Staff Question-1

Ref: IRM Application, Page 13

a) Please explain what steps Oakville Hydro took to negotiate the scope and timing of the road widening projects with Halton Region.

Response:

This project is a mandatory obligation in accordance with the *Public Service Works on Highways Act* ("PSWHA"). The road authority controls the timing of the project and their road design dictates the scope of the project. The timing for project construction is dependent on the road authority meeting certain conditions (road design complete, property and easement acquisitions, and purchase order authorization to proceed with relocations). Oakville Hydro does not negotiate the scope and timing of the road widening projects with Halton Region, but meets frequently with Halton Region project managers so that Oakville Hydro's relocations can be scheduled to meet road project schedules.

b) Please explain what steps Oakville Hydro took to negotiate the scope and timing of the road widening projects with the Town of Oakville.

Response:

Please see response to part a) of this interrogatory.

Staff Question-2

Ref: ICM Model, Tab 9b – Proposed ACM ICM Projects

Oakville Hydro Reply Submission on the Preliminary Question, October 24, 2019, Page 12

Oakville Hydro cited the OEB's decision in Rideau St. Lawrence Distribution Inc.'s 2018 IRM Application (EB-2017-0265). OEB staff notes that, in that proceeding, the opening net book value of the asset used to calculate the ICM revenue requirement was reduced by six months of depreciation to account for the fact that the asset had in fact gone in-service in the previous year, 2017. OEB staff notes that there were unique circumstances in Rideau St. Lawrence's case, relating to its late 2016 cost of service application that factored into the settlement proposal that was accepted by the OEB.

a) If the OEB were to consider the approach accepted for Rideau St. Lawrence, please provide Oakville Hydro's views with reasons on the reasonableness of this approach.

Response:

As noted by the OEB in its Decision and Rate Order in Rideau St. Lawrence Distribution Inc.'s 2018 IRM application, the OEB's models have been designed for requests for incremental capital funding in the year in which the asset is planned to be in service[1].

In Oakville Hydro's view, reducing the opening net book value of the assets that will be in service in 2019 by an amount equal to six months of depreciation is an effective way of adapting the OEB's model to accommodate ICM funding for projects with an in service date that precedes the requested ICM year.

b) Please identify whether the values used for the proposed ICM projects reflect the gross book value of the capital costs or the January 1, 2020 opening net book value of each project. If the former, please provide the January 1, 2020 opening net book value for each project.

Response:

As discussed in Oakville Hydro's Reply Submission on the Preliminary Question of whether it is appropriate for Oakville Hydro to seek ICM funding in its 2020 IRM application (the "Preliminary Question"), it is extremely difficult to predict the timing, nature, and scope third party requests for access to its distribution system[2].

At the time that Oakville Hydro submitted its request for ICM funding, it had expected that the four projects for which it sought funding would be in service in 2019. However, as the end of 2019 approaches, it is now evident that three of the four projects will be in service in 2019 and the fourth project will be in service in 2020.

Therefore, Oakville Hydro is proposing that the opening book value of the three in service project be reduced by an amount equal to six months depreciation to reflect the net book value of those projects and the fourth project reflect the gross book value as set out in the following table.

Incremental Capital Additions

Project Description	2019 Capital Additions	Amortization (Half-year Rule)	2020 ICM Claim
Bronte Feeder Replacement Project	$ 1,700,000	$ 24,500	$ 1,675,500
Town of Oakville Road Widening - Speers Road	2,000,000	23,000	1,977,000
Halton Region Road Widening - Trafalgar Road	2,200,000	25,500	2,174,500
Halton Region Road Widening - William Halton Parkway	-	-	1,200,000
Total	$ 5,900,000	$ 73,000	$ 7,027,000

[1] Decision and Rate Order, EB-2017-0265, page 4.
[2] Oakville Hydro's Reply Submission on the Preliminary Question, page 11.

Staff Question-3

Ref: IRM Application, Page 14-15

Oakville Hydro notes that it is installing new underground feeders and feeder meters to connect to the new location of Hydro One Networks Inc. assets at Bronte TS.

a) What will be the treatment of the existing assets currently connecting Oakville Hydro to Bronte TS?

Response:

Oakville Hydro will be removing overhead wires, wooden poles and overhead switches as detailed in response to part c) of this question. The overhead wires and wooden poles were installed in the 1960's and, as such, are fully amortized.

b) Will these become stranded assets?

Response:

These assets are fully amortized and therefore they will not become stranded assets.

c) For each asset, please indicate the age of the asset.

Response:

The assets being removed are listed in the following table.

Asset	Age
Wooden Poles (15)	**53 Years**
Wooden Poles (1)	**32 Years**
Overhead Wire (3,295 metres)	**53 Years**

d) With regards to the existing assets at Bronte TS, does Oakville Hydro currently connect to the Hydro One system via overhead feeders or underground feeders?

i) If Oakville Hydro currently connects to Bronte TS via overhead feeders, please explain why the overhead feeders are being replaced with underground feeders. Additionally, please provide the estimated difference in cost between constructing overhead versus underground feeders.

Response:

Hydro One's station design required that Oakville Hydro's connection to new Bronte TS be underground infrastructure. At present, the most common transformer station design includes underground egress of out-going feeders. These feeders are then connected to some new and existing overhead egress feeders. This approach also minimizes the amount of reconfiguration of existing overhead circuits.

There are a number of factors that would impact the difference in cost between constructing overhead versus underground feeders and, without preparing an engineering design, Oakville Hydro is unable to estimate the difference.

Staff Question-4

Ref: Appendix 6 – Hydro One Transmission System Plan IRM Application, Page 14-15

Appendix 6 provides a Q3 2019 targeted in-service date of the new Hydro One Networks Inc. assets at Bronte TS. It states that relocating the new assets was the preferred option over in situ replacement because it would reduce staging risks with both outage durations and supply constraints, and avoid space limitations.

On page 15, Oakville Hydro supports the relocated assets as the most prudent option and submits, by extension, that its ICM work is also prudent.

a) Please confirm the in-service date of the Hydro One Networks Inc. assets at Bronte TS.

Response:

The planned in-service date for Oakville Hydro's assets at the Bronte TS was scheduled for November 2019. However, due to delays in Hydro One's commissioning of the TS, the new feeders are now to be cutover in December 2019 and January 2020. However, for the purpose of determining the additions to rate base, Oakville Hydro suggests that, since the assets are currently "used or usable" it is appropriate to use an in-service date of December 2019.

b) What risk analysis was performed, by either Hydro One or Oakville Hydro, on the staging risks identified and the probability of such risks?

Response:

In its Transmission System Plan, Hydro One stated that in-situ replacement would impose staging risks associated with maintaining supply to the local distribution company.

Subsequent to that, Hydro One and Oakville Hydro discussed the option to relocate the assets rather than doing an in-situ replacement. Both Hydro One and Oakville Hydro agreed that, among other things, due to the site layout, existing overhead transmission lines and the high complexity of the overhead distribution feeders, there was not a viable solution for rebuilding the old transformer station or maintaining the overhead interconnection.

Oakville Hydro optimized the design for the routing and interconnection of the new underground feeder relocations with the existing overhead infrastructure to minimize the impact on existing infrastructure and to ensure that there was no cascade effect on other assets that would have increased the project costs.

c) Please provide the analysis. If no analysis was performed, please explain what certainty Oakville Hydro has on the asserted likelihood and severity of staging risks associated with an in-situ replacement.

Response:

In Oakville Hydro's view, Hydro One and Oakville Hydro have adopted the optimal design solution for the new transformer station, upstream transmission supply as well as the downstream interconnection for the distribution feeders.

Staff Question -5

a) Please provide a table of Oakville Hydro's historical capital expenditures for the years 2014-2018 broken down into the OEB's four investment categories (i.e. system access, system service, system renewal, general plant).

Response:

Oakville Hydro's historical in-service capital expenditures, net of capital contributions, for the years 2014 to 2018 are provided in the following table.

Net Capital Expenditures 2014 to 2018

Category	2014	2015	2016	2017	2018
System Access	$ 6,009,266	$ 4,369,299	$ 2,424,108	$ 2,898,239	$ 4,153,773
System Renewal	5,275,252	5,275,252	6,236,602	7,528,558	7,573,478
System Service	340,718	122,810	413,214	645,693	565,414
General Plant	1,101,639	1,519,992	2,158,317	1,200,402	2,484,653
Total	$13,086,215	$11,287,353	$11,232,242	$12,272,891	$14,777,318

b) What is the dollar amount of in-service capital additions related to road widening projects that have previously been approved by the OEB in Oakville Hydro's last cost of service rate application?

Response:

Oakville Hydro's 2014 approved distribution rates include $403,000 for road widening, net of capital contributions, for road widening projects. The total value of in-service capital additions related to road widening projects from 2014 to 2018 was $2,008,678.

In-Service Capital Additions Related to Road Widening Project 2014 to 2018

Year	Road -Widening Projects
2014	$ 823,505
2015	286,555
2016	397,961
2017	500,657
2018	-
Total	$ 2,008,678

c) What is the dollar amount of in-service capital additions related to road widening projects that Oakville Hydro has included in its annual budgets for 2014-2018?

Oakville Hydro's annual budgets for the years 2014 to 2018, as set out in the table below, included amounts for projects that were planned by the Town of Oakville and the Region of Halton.

Annual Budget – Net Capital Additions Related to Road Widening Projects

Year	Budget
2014	$ 403,000
2015	517,779
2016	750,000
2017	1,262,000
2018	$ 1,965,000

Staff Question-6

Ref: IRM Application, Page 14

On page 14, the application states that:

Due to the cost involved in underground installations, it is Oakville Hydro's policy to relocate overhead assets on roadways rather than bury them underground, unless specifically asked to do so. Oakville Hydro submits that this is the most prudent approach.

a) As part of the ICM road widening projects, did Oakville Hydro relocate any assets underground that were previously overhead?

Response:

Oakville Hydro confirms that none of the ICM road widening projects involved the replacement of overhead assets with underground assets.

If Yes:

i. Please provide the number of assets relocated underground and the km of line relocated underground.

ii. Please provide the incremental costs incurred to relocate the assets underground.

iii. Were these relocations performed at the request of the road authorities or for other reasons? If for other reasons, please provide the reasons and the justification for them.

b) If part (a) identified any assets that were relocated underground at the request of the road authorities, which party paid for the incremental costs of relocating the assets underground?

i. Did Oakville Hydro negotiate with the road authorities for the road authorities to pay the full amount of the incremental costs, given that the road authorities requested the incremental upgrades? If no, why not?

Response:

See response to part a) of this interrogatory. There were no replacements of overhead assets with underground assets.

Staff Question 7

Ref: ICM Model, Tab 3 – Growth Factor NUM_CALC1 IRM Application, Page 16

OEB staff notes that Oakville Hydro has not included its embedded distributor class in the ICM model, nor any billing data for that class. In its application, Oakville Hydro has exempted the embedded distributor class from the ICM rate riders because "[...] the embedded distributor's customers will not benefit from the proposed incremental capital projects."

a) Please confirm the reason Oakville Hydro did not include the embedded distributor class in the ICM model was so that no ICM revenue requirement would be allocated to the embedded distributor class. Otherwise, please provide the reason.

Response:

Oakville Hydro confirms that the reason that Oakville Hydro did not include the embedded distributor class in the ICM model was so that no ICM revenue requirement would be allocated to the embedded distributor class.

i. By excluding the embedded distributor class, Oakville Hydro ICM model's growth factor calculation has not included the impact of the embedded distributor class. Please provide an updated ICM model that includes the embedded distributor class and its associated billing data, for the purposes of calculating the growth factor.

Response:

Oakville Hydro has provided an updated ICM model that includes the embedded distributor class and its associated billing data. The growth factor has increased from 1.98% to 2.04%. The updated ICM model also includes updates to Oakville Hydro's ICM claim to reflect the January 1, 2020 opening net book value of the ICM projects, Oakville Hydro's preliminary 2020 capital budget and the updated Input Price Index ("IPI") of 2.0%. The revised incremental revenue requirement is $432,953, as set out in the following table.

Updated Incremental Revenue Requirement

Total Incremental Revenue Requirement	Amount
Long-term Debt	$ 137,850
Short-term Debt	4,440
Return on Equity	196,945
Amortization Expense - Total	129,584
Grossed-Up Taxes/PILs	(35,866)
Incremental Revenue Requirement	$ 432,953

b) As noted in its application, the widening projects are mandatory system access projects designed to accommodate the requests of road authorities.

i. What benefits do Oakville Hydro's customers receive from the road widening projects?

Response:

The road widening projects are undertaken by the Town and Region to accommodate population and economic growth, which benefits residents and businesses in Oakville. In addition, these improvements ease congestion, add bike lanes and enhance public safety.

ii. Please explain which benefits identified in (i) are not applicable to the embedded distributor class.

Response:

Oakville Hydro's embedded distributor, Milton Hydro, purchases electricity from Oakville Hydro and delivers it to its customers, most of which, reside in the Town of Milton. In Oakville Hydro's view, the embedded distributor's customers do not benefit from improvements to the roadways in the Town of Oakville and therefore, they should not bear the costs of those improvements. Oakville Hydro believes that this view is consistent with the "beneficiary pays" principal.

c) Please explain why the embedded distributor class should be exempt from being allocated the ICM revenue requirement, when presumably other customers may be exempt on the basis that they do not receive benefits from the Bronte TS ICM project.

Response:

In its 2014 Cost of Service application, Oakville Hydro proposed that it was appropriate to allocate the costs associated with Milton Hydro's connection to Oakville Hydro's high voltage municipal transformer station directly to the embedded distributor rate class. In the Settlement Agreement, the parties agreed that it was appropriate to allocate these costs to Milton Hydro based on their peak demand as this was the capacity that was being reserved for them.[3] Milton Hydro is not benefiting from the assets associated with the Bronte TS.

d) Please confirm that none of the feeders from Bronte TS (that are being relocated as part of this ICM request) are upstream of the embedded distributor.

Response:

Oakville Hydro confirms that none of the feeders from the Bronte TS are upstream of the embedded distributor.

Staff Question 8

Ref: Appendix 5, ICM Model

a) Please provide the CCA calculation in the ICM model, including the CCA class as well.

i. Please confirm that Oakville Hydro has not implemented accelerated CCA in its calculation of the CCA in the ICM model.

[3] Settlement Proposal, EB-2013-0159, April 17, 2014, page 40.

Response:

Oakville Hydro confirms that it did not reflect the implementation of accelerated CCA in its calculation of the CCA in the ICM model.

b) Please confirm that Oakville Hydro will record the impact from the change to accelerated CCA in Account 1592 – PILS and Tax Variances- CCA Changes. If not, please explain how Oakville Hydro plans to treat the impact from the change in CCA.

Response:

Oakville Hydro confirms that it will record the impact from the change to accelerated CCA in Account 1592 – PILs and Tax Variances – CCA Changes.

c) If the response to part (a)(i) is no and Oakville Hydro has implemented accelerated CCA in its calculation of the CCA in the ICM model, please provide an ICM model calculating the CCA before the rule change to accelerated CCA.

Response:

Oakville Hydro has provided an ICM model with the calculation of the CCA before the rule change to accelerated CCA.

AMPCO-1

Ref: Incremental Capital Module Page 12

Oakville Hydro indicates it has invested $3,600,000 year-to-date, which has put significant pressure on cash flow.

Please provide the latest investment levels incurred to date by ICM project.

Response:

Oakville Hydro's investment level as of October 31, 2019 was $5,826,044 and it has collected capital contributions of $2,252,328. The total project costs as of October 31, 2019 are $8,078,372.

ICM Project Costs as of October 31, 2019

Project Description	Oakville Hydro's Cost	Contributed Capital	Total Costs
Feeder metering Bronte TS Upgrade	$ 1,579,714	$ -	$ 1,579,714
Town of Oakville Road Widening - Speers Road	2,014,733	1,069,050	3,083,783
Halton Region Road Widening - Trafalgar Road	1,910,173	1,034,139	2,944,312
Halton Region Road Widening - William Halton Parkway	321,424	149,139	470,563
Total	$ 5,826,044	$ 2,252,328	$ 8,078,372

AMPCO-2

Ref: Incremental Capital Module Page 13

Oakville Hydro indicates the three road widening projects (Spears, Trafalgar & William Halton Pkwy) are planned to be completed in 2019. The timing for these projects is determined by the applicable road authority and Oakville Hydro has no control over the pacing of the expenditures.

a) Please discuss when Oakville Hydro first determined it would require ICM funding for each of these projects.

Response:

As discussed in Oakville Hydro's reply submission on the Preliminary Question, Oakville Hydro determined that it would require ICM funding for these projects in 2019 when it became clear that the Town and Region intended to complete the road work on schedule.[4]

b) Please provide the total project schedule length, start date and current completion date for each of the road widening projects as determined by the Town and Region.

Response:

Typically, the Town and the Region will plan for the start date of their civil road work and then coordinate the relocation of utility assets to ensure that this work is complete prior to that date. This requires coordination with Oakville Hydro, Enbridge Gas, Bell Canada and other communication companies.

The planned start date for the civil road work for the three ICM projects were:

- Town of Oakville - Speers Road: June 2019
- Halton Region - Trafalgar Road: Fall 2019

[4] Oakville Hydro's Reply Submission on the Preliminary Question, page 6.

- Halton Region - William Halton Parkway: Fall 2019

c) Please provide the total project schedule length, start date and in-service date related to Oakville Hydro's work for each of these projects.

Response:

The Speers Road and Trafalgar Road projects were started early in 2019 and are expected to be completed by the end of 2019. The William Halton Parkway project was delayed due to changes in the timing of the Region's civil work and is now expected to be complete in early January 2020.

Project	Start Date	Schedule Length	In-Service Date
Town of Oakville Road Widening - Speers Road	4-Feb-19	6 Months	30-Jul-19
Halton Region Road Widening - Trafalgar Road	25-Mar-19	9 Months	20-Dec-19
Halton Region Road Widening - William Halton Parkway	30-Apr-19	9 Months	10-Jan-20

AMPCO-3

In order to facilitate the completion of these road-widening projects, the Town and Region have requested that Oakville Hydro relocate its distribution assets.

Please provide all correspondence from the Town and Region regarding the need to relocate Oakville's distribution assets and the timing.

Response:

Oakville Hydro has provided the relevant correspondence from the Town and Region in Appendix 1.

AMPCO-4

Ref: Incremental Capital Module Page 14

Oakville Hydro will receive a capital contribution equal to 50% of the labour costs for these projects.

Please provide the capital contribution calculation for each of the projects.

Response:

Oakville Hydro has billed the Town and Region for capital contribution of $2,252,328 as of October 31, 2019. The actual capital contribution will be based upon the final posted costs for each project.

Capital Contributions as of October 31, 2019

Project		Capital Contribution
Town of Oakville Road Widening - Speers Road	$	1,069,050
Halton Region Road Widening - Trafalgar Road		1,034,139
Halton Region Road Widening - William Halton Parkway		149,139
Total	**$**	**2,252,328**

AMPCO-5

Please provide Oakville Hydro's capital spending for the years 2015 to 2020 in the same format as Appendix 2-AA.

Response:

Oakville Hydro's actual net capital additions for the years 2014 to 2018 and its forecasted net capital additions for 2019 are provided in the following table. Oakville Hydro's 2020 budget process is underway.

Appendix 2-AA
Capital Projects Table

Projects	2014	2015	2016	2017	2018	2019 Fcst.
Reporting Basis	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access						
Distribution Meters	$ 572,707	$ 629,874	$ -	$ -	$ 2,001,032	$ -
Glenorchy Backup Transformer	2,991,940	1,216,247	-	-	-	-
Milton Hydro Feeders	37,286	-	-	-	-	-
New Services	1,583,829	2,236,622	2,026,148	2,397,581	2,152,741	7,453,400
Road Widening	823,505	286,555	397,961	500,657		5,475,000
Sub-Total	**$ 6,009,266**	**$ 4,369,299**	**$ 2,424,108**	**$ 2,898,239**	**$ 4,153,773**	**$ 12,928,400**
System Renewal						
Transformer Replacements	$ 853,640	$ 727,175	$ 379,133	$ 663,239	$ 374,699	$ 1,509,000
Municipal Station Upgrades	919,831	56,035	316,189	339,222	1,098,229	-
Pole Replacements	307,950	273,728	-	8,030	1,230	-
Rear Lot Conversion	25,904	-	-	-	-	-
Replace Underground Assets	1,154,429	1,865,592	2,446,391	2,802,597	2,533,130	2,005,000
Replace Overhead Assets	1,642,066	742,119	1,043,218	1,112,894	1,461,700	200,000
Switchgear Replacement	730,772	586,159	571,861	1,159,007	452,776	740,000
DPU IED Replacements	-	70,349	-	-	-	-
Reactive Replacements		954,095	1,479,809	1,372,567	1,504,516	751,000
Metering Upgrade		-	-	71,003	147,198	-
Sub-Total	**$ 5,634,591**	**$ 5,275,252**	**$ 6,236,602**	**$ 7,528,558**	**$ 7,573,478**	**$ 5,205,000**
System Service						
Asset Management	$ 340,718	$ 69,983	$ 234,149	$ 300,201	$ 428,411	$ 155,000
SCADA Enhancements	-	52,827	88,024	47,218	137,003	170,000
GIS Enhancements	-	-	91,042	298,274	-	150,000
Sub-Total	**$ 340,718**	**$ 122,810**	**$ 413,214**	**$ 645,693**	**$ 565,414**	**$ 475,000**
General Plant						
Asset Management	$ 103,908	$ -	$ -	$ -	$ -	$ -
Communications	58,112	-	158,815	24,733	18,075	30,000
Software	525,114	366,118	60,647	176,352	480,846	875,300
Tools	76,276	64,999	30,247	96,168	27,379	150,000
Vehicles	338,228	-	339,786	501,597	1,205,350	-
Network/Server Infrastructure	-	397,426	376,499	-	-	-
Leasehold Improvements	-	691,450	1,192,324	-	193,857	757,000
Equipment	-	-	-	401,552	559,146	753,300
Sub-Total	**$ 1,101,639**	**$ 1,519,992**	**$ 2,158,317**	**$ 1,200,402**	**$ 2,484,653**	**$ 2,565,600**
Miscellaneous						
Total	**$ 13,086,215**	**$ 11,287,353**	**$ 11,232,242**	**$ 12,272,891**	**$ 14,777,318**	**$ 21,174,000**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated						
Total	**$ 13,086,215**	**$ 11,287,353**	**$ 11,232,242**	**$ 12,272,891**	**$ 14,777,318**	**$ 21,174,000**

AMPCO-6

Please provide Oakville Hydro's forecast versus actual budget for the years 2015 to 2020 in the same format as Appendix 2-AB.

