 50,451
Balance at January 1, 2016	$ 29,494	$ 18,199	$ -	$ 47,693
Net income and net movement in regulatory balances	-	3,640	-	3,640
Dividends	-	(2,677)	-	(2,677)
Balance at December 31, 2016	$ 29,494	$ 19,162	$ -	$ 48,656

See accompanying notes to the financial statements.

WHITBY HYDRO ELECTRIC CORPORATION

Statement of Cash Flows
Year ended December 31, 2017, with comparative information for 2016
(In thousands of dollars)

	2017	2016
Operating activities		
Net income and net movement in regulatory balances	$ 4,315	$ 3,640
Adjustments for:		
Depreciation and amortization	4,784	4,677
Amortization of deferred revenue	(1,017)	(849)
Losses on disposal of property, plant and equipment	72	86
Net finance costs	2,141	2,188
Income tax expense	1,244	1,316
Contributions received from customers	1,795	2,962
Change in non-cash operating working capital:		
Accounts receivable	1,530	(2,736)
Due to/from related parties	2,330	2,043
Unbilled revenue	3,643	(265)
Materials and supplies	(9)	(60)
Prepaid expenses	(1)	9
Accounts payable and accrued liabilities	(652)	1,606
Customer deposits	272	466
	20,447	15,083
Net movement in regulatory balances	(2,023)	44
Income tax paid	(1,071)	(1,275)
Income tax received	122	69
Interest paid	(2,162)	(2,190)
Net cash from operating activities	15,313	11,731
Investing activities		
Purchase of property, plant and equipment	(10,194)	(10,926)
Purchase of intangible assets	(147)	(65)
Net cash used by investing activities	(10,341)	(10,991)
Financing activities		
Dividends paid	(2,520)	(2,677)
Repayment of long-term debt	(400)	(400)
Net cash used by financing activities	(2,920)	(3,077)
Change in cash and cash equivalents	2,050	(2,337)
Cash and cash equivalents, beginning of year	735	3,072
Cash and cash equivalents, end of year	$ 2,785	$ 735

See accompanying notes to the financial statements.

1. Reporting entity

Whitby Hydro Electric Corporation (the "Corporation") is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Corporation is located in the Town of Whitby of the Region of Durham. The address of the Corporation's registered office is 100 Taunton Rd. East, Whitby Hydro, Ontario.

The Corporation delivers electricity and related energy services to residential and commercial customers in Whitby. The Corporation is wholly owned by Whitby Hydro Energy Corporation and the ultimate parent is the Corporation of the Town of Whitby.

The financial statements are for the Corporation as at and for the year ended December 31, 2017.

2. Basis of presentation

(a) Statement of compliance

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The financial statements were approved by the Board of Directors on April 13, 2018.

(b) Basis of measurement

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand.

(d) Use of estimates and judgments

(i) Assumptions and estimation uncertainty

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

2. Basis of presentation (continued)

(d) Use of estimates and judgments (continued)

(i) Assumptions and estimation uncertainty (continued)

Information about assumptions and estimation uncertainties that have a significant risk of resulting in material adjustment is included in the following notes:

(i) Note 3(b) – measurement of unbilled revenue
(ii) Notes 3(d) and 3(e) – estimation of useful lives of its property, plant and equipment and intangible assets
(iii) Note 3(i) – recognition and measurement of regulatory balances
(iv) Note 18 – recognition and measurement of provisions and contingencies

(ii) Judgments

Information about judgments made in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in the following note:

(i) Note 3(j) – leases: whether an arrangement contains a lease and classification as an operating lease versus financing

(e) Rate regulation

The Corporation is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the *Ontario Energy Board Act, 1998*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as the Corporation, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

The Corporation is required to bill certain customers for the debt retirement charge set by the province. The Corporation may file to recover uncollected debt retirement charges from Ontario Electricity Financial Corporation ("OEFC") once each year.

2. Basis of presentation (continued)

(e) Rate regulation (continued)

Rate setting

(i) Distribution revenue

For the distribution revenue, the Corporation files a "Cost of Service" ("COS") rate application with the OEB approximately every five years. The COS filing timeline may be extended if the Corporation is able to maintain good reliability and operations under the existing approved rate structure, and has either received approval by the OEB for such a deferral or has elected to follow the Annual Incentive Rate Setting Index ("Annual IR Index") approach. The COS rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholder's equity required to support the Corporation's business. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and interveners; rates are approved based upon this review, including any revisions resulting from the review.

In the intervening years an Incentive Rate Mechanism ("IRM") or an Annual IR Index application is filed. Both of these annual applications result in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year's rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "stretch factor" determined by the relative efficiency of an electricity distributor. The only difference in the rate calculations under each type of annual application is the "stretch factor" applied. An annual IR Index is applicable if an LDC anticipates a cost of service deferral for multiple years.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

The Corporation last filed a COS application in January 2010 for rates effective May 1, 2010. The Corporation has filed an Annual IR Index application annually since 2011. The GDP IPI-FDD for 2017 is 1.90%, the Corporation's productivity factor is 0.0% and the stretch factor is 0.3%, resulting in a net adjustment of 1.6% to the previous year's rates.

(ii) Electricity rates

The OEB sets electricity prices for low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity. The Corporation is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

2. Basis of presentation (continued)

(e) Rate regulation (continued)

Rate setting (continued)

(ii) Electricity rates (continued)

The OEB issued a new distribution rate design for residential electricity customers which will be phased in over a four year period commencing January 2016. Under this new policy, electricity distributors will structure residential rates so that all of the distribution charge will be collected through a fully fixed monthly charge instead of the current fixed and variable charge.

Effective 2017, all electricity distributors in Ontario are required to bill their customers on a monthly basis rather than the historical bi-monthly basis. This policy change incorporates an expectation that distributors will issue bills based on actual meter readings rather than estimates at least 98% of the time.

3. Significant accounting policies

The accounting policies set out below have been applied consistently in all years presented in these financial statements:

(a) Financial instruments

All financial assets are classified as loans and receivables and all financial liabilities are classified as other liabilities. These financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets as described in note 3(f). The Corporation does not enter into derivative instruments.

Hedge accounting has not been used in the preparation of these financial statements.

Cash equivalents include short-term investments with maturities of three months or less when purchased.

(b) Revenue recognition

Sale and distribution of electricity

Revenue from the sale and distribution of electricity is recognized as the electricity is delivered to customers on the basis of cyclical meter readings and estimated customer usage since the last meter reading date to the end of the year. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

3. Significant accounting policies (continued)

(b) Revenue recognition (continued)

Sale and distribution of electricity (continued)

Customer billings for debt retirement charges are recorded on a net basis as the Corporation is acting as an agent for this billing stream.

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered or contract milestones are achieved. Amounts received in advance of these milestones are presented as deferred revenue.

Certain customers and developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. Cash contributions are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Government grants and the related performance incentive payments under CDM programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

(c) Materials and supplies

Materials and supplies, the majority of which are consumed by the Corporation in the provision of its services, are valued at the lower of cost and net realizable value, with cost being determined on a weighted average cost basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition.

Net realizable value is the estimated selling price in the ordinary course of business, less estimated selling expenses.

(d) Property, plant and equipment

Items of property, plant and equipment ("PP&E") used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date, less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labour, overhead costs, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

(In thousands of dollars)

3. Significant accounting policies (continued)

(d) Property, plant and equipment (continued)

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Corporation's borrowings. Qualifying assets are considered to be those that take in excess of 12 months to construct.

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item and is included in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically. The Corporation has concluded it does not have any legal or constructive obligation to remove PP&E.

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

The estimated useful lives are as follows:

Buildings & fixtures	10-50 years
Distribution lines	25-60 years
Distribution transformers	40 years
Distribution meters	30 years
Smart meters	12 years
Electricity generation equipment	20 years
General office equipment	10 years
Computer equipment	3-5 years
Major tools	10 years

3. Significant accounting policies (continued)

(e) Intangible assets

Intangible assets used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date, less accumulated amortization. All other intangible assets are measured at cost.

Computer software that is acquired or developed by the Corporation after January 1, 2014, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization.