Response:

Oakville Hydro's budget for the years 2014 to 2019 are provided in the following table in the same format as the OEB's Appendix 2-AB. Oakville Hydro's 2020 has not yet been approved by its Board.

Appendix 2-AB

CATEGORY	Historical Period (previous plan & actual)															Forecast Period
	2014			2015			2016			2017			2018			2019
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000
System Access	3,016	9,444	213.1%	2,130	8,859	315.9%	2,448	11,493	369.5%	2,497	8,326	233.4%	2,639	12,032	355.9%	21,382
System Renewal	6,127	5,635	(8.0%)	5,436	5,275	(3.0%)	5,505	6,237	13.3%	5,599	7,529	34.5%	5,599	7,573	35.3%	5,205
System Service	5,589	341	(93.9%)	559	123	(78.0%)	581	413	(28.9%)	605	646	6.7%	629	565	(10.1%)	475
General Plant	2,315	1,102	(52.4%)	2,126	1,520	(28.5%)	2,866	2,158	(24.7%)	2,052	1,200	(41.5%)	2,063	2,485	20.4%	2,566
TOTAL EXPENDITURE	17,047	16,520	(3.1%)	10,251	15,777	53.9%	11,400	20,302	78.1%	10,753	17,701	64.6%	10,930	22,656	107.3%	29,628
Deferred Revenue (Capital Contributions)		(3,434)	--		(4,490)	--		(9,069)	--		(5,428)	--		(7,878)	--	(8,454)
Net Capital Expenditures	17,047	13,086	(23.2%)	10,251	11,287	10.1%	11,400	11,232	(1.5%)	10,753	12,273	14.1%	10,930	14,777	35.2%	21,174
System O&M		9,571	--		9,823	--		9,249	--		9,318	--		9,505	--	9,653

AMPCO-7

a) Please provide a copy of Oakville Hydro's last Distribution System Plan (DSP) approved by the Board.

Response:

A copy of Oakville Hydro's 2014 to 2018 DSP is provided as Appendix 2.

b) Please provide a copy of any subsequent internal DSPs.

Response:

Oakville Hydro has provided its capital expenditure plan from its last cost of service application as Appendix 3.

c) Please provide Oakville Hydro's latest 5-year capital expenditure plan.

Response:

The capital expenditure plan provided in response to part b) of this question was based on a 20-year outlook on asset renewals. Oakville Hydro develops annual plans based on this 20-year outlook.

AMPCO-8

Please provide a detailed cost breakdown for each of the ICM projects and the costs spent to date under each line item.

Response:

Oakville Hydro has provided a detailed breakdown of the gross capital costs as of October 31, 2019 for each of the ICM projects in the following table.

Gross Capital Costs – Incremental Capital Projects

Project Description	Materials	Labour	Sub-contractors	Vehicles	Total
Feeder metering Bronte TS Upgrade	$ 801,695	$211,489	$ 537,816	$28,714	$1,579,714
Town of Oakville Road Widening - Speers Road	766,520	95,797	2,219,684	1,781	3,083,783
Halton Region Road Widening - Trafalgar Road	756,929	70,844	2,116,045	494	2,944,312
Halton Region Road Widening - William Halton Parkway	171,800	16,649	282,090	24	470,563
Total Capital Costs	$2,496,944	$394,780	$5,155,635	$31,014	$8,078,372
Contributed Capital					2,213,102
Oakville Hydro's Cost					$5,865,270

AMPCO-9

a) Please provide the contingency amounts for each of the ICM projects.

Response:

Oakville Hydro typically builds in a contingency amount of 5% of total estimated costs into its capital projects.

b) Please provide the contingency amounts used to date and forecast to be spent by the end of the year by project.

Response:

Oakville Hydro estimates that its total costs will exceed the total budgeted costs for the Bronte Feeder Replacement Project and the Speers Road Widening Project by the end of the year. Therefore, the total contingency amounts for these projects will be fully used. The forecasted costs to be incurred for the Trafalgar Road Widening project are expected to be close to budget. The William Halton Parkway Road Widening Project has been delayed.

Estimated and Forecasted Capital Costs

Project	Oakville Hydro's Budgeted Costs	Budgeted Contingency	Total Budgeted Costs	Forecasted Costs by Dec. 31, 2019
Feeder metering Bronte TS Upgrade	$ 1,615,000	$ 85,000	$ 1,700,000	$1,900,000
Town of Oakville Road Widening - Speers Road	1,900,000	100,000	2,000,000	2,080,000
Halton Region Road Widening - Trafalgar Road	2,090,000	110,000	2,200,000	2,200,000
Halton Region Road Widening - William Halton Parkway	1,140,000	60,000	1,200,000	321,000
Total	**$ 6,745,000**	**$ 355,000**	**$ 7,100,000**	**$ 6,501,000**

AMPCO-10

Please provide business case for each of the ICM projects.

Response:

Oakville Hydro has provided business cases for each of the ICM projects in Appendix 4.

AMPCO-11

With respect to the Bronte TS feeder project, Oakville Hydro noted that it would not have sought approval for any ICM funding had the road widening projects been deferred, as the incremental revenue requirement associated with the project would have fallen below its materiality level.

Please provide the current status of Oakville Hydro's ICM funding request regarding the Bronte TS feeder.

Response:

Oakville Hydro has included the Bronte TS feeder project in the list of ICM projects that it is seeking approval for incremental capital funding. However, based on the updated ICM model, approval of all four ICM projects would result in the approval of the maximum allowed incremental capital amount of $5,325,085 and $1,701,915 would be funded through current rates.

	Amount
2020 Preliminary Budget	$15,600,000
ICM Projects - Staff Question 2:	
Feeder metering Bronte TS Upgrade	1,675,500
Town of Oakville Road Widening - Speers Road	1,977,000
Halton Region Road Widening - Trafalgar Road	2,174,500
Halton Region Road Widening - William Halton Park	1,200,000
2020 Capital	$22,627,000
Materiality Threshold	$17,301,915
Maximum Allowed Incremental Capital	$ 5,325,085
ICM Projects Funded in Current Rates	$ 1,701,915

CCC-1

Please provide all material provided to Oakville Hydro's Board of Directors regarding the decision to seek a second deferral of a cost of service rebasing. Please provide all material provided to Oakville Hydro's Board of Directors when seeking approval of this Application.

Response:

Oakville Hydro did not provide materials regarding its decision to seek a second deferral of its cost of service rebasing to its Board of Directors.

Oakville Hydro did not provide materials to its Board of Directors seeking approval of this application. The President and CEO of Oakville Hydro, in conjunction with the Senior Leadership Team, has the mandate to proceed with this application.

CCC-2

Please indicate when Oakville Hydro intends to file its next cost of service Application with the OEB. When does Oakville Hydro intend to file its next ICM Application?

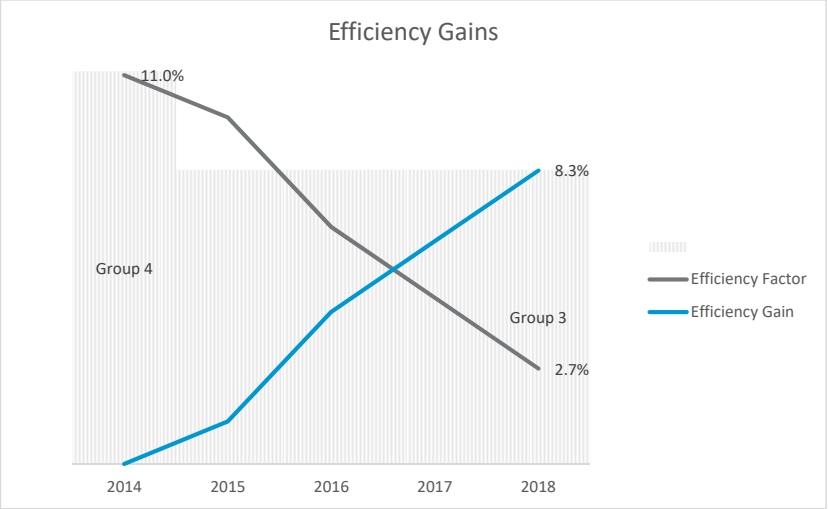
Response:

Under the OEB's Renewed Regulatory Framework ("RRF"), electricity distributors are permitted to choose between three incentive rate-setting (IR) methodologies: Price Cap IR, Custom IR, and the Annual IR Index. Electricity distributors may choose from any of these three methodologies. There are no eligibility requirements for any of these methods, but the rate application must meet the requirements of the rate-setting option[5].

[5] Handbook for Utility Rate Applications, October 13, 2016, page 24.

As stated in the Handbook for Utility Rate Applications, performance-based regulation under the RRF is the framework for rate-setting, which represents a shift from a process of simply recovering costs to one of driving improved utility performance through incentives.

Since its last rebasing, Oakville Hydro's utility performance has increased dramatically. In 2014, Oakville Hydro's average distribution costs were 11% higher than its predicted costs and therefore, it had been assigned to efficiency group four. In 2015, Oakville Hydro's performance measure decreased to 9.8%, allowing it to move into group three.



Since then, Oakville Hydro has improved its efficiency factor each year, as shown in gray in the graph. A decrease in the percentage that Oakville Hydro's costs are higher than its predicted costs equates to an increase in efficiency.

These efficiency gains have allowed Oakville Hydro to extend its Price Cap IR term and, it is Oakville Hydro's expectation that it can continue to improve its performance under the Annual IR Index in the short-term. However, under the Annual IR Index framework, Oakville Hydro would no longer be eligible for incremental capital funding and unanticipated or lumpy capital spending needs could trigger the need to submit an application for an increase in rates through a cost of service application. Oakville Hydro will continue to monitor its financial and operational performance and adopt the rate setting method that best meets its needs.

CCC-3

In its Reply Submission regarding the Motion dated October 24, 2019, Oakville Hydro provided the Deemed ROE and Achieved ROE for each year 2014-2018 (Table 4, p. 8/13). Please provide the underlying calculations to support that Table. For example, please provide the approved revenue requirement and actual results for each year. What is Oakville Hydro's expected ROE for 2019? Please explain the reasons that Oakville Hydro has exceeded its ROE in the years 2014, 2016, 2017 and 2018.

Response:

The underlying calculations for Oakville Hydro's regulated rate of return are provided in the table below. Oakville Hydro's expected ROE for 2019 is 9.3%.

Regulated Rate of Return Calculations

Revenue drivers	2014 Approved	2014	2015	2016	2017	2018
Distribution revenues	$ 35,586,668	$38,423,903	$38,292,999	$40,372,924	$38,898,364	$40,900,145
Other revenues	2,205,265	45,735	1,006,322	2,542,944	2,995,572	2,699,768
Total Revenue	$ 37,791,933	$38,469,638	$39,299,321	$42,915,868	$41,893,936	$43,599,913
Cost drivers						
OM&A	$ 17,784,721	$17,498,629	$18,149,202	$17,980,234	$18,383,553	$18,787,858
Amortization	8,124,658	8,260,513	8,545,048	8,984,647	9,156,545	9,123,190
Financing	4,984,042	6,043,164	6,031,002	6,066,505	5,912,617	5,961,112
Taxes	-	237,124	179,270	2,027,995	1,041,253	872,051
Total Expenses	30,893,421	32,039,430	32,904,523	35,059,380	34,493,968	34,744,210
Net Income	$ 6,898,512	$ 6,430,208	$ 6,394,799	$ 7,856,488	$ 7,399,967	$ 8,855,703
Tax adjustments	-	460,281	(201,600)	(14,118)	41,839	277,961
Items not in base rates	-	(436,617)	(220,075)	(561,099)	(742,853)	(1,323,181)
Adjustment to Interest Expense	-	810,002	956,010	855,862	690,631	535,751
Regulated Net Income	6,898,512	7,263,874	6,929,133	8,137,133	7,389,584	8,346,234
Rate Base	184,255,129	182,652,692	185,241,817	189,933,137	190,559,133	195,891,948
Regulated Rate of Return	9.36%	9.94%	9.35%	10.71%	9.69%	10.65%

The primary reason that Oakville Hydro exceeded its ROE in 2014 and 2016 was due to unusual / non-recurring revenue. In 2014, Oakville Hydro recorded additional revenue related to the recovery of smart meter costs. In 2016, Oakville Hydro changed its accounting practice to accrue fixed distribution charges resulting in a one-time increase in distribution revenue. When adjusted for these additions to revenue, Oakville Hydro's regulated rate of return would have been 8.29% and 8.11% for 2014 and 2016 respectively as shown in the table below.

In 2017, Oakville Hydro's regulated rate of return was 0.33% higher than its deemed rate of return. In 2018, Oakville Hydro's regulated rate of return was 1.29% higher than its deemed rate of return as a result of an increase in distribution revenue.

Oakville Hydro notes that its 2014 to 2018 adjusted regulated rate of return is 9.24% which is lower than its deemed rate of return of 9.36% and that each year, its adjusted and non-adjusted ROE, is well within the OEB's band of 300 basis points.

CCC-4

(Ex. Manager's Summary, p. 11)

Please provide a schedule for each of the Incremental Capital Projects setting out the following:

a) The total current cost of each project including capital contributions broken out between Oakville Hydro's costs and the capital contributions;

Response:

Please see Oakville Hydro's responses to AMPCO interrogatory number 1.

b) A detailed breakdown of costs for each project and the associated business case for each project;

Response:

For the detailed breakdown of costs for each project, please see response to AMPCO interrogatory number 8. For the business cases for each ICM project, please see Appendix 4.

c) The current expected in-service date for each project.

Response:

Please see response to AMPCO interrogatory number 2.

CCC-5

(Ex. Manager's Summary, p. 11)

The evidence states that Oakville Hydro's 2019 Capital Budget is $21.174 million. Please provide a detailed breakdown for all of the components of Oakville Hydro's 2019 Capital Budget. Please provide detailed Board Approved and Actual Capital Budget amounts for the years 2014-2018. Please provide a detailed capital budget for 2020.

Response:

Please see Oakville Hydro's response to AMPCO interrogatory number 5.

CCC-6

(Ex. Manager's Summary, p. 12)

Please provide a detailed calculation setting out how Oakville Hydro's materiality threshold was derived.

Response:

In assessing whether the proposed ICM projects were material, Oakville Hydro relied on the OEB's Decision in Alectra's 2018 IRM Application for guidance (EB-2017-0024). In that decision, the OEB stated that, "Amending the

ICM policy to include a mathematical materiality calculation for this second test should only be done through a policy review[6]."

In assessing the project-specific materiality of each project, the OEB was guided by the words "significant influence on the operation of the distributor" and "minor expenditure in comparison to the overall capital budget"[7]. Alectra's combined capital budget was $267.7M and the lowest individual project that was approved for the recovery of incremental capital funding was the York MS project with a total cost of $2.3M[8].

This suggests that, in the OEB's view, a project that has a cost that is 1% of the total capital budget is a major project that has significant influence on the operation of the distributor. If Oakville Hydro was to apply that same reasoning, it would suggest that a project that had a cost greater than 1% of its capital budget of $21,174,000, including the ICM projects, or $182,000 is a material project.

Each of the projects for which Oakville Hydro is requesting approval for incremental capital funding is well above this amount. Oakville Hydro also notes that the total of these mandatory projects is equal to approximately one half of its typical capital spending. In Oakville Hydro's view, there is no question as to whether these projects have a significant influence on its operations.

CCC-7

Please provide Oakville Hydro's most recent Distribution System Plan (DSP). When does Oakville Hydro intend on completing its next DSP?

Response:

A copy of Oakville Hydro's most recent DSP is provided as Appendix 2. Oakville Hydro recognizes the value of having a DSP and it is updating its DSP.

CCC-8

Please provide a schedule setting out Oakville Hydro's Board Approved and Actual OM&A amounts for the years 2014-2018. What are Oakville Hydro's expected OM&A costs for 2019 and 2020?

Response:

Oakville Hydro's OEB approved and actual OM&A for 2014 to 2018 is provided in the table below. Oakville Hydro's expected OM&A for 2019 is $18,900,000. Oakville Hydro's 2020 budget process is underway.

[6]Decision and Order, Alectra Utilities Corporation, EB-2017-0024, page 24.
[7] IBID, page 25.
[8] IBID, page 60.

Operations, Maintenance and Administration (OM&A) Expenses

Year	OM&A Expenses
2014 OEB Approved	$ 17,600,000
2014	17,498,629
2015	18,149,202
2016	17,980,234
2017	18,383,553
2018	$ 18,787,858

CCC-9

What is the approved working capital allowance embedded in Oakville Hydro's current rates?

Response:

The approved working capital allowance embedded in Oakville Hydro's current rates is 13%. However, as noted in its reply submission to the Preliminary Question, Oakville Hydro is recording the difference between its approved and estimated working capital allowance as an offset to the incremental costs associated with the transition to monthly billing in a deferral account.[9]

CCC-10

Oakville Hydro has established a working capital allowance variance account. What is the current amount in that account? What is the annual difference for Oakville Hydro between its embedded WCA and 7.5%?

Response:

In its Decision and Order in Oakville Hydro's 2017 IRM application (EB-2016-0097), the OEB approved its request to establish a deferral account to record the net incremental costs associated with the transition to monthly billing. Oakville Hydro has recorded $543,300 in savings related to the reduction in working capital allowance related to the transition to monthly billing. This amount is subject to a prudence review by the OEB when Oakville Hydro applies for the disposition of the balance in the account.

CCC-11

[9] Oakville Hydro reply submission on the Preliminary Question, page 9.

Oakville Hydro, in its 2017 IRM application, applied for an account to record the costs associated with the transition to monthly billing. How much is being recorded in that account on an annual basis? What is the current balance in that account? Please provide all detailed calculations.

Response:

In its Decision and Order in Oakville Hydro's 2017 IRM application (EB-2016-0097), the OEB approved its request to establish a deferral account to record the net incremental costs associated with the transition to monthly billing. Oakville Hydro has recorded estimated net incremental costs of $354,389 for the period August 2016 to November 2019. This amount is subject to a prudence review by the OEB when Oakville Hydro applies for the disposition of the balance in the account. The detailed calculations are provided in the table below.

Monthly Billing Variance Account Details

Description	2016	2017	2018	2019 YTD	Total
One time incremental costs:					
Incremental Staffing Costs	$ 15,125	$ -	$ -	$ -	$ 15,125
Customer Communications	2,500	-	-	-	2,500
System Upgrades and Review	22,415	-	-	-	22,415
Ongoing Incremental Costs:					
Labour Costs	19,747	23,722	53,364	45,463	142,296
Bill Processing Costs	14,826	38,451	36,397	32,173	121,847
Envelope and Bill Stock	7,580	19,659	21,574	20,026	68,839
Postage	96,081	249,193	256,052	230,591	831,918
Total Costs	$ 178,273	$ 331,026	$ 367,387	$ 328,253	$ 1,204,939
Estimated Incremental Savings					
Working Capital Allowance	$ 64,400	$ 160,700	$ 161,700	$ 156,600	$ 543,400
Reduction in Bad Debts	21,162	54,000	120,259	111,729	307,150
Total Savings	85,562	214,700	281,959	268,329	850,550
Monthly Billing Variance Account	$ 92,711	$ 116,326	$ 85,428	$ 59,924	$ 354,389

CCC-12

Is Oakville Hydro seeking to include 100% of the costs of the proposed ICM projects in the 2020 opening rate base?

Response:

Please see response to OEB staff interrogatory number two.

CCC-13

For each of the proposed projects please indicate whether the capital contribution amounts are currently fixed, or whether they may vary at any point.

Response:

The PSWHA requires that the cost of labour employed for the removal or relocation of Oakville Hydro's distribution assets be apportioned equally between the road authority and Oakville Hydro. Oakville Hydro will receive a capital contribution equal to 50% of the final labour and equipment costs for these projects. The capital contribution amount is not fixed.