Payments to obtain rights to access land ("land rights") are classified as intangible assets. These include payments made for easements, right of access and right of use over land for which the Corporation does not hold title. Land rights are measured at cost less accumulated amortization.

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

Computer software	5 years
Land rights	Indefinite

(f) Impairment

(i) Financial assets measured at amortized cost

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss is calculated as the difference between an asset's carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Interest on the impaired assets continues to be recognized through the unwinding of the discount. Losses are recognized in profit or loss. An impairment loss is reversed through profit or loss if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

3. Significant accounting policies (continued)

(f) Impairment (continued)

(ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than materials and supplies and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

For other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(g) Customer deposits

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid on customer deposits.

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

(h) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

3. Significant accounting policies (continued)

(i) Regulatory balances

Regulatory debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit (loss) or OCI. When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

The probability of recovery of the regulatory debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB, etc. Any resulting impairment loss is recognized in profit or loss in the year incurred.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

(j) Leased assets

Leases, where the terms cause the Corporation to assume substantially all the risks and rewards of ownership, are classified as finance leases. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

All other leases are classified as operating leases and the leased assets are not recognized on the Corporation's statement of financial position. Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease.

3. Significant accounting policies (continued)

(k) Finance income and finance costs

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash and cash equivalents.

Finance costs comprise interest expense on borrowings and customer deposits. Finance costs are recognized in profit or loss unless they are capitalized as part of the cost of qualifying assets.

(l) Income taxes

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the "Tax Acts"). Under the *Electricity Act*, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the *Electricity Act*, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes. Payments in lieu of taxes are referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

4. Future changes in accounting policy and disclosures

The Corporation is still evaluating the adoption of the following new and revised standards along with any subsequent amendments.

Revenue Recognition

In May 2014, the IASB has issued IFRS 15, Revenue from Contracts with Customers ("IFRS 15"). The new standard is effective for annual periods beginning on or after January 1, 2018. IFRS 15 replaces IAS 11 Construction Contracts, IAS 18 Revenue and various interpretations and establishes principles regarding the nature, amount, timing and uncertainty of revenue arising from contracts with customers. The standard contains a single model that applies to contracts with customers and two approaches to recognising revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. The Corporation will adopt IFRS 15 and the clarifications in its financial statements for the annual period beginning on January 1, 2018. The Corporation does not expect the standard to have a material impact on the financial statements.

Financial Instruments

In July 2014, the IASB issued a new standard, IFRS 9 Financial Instruments which will replace IAS 39 Financial Instruments: Recognition and Measurement. The mandatory effective date of IFRS 9 is for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions. The restatement of prior periods is not required and is only permitted if information is available without the use of hindsight. The Corporation will adopt IFRS 9 in its financial statements for the annual period beginning on January 1, 2018. The Corporation does not expect the standard to have a material impact on the financial statements.

Leases

In January 2016, the IASB issued IFRS 16 Leases. The new standard is effective for annual periods beginning on or after January 1, 2019. Earlier application is permitted for entities that apply IFRS 15 Revenue from Contracts with Customers at or before the date of initial adoption of IFRS 16. IFRS 16 will replace IAS 17 Leases. The standard introduces a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments. This standard substantially carries forward the lessor accounting requirements of IAS 17, while requiring enhanced disclosures to be provided by the lessor. Other areas of the lease accounting model have been impacted, including the definition of a lease. Transitional provisions have been provided. The Corporation intends to adopt IFRS 16 in its financial statements for the annual period beginning January 1, 2019. The extent of the impact of adoption of the standard has not yet been determined.

(in thousands of dollars)

5. Cash and cash equivalents

		2017		2016
Bank balances	$	2,785	$	735
Cash and cash equivalents	$	2,785	$	735

6. Accounts receivable

		2017		2016
Trade receivables	$	7,993	$	9,632
Other trade receivables		606		414
Billable work		918		1,095
		9,517		11,141
Less allowance for doubtful accounts		(340)		(434)
	$	9,177	$	10,707

7. Materials and supplies

No amounts written down due to obsolescence in 2017 (2016 – $nil).

(In thousands of dollars)

8. Property, plant and equipment

	Land and buildings	Distribution equipment	Other fixed assets	Construction -in-progress	Total
Cost or deemed cost					
Balance at January 1, 2017	$ 16,039	$ 83,355	$ 2,811	$ 374	$ 102,579
Additions	2,430	6,932	281	551	10,194
Transfers	-	356	-	(356)	-
Disposals/retirements	-	(342)	-	-	(342)
Balance at December 31, 2017	$ 18,469	$ 90,301	$ 3,092	$ 569	$ 112,431
Balance at January 1, 2016	$ 15,077	$ 73,313	$ 2,526	$ 1,234	$ 92,150
Additions	962	9,451	285	228	10,926
Transfers	-	1,088	-	(1,088)	-
Disposals/retirements	-	(496)	-	-	(496)
Balance at December 31, 2016	$ 16,039	$ 83,356	$ 2,811	$ 374	$ 102,580
Accumulated depreciation					
Balance at January 1, 2017	$ (1,209)	$ (9,850)	$ (921)	$ -	$ (11,980)
Depreciation	(479)	(3,617)	(335)	-	(4,431)
Disposals/retirements	-	270	-	-	270
Balance at December 31, 2017	$ (1,688)	$ (13,197)	$ (1,256)	$ -	$ (16,141)
Balance at January 1, 2016	$ (763)	$ (6,495)	$ (604)	$ -	$ (7,862)
Depreciation	(446)	(3,765)	(316)	-	(4,527)
Disposals/retirements	-	410	-	-	410
Balance at December 31, 2016	$ (1,209)	$ (9,850)	$ (920)	$ -	$ (11,979)
Carrying amounts					
At December 31, 2017	$ 16,781	$ 77,104	$ 1,836	$ 569	$ 96,290
At December 31, 2016	$ 14,830	$ 73,506	$ 1,891	$ 374	$ 90,601

During the year, no borrowing costs were capitalized as part of the cost of property, plant and equipment (2016 – $nil).

At December 31, 2017, property, plant and equipment with a carrying value of $96,290 (2016 – $90,601) are subject to a general security agreement.

(In thousands of dollars)

9. Intangible assets

		Computer software		Land rights		Total
Cost or deemed cost						
Balance at January 1, 2017	$	1,025	$	-	$	1,025
Additions (disposals)		147		-		147
Balance at December 31, 2017	$	1,172	$	-	$	1,172
Balance at January 1, 2016	$	949	$	11	$	960
Additions (disposals)		76		(11)		65
Balance at December 31, 2016	$	1,025	$	-	$	1,025
Accumulated amortization						
Balance at January 1, 2017	$	(567)	$	-	$	(567)
Amortization		(352)		-		(352)
Balance at December 31, 2017	$	(919)	$	-	$	(919)
Balance at January 1, 2016	$	(418)	$	-	$	(418)
Amortization		(149)		-		(149)
Balance at December 31, 2016	$	(567)	$	-	$	(567)
Carrying amounts						
At December 31, 2017	$	253	$	-	$	253
At December 31, 2016	$	458	$	-	$	458

10. Income tax expense

Current tax expense

		2017		2016
Current year	$	433	$	908
Adjustment for prior years		-		75
	$	433	$	983

Deferred tax expense

		2017		2016
Origination and reversal of temporary differences	$	811	$	333

(in thousands of dollars)

10. Income tax expense (continued)

Reconciliation of effective tax rate

	2017	2016
Income before taxes	$ 3,536	$ 5,000
Canada and Ontario statutory income tax rates	26.5%	26.5%
Expected tax provision on income at statutory rates	937	1,325
Increase (decrease) in income taxes resulting from:		
Permanent differences	4	2
Tax on regulatory timing differences	303	(11)
Income tax expense	$ 1,244	$ 1,316

Significant components of the Corporation's deferred tax balances

	2017	2016
Deferred tax assets:		
Cumulative eligible capital	$ 121	$ 130
Deferred tax liabilities:		
Property, plant and equipment	(435)	61
Timing differences on regulatory assets and liabilities	(29)	317
Other reserves	(67)	(108)
	$ (410)	$ 400