CCC-14

Please indicate how Oakville Hydro intends to "true-up" its ICM amounts going forward.

Response:

Oakville Hydro suggests that it would be appropriate to address any variances between the forecast and actual capital costs, including any variances in the amount of capital contributions, at the time of its next cost of service application. The OEB can make a determination on any true-up treatment for variances between forecast and actual capital contributions during the Price Cap IR term at that time.

EP-1

Reference: Page 11, Table 6

Question:

a) Please provide the original detailed forecast of cost estimates for each of four proposed ICM projects that shows the amounts for each of the following cost categories: Materials, Construction and labour, Contingencies, Interest During Construction, Indirect Overhead, and Contributions in Aid of Construction. For each cost category please explain how the cost estimate was produced showing all supporting calculations.

Response:

The original detailed forecast cost estimates for each of the four proposed ICM projects is provided in the following table. Oakville Hydro does not record indirect overhead costs (in accordance with IFRS Standards) or interest during construction.

Original Detailed Cost Estimates

Project	Materials	Labour	Sub-Contractors	Vehicles	Contingency	Total	Contributed Capital	Oakville Hydro Share
Feeder metering Bronte TS Upgrade	$ 762,000	$ 238,000	$ 757,000	$ 33,000	$ 94,000	$ 1,884,000	$ -	$ 1,884,000
Town of Oakville Road Widening - Speers Road	627,000	121,000	1,964,000	3,000	143,000	2,858,000	1,099,000	1,759,000
Halton Region Road Widening - Trafalgar Road	653,000	144,000	2,135,000	9,000	155,000	3,096,000	1,204,000	1,892,000
Halton Region Road Widening - William Halton Parkway	260,000	123,000	1,144,000	12,000	81,000	1,620,000	673,000	947,000
Total	**$ 2,302,000**	**$ 626,000**	**$ 6,000,000**	**$ 57,000**	**$ 473,000**	**$ 9,458,000**	**$ 2,976,000**	**$ 6,482,000**

Oakville Hydro uses a third-party engineering design software application that produces costs estimates based on Oakville Hydro's detailed design. The third-party engineering software uses IFRS components (e.g. overhead structure work, overhead devices, underground cable, etc.)

b) Please provide the latest actual or forecast cost of each of the four projects with detailed explanation of all variances.

Response:

Oakville Hydro's updated forecasted capital cost for the four ICM projects, net of capital contributions, is $7,530,000 as detailed in response to AMPCO interrogatory 9. There is a variance of $1,048,000, primarily associated with the road-widening projects, due to unexpected costs related to the following:

- Design changes to accommodate underground communications infrastructure
- Requirement to provide on duty police officers at the Trafalgar Road project
- Provision of generators to customers who had their power interrupted for more than one day during the Speers Road project
- Increased costs to bore holes through shale conditions for both the Trafalgar Road and Speers Road projects

Original and Forecasted Costs

Project	Original Estimate	Forecast	Variance
Feeder metering Bronte TS Upgrade	$ 1,884,000	$ 1,900,000	$ 16,000
Town of Oakville Road Widening - Speers Road	1,759,000	2,080,000	321,000
Halton Region Road Widening - Trafalgar Road	1,892,000	2,200,000	308,000
Halton Region Road Widening - William Halton Parkway	947,000	1,350,000	403,000
Total	**$ 6,482,000**	**$ 7,530,000**	**$ 1,048,000**

c) Are there any incentives for the project manager of this project to complete the project ahead of schedule or under budget? If the answer is yes, please describe the incentives. If the answer is no, please explain why not.

Response:

There is no specific incentive for project managers to complete projects ahead of schedule or under budget. However, Oakville Hydro's non-union employees may receive compensation if their performance exceeds expectations for all their project responsibilities.

EP-2

Reference: Page 13

Question:

When did Oakville Hydro first learn about the four road widening projects? Please list the exact dates and file any relevant letters and dates of meetings.

Oakville Hydro first learned about the three road widening projects on the following dates:

i. Town of Oakville Road Widening - Speers Road

Response:

The Town first notified Oakville Hydro of the Speers Road project on October 22, 2015. However, discussion did not begin until early 2016 when the Town issued the preliminary civil road design.

ii. Halton Region Road Widening - Trafalgar Road

Response:

The Region held the first utility coordination meeting for the Trafalgar Road project on August 26, 2016.

iii. Halton Region Road Widening - William Halton Parkway

Response:

The Region initiated the William Halton Parkway project in 2013. However, Oakville Hydro did not receive notification that the project would proceed until November 5, 2015.

The relevant correspondence is provided in Appendix 5.

EP-3

Reference: Page 13

Preamble: "The Public Service Works on Highways Act ("PSWHA") requires that the cost of labour employed for the removal or relocation of Oakville Hydro's distribution assets be apportioned equally between the road authority and Oakville Hydro. Therefore, Oakville Hydro will receive a capital contribution equal to 50% of the labour costs for their projects.

Question:

a) Are the labour costs that are mentioned in the referenced preamble, the costs of Oakville Hydro's own employees, the costs of contractors working for Oakville Hydro, or the costs of contractors working for the road authority? Please provide the amounts for each of the four projects and for each category.

Response:

The labour costs that are mentioned in the preamble include both the costs of Oakville Hydro's own employees and the costs of subcontractors working for Oakville Hydro. There are no costs for contractors working for the road authority included in the project costs.

The amounts for each of the four projects and for each category as of October 31, 2019, are provided in the following table.

Labour and Contractor Costs

Project Description	Oakville Hydro Employees	Oakville Hydro Contractors
Feeder metering Bronte TS Upgrade	$ 211,489	$ 537,816
Town of Oakville Road Widening - Speers Road	95,797	2,219,684
Halton Region Road Widening - Trafalgar Road	70,844	2,116,045
Halton Region Road Widening - William Halton Parkway	16,649	282,090
Total	$ 394,780	$ 5,155,635

b) Did Oakville Hydro negotiate with the road authorities regarding which labour costs would be subject to 50% sharing? If the answer is yes, please list the dates of negotiations and the results achieved. If the answer is no, please explain why not.

Response:

In its initial estimate, Oakville Hydro advised the Town and Region that, upon completion of the work, they would be invoiced at the normal 50% labour, equipment and subcontractor costs.

VECC-1

Reference: Exhibit Section 15.3

a) Please provide the details of the total capital budget shown in Table 7 of $21.174 million. Please show the amounts by the filing requirement categories: System Access, Renewal, Service and General Plant.

Response:

The details of Oakville Hydro's 2019 capital budget of $21,174,000 is provided in the following table.

2019 Capital Budget

Category	Amount
System Access	$12,928,400
System Renewal	5,205,000
System Service	475,000
General Plant	2,565,600
Total	$21,174,000

VECC-2

Reference: Exhibit Section 15.1

In the Report of the Board EB-2014-0219 New Policy Options for Funding of Capital Investments: The Advanced Capital Module, the following statements are made:

No ICM applications were filed for the 2010 rate year. For the 2011 rate year, two distributors filed requests for ICM funding in relation to new municipal transformer stations. In its decisions for Oakville Hydro Electricity Distribution Inc. and Guelph Hydro Electric Systems Inc., the Board approved ICM funding for both applications noting that the projects were non-discretionary expenditures that were clearly outside of the base upon which rates were derived.

These two decisions clarified two significant principles. First, they clarified that ICM requests must first establish the amount of eligible capital available to distributors by subtracting the materiality threshold result from the total non-discretionary capital budget for the subject year. This clarification was consistent with the Board's decision on Hydro One's 2009 application, which noted that the mere existence of a gap between the threshold and the capital budget is not determinative for ICM funding.

a) Please provide the non-discretionary capital budget for the 2019 and 2020 year.

Response:

In the Report of the Board EB-2014-0219 New Policy Options for Funding of Capital Investments: The Advanced Capital Module, the OEB went on to say that, "The determination of the maximum allowable incremental capital amount has not changed from the guidance provided in the Board's recent Filing Requirements other than to remove the reference to non-discretionary. It is now determined by taking the difference between the forecasted total capital expenditures for a subject year and the materiality threshold for that year[10]".

Oakville Hydro's total capital budget for 2019 was $21,174,000 and its total capital preliminary budget for 2020 is $15,600,000.

VECC -3

Reference: Exhibit Section 15.1

a) Please provide a reference to the Board ICM policy, which allows for projects already completed to be eligible for ICM rate recovery.

[10] Report of the Board EB-2014-0219 New Policy Options for Funding of Capital Investments: The Advanced Capital Module, page 22.

Response:

As discussed in Oakville Hydro's Reply to the submissions of OEB staff and intervenors on the Preliminary Question, Oakville Hydro has relied on the guidance provided by the OEB in its Decision and Rate Order in Rideau St. Lawrence Distribution Inc.'s 2018 IRM application. In that Decision, the OEB agreed that the typical approach to the ICM is for incremental funding to start in the year that the asset is planned to go into service. The OEB's models have been designed for this typical situation. However, the OEB noted that the ICM policy states that the Advanced Capital Module ("ACM") and the ICM are incremental funding for capital projects to go into service during the IRM term. The OEB went on to say that, it considers any period of time between cost of service applications to be part of the term[11].

A similar decision was made in Burlington Hydro's request for incremental capital funding for CCRA payments made to Hydro One for additional breakers at the Tremaine TS in 2018 and 2019 (EB-2018-0021).

VECC-4

Reference: Exhibit Section 15.1

a) Please provide a table showing Oakville Hydro's reported return on equity (ROE) for each year 2014 through 2018 and the Board's annual (November) posted ROE for each of those years.

Response:

The table below provides Oakville Hydro's reported ROE, the OEB's annual posted deemed ROE and Oakville Hydro's adjusted ROE, as presented in response to CCC interrogatory number 3.

Return on Equity (ROE)

Year	Posted ROE	Achieved ROE	Adjusted ROE
2014	9.36%	9.94%	8.29%
2015	9.30%	9.35%	9.35%
2016	9.19%	10.71%	8.11%
2017	8.78%	9.69%	9.69%
2018	9.00%	10.65%	10.65%

VECC-5

[11] Oakville Hydro's Reply Submission on the Preliminary Question, page 12.

Reference: Exhibit Section 15.1

a) Please provide Oakville Hydro's audited financial statements for each year 2014 through 2018.

Response:

Oakville Hydro's audited financial statements for 2014 to 2018 are provided as Appendix 6.

b) Please provide Oakville Hydro's annual reports for the years 2014 through 2018.

Response:

Oakville Hydro does not prepare annual reports.

c) Please provide Oakville Hydro's 2019 pro-forma Consolidated Statement of Operations.

Response:

Oakville Hydro's 2019 Pro-forma Statement of Operations is provided below.

Oakville Hydro 2019 Forecast	
Energy revenue	$185,053,172
Distribution revenue	42,406,117
Other revenue	4,829,249
Total Revenue	**$232,288,538**
Cost of power	190,646,314
Wages & benefits	13,669,314
Operation expense	8,377,886
Amortization	10,100,435
Total Operating Expenses	**$222,793,949**
Income from operating activities	**9,494,589**
Finance income	559,744
Finance cost	6,232,711
Income Before Income Taxes	**$ 3,821,622**
Income tax expense	733,081
Net income, continuing operations	**$ 3,088,541**
Net movement in regulatory balances	4,461,404
Net income and regulatory	**$ 7,549,944**
Other comprehensive income	-
Total comprehensive income	**$ 7,549,944**

VECC-6

Reference: Exhibit Section 15.3

a) For each of the projects listed in Table 6 please provide:

i. The expected completion and in-service (if different) date.

Response:

The expected completion date for each of the ICM projects is provided in the following table.

Expected Completion Dates

Project	Start Date	Schedule Length	In-Service Date
Feeder metering Bronte TS Upgrade	1-Nov-18	12 Months	1-Oct-19
Town of Oakville Road Widening - Speers Road	4-Feb-19	6 Months	30-Jul-19
Halton Region Road Widening - Trafalgar Road	25-Mar-19	9 Months	20-Dec-19
Halton Region Road Widening - William Halton Parkway	30-Apr-19	9 Months	10-Jan-20

ii. The dollar amount of capital contributions agreed to and the amount paid to date.

Response:

Oakville Hydro had originally estimated the capital contributions to be $2,975,861 and the amount collected to date is $2,213,102. Oakville Hydro notes that the actual contributed capital will be based on the final project costs.

Estimated and Collected Capital Contributions

Project	Estimated Contributed Capital	Contributed Capital Collected
Feeder metering Bronte TS Upgrade	$ -	$ -
Town of Oakville Road Widening - Speers Road	1,098,809	1,069,050
Halton Region Road Widening - Trafalgar Road	1,204,009	1,034,139
Halton Region Road Widening - William Halton Parkway	673,043	109,913
Total	**$ 2,975,861**	**$ 2,213,102**

iii. The actual or current estimate of the gross capital cost for each project.

Response:

Please see response to CCC interrogatory number 4 for the current gross capital cost for each project and EP interrogatory number 1b) for the forecasted gross capital cost for each project.

VECC-7

Reference: Exhibit Section 15.1

a) Please file the actual in-service capital expenditures for each of the years 2014 through 2019 (end of year forecast) in the format of Board filing requirement Appendix 2-AA.

Response:

Please see response to AMPCO interrogatory number 5.

VECC-8

Reference: Exhibit Section 15.1

The July 12, 2018 Filing Guidelines state (pg. 23):

Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the OEB-defined threshold calculation is expected to be absorbed within the total capital budget.

a) Please demonstrate how the projects listed in Table 6 and specifically the least costly of these projects (William Halton Parkway), are not comparable in scope and cost to prior year projects.

Response:

As discussed in response to CCC interrogatory number 6, the OEB's decision in Alectra's 2018 ICM applications suggests that, In the OEB's view, a project that has a cost that is 1% of the total capital budget is a major project that has significant influence on the operation of the distributor.

If Oakville Hydro was to apply that same reasoning, it would suggest that a project that had a cost greater than 1% of its capital budget of $21,174,000 or $182,000 is a material project.

Each of the projects for which Oakville Hydro is seeking approval for incremental capital funding is well over this amount. Oakville Hydro also notes that the total of these mandatory projects is equal to approximately one half of its typical capital spending. In Oakville Hydro's view, there is no question as to whether these projects have a significant influence on its operations.

VECC-9

Reference: Exhibit Section 15.1

a) Please explain how Oakville Hydro is financing the incremental projects listed in Table 6.

Response:

Oakville Hydro is financing the ICM projects through its cash reserves, operating line of credit and capital contributions from the Town and Region.

VECC -10

Reference: Exhibit Section 15.1

a) For the three projects subject to the Public Service Works on Highways Act ("PSWHA") please provide the agreement with the municipal authority(ies).

Response:

Oakville Hydro does not have an agreement with the Town or Region related to cost sharing under the PSWHA.

b) If separate from the agreements please provide the agreed to schedule for the projects and the scope and amount of the cost sharing arrangement.

Response:

Oakville Hydro provides an estimate of the cost sharing amount prior to the start of the projects and advises the Town or Region that the cost sharing amount is subject to adjustment and will be invoiced based on actual labour, equipment and sub-contractor costs.

The initial estimate of the cost sharing amount and the initial schedule for the projects is summarized in the following table.

Initial Capital Contribution Estimate

Project	Tentative Start Date	Estimated Duration	Total Estimated Costs	Initial Cost Estimate
Town of Oakville Road Widening - Speers Road	Sep-18	6 Months	2,858,000	1,100,000
Halton Region Road Widening - Trafalgar Road	Mar-19	8 Months	3,095,000	1,204,000
Halton Region Road Widening - William Halton Parkway	Feb-19	9 Months	1,619,000	673,000

VECC-11

Reference: Exhibit Section 15.1

a) Please provide the agreement for any cost sharing between Hydro One and Oakville Hydro with respect to the Bronte TS.

Response:

There is no cost sharing agreement between Hydro One and Oakville Hydro for the Bronte TS project. Oakville Hydro is responsible for the replacement of the distribution feeders and the installation of the primary meters.

b) Please clarify whether this project is one or two projects, i.e.: (1) cost sharing for the Hydro One Bronte TS and (2) Oakville Hydro investments to replace feeders to this TS.

Response:

There is only one project related to Oakville Hydro's investment.

c) If confirmed as two projects please provide the capital contributions to be paid to Hydro One separate from the costs for the Oakville feeder replacement.

Response:

There is only one project.

d) Please provide the business case for any Oakville Hydro portion of the project to replace feeders or other investments made to Oakville Hydro's distribution system as part of the Bronte TS rebuild.

Response:

The business case for Oakville Hydro's portion of the Bronte TS project is provided as Appendix 4.

VECC-12

Reference: Exhibit Section 15.6

"Oakville Hydro is currently scheduled to file a cost of service application for rates effective January 1, 2021. However, based on its 2018 actual and 2019 forecasted financial and non-financial performance, Oakville Hydro does not anticipate filing a cost of service application for rates effective January 1, 2021. Therefore, Oakville Hydro submits that it is not appropriate to apply the half-year rule."

a) Has the OEB granted Oakville Hydro a further deferment of a rebasing application?

Response:

The OEB has not granted Oakville Hydro a further deferment of a rebasing application. However, in its letter regarding Applications for 2021 Electricity Distribution Rates, the OEB acknowledged that Oakville Hydro had already requested a deferral of its 2021 rebasing application.

b) If Oakville were to continue to defer its rebasing what is its proposal for the true-up of any ICM program approved by the Board?

Response:

In response to CCC interrogatory number 14, Oakville Hydro suggested that it would be appropriate to true-up its ICM application in its next cost of service application.

c) If Oakville Hydro is claiming the half-year rule should not apply than what is the basis for using the half-year amount of amortization when calculating the incremental revenue requirement in Table 9?

Response:

Oakville Hydro has calculated the incremental capital to be included in rate base based on the average net book value in the year. Amortization expense to be included in the incremental revenue requirement is based on a full year. This calculation is consistent with Tab 10, Incremental Capital Adj., of the ICM model.

VECC-13

Reference: Exhibit Section 15.6

In their letter of May 13, 2019 granting deferment, the OEB states in part:

This is the second year that Oakville Hydro has sought a deferral to filing a cost of service rate application. If Oakville Hydro subsequently seeks a further deferral the OEB will consider whether the Annual Incentive Rate-setting Index method that was developed for distributors intending longer periods without rebasing should be applied. The OEB will also consider whether the filing of a distribution system plan would be required at that time.

a) Has Oakville Hydro begun a distribution system plan in anticipation of the Board requirement to file a plan for 2021? If not, please provide the current estimate for when this plan will be completed.

Response:

Oakville Hydro has begun to update its distribution system plan for the period 2021 to 2025.

VECC-14

Reference: Exhibit Section 15.7

a) Please recalculate the Revenue Requirement Table 7 using the current Board approved cost of capital variables:

Return on Equity 8.52%
Deemed LT Debt 3.21%
Deemed ST Debt 2.75%

Response:

Oakville Hydro has calculated the incremental capital amount based on the updated ICM costs presented in response to OEB staff question number 7 and its 2020 preliminary budget in the following table.

Incremental Capital to be Included in Rate Base

	Amount
Total Capital Budget	$ 22,627,000
Less Materiality Threshold	17,301,915
Maximum Eligible Incremental Capital	5,325,085
Depreciation Expense (prorated to Eligible Incremental Capital)	64,792
Incremental Capital to be included in Rate Base (average NBV in year)	$ 5,260,293

Oakville Hydro has calculated the revenue requirement using the updated ICM costs presented in response to OEB staff question number 2 and both the approved and current OEB approved cost of capital parameters in the following table.

Incremental Capital Revenue Requirement

Total Incremental Revenue Requirement	Approved	Current	Difference
Long-term Debt	$ 137,850	$ 94,559	$ (43,291)
Short-term Debt	4,440	5,786	1,347
Return on Equity	196,945	179,271	(17,675)
Amortization Expense - Total	129,584	129,584	-
Grossed-Up Taxes/PILs	(35,866)	(35,866)	-
Incremental Revenue Requirement	$ 432,953	$ 373,335	$ (59,618)

VECC-15

Reference: Exhibit Section 15.9

Oakville Hydro explains that it proposes to exclude the embedded distributor class from the allocation of any incremental revenue requirement associated with the ICM proposal on the basis that this class does not benefit from the proposed projects.

a) Please explain the benefit to the other classes of the mandated plant relocations under the PSWHA.

Response:

Please see response to OEB staff interrogatory number 7 b).

b) Please demonstrate that the Bronte TS project does not benefit the embedded rate class.

Response:

Please see response to OEB staff interrogatory number 7 c).

VECC-16

Reference: Exhibit Section 15

a) Please provide the 2019 and 2020 Board approved business plans of Oakville Hydro.

Response:

Oakville Hydro has provided the portions of its 2019 Board approved business plan that relate to its ICM application in Appendix 7. Oakville Hydro's 2020 business plan is in process and has not yet been approved by its Board.