(In thousands of dollars)

11. Regulatory balances

Regulatory deferral account debit balances	January 1, 2017	Additions	Recovery/ reversal	December 31, 2017	Remaining recovery/ reversal years
Deferred meter costs	$ 877	$ -	$ (96)	$ 781	1
Group 1 deferral accounts	1,645	1,111	(56)	2,700	2
Retail services variances	597	65	-	662	1
Other regulatory assets	1,078	501	(634)	945	3
Regulatory recovery account	7	-	(7)	-	N/A
Future income tax	144	558	(144)	558	*
	$ 4,348	$ 2,235	$ (937)	$ 5,646	

Regulatory deferral account debit balances	January 1, 2016	Additions	Recovery/ reversal	December 31, 2016	Remaining recovery/ reversal years
Deferred meter costs	$ 980	$	$ (103)	$ 877	2
Group 1 deferral accounts	3,681	501	(2,537)	1,645	2
Retail services variances	526	71	-	597	2
Other regulatory assets	751	327	-	1,078	2
Regulatory recovery account	-	47	(40)	7	2
Future income tax	263	144	(263)	144	*
	$ 6,201	$ 1,090	$ (2,943)	$ 4,348	

Regulatory deferral account credit balances	January 1, 2017	Additions	Recovery/ reversal	December 31, 2017	Remaining years
Group 1 deferral accounts	$ 3,282	$ 907	$ -	$ 4,189	2
Regulatory recovery account	-	6	-	6	2
Other regulatory liabilities	1,241	-	(1,241)	-	N/A
Future income taxes	545	148	(545)	148	*
	$ 5,068	$ 1,061	$ (1,786)	$ 4,343	

Regulatory deferral account credit balances	January 1, 2016	Additions	Recovery/ reversal	December 31, 2016	Remaining years
Group 1 deferral accounts	$ 2,447	$ 1,217	$ (382)	$ 3,282	2
Regulatory recovery account	215	-	(215)	-	0
Other regulatory liabilities	3,218	14	(1,991)	1,241	1
Future income taxes	997	545	(997)	545	*
	$ 6,877	$ 1,776	$ (3,585)	$ 5,068	

* These balances will reverse as the related deferred income taxes reverse.

11. Regulatory balances (continued)

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using estimates of future consumption of electricity by the Corporation's customers. Future consumption is impacted by various factors including the economy and weather. The Corporation has received approval from the OEB to establish its regulatory balances.

Deferred meter costs arose as a result of the Ontario Governments' initiative - the Provincial Smart Meter Program. The current deferred balance represents the residual net book value of stranded meters. The Corporation has received approval to dispose of this balance in 2018.

Group 1 deferral accounts represent retail settlement variances between purchase costs and amounts billed to customers. Settlement to clear these amounts is done through an application to the OEB on an annual basis when the audited balances exceed an OEB standard threshold test. The Corporation received approval from the OEB to dispose of a net credit amount of $1,774 effective January 1, 2018. At the beginning of 2018, the Corporation will move the approved account balance to the regulatory recovery account for disposition over the one year period ending December 31, 2018.

The retail services variance captures the difference between revenue collected and the associated costs to support retailer activities and transactions. These balances are generally settled as part of the COS rate application process however the Corporation has filed a stand-alone application and received approval to dispose of $603 (representing December 31, 2016 ending balances plus interest) over a one year period ending December 31, 2018.

Other regulatory assets include amounts for the following:

- Lost revenue adjustment variance of $586. This account captures the difference between the results of actual verified impacts of authorized CDM program activities and the level of CDM program activities included in the Corporation's 2011 load forecast. The lost revenue balances may be settled as part of the annual rate setting process;
- Incremental costs incurred to prepare and complete the transition to IFRS accounting and the OEB assessment cost variance of $306. These balances are generally settled during a COS rate application process, however, the Corporation received approval to dispose of $253 (representing December 31, 2016 balances plus interest) during 2018 as part of a stand-alone application; and
- Differences associated with required regulatory accounting changes under CGAAP which were implemented in 2013 of $53. The OEB has previously approved two interim dispositions in order to begin to return funds to customers. This account will continue to track the differences each year until the next COS application is completed and the regulatory changes to IFRS accounting are incorporated in approved distribution rates. Alternatively, the Corporation may propose a final disposition as part of a stand- alone application. Additional transactions in 2017 resulted in a shift from an opening regulatory credit amount to a closing regulatory debit balance.

(In thousands of dollars)

11. Regulatory balances (continued)

The regulatory recovery account is comprised primarily of Group 1 deferral accounts which have been previously approved for disposition by the OEB. Rate riders related to these balances have expired. The 2017 balance represents a credit of $102 related to Shared Tax Savings which have been approved for deferral plus small residual balances for the difference between approved balances and rate rider amounts.

The OEB requires the Corporation to estimate its income taxes when it files a COS application to set its rates. As a result, the Corporation has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be recovered from/paid back to its customers. This balance will fluctuate as the Corporation's deferred tax balance fluctuates.

Other regulatory liabilities reflect the differences associated with required regulatory accounting changes under CGAAP which were implemented in 2013. The OEB has previously approved two interim dispositions in order to begin to return funds to customers. The most recent approval included a return of $1,285 to customers over a one year period starting January 1, 2017. This account will continue to track the differences each year until the next COS application is completed and the regulatory changes to IFRS accounting are incorporated in approved distribution rates. Alternatively the Corporation may propose a final disposition as part of a stand-alone application.

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers' Acceptances three-month rate plus a spread of 25 basis points. In 2017 the rate was 1.10% for the first three quarters of the year and then increased to 1.50% in the final quarter.

12. Accounts payable and accrued liabilities

	2017	2016
Accounts payable – IESO energy purchases	$ 7,970	$ 10,601
Customer credit balances	1,600	611
Debt retirement charge payable to OEFC	251	249
Interest payable	13	15
Accounts payable – WHESC	-	35
Other	3,837	2,812
	$ 13,671	$ 14,323

(In thousands of dollars)

13. Long-term debt

		2017		2016
Town of Whitby notes payable	$	28,338	$	28,338
Ontario Infrastructure loans		3,600		4,000
		31,938		32,338
Less current portion		400		400
Long-term portion	$	31,538	$	31,938

The notes payable bear interest at an average rate of 7.06% and are due on demand to the Town of Whitby. The Town of Whitby has waived its right to demand payment until January 1, 2019.

The Ontario Infrastructure loans have a maturity date of December 1, 2026 and have an interest rate of 3.36% per annum. Interest is payable in equal monthly installments, in advance, commencing on January 3, 2012. The loans are secured by a general security agreement over the assets of the Corporation.

14. Share capital

		2017		2016
Authorized:				
Unlimited number of common shares				
Issued:				
165 common shares	$	29,494	$	29,494

Dividends

The holders of the common shares are entitled to receive dividends as declared from time to time.

The Corporation paid dividends in the year of $2,520 (2016 – $2,677).

15. Other revenue

		2017		2016
Contributions received from customers	$	1,017	$	853
Collection and other service charges		352		368
Late payment charges		221		368
Pole and other rental income		134		135
Conservation and Demand Management performance adjustment		-		40
Miscellaneous		132		131
	$	1,856	$	1,895

(In thousands of dollars)

16. Operating expenses

		2017		2016
Service agreement contract expense	$	9,615	$	9,442
Depreciation and amortization		4,784		4,677
Contract/consulting/service fees		2,280		1,975
Salaries, wages and benefits		908		694
Community relations		131		106
Losses on disposal of property, plant and equipment		72		86
Other		96		171
	$	17,886	$	17,151

17. Net finance costs

		2017		2016
Finance income				
Interest income on bank deposits	$	15	$	-
Finance costs				
Interest expense on long-term debt		2,128		2,153
Interest expense on customer deposits		14		12
Other		(16)		23
		2,126		2,188
Net finance costs recognized in profit or loss	$	2,141	$	2,188

18. Commitments and contingencies

General Liability Insurance

The Corporation maintains appropriate types and levels of insurance with major insurers. With respect to liability insurance, the Corporation is a member of the Municipal Electricity Association Reciprocal Insurance Exchange ("MEARIE"). 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. MEARIE is licensed to provide general liability insurance to its members. All members of the pool could potentially be subjected to an assessment for losses experiences by the pool for the years in which they were members on a pro-rata basis on the total of their respective service revenues. It is anticipated that should such an assessment occur it would be funded over a period of up to 5 years. As at December 31, 2017, no such assessments have been made.