Appendix 1

Correspondence
Regarding the
Speers Road Project

Minutes

Date:	March 27, 2017
File #:	TP115099
Date & Time:	Friday, March 3, 2017 - 8:30 am
Meeting at:	Oakville Hydro, Engineering Boardroom
Subject:	Widening and Reconstruction of Speers Road - Oakville Hydro Review Meeting

Attendees:

Daniela Motoc, Oakville Hydro
Lauren Sebastian, Oakville Hydro
Kasia Piskorz, Town of Oakville
Felix Wong, Amec Foster Wheeler
John Nguyen, Amec Foster Wheeler

MATTERS DISCUSSED	**ACTION BY:**
Property Acquisition	
1. The Town noted that property acquisition is currently ongoing. Oakville Hydro will require the property prior to relocation as their relocation design show pole(s) relocated on proposed property limits.	
2. Oakville Hydro requested latest AutoCAD drawings of the property limits. Amec Foster Wheeler to provide.	**Amec Foster Wheeler**
Speers Road Reconstruction Design	
3. Amec Foster Wheeler noted that the preliminary plan layout of Speers Road is beyond 30% and do not anticipate major alteration. Minor adjustments are still to be completed.	
4. Amec Foster Wheeler provided Hydro with preliminary design cross sections at each proposed and existing Hydro Pole locations. The vertical grade of the sections may be adjusted subject to the Town's approval on the pavement recommendation. Grading cut/fill information for each Hydro Pole will be provided to Hydro by Amec Foster Wheeler when the pavement design is finalized.	**Town of Oakville/** **Amec Foster Wheeler**

PLEASE NOTE: If there is any comment or amendment to be made to these meeting notes, they should be brought to the notice of Amec Foster Wheeler within five (5) business days of issue and confirmed in writing

3215 North Service Road
Burlington, On L7N 3G2 Canada
905-335-2353
amecfw.com

Amec Foster Wheeler Environment & Infrastructure
A division of Amec Foster Wheeler Americas Limited

MATTERS DISCUSSED	ACTION BY:
Hydro Relocation Design – Drawings	
5. Amec Foster Wheeler noted that Oakville Hydro relocation design indicates some proposed poles are within the roadway clear zone (4.0 m), measured from the edge of travelled lane(s). These poles are placed according to Oakville Hydro's minimum 1.0 m from the back of curb to the face of pole, which therefore provides a 3.20 m clear zone. The Town to confirm if this offset is acceptable. Note: Town had previously confirmed acceptance of existing poles being 3 m from the travelled lane.	**Town of Oakville**
6. Amec Foster Wheeler to revise proposed sidewalk location at Hydro Pole No. P2, P3 and P4 to provide a minimum 1.0 boulevard between back of curb to face of pole(s).	**Amec Foster Wheeler**
7. Amec Foster Wheeler to revise proposed sidewalk adjacent to the bridge structure at pole P15 and P16 closer to property line to provide a wider boulevard to help mitigate requirement for an Aerial Easement. Oakville Hydro to review pole layout at this location.	**Amec Foster Wheeler**
8. Oakville Hydro to relocate Pole No. P22A and P41A to behind proposed sidewalk.	
9. Oakville Hydro noted several existing hydro transformers located near private property and/or crossing existing property limits. Town to confirm if the existing locations are acceptable or if relocation of the transformers are required.	**Town of Oakville**
10. Amec Foster Wheeler noted missing HP located in front of property No. 1141 Speers Road. Pole is picked up on the topographic survey. Oakville Hydro to confirm.	**Oakville Hydro**
11. Oakville Hydro noted concerns with Hydro Pole P53, P54 and P55 as guy pole anchor wire length requirements are within private properties. P54 and P55 are in conflict with proposed retaining wall. Oakville Hydro to explore alternatives, including shifting pole line to south side and confirm if additional property acquisition is required. Town of Oakville noted that property acquisition on 1005 Fourth Line may be difficult to obtain with land owner(s). Amec Foster Wheeler to revised north sidewalk adjacent to back of proposed curb at Hydro Pole P53.	**Oakville Hydro/ Amec Foster Wheeler**
12. Amec Foster Wheeler to revise design drawings and provide updated AutoCAD drawings to Oakville Hydro.	**Amec Foster Wheeler**

MATTERS DISCUSSED **ACTION BY:**

Electrical

13. Amec Foster Wheeler to follow up with UTech to discuss traffic staging. Oakville Hydro does not have any concerns with temporary traffic signals to be placed on their existing hydro pole(s) at Third Line and Fourth Line intersections. **Amec Foster Wheeler**

Meeting Minutes prepared by,

Amec Foster Wheeler Environment & Infrastructure
a Division of Amec Foster Wheeler Americas Limited

Per: John Nguyen, C.Tech.
Design Technologist

JN/jn

c.c. Paul Allen, Town of Oakville
Upul Padmanath, U Tech Engineers Inc.
David Sinke, Amec Foster Wheeler

From: Kasia Piskorz [mailto:kasia.piskorz@oakville.ca]
Sent: October 22, 2015 3:17 PM
To: Daniela Motoc <dmotoc@oakvillehydro.com>
Subject: Speers Rd Widening (West of Third Line to Fourth Line)

Hi Daniela,
The Town has retained a design consultant for the widening of Speers Road from west of Third Line to Fourth Line.
It is most likely that the design will require the relocation of the hydro poles along the south side of the Road and I would like to arrange a meeting to discuss this.

Can you suggest some dates and times that you are available for the week of Nov 2, Nov 9 and Nov 16 and I will set up a meeting along with our consultant.

Thanks,
Kasia

Kasia Piskorz
Project Leader - Capital Projects
Engineering and Construction
Town of Oakville | 905-845-6601, ext.3533 | f: 905-338-4159 | www.oakville.ca
Complete our Community Development customer service survey

From: Wong, Felix [mailto:Felix.Wong@amecfw.com]
Sent: April 26, 2017 3:34 PM
To: Daniela Motoc <dmotoc@oakvillehydro.com>; Lauren Sebastian <lsebastian@utsconsultants.ca>; Kasia Piskorz <kasia.piskorz@oakville.ca>
Cc: Nguyen, John <John.Nguyen@amecfw.com>
Subject: RE: Apr 18/2017- Hydro Design Speers Rd Widening(3rd Line to 4th Line) - Q62007 - H2324

Daniela/ Lauren,

We have reviewed the pole location behind the proposed retaining wall and noted that there may not be sufficient space to place a pole without impacting the parking.

Attached is a typical section of the proposed wall design (which we have looked at a couple options and determined this is the narrowest we can go). There is only about 0.25m available from the wall to the property line. I don't believe this is sufficient for the pole placement.

Kasia – is there any possibility to obtain an easement/ property from one parking space for the placement of the pole? We will still require the aerial easement for the OH line.

Please confirm and comment.
Thanks,
Felix

From: Daniela Motoc [mailto:dmotoc@oakvillehydro.com]
Sent: April-19-17 9:48 AM
To: Wong, Felix <Felix.Wong@amecfw.com>
Cc: Nguyen, John <John.Nguyen@amecfw.com>; Lauren Sebastian <lsebastian@utsconsultants.ca>; Kasia Piskorz <kasia.piskorz@oakville.ca>
Subject: RE: Apr 18/2017- Hydro Design Speers Rd Widening(3rd Line to 4th Line) - Q62007 - H2324

Hi Felix will review and advise.

The poles on the north side should remain in the blvd, assuming that blvd will be extended and retaining wall moved to the north.

A min 3.5 – 4.0 m is required from pole location to allow for max swing/ sag of aerial conductor, so easement / property will need to be acquired for this purpose.

Thank you
Daniela

This message is being sent to you by the sender identified above. If you no longer wish to receive email communications including information about our company, publications on issues such as ways to conserve energy and reduce your energy costs, information about your ongoing use of our products and services or about products and services we are introducing that may be of interest to you, invitations to or information about events, you can unsubscribe at any time by contacting us at unsubscribe@oakvillehydro.com.

From: Wong, Felix [mailto:Felix.Wong@amecfw.com]
Sent: Wednesday, April 19, 2017 9:45 AM
To: Daniela Motoc
Cc: Nguyen, John; Lauren Sebastian; Kasia Piskorz
Subject: RE: Apr 18/2017- Hydro Design Speers Rd Widening(3rd Line to 4th Line) - Q62007 - H2324

Thanks Daniela,

We'll review the drawings that you just provided.

We spoke with the Town yesterday with regards to the 4th Line intersection. We agreed that the north option is preferred as the south option would impact 2 properties on the south side of Speers Rd. We want to confirm, however, that there will be no parking spot impacts as noted on your drawing. As shown on our design drawing, the existing retaining wall is being relocated northerly and want to confirm that the new hydro pole can still stay within the existing boulevard area. We'll further review this but if you can also review and confirm.

Thanks,

Felix

From: Daniela Motoc [mailto:dmotoc@oakvillehydro.com]
Sent: April-13-17 5:28 AM
To: Wong, Felix <Felix.Wong@amecfw.com>
Cc: Lauren Sebastian <lsebastian@utsconsultants.ca>; Michael Mehagan

<mmehagan@utsconsultants.ca>
Subject: Q62007/ H-2324 / UTS Ref: OAK-077- Speers Rd.Widening -Hydro Design Apr 4th 2017

Hi Felix:

Please see attached latest hydro design (CAD and .pdf files) as of April 4th, 2017,
related to overhead relocation c/w comments for items that require your review/ feedback.
It is my understanding from Lauren that not all items discussed with regard to sidewalk adjustments have been updated within the latest cad files received.

Please note that these plans do not include any reference information with regard to latest meeting for the UG crossings that may be impacted by road work, as this information is under review.
In order to allow our hydro design for OH relocations be finalized, please review comments below and within attached .pdf files.
Would greatly appreciate if these civil revisions / adjustments are all addressed as well your confirmation of which option would be preferred to choose for the relocations at Speers and Fourth Line.
In addition final cut/fill information at each new pole location and existing are required to finalize hydro design.

With regard to UG crossings that may be impacted by the road construction after reviewing with my colleagues please note that for UG CE structure we will allow to have the min .6m to final grade; Our typical min clearance would be min .9m.
However for all other cases we would still require to see final expected separation , and we will review on a case by case. Please confirm when the additional details for the UG conflicts can be provided to allow our review.

Thank you
Daniela'

Correspondence

Regarding the

Trafalgar Road Project

R.V. Anderson Associates Limited
engineering · environment · infrastructure

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MEETING NOTES

THE REGIONAL MUNICIPALITY OF HALTON

TRAFALGAR ROAD (REGIONAL ROAD 3) FROM LEIGHLAND AVENUE TO HIGHWAY 407
Region File PR-2079 B/C/D

Oakville Hydro Meeting

DATE: August 26, 2016 at 9:00 a.m.

PLACE: 1075 North Service Road West, Oakville, Ontario, Oak Room

PROJECT NO.: 163269

PRESENT:

Chris Ewen	- Region of Halton (Region)
Rama Garigipati	- Region of Halton
Daniel Steele	- Oakville Hydro (OH)
Daniela Motoc	- Oakville Hydro
Lauren Sebastian	- UTS Consultants
John Does	- R.V. Anderson Associates Limited (RVA)
Peter Cho	- R.V. Anderson Associates Limited

The purpose of the meeting was to meet with Oakville Hydro to start the relocation design process.

DISCUSSION:	**ACTION BY:**
1. Project Schedule	
Phase 1 – Leighland to Hays – Spring 2017	INFO
Phase 2 – Hays to William Halton Parkway – summer 2018	INFO
2. Project Details	
6 lane configuration with sidewalk and multi-use path.	INFO
Hydro informed us that there's a lot of third parties on the Trafalgar Road pole line.	INFO
Currently there should be Bell, Rogers and Cogeco on existing hydro pole.	INFO
Hydro will try to include the third-party design with their work.	INFO
Upper Middle Road East is a heavy pole line, if possible, avoid relocating at the intersection.	RVA
Oakville Hydro spacing limit is 60m, 47m is the general limit.	INFO

DISCUSSION:	ACTION BY:
At mid-block locations where we have bus pad, due to property constraints, would an underground hydro line be a feasible option.	OH
OH to contact the telecom companies about this relocation.	OH
OH recommended the Region contact all other telecom companies to discuss the timeline of the project and try to get commitments on allocating their resources. OH expressed their concerns with the short timeframe to complete their relocation, but they have no control over the resources of their third party companies.	REGION/RVA
Street lighting is to be joint-use on the east side whereever possible.	INFO
RVA to forward Hydro's contact to Moon Matz (RVA's lighting sub-consultant)	RVA
Ideal location for Hydro is to be between back of curb and SW.	OH
3.0m clearance minimum safety clearance.	INFO
7.0m clearance for neutral wires, Moon Matz to confirm with OH, probably will be higher for Trafalgar.	RVA
5.0m clear zone from edge of travel lane. For Trafalgar Road, we won't be able to achieve this for phase 1 due to property constraints. There are opportunities to achieve the 5.0m clear zone in Phase 2.	RVA
Wherever possible, provide minimum 1.5 m from back of curb to face of pole in Phase 1.	RVA
0.5m from edge of sidewalk to face of pole to avoid snow plows.	RVA
3.5m minimum require for pole off-set to property line. If heavy circuit pole 5m.	OH/RVA
RVA to discuss with Multi-view and see when we can finalize Sue-B.	RVA
UTS will require a couple of weeks to get all the information on the existing poles, and a couple of weeks to do the preliminary design and discuss with other utilities. Mid October will probably have our preliminary design.	OH
RVA to finalize our plan locations for sidewalk and curb by September.	RVA
Target for OH is to target final design in December and the cost estimate in January.	OH

Notes prepared by: P. Cho, P.Eng.

Distribution: All present/absent

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MEETING NOTES

THE REGIONAL MUNICIPALITY OF HALTON

TRAFALGAR ROAD (REGIONAL ROAD 3) FROM LEIGHLAND AVENUE TO HIGHWAY 407
Region File PR-2079 B/C/D

Oakville Hydro Meeting

DATE: January 11, 2017 at 9:00 a.m.

PLACE: 1075 North Service Road West, Oakville, Ontario

PROJECT NO.: 163269

PRESENT:	Chris Ewen	- Region of Halton (REGION)
	Daniel Steele	- Oakville Hydro (HYDRO)
	Daniela Motoc	- Oakville Hydro
	John Does	- R.V. Anderson Associates Limited (RVA)
	Peter Cho	- R.V. Anderson Associates Limited
ABSENT:	Lauren Sebastian	- UTS Consultants

The purpose of the meeting was to meet with Oakville Hydro to start the relocation design process.

DISCUSSION: **ACTION BY:**

1. Project Schedule

Due to various issues, the construction date for Phase 1 has been delayed. INFO

2. Project Details

Underground Hydro*:*

The Region expressed their preference to install the Trafalgar Hydro line underground. It will make the corridor more **aesthetically pleasing** because Trafalgar is considered one of the major corridors in Halton. INFO

The underground lines will preferably be from Leighland to Hays. INFO

Hydro expressed their concerns with going underground for this section of Trafalgar Road due to the following: INFO

- The Trafalgar line is a high voltage distribution line and is one of Hydro's major supply lines.

DISCUSSION: **ACTION BY:**

- Underground hydro cables lines are very expensive. Approximate cost for underground cables is $100/metre which does not include installation and labour. From Leighland to Hays is approximately 3.2km.

- Switch gear will require a large amount of space (6m x 8m). Not all switch gear will be located near the intersection. An analysis will need to be completed to determine the exact location.

- Existing properties connecting to the Trafalgar hydro lines are on Radio feed, a loop connection will need to be created to meet Hydro's standard. The process is very complicated and additional easements/property will be required from property owners. Obtaining additional properties from existing owners has been very difficult from past experience.

- Hydro will require a few years to construct the underground infrastructure.

- It is very difficult and expensive to maintain underground infrastructure.

If the underground hydro wires are to be installed, the ideal location will be the west side of Trafalgar Road. Currently, there are not many existing utilities based on the SUE level B results. It will also allow hydro to install all the proposed work before disconnecting from the existing hydro poles. INFO

RVA to forward SUE level B drawings to Hydro. RVA

Region is willing to compensate Hydro to complete a preliminary design of underground hydro wires on Trafalgar. This will provide more detail to determine the feasibility to construct underground hydro wires on Trafalgar road (cost, schedule, technical and etc.). INFO

Hydro to provide estimate and schedule for the preliminary design and study for underground hydro lines. HYDRO

<u>Overhead Hydro:</u>

Hydro's long term plan will require additional circuit from Highway 403 to Dundas. INFO

Existing hydro poles will not be able to accommodate the additional circuit, higher poles will be required. INFO

The Region's Reality group will check and confirm if swing easements on Town of Oakville and private properties are acceptable. REGION

RVA is to create a drawing with aerial photo, legal boundary, proposed property line and swing and guiding easement. RVA

DISCUSSION:	**ACTION BY:**
RVA is to revise sidewalk locations wherever possible to accommodate Hydro's pole layout. RVA is to forward revised drawings to Hydro	RVA
RVA indicated to the Region and Hydro that due to the tight property constraints in Phase 1 for the Trafalgar road project, compromises will have to be made by both parties. Clear zone requirements will not be met and clearance between poles and SW/curb will be minimal at some locations. Region and Hydro is to review revised design and discuss at next meeting.	REGION/ HYDRO
Region is to discuss with road operations the pole setback from back of curb.	REGION
If excavation limits are within 3m of hydro pole, hydro requires the pole to be supported.	INFO

Notes prepared by: P. Cho, P.Eng.

Distribution: All present/absent

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MEETING NOTES

THE REGIONAL MUNICIPALITY OF HALTON

TRAFALGAR ROAD (REGIONAL ROAD 3) FROM LEIGHLAND AVENUE TO HIGHWAY 407
Region File PR-2079 B/C/D

Oakville Hydro Meeting

DATE: September 19, 2017 at 9:30 p.m.

PLACE: 1075 North Service Road West, Oakville, Ontario, Beech Room

PROJECT NO.: 163269

PRESENT:

Chris Ewen	- Region of Halton (Region)
Phil Antoniow	- Region of Halton
Brian Gregatti	- Region of Halton
Melissa Fialho	- Region of Halton
Daniela Motoc	- Oakville Hydro (OH)
Dave Gadbois	- Uniongas
Peter Cho	- R.V. Anderson Associates Limited (RVA)

The purpose of the meeting was to meet with Oakville Hydro to re-engage on the relocation design process.

DISCUSSION: **ACTION BY:**

1. Project Schedule

   Phase 1 – Leighland to Hays – target tender date September 2018. INFO

   Relocation to be completed by summer 2018. INFO

2. Project Details

   OH informed us that they require a minimum of eight (8) weeks to order materials. INFO

   Region is to notify Bell and Rogers on the new target date.

   Update: Test Pit and utility conflict plan has been distributed to all utilities in project corridor. RVA is to forward email to Oakville Hydro. RVA

3. Oakville Hydro

   Oakville Hydro will complete overhead design for other utilities unless they are informed otherwise. INFO

   Region to fill in application to attach street lighting to Hydro pole and submit to OH. RVA to contact subs and confirm use of lighting equipment. RVA

DISCUSSION:	**ACTION BY:**
Region is to confirm and forward latest LED lighting standard to RVA.	REGION
OH will require photometric from the Region. RVA to discuss with sub-consultant.	RVA
RVA to review the road design from Upper Middle to Briarhall to accommodate the hydro poles. OH's preference is to stay within the boulevard with a 1.5m offset from back of proposed curb. RVA will investigate the following options: RVA is to provide revised drawings to OH by September 11, 2017. Update: Revised design was sent to OH on August 28, 2017. RVA has received updated drawings, with one pole locations still needing to be resolved. RVA to respond to OH's email regarding the one pole.	RVA RVA
Once the pole locations have been finalized, OH to send easement requirements to RVA. RVA is to incorporate into property acquisition plan.	OH / RVA
OH to submit cost estimate after final design.	OH.
OH confirmed there are no overhead Bell lines on the existing hydro poles.	INFO
OH to check if Oakville's PSN lines are on the existing hydro poles.	OH
OH requested Hydro Vac hydro to confirm depth of existing crossings.	RVA/REGION
4. General	
RVA to follow up with all utilities and obtain comments on utility conflict plan and test pit plan.	RVA
RVA to forward watermain design drawings and new construction plans to all utilities.	RVA
RVA is to double check with Trans Northern Canada and confirm if they require site presence during hydro-vac.	RVA
Further discussion will need to be held on how to stage the utility relocation that's currently on existing Hydro poles (Cogeco, Rogers and Street lighting). If old street light stays in place, it might delay Bell and Rogers transferring their existing lines to the new poles.	
Next utility meeting – TBD.	OH

Notes prepared by: P. Cho, P.Eng.

Distribution: All present/absent

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MEETING NOTES

THE REGIONAL MUNICIPALITY OF HALTON

TRAFALGAR ROAD (REGIONAL ROAD 3) FROM LEIGHLAND AVENUE TO HIGHWAY 407
Region File PR-2079 B/C/D

Oakville Hydro Meeting

DATE: September 19, 2017 at 9:30 p.m.

PLACE: 1075 North Service Road West, Oakville, Ontario, Beech Room

PROJECT NO.: 163269

PRESENT:

Chris Ewen	- Region of Halton (Region)
Phil Antoniow	- Region of Halton
Brian Gregatti	- Region of Halton
Melissa Fialho	- Region of Halton
Daniela Motoc	- Oakville Hydro (OH)
Dave Gadbois	- Uniongas
Peter Cho	- R.V. Anderson Associates Limited (RVA)

The purpose of the meeting was to meet with Oakville Hydro to re-engage on the relocation design process.