Contractual Obligations

The Corporation is party to a connection and cost recovery agreement with Hydro One Networks Inc. ("Hydro One") related to the construction by Hydro One of a transformer station designated to meet the Corporation's anticipated load growth. Construction of the project was completed during 2007 and the Corporation connected to the transformer station in November 2007.

(In thousands of dollars)

18. Commitments and contingencies (continued)

To the extent that the cost of the project is not recoverable from future transformer connection revenues, the Corporation is obliged to pay a capital contribution equal to the difference between these revenues and the construction costs allocated to the Corporation. Hydro One performs a true-up based on actual load on a periodic basis. There is currently no revenue shortfall owing by the Corporation based on the most recent true-up. Any estimated short fall in the future would be recorded as a liability and a corresponding intangible asset when determined.

General

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

19. Operating leases

The Corporation is committed to lease agreements for various vehicles and equipment.

The future minimum non-cancellable annual lease payments are as follows:

	2017	2016
Less than one year	$ 401	$ 332
Between one and five years	2,007	1,657
More than five years	138	111
	$ 2,546	$ 2,100

During the year ended December 31, 2017 an expense of $159 (2016 – $176) was recognized in net income in respect of operating leases.

20. Related party transactions

(a) Parent and ultimate controlling party

The Parent of both the Corporation and Whitby Hydro Services Corporation is Whitby Hydro Energy Corporation, which in turn is wholly-owned by the ultimate controlling party, the Corporation of the Town of Whitby ("Town of Whitby"). The Town produces consolidated financial statements that are available for public use.

(b) Outstanding balances due from related parties

	2017	2016
Town of Whitby	$ 381	$ 398
Whitby Hydro Energy Services	14	13
	$ 395	$ 411

(In thousands of dollars)

20. Related party transactions (continued)

(b) Outstanding balances due from related parties (continued)

Outstanding balances due to related parties

		2017		2016
Whitby Hydro Energy Services	$	7,858	$	5,544
Town of Whitby		28,338		28,338
	$	36,196	$	33,882

Transactions between Whitby Hydro Energy Corporation, Whitby Hydro Electric Corporation, and the Whitby Hydro Energy Services Corporation are pursuant to an annual agreement and recorded at the exchange amount.

(c) Transactions with the Town of Whitby

The Corporation had the following significant transactions with the Town of Whitby, a government entity:

The Corporation delivers electricity to the Town of Whitby throughout the year for the electricity needs of the Town and its related organizations. Electricity delivery charges are at prices and under terms approved by the OEB.

The Corporation pays interest expense on outstanding promissory notes. Included in Operation, maintenance, and administration expense are fees remitted to the Town for providing fleet maintenance services on an ongoing basis in order for the Corporation to maintain its fleet.

		2017		2016
Revenue				
Energy and distribution	$	3,671	$	4,175
Expenses				
Interest	$	2,000	$	2,000
Operations, maintenance and administration		497		994
	$	2,497	$	2,994

(d) Key management personnel

The key management personnel of the Corporation have been defined as members of its board of directors and executive management team members. The compensation paid or payable is as follows:

		2017		2016
Directors' fees	$	117	$	135
Salaries and other short-term benefits		213		216
	$	330	$	351

20. Financial instruments and risk management

Fair value disclosure

The carrying values of cash and cash equivalents, accounts receivable, unbilled revenue, due from/to related parties and accounts payable and accrued liabilities approximate fair value because of the short maturity of these instruments. The carrying value of customer deposits approximates fair value as the deposits bear interest at current rates.

The fair value of the Town of Whitby notes payable at December 31, 2017 is $41,929 (2016 – $42,243). 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 interest rate used to calculate fair value at December 31, 2017 was 3.64% (2016 – 3.25%).

The fair value of the Ontario Infrastructure long-term debt at December 31, 2017 is $3,574 (2016 – $4,031). 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 interest rate used to calculate fair value at December 31, 2017 was 3.61% (2016 – 3.25%).

Financial risks

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

(a) Credit risk

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the Town of Whitby. No single customer accounts for a balance in excess of 4.8% of total accounts receivable.

The carrying amount of accounts receivable is reduced through the use of an allowance for impairment and the amount of the related impairment loss is recognized in profit or loss. Subsequent recoveries of receivables previously provisioned are credited to profit or loss. The balance of the allowance for impairment at December 31, 2017 is $340 (2016 – $434).

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2017, approximately $584 (2016 – $675) is considered over 60 days past due. The Corporation has just over 42 thousand customers, the majority of whom are residential. Credit risk is managed through collection of security deposits from customers in accordance with direction provided by the OEB. As at December 31, 2017, the Corporation holds security deposits in the amount of $2,498 (2016 – $2,228).

20. Financial instruments and risk management (continued)

Financial risks (continued)

(b) Market risk

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

(c) Liquidity risk

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $5,000 revolving credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. As at December 31, 2017, no amounts have been drawn under the Corporation's $5,000 credit facility.

The Corporation also has a bilateral facility for $6,900 (2016 – $6,900) for the purpose of issuing letters of credit to support the prudential requirements of the IESO.

The majority of accounts payable, as reported on the statement of financial position, are due within 30 days.

(d) Capital disclosures

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

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2017, shareholder's equity amounts to $50,451 (2016 – $48,656) and long-term debt amounts to $31,538 (2016 – $31,938).

21. Comparative figures

The financial statements have been reclassified, where applicable, to conform to the presentation used in the current year.

TAB 18

Tab C

SECTION 18(c) ATTACHMENT

Staff 28_IRR part c) 2019 Pro-Forma Cash Flow Statement

LDC MergeCo	2019 Combined Proforma (in $000's)
CASHFLOW STATEMENT	
Operating activities	
Net Income	9,968
Items not affecting cash	
Amortization	16,807
Change in non-cash working capital	4,900
Cashflow from operating activitues	31,675
Investing activities	
Acquisition of PPE and intangible assets	(34,623)
Cashflow from investing activitues	(34,623)
Financing Activities	
Net repayment of/proceeds from Long Term Debt	7,500
Dividends paid	(7,120)
Cashflow from financing activitues	380
Increase/(decrease) in cash and cash equivalents	(2,568)
Cash Balance	
Cash and cash equivalents, beginning of year	10,568
Cash and cash equivalents, end of year	8,000

LDC MergeCo	2019 Combined Proforma (in $000's)
BALANCE SHEET	
ASSETS	
Current assets	
Cash	8,000
Accounts receivable	73,634
Other current assets	6,394
Total current assets	88,028
Capital Assets	
Net fixed assets	357,252
Other Assets	
Other non-current assets	18,311
Total Assets	**463,591**
LIABILITIES	
Current Liabilities	
Accounts Payable	60,621
Developer & customer obligations	11,281
Other current liabilities	11,696
Total current liabilities	83,598
Long-term Liabilities	
Long-term debt	195,779
Other long-term liabilites	14,498
Total Liabilities	293,875
SHAREHOLDER'S EQUITY	
Share capital	98,819
Retained earnings	70,897
Total Liabilities and Shareholder's Equity	**463,591**

LDC MergeCo	2019 Combined Proforma (in $000's)
INCOME STATEMENT	
Distribution revenue	80,527
Cost of Power revenue	407,213
Sale of electrical energy	487,740
Less: Cost of power expense	407,213
Net sale of electrical energy	80,527
Other revenues	4,295
Total Revenues	84,822
OM&A expenses	50,226
EBITDA	34,596
Amortization	16,807
Operating income	17,790
Interest	6,265
EBT	11,524
Taxes	1,556
Net Income	**9,968**