DISCUSSION: **ACTION BY:**

1. Project Schedule

   Phase 1 – Leighland to Hays – target tender date September 2018. INFO

   Relocation to be completed by summer 2018. INFO

2. Project Details

   OH informed us that they require a minimum of eight (8) weeks to order materials. INFO

   Region is to notify Bell and Rogers on the new target date.

   Update: Test Pit and utility conflict plan has been distributed to all utilities in project corridor. RVA is to forward email to Oakville Hydro. RVA

3. Oakville Hydro

   Oakville Hydro will complete overhead design for other utilities unless they are informed otherwise. INFO

   Region to fill in application to attach street lighting to Hydro pole and submit to OH. RVA to contact subs and confirm use of lighting equipment. RVA

DISCUSSION:	**ACTION BY:**
Region is to confirm and forward latest LED lighting standard to RVA.	REGION
OH will require photometric from the Region. RVA to discuss with sub-consultant.	RVA
RVA to review the road design from Upper Middle to Briarhall to accommodate the hydro poles. OH's preference is to stay within the boulevard with a 1.5m offset from back of proposed curb. RVA will investigate the following options: RVA is to provide revised drawings to OH by September 11, 2017. Update: Revised design was sent to OH on August 28, 2017. RVA has received updated drawings, with one pole locations still needing to be resolved. RVA to respond to OH's email regarding the one pole.	RVA RVA
Once the pole locations have been finalized, OH to send easement requirements to RVA. RVA is to incorporate into property acquisition plan.	OH / RVA
OH to submit cost estimate after final design.	OH.
OH confirmed there are no overhead Bell lines on the existing hydro poles.	INFO
OH to check if Oakville's PSN lines are on the existing hydro poles.	OH
OH requested Hydro Vac hydro to confirm depth of existing crossings.	RVA/REGION
4. General	
RVA to follow up with all utilities and obtain comments on utility conflict plan and test pit plan.	RVA
RVA to forward watermain design drawings and new construction plans to all utilities.	RVA
RVA is to double check with Trans Northern Canada and confirm if they require site presence during hydro-vac.	RVA
Further discussion will need to be held on how to stage the utility relocation that's currently on existing Hydro poles (Cogeco, Rogers and Street lighting). If old street light stays in place, it might delay Bell and Rogers transferring their existing lines to the new poles.	
Next utility meeting – TBD.	OH

Notes prepared by: P. Cho, P.Eng.

Distribution: All present/absent

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MEETING NOTES

THE REGIONAL MUNICIPALITY OF HALTON

TRAFALGAR ROAD (REGIONAL ROAD 3) FROM LEIGHLAND AVENUE TO HIGHWAY 407
Region File PR-2079 B/C/D

Hydro Utility Meeting

DATE: June 19, 2018

PLACE: 1075 North Service Road West, Oakville, Ontario, Willow Room

PROJECT NO.: 163269

PRESENT:

Phil Antoniow	- Region of Halton (Region)
Daniela Motoc	- Oakville Hydro (OH)
Michael Mehagan	- UTS Consultants
Nick Palomba	- R.V. Anderson Associates Limited (RVA)
Peter Cho	- R.V. Anderson Associates Limited
Susan Jacob	- R.V. Anderson Associates Limited

REGRETS:

Cathy Robertson	- Region of Halton (Region)
John Does	- R.V. Anderson Associates Limited (RVA)

The purpose of the meeting was to review relocation design progress to date, discuss outstanding issues/resolutions and confirm schedule.

DISCUSSION: **ACTION BY:**

1. Project Schedule

   To maintain the Region's Project schedule, progress meetings will be held every three weeks at the Region's North Service Road Office. — INFO

   Susan Jacob has been designated as the Project Coordinator for property and utility relocation and will be following up with the team on a bi-weekly basis to track project status. — INFO

   The Realty due date for expropriation is scheduled for mid-October — INFO

   Easement registration for east side needs to be completed by early October for east side. — INFO

2. Hydro Relocation update:

   Hydro presented their design; the following is the outcome of the discussions around areas of conflict or concern with various poles:

DISCUSSION:	**ACTION BY:**
7a – RVA to review cross sections and confirm height of retaining wall and possibility of moving the wall west to accommodate pole and guide wire.	RVA
14a – Relocate pole to the east	OH/UTS
- Increase easement size	OH/UTS/ RVA
- RVA to check drawing and confirm if easement location is in subdivision plan.	RVA
9a – Relocate pole to the west	OH/UTS
10a - Relocate pole to the east between the sidewalk and bike path	OH/UTS
19a – Relocate pole to the west	OH/UTS
22a – Relocate pole to the east	OH/UTS
- Increase easement size	OH/UTS/ RVA
28a – Relocate pole to the west	OH/UTS
- Cross check to see how it works with the ditch	RVA
35a – Relocate pole to the west	OH/UTS
- Be careful not to go into resident's fence	
40a – Relocate pole to the west	OH/UTS
40b – Relocate pole to the west	OH/UTS
41a – Relocate pole to the west	OH/UTS
43a – Region cannot obtain more land (UTS to confirm if split anchors can work)	OH/UTS
46a - Relocate pole to the west	OH/UTS
- Be sure to not encroach into parking space	
47a – Hydro to review pole location	OH/UTS
48a – Hydro to review pole location	OH/UTS
54a - Oakville Development – Relocate pole to the west	OH/UTS
58a - Oakville Development – Relocate pole to the west	OH/UTS

DISCUSSION: **ACTION BY:**

- Oakville Development - Relocate pole to the west

61a - Oakville Development - Relocate pole to the west OH/UTS

63a - Region cannot acquire land from the dealership. OH/UTS

- Relocate pole between sidewalk and bike path

66a - Region to acquire property - Relocate pole to the west OH/UTS

3. General

Next Utility Meeting – July 10, 2018 – Tentative Date

Notes prepared by: Susan Jacob

Distribution: Distribution List

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MEETING NOTES

THE REGIONAL MUNICIPALITY OF HALTON

TRAFALGAR ROAD (REGIONAL ROAD 3) FROM LEIGHLAND AVENUE TO HIGHWAY 407
Region File PR-2079 B/C/D

Hydro Utility Meeting

DATE: July 10, 2018

PLACE: 1075 North Service Road West, Oakville, Ontario, Oak Room

PROJECT NO.: 163269

PRESENT:	Phil Antoniow	- Region of Halton (Region)
	Daniela Motoc	- Oakville Hydro (OH)
	Michael Mehagan	- UTS Consultants
	Nick Palomba	- R.V. Anderson Associates Limited (RVA)
	Peter Cho	- R.V. Anderson Associates Limited
	Susan Jacob	- R.V. Anderson Associates Limited
REGRETS:	Cathy Robertson	- Region of Halton (Region)
	John Does	- R.V. Anderson Associates Limited (RVA)

The purpose of the meeting was to review relocation design progress to date, discuss outstanding issues/resolutions and confirm schedule.

DISCUSSION:	**ACTION BY:**
1. Hydro Relocation update:	
For pole locations – Typically Hydro does not want anchors embedded in assets owned by others due to possible access and maintenance issues. Small platforms will be built behind the retaining wall to easily access poles and to avoid any access issues.	OH/UTS
7a – Hydro to comment on the hand drawn sketch presented by RVA.	OH/UTS
43a –UTS confirmed that the split anchors can work	OH/UTS
48a – Hydro needs 10m more space for guy wire	RVA
48a,b,c – review location of poles, hydro to confirm UTS design.	UTS
63a – Pole to be placed between curb and pathway, anchor to go around the pole. Half a meter clearance is required on each side of the pole. RVA to check if this will have property impacts.	RVA

DISCUSSION:	**ACTION BY:**
RVA to review drawings sent for the west side.	RVA
RVA to get locates for underground conflicts. Once locates have been finalized then Hydro will order materials for relocation.	RVA
RVA to discuss with Region the possibility of stocking hydro poles in the Regional yard.	RVA/REGION
UTS reviewed Draft R-Plans. Discrepancies noticed on plan 18. RVA to review and revise.	RVA
Hydro requires demarcation of culvert for phase 2. RVA to send drawings	RVA
Hydro has requested future crossing from Region around Sheridan College Area.	
2. <u>Lighting</u>	
RVA to send Hydro lighting layout for corridor	RVA
Photometric design for street light to be reviewed by Moon-Matz. Hydro will then require applications for transfers	RVA
Direct agreement is needed between Region and Contactor if using Hydro's contractor for street light. Tender documents to reflect separate costing for what is Hydro and what is street lighting. RVA to approach Hydro approved contractor (KLINE) to do the relocation	RVA
RVA to send finalized hydro drawings to Moon-Matz for review of traffic and street lights.	RVA
3. <u>General</u>	
RVA to send staging for Phase 2	RVA
Next Utility Meeting – August 14, 2018	

Notes prepared by: Susan Jacob

Distribution: Distribution List

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MEETING NOTES

THE REGIONAL MUNICIPALITY OF HALTON

TRAFALGAR ROAD (REGIONAL ROAD 3) FROM LEIGHLAND AVENUE TO HIGHWAY 407
Region File PR-2079 B/C/D

Hydro Utility Meeting

DATE: August 14, 2018

PLACE: 1075 North Service Road West, Oakville, Ontario, Hickory Room

PROJECT NO.: 163269

PRESENT:	Phil Antoniow	- Region of Halton (Region)
	Daniela Motoc	- Oakville Hydro (OH)
	Michael Mehagan	- UTS Consultants
	Nick Palomba	- R.V. Anderson Associates Limited (RVA)
	Peter Cho	- R.V. Anderson Associates Limited
	Susan Jacob	- R.V. Anderson Associates Limited
REGRETS:	Cathy Robertson	- Region of Halton (Region)
	John Does	- R.V. Anderson Associates Limited (RVA)

The purpose of the meeting was to review relocation design progress to date, discuss outstanding issues/resolutions and confirm schedule.

DISCUSSION:	**ACTION BY:**
1. Hydro Relocation update:	
7a – Hydro prefers to have the anchor closer to the retaining wall. Vertical strut with wall behind may be beneficial during construction stage. Hydro/UTS to review.	OH/UTS
43a –UTS confirmed that the split anchors can work	OH/UTS
48a, b,c – Hydro to confirm UTS design.	UTS
63a – Pole to be placed between curb and pathway, anchor to go around the pole. Half a meter clearance is required on each side of the pole. RVA to check if this will have property impacts.	RVA
Post Update – Bike lanes guy wires will need to be longer than 3m. To be discussed at next utility meeting.	
RVA to review drawings and send comments for the west side to Hydro/UTS.	UTS

DISCUSSION:	**ACTION BY:**
Post Update: Comments were sent to Hydro/UTS. RVA awaiting updated drawings.	
Hydro – vac will proceed once road occupancy permits have been received. Telecon will be completing the hydro-vac work.	INFO
Region has a location, south of Burnhamthorpe, to store hydro poles. Region to be advised before delivery of hydro poles. An alternative location north of Riverstone Drive was proposed as an option for pole storage. It was agreed that this location is not a viable option due to safety issues (i.e. open area).	RVA/REGION
It was discussed for houses 2124 Trafalgar Road (48c), 2136 Trafalgar Road (48b) & 2148 Trafalgar Road (48a), the approximate cost to convert overhead supply to underground supply is $35,000 per house.	INFO
RVA advised that the west side R-Plans will only be completed after relocation process of the east side. In the worst-case scenario, temporary hydro poles on the west side might be required (i.e. mainly guide poles).	INFO
Region has advised that they have suspended the design of the culvert until Phase 1 has been completed. RVA to send Hydro/UTS any preliminary drawings that were completed.	RVA
Hydro informed that two sets of crossing may be required for Sheridan college. RVA to send latest plan and profile drawings to Hydro/UTS.	RVA
To service the Oak Walk Drive connection, servicing cannot be directly across. The servicing will have to cross closer to Hayes and then up to Oak Walk Drive. This will avoid any throw away costs and avoid relocation during phase 2 of Trafalgar Road.	INFO
2. <u>Lighting</u>	
RVA to send Hydro lighting layout for corridor	RVA
Hydro advised that photometric design should incorporate Hydro's latest pole designs. Moon-Matz is currently reviewing the traffic supply. If there are any probability of clearance issues, then Hydro/UTS should be informed immediately.	RVA
Hydro advised that KLINE is open to offer a quote for street lighting relocation. Hydro advised not finalize the quote until design is complete. Region has requested that KLINE invoice Hydro and then Hydro will invoice the Region. Region and Hydro to talk further on this request.	OH/REGION

DISCUSSION: **ACTION BY:**

RVA/Region advised hydro to start relocation from the south end of Trafalgar to the North end, in order to avoid any potential conflict with other utilities. OH/UTS

Hydro is proposing open cut for crossing if needed. This will be determined once hydro – vac has been completed. RVA to follow up. RVA

3. General

Gas relocation will begin October 9, 2018. INFO

Hydro has advised that there will be delays in pole delivery due to fires in BC. As per recent information, Hydro has advised that poles will be expected in spring 2019.

Next Utility Meeting – October 11, 2018 RVA

Notes prepared by: Susan Jacob

Distribution: Distribution List

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MEETING NOTES

THE REGIONAL MUNICIPALITY OF HALTON

TRAFALGAR ROAD (REGIONAL ROAD 3) FROM LEIGHLAND AVENUE TO HIGHWAY 407
Region File PR-2079 B/C/D

Hydro Utility Meeting

DATE: December 4, 2018

PLACE: 1075 North Service Road West, Oakville, Ontario, Beech Room

PROJECT NO.: 163269

PRESENT:	Cathy Robertson	- Region of Halton (Region)
	Alexander Andrenkov	- Region of Halton (Region)
	Daniela Motoc	- Oakville Hydro (OH)
	Belal Mohamad	- UTS Consultants (UTS)
	Rami Alijadba	- UTS Consultants
	Cameron Aitkens	- UTS Consultants
	Peter Cho	- R.V. Anderson Associates Limited
	Susan Jacob	- R.V. Anderson Associates Limited
REGRETS:	Phil Antoniow	- Region of Halton (Region)
	John Does	- R.V. Anderson Associates Limited (RVA)
	Nick Palomba	- R.V. Anderson Associates Limited (RVA)

The purpose of the meeting was to review relocation design progress to date, discuss outstanding issues/resolutions and confirm schedule.

DISCUSSION: **ACTION BY:**

1. General

Oakville Hydro advised that all design related questions should be directed to Cameron at UTS and CC' d to Belal and Daniela. — INFO

RVA to update civil drawings with the updated hydro design plans. — RVA

Hydro has advised that there will be delays in pole delivery due to fires in BC. As per recent information, Hydro has advised that poles will be delivered to site by mid-December. Poles will be store at the Neyagawa. Hydro to co-ordinate with the Region. — OH/Region

Post Update: Halton Region and Hydro met on-site on December 4, 2018. Halton advised Hydro of insurance and agreement requirements that must be put in place before the poles can be stored.

DISCUSSION: **ACTION BY:**

2. Hydro Relocation update:

P9c – Proposed hydro pole location to be revised closer to back of curb. The easement will need to be updated to include the guy wire. Alternative is to go with spider guying. Hydro/UTS to review and confirm. — OH/UTS

P10a – proposed guy location conflicts with pathway at intersection. RVA to review and confirm as per Hydro's updated design. — RVA

P22a – Hydro to review anchor location. The proposed anchor will be part of the future ditch. Hydro to review if a split anchor can be used. — OH/UTS

P58a – Proposed hydro pole location conflicts with proposed bike path. Hydro pole to be moved west of proposed bike path — RVA

63a – Proposed hydro pole locations to be revised; sidewalk and bike path have been redesigned to accommodate guy anchor location. UTS to review. — OH/UTS

Underground information for Hydro has been sent for review. Two crossing locations have been recommended for relocation.

12+260 – North of Lynnwood

15+020 – South of Hayes — OH/UTS

Underground hydro line is to shallow and falls right below the proposed road base. Hydro to review and relocate.

Hydro has requested for CAD files for the two crossing for relocation with existing utilities and proposed water and sewer design on cross-sections. RVA to forward design files to Hydro/UTS. — RVA

Hydro has advised that their proposed start date for relocation is March 2019. Hydro would like to do a walk-through of the corridor with their contractors prior to relocation. Construction drawings need to be finalized before walk-through. Hydro relocation sequence will begin from south of Trafalgar to North of Trafalgar. Hydro requires a minimum of 6 months for all relocation work. Hydro to provide more accurate time duration for relocation work. — OH

Hydro informed project team, in general, they will require four (4) weeks to complete the locates. — INFO

Hydro advised that they require the gas relocation schedule by January, so that they can work around gas if need be. Gas has advised that their proposed relocation end date is February with the exception of the crossing at Sheridan college which will be completed in June. RVA to follow up with gas regarding their schedule. — RVA

DISCUSSION:	**ACTION BY:**
Hydro advised that they require the gas relocation schedule by January, so that they can work around gas if need be. Gas has advised that their proposed relocation end date is February with the exception of the crossing at Sheridan college which will be completed in June. RVA to follow up with gas regarding their schedule.	RVA
Hydro to notify Rogers and Cogeco on their construction schedule.	OH
RVA to provide Hydro with ultimate cut-fill locations for east side.	RVA
Region has advised that they have suspended the design of the culvert until Phase 1 has been completed. RVA to send Hydro/UTS any preliminary drawings that were completed.	RVA
RVA to follow up with the Town of Oakville's Mark Covert to confirm maintenance vehicle height.	RVA
Hydro will need a new crossing for Sheridan College, RVA to review proposed location.	OH/RVA
3. <u>Lighting:</u>	
RVA to send Hydro street and traffic lighting layout for corridor	RVA
Hydro to forward application for traffic and lighting transfer to RVA.	OH/UTS
Hydro advised that KLINE is open to offer a quote for street lighting relocation. Hydro advised not to finalize the quote until design is complete. Region has requested that KLINE invoice Hydro and then Hydro will invoice the Region. Region and Hydro to talk further on this request.	
RVA to update Moon-Matz on the stand-alone package. Moon-Matz to confirm how the traffic supply and appurtenance work during the gap between completion of Hydro poles and starting of construction for Trafalgar Road. (let me know if this is clear). Moon Matz to double check all clearances.	
Next Utility Meeting – February 11, 2019	RVA

Notes prepared by: Susan Jacob

Distribution: Distribution List

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MEETING MINUTES

THE REGIONAL MUNICIPALITY OF HALTON

TRAFALGAR ROAD – LEIGHLAND AVE TO HIGHWAY 407
Region File PR-2079 B/C/D

Hydro and Cable Coordination Meeting

DATE: March 6, 2019 @ 3:30 pm

PLACE: 1075 North Service Road West, Oakville, Ontario – Oak Room

PROJECT NO.: 163269

PRESENT:	Alexander Andrenkov	- Region of Halton (REGION)
	Robert Flindall	- Region of Halton
	Daniela Motoc	- Oakville Hydro (OH)
	Jordan Welbanks	- UTS Consultants (UTS)
	Bien Bengco	- Rogers (ROGERS)
	Deepak Mistry	- Cogeco (COGECO)
	Nick Palomba	- R.V. Anderson Associates Limited (RVA)
	Peter Cho	- R.V. Anderson Associates Limited
	Susan Jacob	- R.V. Anderson Associates Limited
REGRETS:	Daniela Policelli	- Cogeco

The purpose of the meeting was to discuss hydro relocation and design updates with Rogers and Cogeco.

DISCUSSION:	**ACTION BY:**
1. Hydro relocation to start on March 20, 2019, from South to North of Trafalgar Road. Contractor for hydro relocation is K-Line.	INFO
2. East side hydro pole line will go in first. West side hydro poles will be dependent on property acquisition, which is currently on-going.	INFO
3. Hydro to relocate, then illumination will go on poles and after that relocation of Rogers and Cogeco cable will occur.	INFO
4. Hydro has advised that relocation will occur in two stages. Stage 1 will be from Iroquois to Upper Middle Road. Relocation will be complete within approximately 94 days. This timeline does not include streetlighting transfers. Stage 2 will be from Upper Middle Road to Hayes.	INFO
5. Hydro has advised that K-Line has offered communication transfer work for both Rogers and Cogeco at the same time. This will allow to save time for relocation process.	INFO

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MEETING MINUTES

THE REGIONAL MUNICIPALITY OF HALTON

TRAFALGAR ROAD – LEIGHLAND AVE TO HIGHWAY 407
Region File PR-2079 B/C/D

Hydro and Gas Coordination Meeting

DATE:	April 23, 2019 @ 2:00 pm	
PLACE:	1075 North Service Road West, Oakville, Ontario – Oak Room	
PROJECT NO.:	163269	
PRESENT:	Martin Larkin	- Region of Halton (REGION)
	Robert Flindall	- Region of Halton
	Daniela Motoc	- Oakville Hydro (OH)
	Dave Gadbois	- Union Gas
	Nick Palomba	- R.V. Anderson Associates Limited (RVA)
	Peter Cho	- R.V. Anderson Associates Limited
	Susan Jacob	- R.V. Anderson Associates Limited
REGRETS:	Alexander Andrenkov	- Region of Halton (REGION)

The purpose of the meeting was to discuss relocation and design updates with hydro and gas.

DISCUSSION:	**ACTION BY:**
1. Hydro relocation started April 01, 2019, from South to North of Trafalgar Road. Contractor for hydro relocation is K-Line.	INFO
2. Hydro has advised that relocation will occur in two stages. Stage 1 will be from Iroquois to Upper Middle Road. Stage 2 will be from Upper Middle Road to Hayes.	INFO
3. Hydro has advised that they have 10 poles left to install after which the transfer from old poles to new poles with commence.	INFO
4. Hydro has advised that there will be a delay in their relocation for stage 1 – Iroquois to Upper Middle Road. Originally estimated stage 1 relocation to be complete by end of June (94 days). Hydro to provide an updated schedule and advice when they anticipate finishing the relocation of stage 1. **Post Meeting Update:** As per May 24, 2019 email from Hydro, they have advised that Stage 1 relocation has been delayed by an additional 2 weeks due to unforeseen soil conditions/ hard excavation for pole installation. Hydro expects Stage 1 of the work to be completed by mid-July.	OH

CANADA'S BEST MANAGED COMPANIES
Platinum member

DISCUSSION:	**ACTION BY:**
5. Hydro to relocate, then illumination will go on poles and after that relocation of Rogers and Cogeco cable will occur.	INFO
6. Streetlight installation still pending items to be provided by Moon-Matz and then a quote will be sent to Region. Moon- Matz to do following revisions: • Drawings should be revised to show street lighting design till Hays Blvd; • Advice if quantities that have been submitted included the section from Hays to Dundas; RVA to follow up with Moon Matz. **Post Meeting Update:** Moon-Matz has updated drawings and has provided it to Hydro.	RVA
7. RVA to follow-up with Moon-Matz regarding online application for streetlighting. **Post Meeting Update:** Moon-Matz following up with Oakville Hydro	RVA
8. Hydro has been in correspondence with Sheridan College regarding their underground crossings.	INFO
9. Hydro has advised that shelters currently with power that will be relocated from where they are currently, will require an application to be submitted to them.	
10. Rogers and Cogeco are attached to Hydro owned poles. Hydro has advised them that permit can only be issued once all poles and anchors have been installed. Hydro has advised both third party transfers (Rogers and Cogeco) that they need to plan internally to finish their design and not wait for hydro relocations to finish.	INFO
11. Hydro has advised that relocation of power supplies are the responsibility of the owners.	
12. Gas is currently doing relocation on the west side of Trafalgar at River Oaks and Glenashton. The west side is where they are installing the new gas pipe and the east side is where they are abandoning the old pipe. Gas estimating approximately 7 weeks to finish at River Oaks and Glenashton.	INFO
13. Gas relocation is now fully north of Upper Middle Road.	INFO
14. Gas to schedule any schedule conflicts with Hydro's foreman.	INFO
15. Project will be tendered June 25, 2019. All utilities to keep Region and RVA updated on their schedule.	GAS/OH

Minutes prepared by: S. Jacob

Distribution: All Present and Absent

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DISCUSSION:	**ACTION BY:**
Rogers and Cogeco has advised that they are currently committed to their respective contractors. They have advised that K-Line does not have fiber cable splicing experience.	INFO
6. Hydro forwarded their 90% design to both Rogers and Cogeco. 90% hydro design will allow both Rogers and Cogeco to do their internal planning (i.e. ordering materials, requesting permits)	INFO
7. Both Rogers and Cogeco to advice their contractors that relocation will happen in two stages. Rogers and Cogeco to investigate crew availabilities.	ROGERS / COGECO
8. Rogers to confirm duration of their transfer after completion of hydro and streetlighting transfer on phase 2. Cogeco will transfer last, Cogeco to also confirm transfer duration for phase 2.	ROGERS / COGECO
9. RVA to update schedule upon confirmation transfer timing from all utilities.	RVA
10. Region requires formal MC application for crossings. Rogers and Cogeco to submit formal MC application to Region which will also be reviewed by RVA.	ROGERS / COGECO
11. Project will be tendered in June. All utilities to keep Region and RVA updated on their schedule.	ROGERS/ COGECO/HYDRO
12. RVA to communicate Hydro's timeline to Gas. **Post Meeting Update:** Gas' current schedule was communicated to Hydro on March 20, 2019.	RVA
13. Gas has completed up to south of Upper Middle Road. Gas preparing detailed schedule and will be shared with hydro in order to avoid conflicts between contractors. **Post Meeting Update:** Gas has advised that they will finish up at the corner of McCraney and Trafalgar by March 27, 2019. They will then move onto Old Orchard and Upper Middle.	INFO
14. Rogers and Cogeco to advice if there are any slack in their crossing design. **Post Meeting Update: -** Received from Cogeco on March 12, 2019, Received from Rogers on March 20, 2019	ROGERS / COGECO
15. RVA to provide watermain drawings, SUE A and SUE B files to Hydro.	RVA

Minutes prepared by: S. Jacob

Distribution: All Present and Absent

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Correspondence

Regarding the

William Halton Parkway Project

Meeting Notes

Utility Coordination Meeting No. 1

New North Oakville Transportation Corridor, Trafalgar Road to Ninth Line, Town of Oakville

Halton Region File PR-2538A

Stantec

Date/Time:	December 6, 2013 / 1:30 – 4:30 PM
Place:	Halton Region Offices, 1151 Bronte Road, Oakville
Attendees:	Steve Andrews (Rogers, System Planner) Jeremy Getson (Union Gas, Utility Service Manager) Octavian Ghiricociu (Union Gas, Construction Project Manager) Rick Schatz (HONI, Senior Real Estate Coordinator) Angela Fedorenko (Cogeco, Planner) Jon Foreshaw (Oakville Hydro, Distribution Engineer) Adam Sheldon (TransCanada, Regional Land Representative) Bob Wicklund, Halton Region (Halton Region, Project Manager) Bill Hopkins (Halton Region, Water) Gord Murray (Stantec, Project Manager) Jerry Zhu (Stantec Project Engineer)
Distribution:	Attendees, Joseph Choi (Halton Region), Faye Wang (Union Gas), Ann Newman (Enbridge), Amanda Mcquay (Bell Canada)

Item:	Action:
1. INTRODUCTION	
Meeting started with a brief introduction of all attendees.	
2. REVIEW THE STATUS OF THE PROJECT	
Gord Murray provided a general overview of NNOTC project and the purpose for the meeting, and indicated that construction is planned to start in summer 2014.	
3. UTILITY RELOCAITON PLANS	
<u>Rogers</u> Rogers cable is currently on the hydro poles on east side of Ninth Line south of Burnhamthorpe Road. It was agreed to relocate the Rogers aerial cable following the relocated hydro poles. Rogers and Oakville Hydro to coordinate.	

<u>Oakville Hydro</u> Jon indicated that they require a minimum 3.5 metre offset from the property line to place hydro poles. Stantec suggested that new hydro poles on NNOTC will be placed on the boulevard between the curb line and multiuse pathway (or sidewalk). Installation at bottom of ditch or on the grading slope is not desirable. The pole spacing is generally 45-60 metres. Region would like to sell a part of existing Burnhamthorpe ROW. It was suggested that the Hydro line could be moved on to the new Connecting Link right-of-way to clear the abandoned section of ROW for sale. Region will determine how to illuminate NNOTC using either the new pre-installed hydro poles, or provide power to new street lights, if pre-installing hydro poles is not feasible. Stantec will provide Oakville Hydro with revisions to the suggested relocation plan, and the relevant cross-sections on NNOTC, Ninth Line and Trafalgar Road, for design of the relocations and new aerial pole line on NNOTC.	 Region Stantec
<u>Union Gas</u> Relocation of a 12" line is required due to the conflict with the new roundabout intersection at Ninth Line and Burnhamthorpe. The exact location and depth will be determined once Union Gas provides approximate location of their lines. Generally, the relocated line should be 1 metre from the property line. Jeremy indicated that the 2" plastic live gas line is on the south side of Burnhamthorpe Road. Further verification is required to determine if there are conflicts with design. Union Gas has plans to install a 20" diameter gas main along Trafalgar Road. Installation is scheduled for 2015 – 2016. Union Gas will provide additional details as they are available. Stantec will provide relevant cross-sections for Ninth Line, NNOTC, Burnhamthorpe and Trafalgar Road to Union Gas.	 Union Gas Stantec Union Gas Stantec Union Gas Stantec

<u>Hydro One Networks Inc. (HONI)</u> Rick indicated that HONI will ultimately install a double line of hydro towers within the corridor crossing NNOTC (west of Ninth Line) in the future. The tower locations may conflict with NNOTC corridor. To avoid this conflict, additional property may be required from adjacent owners, or additional towers installed to "turn the corner" across NNOTC.	
In term of landscape, trees are not allowed to plant on hydro One property within the hydro corridor.	Stantec
Rick will provide some guidance on the future tower locations so that they can be installed without conflict in the future.	HONI
A 6.0 metre wide access is required from NNOTC for future construction and/or maintenance on the corridor (both sides of NNOTC).	Stantec
HONI requires the drawings showing all pole heights within the hydro corridor for their review of separation from future hydro transmission lines.	Stantec
<u>TransCanada Pipelines and Enbridge Gas</u> The existing TCPL oil pipe line has been shown on the drawings based on best estimates. A 24" Enbridge Gas line in an 18.3m wide easement also runs within the corridor. While the proposed construction will place substantial earth fill over the pipe, there are no permanent structures (such as concrete culvert, storm sewer pipe, etc.) proposed above the pipe line.	
Stantec/Region will contact TransCanada's land service representative and apply for a crossing approval.	Stantec
<u>Region Watermain</u> An existing 1200mm feedermain is installed outside of the existing east gravel shoulder on Trafalgar Road. Relocation of the feedermain is not anticipated for Trafalgar Road reconstruction and widening. One of the chambers will need to be adjusted upward, and the air release vent pipe will need to be relocated to the boulevard.	Stantec

Cogeco Cogeco has no cables on existing Burnhamthorpe Road, Ninth Line or Trafalgar Road. Cogeco intends to place new aerial/cable along the new corridor (likely joint use with Bell Canada and Oakville Hydro).	
Bell Canada (A Bell representative was not present at the meeting.) It was suggested that the existing buried cable/conduit on Ninth Line and Burnhamthorpe Road be relocated aerially with the relocated Oakville Hydro poles. There are two buried lines on the west side of Trafalgar Road. The innermost line must be relocated, either buried further west in the new ROW, or joint use aerially, with hydro poles on the east side of Trafalgar Road. An updated suggested utility relocation plan and cross-sections will be provided to Enbridge Gas, Oakville Hydro, Union Gas, Rogers and Bell Canada for review and a request to commence with relocation designs as soon as possible to meet the summer 2014 construction start.	Stantec

The meeting adjourned at 4:00 PM.

The foregoing is considered to be a true and accurate record of all items discussed. If any discrepancies or inconsistencies are noted, please contact the writer immediately.

STANTEC CONSULTING LTD.

Jerry Zhu, P.Eng.
Senior Project Engineer
jerry.zhu@stantec.com

Stantec

Meeting Minutes

Utility Coordination Meeting #3

William Halton Parkway(WHP1) (Ninth Line to Trafalgar Road) (PR2538A) / 160210544

William Halton Parkway(WHP2) (Trafalgar Road to Neyagawa Boulevard) (PR2263D) / 165010557

Date/Time:	September 30, 2015 / 1:30 PM	
Place:	Oakville Hydro – Engineering Boardroom	
Next Meeting:	TBD	
Attendees:	Daniela Motoc, Manager Planning & Design	Oakville Hydro
	Daniel Steele, Director, Engineering & Construction	Oakville Hydro
	Jimmy P. Roxas Jr., Engineering Manager	NBM
	Kelsi McGinty, Design Technician	NBM
	Andrew Gorman, Project Manager	Halton Region
	Jerry Zhu, Project Engineer	Stantec Consulting
Absentees:	**Gord Murray (Stantec)**	
Distribution:	Attendees and Absentees	

Item:	Action:
1. Introduction and Review the Status of the Project Daniela Motoc initialized the meeting. Jerry Zhu went over the minutes for the last utility coordination meeting (meeting #2). Region proposes to construct these two sections of William Halton Parkway (WHP) stating in Spring 2016, and requests the tender documents be ready in February 2016. The 60% detailed design has been completed for both WHP sections. The design files in ACAD have been provided to Oakville Hydro to update their utility relocation design. Stantec requested that the revised hydro pole relocation design be complete by the end of October 2015.	
2. Utility Relocation Design for WHP1 and WHP2 The easements for some relocated hydro poles are not included in the current property plan. It may be necessary to revise the property plan and R-plan after the hydro pole design is complete.	Region Stantec
The streetlighting design will not be finalized until the hydro pole relocation plan is complete. <u>Utility Relocation along Roundabouts (at Sixth Line, and at Ninth Line)</u> NBM outlined the new options for hydro pole relocation in the vicinity of the roundabout at Sixth Line and WHP, based on the 60% design plan. It was discussed that guying and anchor towards the roadway is not desirable. OH and NBM are reviewing these locations and will attempt to	NBM Oakville Hydro

From: Zhu, Jerry
Sent: Tuesday, September 15, 2015 2:06 PM
To: dsteele@oakvillehydro.com; 'McQuay, Amanda (6052460)'; Wang, Faye (fwang@uniongas.com)
Cc: Andrew.Gorman@halton.ca; Murray, Gordon
Subject: PR2538A WHP1 (Trafalgar Rd - Ninth Line) -Utility Relocation Design

Hello, everyone,

The 60% design for William Halton Parkway (Trafalgar Road – Ninth Line) was completed. The ACAD file has been contained in the following FTP site. The 2004 version was also provided in case you may have old ACAD.

Please review the latest plan and update your relocation design where necessary. We would like to have your updated relocation plan by**October 30th, 2015**.

Should you have any question or require any other information, please do not hesitate to contact me.

Regards

Jerry Zhu, P.Eng.

Transportation Engineer
Stantec

From: Gorman, Andrew [mailto:Andrew.Gorman@halton.ca]
Sent: November 9, 2015 10:31 AM
To: 'Zhu, Jerry' <Jerry.Zhu@stantec.com>; Daniela Motoc <dmotoc@oakvillehydro.com>; jimmyr@nbmengineering.com
Cc: Dan Steele <dsteele@oakvillehydro.com>; kelsim@nbmengineering.com; Murray, Gordon <gordon.murray@stantec.com>
Subject: RE: WHP (PR2538A & PR2263D) - Utility Coordination Meeting #3

Additonal response to Jerry's below:

#1)
WHP – Trafalgar to Ninth Line – The plan is to go to construction in the spring time, we expect to have the required property by February 2016 which would allow the relocations to commence. The section at Ninth Line there is a bit of a complication as Union Gas is placing a transmission pipeline North/South on the west side of the roundabout and needs to get in before construction starts to place their crossing. They are expecting to start construction March 1 and a few weeks' worth of construction. Hydro should anticipate around the same time frame for relocations.

WHP – Neyagawa Boulevard to Trafalgar – we expect to have the required property by March/April which would allow your relocations to begin in May.

#5)
Minimum neutral height without the addition of street lighting attachments is 7.0m. If street lighting is being attached, 8.0m is requested. In general the higher the neutral height can go the better.

Let me know if you need anything further.

Andrew Gorman, C.E.T.
Project Manager
Engineering & Construction Services
Region of Halton Public Works Department
905-825-6000, Ext. 7256| Toll Free: 1-866-442-5866
1151 Bronte Road, Oakville, ON L6M 3L1
Email: andrew.gorman@halton.ca | Web: www.halton.ca
Please consider the environment before printing this e-mail

From: Zhu, Jerry
Sent: Monday, October 05, 2015 5:31 PM
To: Daniela Motoc (dmotoc@oakvillehydro.com); dsteele@oakvillehydro.com; jimmyr@nbmengineering.com; kelsim@nbmengineering.com; Andrew.Gorman@halton.ca
Cc: Murray, Gordon
Subject: WHP (PR2538A & PR2263D) - Utility Coordination Meeting #3

Hi, everybody,

Thanks for attending the utility coordination meeting (#3) for William Halton Parkway (Neyagawa Blvd – Ninth Line) on September 30th, 2015. The attached meeting minutes is for your record. Please do not hesitate to contact me should you have any problem.

Also please note the following issue arose post the meeting:

- In WHP 1 (Trafalgar Road – Ninth Line), a surplus property bounded by existing Burnhamthorpe Road, WHP and the eastern Connecting Link (west of Ninth Line) may be dealt with for sale in the future, similarly as the surplus property in WHP2 discussed in the meeting. It is also preferred to move all utilities off the property.

Regards

Jerry Zhu, P.Eng.

Transportation Engineer
Stantec
Phone: (905) 944-7777 ext 6861
Cell: (647) 402-1255
Fax: (905) 474-9889

Appendix 2

Distribution System Plan



OAKVILLE HYDRO
ELECTRICITY
DISTRIBUTION

Distribution System Plan

September 13, 2013

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Distribution System Plan

On March 28, 2013 the Board issued Chapter 5 of the Board's Filing Requirements for Electricity Transmission and Distribution Applications, entitled *Consolidated Distribution System Plan Filing Requirements* ("DS Plan Filing Requirements"). The filing requirements provide a standard approach to a distributor's filing of asset management and capital expenditure plan information in support of a rate application. Oakville Hydro's Distribution System Plan ("DS Plan") has been prepared in accordance with the DS Plan Filing Requirements. Oakville Hydro has organized the required information using the section headings in the DS Plan Filing Requirements.

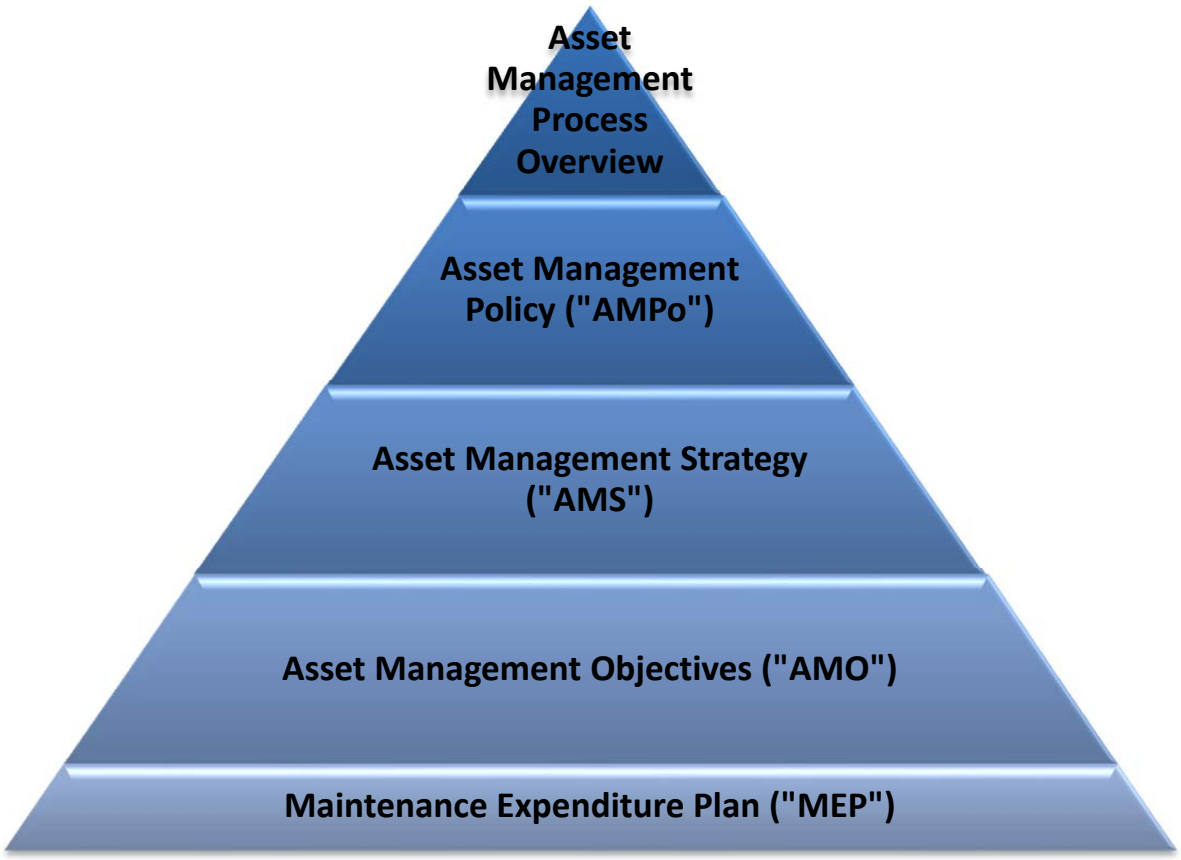
Oakville Hydro's DS Plan is an integrated document that supports the cost-effective planning and operation of the electricity distribution network – a network that is efficient, reliable, sustainable, and provides value for customers. The DS Plan documents the practices, policies and processes that are in-place to ensure that investment decisions support Oakville Hydro's desired outcomes in a cost effective manner and provides value to the customer. Oakville Hydro is committed to adhering to its DS Plan in order to provide the valued outcomes to the customer. Electricity distributors are capital intensive in nature and prudent capital investments and maintenance plans are essential to ensure the sustainability of the distribution network.

Distribution System Plan Overview

Asset Management Process

Oakville Hydro has enhanced its Asset Management process since its last cost of service application. In 2010 Oakville Hydro created and filled a new position – Supervisor, Asset Management. This position is dedicated to managing distribution assets and the associated asset management process and is responsible for assessing the need for capital asset replacements as well as formalizing asset maintenance activities to optimize the life of the assets. In 2012 Oakville Hydro began implementation of an Asset Management Process ("AMP"). Oakville

Hydro's Board of Directors has reviewed the Asset Management Strategy. The AMP consists of the documents listed below which are provided as appendices to the DS Plan in Appendix 1 of the DS Plan.



In 2012, Oakville Hydro began implementation of an Asset Management system to provide the tools necessary to execute its Asset Management process. One component of the Asset Management system, the Computerized Maintenance Management System ("CMMS"), contains a record of all patrols and maintenance activities performed on all assets. The CMMS enables Oakville Hydro to optimize the tracking of equipment, scheduling of patrols, the performance of maintenance and the timing of capital replacements. The CMMS is currently being populated with the specific asset information for all of Oakville Hydro's major distribution assets. In 2014, existing condition assessments will be migrated into the CMMS from the current Microsoft Access Database and by 2015 field staff will enter condition assessment information directly into

this CMMS.

As detailed in the section on the 20-Year Capital Asset View of Appendix 1.3, Asset Management Objectives document to the DS Plan, Oakville Hydro has prepared a capital expenditure forecast for 20 years. The 20-year plan is intended to provide directional information on forecasted capital expenditures as conditions will change with a planning period of this length. However, in accordance with the DS Plan Filing Requirements, Oakville Hydro's DS Plan covers the most recent five year historical period and the forecast for the next five years. A five year planning horizon provides a more reasonable assessment of the level of capital investment required.

Prospective Business Conditions

Oakville Hydro's residential customer base, which represents approximately 90% of its total customer base, continues to grow at a modest pace. The *Best Planning Estimates of Population, Occupied Dwelling Units and Employment, 2011-2031* published by the Region of Halton in June 2011 forecast that the population in Oakville Hydro's service will increase by approximately 35% from 2011 to 2031 with the majority of the growth expected to occur in greenfields. However, actual growth has been slower than forecasted in and Oakville Hydro anticipates growth of approximately one to two per cent per year over the five-year planning horizon with the majority of the growth occurring in greenfield areas not currently connected to Oakville Hydro's distribution system.

Oakville Hydro has been proactive in planning for this growth. In 2011 Oakville Hydro designed and constructed the Glenorchy Municipal Transformer Station to address the capacity constraints and provide for future growth. In August 2013, Milton Hydro connected to Oakville Hydro's distribution system at the Glenorchy Municipal Transformer Station and became an embedded distributor. The addition of Milton Hydro, as an embedded distributor, will benefit Oakville Hydro's customer base by allowing Oakville Hydro to recover a portion of the costs associated with the Glenorchy Municipal Transformer Station.

While the residential customer base is growing, Oakville Hydro's commercial and industrial customer base continues to remain relatively stable. Growth in the industrial and manufacturing industries has not fully recovered from the economic recession. This is evidenced by the announcement published in June 2013 by the Ford Motor Company, a wholesale market participant (that is connected to the grid and is not one of Oakville Hydro's customers) that its contract with a manufacturer of auto parts with two plants in Oakville Hydro's service area will end. The manufacturer has announced that it will close in 2014, after only seven years of operation in the Town of Oakville. In addition, Kraft Canada has announced the closure of its Oakville plant in the third quarter of 2013. The Town of Oakville's Economic Development department dedicates resources to attracting industrial and commercial customers to the Town of Oakville (which it is hoped) will offset some of the impact of these losses. However, this is a difficult and long term process.

In December 2015 a new Regional hospital, currently under construction, is expected to open in the northern region of the Town of Oakville. Following the transfer of all patients and services to from the current hospital to the new site in December 2015, the current hospital will close. The Town of Oakville has undertaken a public consultation regarding the future use of the property as part of its ongoing planning. Oakville Hydro is currently providing service to the hospital during its construction and has included the costs associated with the construction of distribution assets to service their energy needs in its DS Plan.

Contingencies

There are a number of aspects of Oakville Hydro's DS Plan that are contingent upon the outcome of ongoing activities or future events. In preparing its DS Plan, Oakville Hydro has initiated consultation with neighbouring distributors and Hydro One, the lead transmitter serving Oakville Hydro. As discussed in the following section, Oakville Hydro requested a letter confirming the status of regional planning for the two Regional Planning areas of which Oakville Hydro is a member of (GTA West and Burlington to Nanticoke) and requesting a Regional Planning session with the appropriate resources. However, as noted by the Board in the proposed amendments to

the Transmission System Code (the "TSC") and the Distribution System Code (the "DSC") issued on May 17, 2013, it will take approximately four years to complete the transitional planning process. In the event that Oakville Hydro is required to make material investments as a result of the Regional Planning process, it will use the appropriate rate adjustment mechanism to seeking approval for the recovery of those costs.

As discussed in Appendix 1, of Oakville Hydro's 2014 Cost of Service Application, Oakville Hydro has had preliminary discussions with Enersource Inc. ("Enersource") regarding the elimination of load transfers, for approximately ten customers. The proposed solution to eliminate the load transfer is to have Oakville Hydro acquire the related assets from Enersource. Preliminary discussions have indicated that the investment will not be material and therefore Oakville Hydro has not included the costs associated with the acquisition in its 2014 DS Plan.

Coordinated Planning with Third Parties

On May 17, 2013 the Board provided notice of proposed amendments to the TSC and the DSC the purpose of which was to implement the Board's policies set out in its October 18, 2012 *Report of the Board – A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (the "RRFE Board Report"). The proposed amendments related to, among other things, the establishment of a process in order to move to a more structured approach to regional infrastructure planning.

As noted in the RRFE Board Report, regional planning is not a new concept in Ontario. Oakville Hydro has been working with Hydro One Networks Inc. ("Hydro One"), the Ontario Power Authority ("OPA"), the Independent Electricity Systems Operator ("IESO"), and its neighbouring electricity distributors for a number of years. Oakville Hydro was invited to attend a regional planning session with Hydro One, the OPA and the IESO on May 17, 2012 to discuss a number of regional issues including the load forecast for Oakville Hydro's service territory, the West GTA Planning Region, load restoration and the regional planning process.

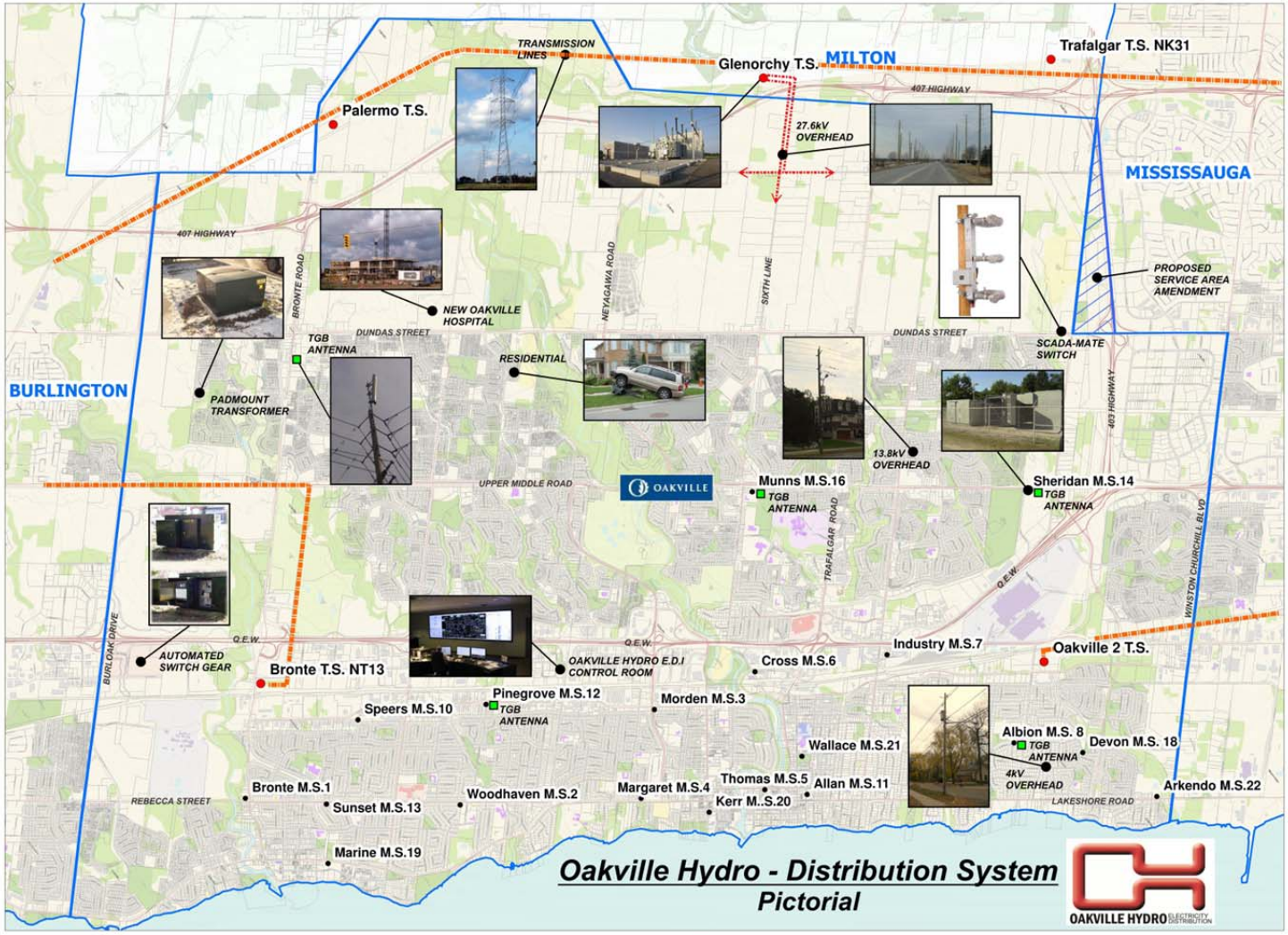
At that time, there were two capacity constraints identified that could be relieved temporarily

through load transfers. The Richview to Manby/Cooksville 230 kV system was approaching capacity limits and the IESO and Hydro One suggested that the transfer of load from the Oakville Transformer Station to other Transformer Stations supplying Oakville Hydro could relieve the capacity constraints until such time as the IESO and Hydro One could implement a solution. The second opportunity related to the Cooksville/Oakville 230 kV line section of line which was an area requiring assessment. Oakville Hydro indicated that it had load transfer capability of about 10-15 MW through remotely-operated sectionalizing of load from Oakville Transformer Station to Trafalgar Transformer Station and Bronte Transformer Station that could be used to relieve capacity constraints.

In discussions regarding the RRFE Board Report, the OPA identified that the West GTA Planning area was likely a candidate for regional planning for a number of reasons including increasing west to east flows caused by changing supply mix, e.g. renewable resource penetration in southwestern Ontario, increased local load growth in Mississauga, Oakville, Milton, Halton Hills, and Brampton and the retirement and refurbishment of nuclear resources at Pickering and Darlington. A number of potential changes were discussed including increased transformation capacity, relief of Trafalgar to Richview 230 kV circuit loading through reconfiguration of the 230 kV system, and load restoration for the Cooksville to Oakville line section.

In addition to the Regional Planning Process, Oakville Hydro frequently works with Hydro One to manage capacity constraints on an informal and as-needed basis. Oakville Hydro is unique in that it is fed by three separate transmission supplies and Oakville Hydro is often called upon by Hydro One to perform short-term load transfers around its distribution system to alleviate capacity constraints within the region. Oakville Hydro has designed its system to accommodate these requests. A map illustrating Oakville Hydro's Service Area and the location of its Municipal Stations is provided below.

Oakville Hydro's Service Area



Oakville Hydro has also worked closely with neighbouring distributors, where possible, to facilitate regional planning. In 2003, Oakville Hydro entered into a connection agreement with Burlington Hydro to provide and maintain two electricity distribution lines from Hydro One's transformer station located at Bronte Road and Wyecroft Road in Oakville to the Burlington Hydro switches located at Burloak Drive to connect the Burlington distribution system to the Oakville distribution system which would allow Burlington to receive electricity from the feeder lines.

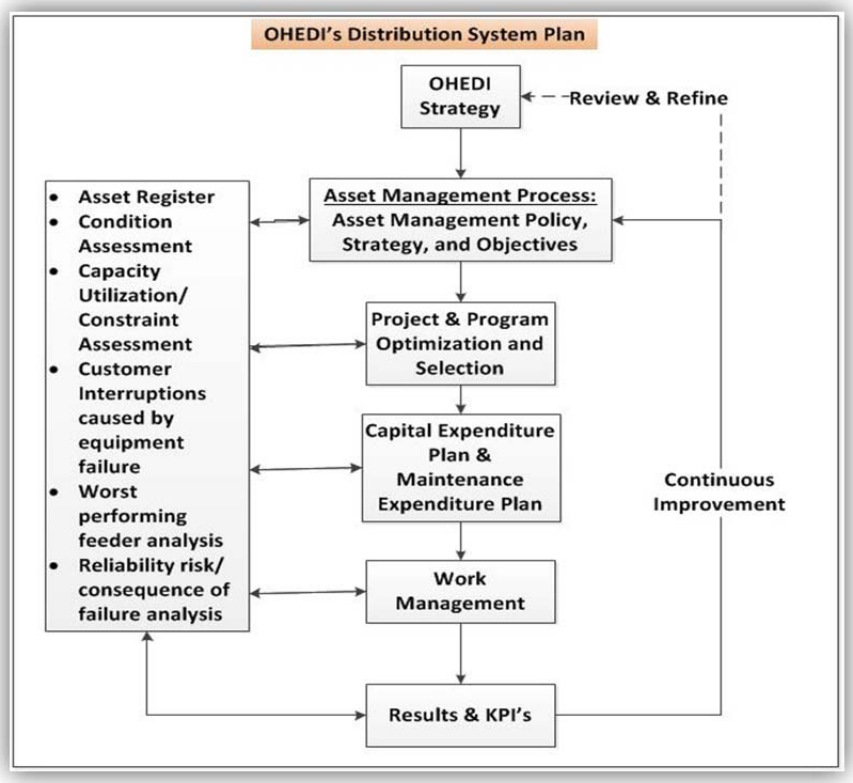
More recently, Oakville Hydro has entered into a 10-year connection agreement with Milton Hydro Electricity Distribution Inc. to provide two feeder positions at Glenorchy Municipal Transformer Station located at 4322 Sixth Line in the Town of Milton, Ontario, to serve a portion of Milton Hydro's service area as this area continues to grow at a fast pace.

As discussed previously, Oakville Hydro sent a letter to the lead transmitter in Oakville Hydro's planning regions, Hydro One, requesting that Hydro One provide Oakville Hydro with a letter confirming the status of regional planning for the two Regional Planning areas of which Oakville Hydro is a member, GTA West and Burlington to Nanticoke, and requesting a Regional Planning session with the appropriate resources. A copy of that letter is provided as Appendix 2 to the DS Plan.

Hydro One provided an update on the status of Regional Planning on September 5, 2013. A copy of that document is provided as Appendix 3 to the DS Plan. In its letter, Hydro One confirmed that the Regional Planning Process has not been initiated and a Regional Infrastructure Plan has not been developed within the GTA West region or the Burlington to Nanticoke Region. Hydro One expects that regional planning will be initiated in the fourth quarter of 2013. Hydro One and Oakville Hydro have begun discussions regarding Hydro One's preliminary information requirements to initiate the regional planning consultation for the two planning regions. However, based on the information received from Hydro One, Oakville Hydro is unable to assess whether the regional planning consultation will affect the DS Plan.

Performance Measurement for Continuous Improvement

As illustrated in Appendix 1.2, Asset Management Strategy and reproduced below, Oakville Hydro has implemented a process for the continuous review and refinement of its Asset Management Process through Key Performance Indicators ("KPI's) such as the evaluation of asset condition, capacity utilization, performance measures, worst performing circuits and risk consequence failure analysis. In addition to customer-oriented reliability measures, Oakville Hydro continuously monitors the cost efficiency and effectiveness of its performance against the DS Plan to ensure that capital spending is in accordance with this DS Plan and that innovative measures are taken where necessary to control costs.

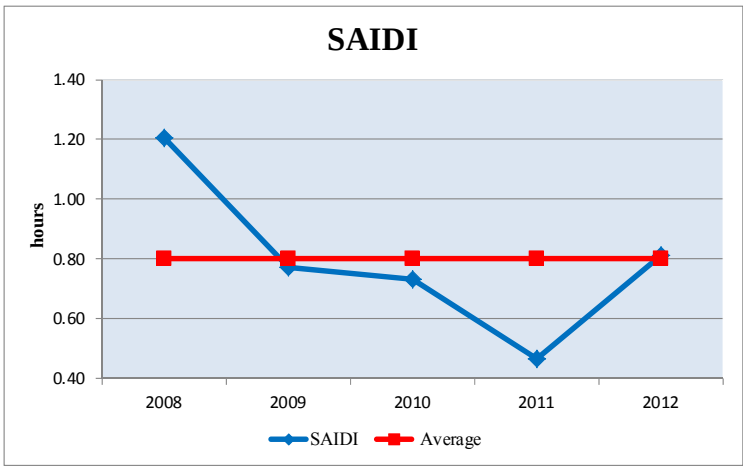


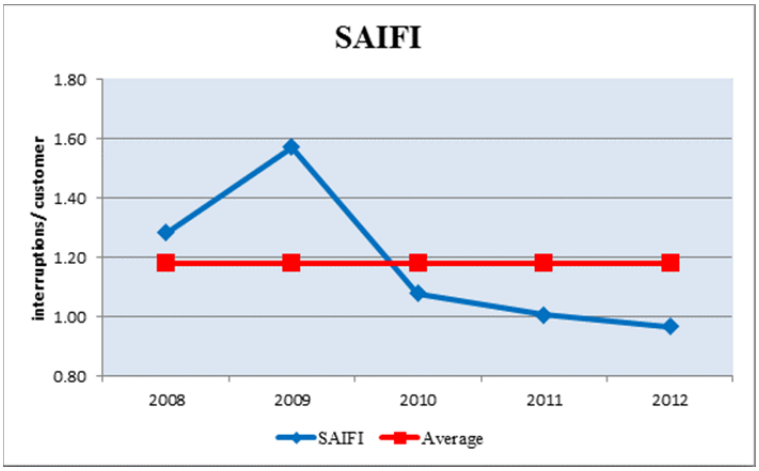
Performance Trends - Service Quality and Reliability

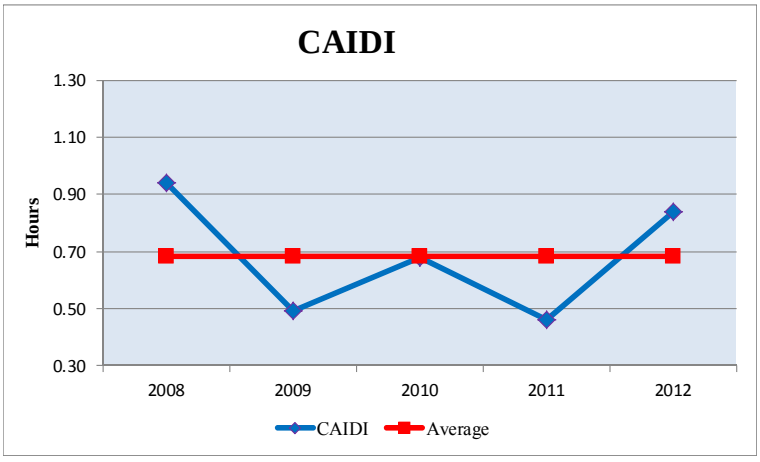
Oakville Hydro tracks service reliability statistics such as, System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI"), including and excluding loss of supply-related incidents, and reports these to the Ontario Energy Board on an annual basis. These measures form part of Oakville Hydro's corporate performance measures which are reported to Oakville Hydro's Board of Directors. Oakville Hydro's performance is within Oakville Hydro's range of performance which Oakville Hydro has defined as the average over the previous five years. Table 1 – Service Reliability Statistics, summarizes the service reliability indicators (SAIDI, SAIFI, CAIDI) for the five historical years. The graphs on the following page illustrate Oakville Hydro's performance as compared to the five year average. Oakville Hydro has provided reliable service to its customers over the five year historical period and is dedicated to continue providing this level of service to its customers over the planning horizon.

Table 1 - Service Reliability Statistics

Year	SAIDI	SAIFI	CAIDI
	hours	interruptions/ customer	hours
Including Loss of Supply			
2008	1.54	1.60	0.96
2009	0.77	1.57	0.49
2010	0.74	1.15	0.65
2011	0.47	1.04	0.45
2012	0.81	0.97	0.84
5 Years Rolling Average	**0.87**	**1.27**	**0.68**
Excluding Loss of Supply			
2008	1.21	1.28	0.94
2009	0.77	1.57	0.49
2010	0.73	1.08	0.68
2011	0.46	1.01	0.46
2012	0.81	0.97	0.84
5 Year Rolling Average	**0.80**	**1.18**	**0.68**


SAIDI
1.40
1.20
1.00
0.80
0.60
0.40
hours
2008
2009
2010
2011
2012
SAIDI
Average


SAIFI
1.80
1.60
1.40
1.20
1.00
0.80
interruptions/customer
2008
2009
2010
2011
2012
SAIFI
Average


CAIDI
1.30
1.10
0.90
0.70
0.50
0.30
Hours
2008
2009
2010
2011
2012
CAIDI
Average

Asset Management Process

Asset Management Process Overview

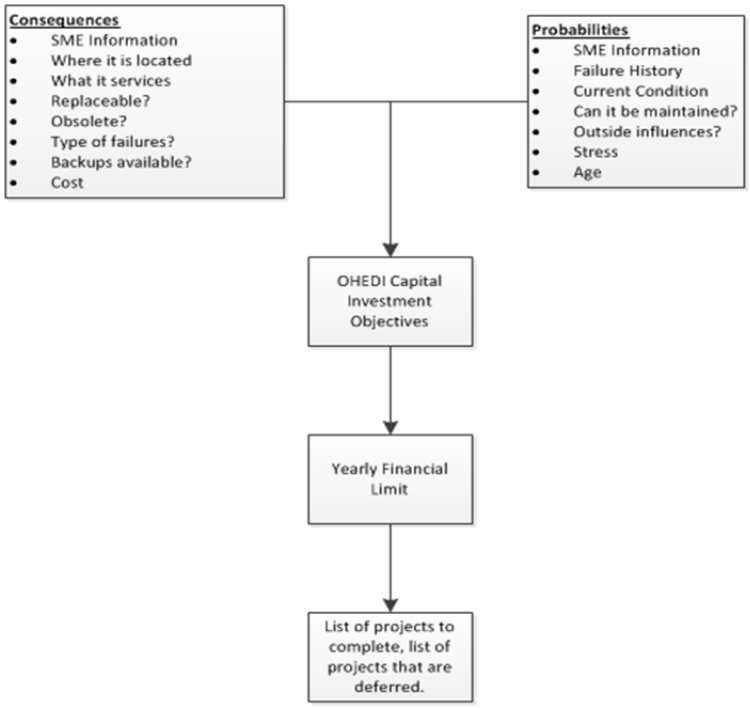
Oakville Hydro's has adopted a renewed approach to distribution system planning to formalize the management of distribution assets. Oakville Hydro's Asset Management process incorporates relevant strategies associated with integrated capital investment, asset maintenance and asset retirement. The objectives are derived from, and are consistent with, the goals of Oakville Hydro's corporate goals and strategic imperatives.

As detailed in the Major Distribution Asset Replacement section of Appendix 1.2 Asset Management Strategy, Oakville Hydro uses a number of components to prepare its capital expenditure plan. These components are listed below.

- Asset Management Components (inputs/outputs):
- Asset Register
- Condition Assessments & Recommendations
- Asset Capacity Utilization/Constraint Assessment
- Reliability-Based 'Worst Performing Feeder" Information and Analysis SAIDI, CAIDI, and SAIFI metrics.
- Interviews with Subject Matter Experts ("SME's")
- Optimization of Project Portfolios
- Typical Useful Lives

The following diagram illustrates the information primary process steps, and information flows used by the Oakville Hydro to identify, select and prioritize investments.

Selection and Prioritization Process



Overview of Assets Managed

As detailed in Oakville Hydro's Asset Management Process Overview document as found in Appendix 1, Oakville Hydro distributes electricity to more than 65,000 customers within its service area through a network of remotely switched power lines of approximately 1,400 circuit km, 55% of the system underground and 45% overhead. Oakville Hydro's distribution system is supplied from four Hydro One owned transformer stations and one Oakville Hydro owned Municipal Transformer Station. The service area is approximately 143 square kilometers and is primarily urban. Oakville is considered in the "Dfb" or "Warm Summer Continental" climate of the Köppen climate classification. Extreme minimum temperature recorded at -30°C and extreme maximum temperature recorded at 38°C with average temperatures ranging between -4.9°C and 20.7°C. Seasonal precipitation ranges between 44.2mm to 78.5mm.

Asset Information and Vintage of Information

Information regarding Oakville Hydro's assets by asset type, including the quantity and years in service is found in Oakville Hydro's Appendix 1.2, Asset Management Strategy of the DS Plan in the section entitled Major Distribution Assets and reproduced below. This data was compiled in September, 2012 and is summarized below.

Low Voltage Station Switches (4.16 & 13.8kV)



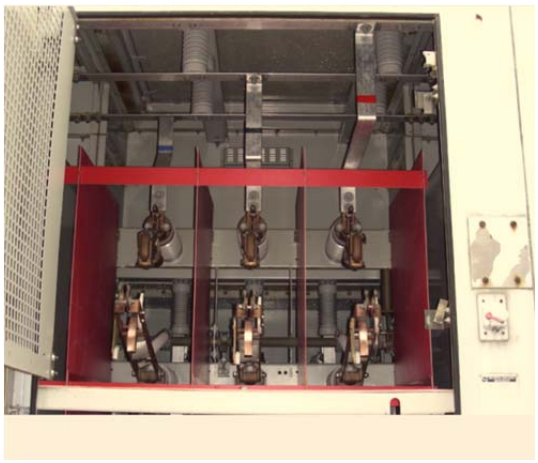
Quantity:	20
Average Age:	2.4 Year(s)
Range:	2-3 Year(s)
Strategy:	Proactive

Low Voltage Switch Breakers (4.16 & 13.8kV)



Quantity:	87
Average Age:	26.2 Year(s)
Range:	1-43 Year(s)
Strategy:	Proactive

High Voltage Station Switches (2.7kV Open Air)



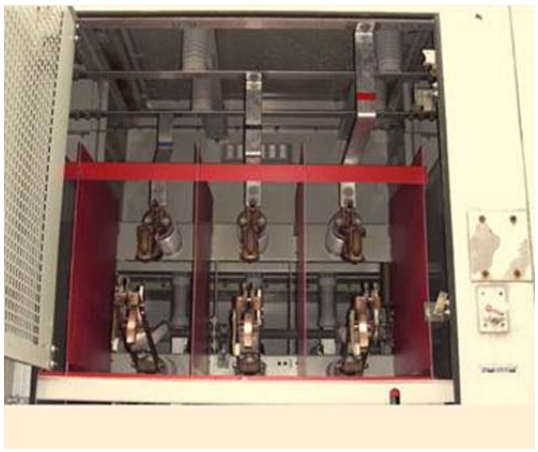
Quantity:	38
Average Age:	35.5 Year(s)
Range:	1-55 Year(s)
Strategy:	Proactive

High Voltage Station Switches (27.6kV GIS)



Quantity:	46
Average Age:	1 Year(s)
Range:	1 Year(s)
Strategy:	Proactive

High Voltage Station Breakers (27.6kV)



Quantity:	21
Average Age:	1 Year(s)
Range:	1 Year(s)
Strategy:	Proactive

High Voltage Station Switches (230kV)



Quantity:	2
Average Age:	1 Year(s)
Range:	1 Year(s)
Strategy:	Proactive

Overhead Distribution Transformer



Quantity:	1812
Average Age:	25.9 Year(s)
Range:	1-72 Year(s)
Strategy:	Run-to Failure

Padmount Distribution Transformer



Quantity:	4857
Average Age:	16.8 Year(s)
Range:	1-49 Year(s)
Strategy:	Run-to Failure

Submersible Distribution Transformer



Quantity:	1235
Average Age:	18.1 Year(s)
Range:	1-46 Year(s)
Strategy:	Run-to Failure

Vault-style Distribution Transformer



Quantity:	223
Average Age:	38.5 Year(s)
Range:	13-63 Year(s)
Strategy:	Proactive

Padmount Switchgear



Quantity:	170
Average Age:	23 Year(s)
Range:	1-42 Year(s)
Strategy:	Proactive

Vault-style Switchgear



Quantity:	11
Average Age:	12 Year(s)
Range:	6-42 Year(s)
Strategy:	Proactive

Overhead Gang-Operated Switch



Quantity:	123
Average Age:	28 Year(s)
Range:	1-31 Year(s)
Strategy:	Proactive

Overhead Primary Wire Circuit Kilometers



Quantity:	561
Average Age:	28 Year(s)
Range:	1-71 Year(s)
Strategy:	Run-to Failure

Underground Primary Wire Circuit Kilometers



Quantity:	894
Average Age:	22 Year(s)
Range:	1-43 Year(s)
Strategy:	Proactive

Poles – Mostly Wood



Quantity:	8004
Average Age:	25 Year(s)
Range:	1-71 Year(s)
Strategy:	Proactive

Secondary Cable Kilometers



Quantity:	1067
Average Age:	22 Year(s)
Range:	1-71 Year(s)
Strategy:	Run-to Failure

Meters



Quantity:	64,652
Average Age:	1.6 Year(s)
Range:	1-30 Year(s)
Strategy:	Proactive

Primary Meters



Quantity:	44
Average Age:	20 Year(s)
Range:	1-42 Year(s)
Strategy:	Run-to Failure

Remote Terminal Units (RTUs)



Quantity:	116
Average Age:	10 Year(s)
Range:	1-20 Year(s)
Strategy:	Proactive

Asset Capacity Utilization

As discussed in Oakville Hydro's Asset Management Objectives, Oakville Hydro reviews capacity utilization at the transformer station connection points (at 27.6 kV) and at the 27.6 kV feeder level, on an individual feeder basis annually. The review is normally done at the time of the annual system peak, to most accurately determine the system capacity utilization. The System Control and Data Acquisition ("SCADA") System is used to monitor feeder loads and assists in the capacity utilization review. For new developments in North Oakville, at present, the assessment is very straightforward due to the recent addition of the Oakville Hydro's Glenorchy Municipal Transformer Station and associated new 27.6kV feeders. At present there is available capacity for new loads in this area. For new load additions in established areas, capacity utilization and constraint assessment is done on a project by project basis to determine if upgrades or load transfers to other feeders are necessary.

Asset Lifestyle Optimization Policies and Practices

In managing its assets, Oakville Hydro applies sound technical, social, financial and economic principles that consider present and future needs. Oakville Hydro's asset management policies and practices are provided in Appendix 1.1, Asset Management Policy and reproduced below.

To guide Oakville Hydro the following policy statements have been developed:

a) Oakville Hydro will continuously refine its asset management program to meet system capacity, reliability, security and operating requirements while ensuring long term affordability and responsible stewardship of the distribution system.
b) Oakville Hydro will continue to meet and maintain regulatory and service requirements, employing good utility practices, while balancing between customer expectations and lifecycle costs.

c) Oakville Hydro will maintain compliance to health and safety policies, environmental

regulations, and electricity rates and filing requirements.

d) Oakville Hydro will optimize capital and maintenance costs throughout the lifecycle of the asset, and corporate value will be enhanced through timely asset renewal.
e) Oakville Hydro will drive asset investment decisions through condition-based system analysis with a goal to extend asset useful life, as appropriate.
f) Oakville Hydro will incorporate the requirements for system growth and asset replacement or renewal decisions as noted in Oakville Hydro's Smart Grid Strategy and Ontario's Green Energy Act.
g) Oakville Hydro will incorporate the elements of the Asset Management Strategy in long term distribution system planning.
h) Oakville Hydro will continually assess evolving technologies for consideration and potential application.

Asset Maintenance Strategy

As detailed in Appendix 1.2, Asset Management Strategy, Oakville Hydro utilizes a combination of patrols and maintenance activities to complete inspection requirements, and records information regarding the condition of distribution assets. A minimum of one-third of each major asset is either patrolled or has maintenance performed each year in order to ensure all assets are inspected a minimum of once every three years. During the patrol, minor maintenance or critical items, that may be immediately addressed, are resolved and reported. Major maintenance that requires more complex coordination is subsequently scheduled for completion within the year, or planned for future years.

Oakville Hydro analyzes the information gathered during the inspection and maintenance routines, as part of condition-based asset assessments. Decisions to replace assets versus proceeding with ongoing maintenance to extend the life of the asset are determined based on a business case assessment.

Asset Life Cycle Risk Management Policies and Practices

Investment Objectives

As detailed in Appendix 1.2, Asset Management Strategy, the optimization of future programs and project portfolios allows Oakville Hydro to ensure that future expenditures will be applied effectively to the appropriate areas of the system to mitigate risk to Oakville Hydro Capital Investment Objectives described below. The risk is assessed by considering probability and consequence to these Objectives if a project or a program is not completed.

Financial

- When assessing the impact on the financial value, Oakville Hydro must consider the mitigation of maintenance expenditures, mitigation of lost revenue due to decreasing reliability, and mitigation of future capital expenditures, through the completion of the proposed projects and programs package, replacement of ageing assets, and maintenance practices. Oakville Hydro's goal is to reduce costs associated with maintaining aging equipment and to mitigate, to the extent possible, future lost revenue due to lower reliability.

Service Quality

- When assessing risk to the SAIFI and SAIDI measures, Oakville Hydro considers the impact on SAIFI and SAIDI through completion of the proposed projects and programs-package, replacement of ageing assets, and maintenance practices. The Service Quality risk is measured by the number of customers that will be without power due to failure of the assets included within the proposed projects and programs package, and its measures are the types of customers affected, number of feeders affected and improvements in SAIFI and SAIDI. Oakville Hydro's goal is to establish a downward trend in SAIFI and SAIDI.

Socio-Political

- When assessing the impact to the community image value, Oakville Hydro considers customer satisfaction as measured by the number of written or verbal complaints received. The risk is also measured by the complaint escalation level, ranging from Individual concerns made to the company to General public outcry – national media coverage. Oakville Hydro's goal is to reduce customer concerns and media focus, and minimizing complaints escalation.

Legal

- When assessing legal risk Oakville Hydro assess the cost and number of potential litigations brought against Oakville Hydro to minimize legal fees associated with capital projects, e.g. acquiring easement rights. Oakville Hydro's goal is to reduce litigation costs, and minimize, to the extent possible, legal costs.

Regulatory

- The regulatory risk is measured by severity of possible non-compliance that could occur due to assets within the proposed projects and programs package. Oakville Hydro's goal is to reduce regulatory compliance issues, and mitigate potential future regulatory non-compliance situations.

Safety

- This value deals with ensuring that both Oakville Hydro's employees work in a safe environment and that potential known public safety hazards are eliminated or minimized to the extent possible. Oakville Hydro's goal is the reduction in existing employee and public safety issues, and mitigation of exposure to potential safety hazards.

Environmental

- Environmental risk is measured by the potential severity of environmental issues due to the assets within the proposed projects and programs package, ranging from minor disturbance, documentation not necessary to disturbance requiring Ministry of Environment assistance and public evacuation. Oakville Hydro's goal is to reduce existing environmental incidents and mitigate.

In order to provide value added risk disciplined decision making Oakville Hydro has assigned weightings to the above noted Capital Investment Objectives. The weightings ensure that capital investments are prioritized appropriately to mitigate the highest risks. The following figure shows the weighting of each of the objectives.



Capital Expenditure Plan

Summary

In managing its distribution system assets, Oakville Hydro's main objective is to optimize the performance of its assets at a reasonable cost, with due regard for customer service expectations, system reliability and public and employee safety. This application provides detailed information on Oakville Hydro's Capital Expenditure Plan for the 2014 Test Year and high level information on capital expenditures for the forecast period 2015 to 2018. These capital expenditures are summarized in Table 2, Capital Expenditure Plan. In accordance with the DS Plan Filing Requirements, Oakville Hydro has categorized its forecasted capital expenditures using the Board's investment categories.

Table 2, Capital Expenditure Plan

CATEGORY	2014	2015	2016	2017	2018
System Access	$ 2,322	$ 2,130	$ 2,448	$ 2,497	$ 2,639
System Renewal	5,980	5,436	5,505	5,599	5,599
System Service	5,589	559	581	605	629
General Plant	2,717	2,126	2,866	2,052	2,063
TOTAL EXPENDITURE	$ 16,607	$ 10,251	$ 11,401	$ 10,752	$ 10,931

As discussed previously and as detailed in Appendix 1.3 - Asset Management Objectives, Oakville Hydro optimizes future capital expenditures through an objective weighting analysis to ensure that expenditures are applied effectively to the appropriate areas of the distribution system to mitigate risk. In addition, Oakville Hydro is conscious of the impact of its capital spending plans on the affordability of electricity for its customers.

Ability to Connect New Load

The population in Oakville Hydro's service area is forecasted to increase by approximately 35% from 2011 to 2031 with the majority of the growth expected to occur in greenfield development areas. While growth has been slower than forecasted in the Best Planning Estimates of Population, Occupied Dwelling Units and Employment, 2011-2031 published by the Region of Halton in June 2011, Oakville Hydro anticipates growth of approximately 1% to 2% per year for over the planning horizon years with the majority of the growth occurring in greenfield areas not currently connected to Oakville Hydro's distribution system.

As detailed in Oakville Hydro's Renewable Energy Generation Investment Plan, provided as Appendix 4, there has been limited interest in FIT and microFIT generation projects in Oakville Hydro's service area and no renewable energy generation investments have been included in Oakville Hydro's DS Plan for the 2014 Test Year. However, industry requirements, policies and initiatives may change in the future and these changes may impact Oakville Hydro's plans involving the connection of renewable generation in the future.

Capital Asset Categories

Oakville Hydro's assets are traditionally divided into three categories; distribution plant, general plant and other capital assets. Distribution plant includes assets such as high voltage transformation, Municipal Transformer Station and substation buildings, poles, conductors, overhead and underground electricity distribution infrastructure, transformers, meters and substation equipment. General plant includes assets such as office building, office furniture, transportation equipment; information technology, computer equipment and software, general equipment, and tools. Other Plant includes capital leases. In accordance with the DS Plan Filing Requirements, Oakville Hydro has grouped its capital expenditures into the four investment categories defined in Table 1 of the DS Plan Filing Requirements.

System Access

System access investments are modifications to a distribution system that a distributor is obligated to perform to provide customers with access to electricity services via the distribution system.

Investments in this category are driven by statutory, regulatory or other obligations on the part of the distributor to provide customers with access to their distribution system. Most frequently, investments relate to request by customers for connections or connection modifications, but also include requests from municipal authorities for a distributor to relocate system assets in order to accommodate infrastructure development or modifications. Consequently, investment budgets for this category can vary from one DS Plan to the next depending on business conditions. Historically, Oakville Hydro has had to make investments in this category, primarily as part of road widening projects, as the infrastructure in the Town of Oakville and Halton Region is being improved.

In the event that the project involves replacing a distribution system assets, there may also be asset life-cycle-related considerations to the extent that infrastructure is taken out of service prior to the end of its service life and new infrastructure is commissioned.

Investments in this category are considered mandatory and allocation of the associated capital expenditure is non-discretionary. Consequently, the level of capital spending in this category directly impacts the level of spending in the other three investment categories.

System Renewal Investments

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with reliable electricity services.

Investments in this category are driven by the relationship between the ability of an asset or asset

system to continue to perform at an acceptable standard on a predictable basis and the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure"). Generally, the higher the risk of failure, the more important it becomes to replace or refurbish the asset(s).

A distributor's discretion over the timing and priority of projects in this category may lessen over time, such as where assets with high consequence of failure are consistently operating outside applicable operating limits. On the other hand, a distributor may have considerable discretion over timing and priority, where deteriorating asset condition has little or no impact on performance, and the consequences in terms of the number of customers and criticality of service potentially affected by an asset failure are relatively low.

Investments in this category are considered non-mandatory. Therefore, allocation of capital investments is optimized based upon risk and value. Investments are optimized against other investments within this category and in the System Service category. Investments are assessed by weighing the probability of failure against the consequences, considering both risk and value and Oakville Hydro's Capital Investment Objectives.

System Service Investments

System service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements. Like the System Renewal Investments, the allocation of the capital budget to this investment category is dependent upon the strategic objective weighting assigned to the individual projects or programs in this category.

Investments in this category are driven by the distributor's expectations that evolving customer use of the system may create system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor's service delivery standards or objectives. Distributor discretion in relation to investments in this category can be relatively high in terms of

both initiating a project and determining the priority and timing of project-related expenditures.

Investments in this category are considered discretionary. Therefore, the allocation of capital to investments within this category is required to be optimized based upon risk and value. Investments are assessed by weighing the probability of failure against the consequences, considering both risk and value and Oakville Hydro's Capital Investment Objectives.

General Plant Investments

General plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system including land and buildings, tools and fleet equipment, rolling stock and electronic devices and software used to support day to day business operations and improve the level of customer satisfaction.

Distributor discretion in relation to investments in this category can be relatively high in terms of both initiating a project and determining the priority and timing of project-related expenditures. Oakville Hydro's Information Technology Strategic Plan supports Oakville Hydro's strategic imperatives. A copy of Oakville Hydro's Information Technology Strategic Plan is provided as Appendix 6. Oakville Hydro's follows a very diligent process for assessing the need for capital investments in this category and looks for innovative ways to maintain its business and operational activities to provide its customers with a level of service that meets their expectations.

Investments in this category are considered non-mandatory. Therefore allocation of capital to investments within this category is required to be optimized based upon risk and value.

Material Capital Expenditures

A list of material capital expenditures by category, including a brief description of the projects and the total capital expenditures, for the 2014 Test Year are provided in Table 3, Material Capital Expenditures. The Regional Planning Process and the connection of Renewable

Generation have not had a material impact on Oakville Hydro's DS Plan for the 2014 Test Year.

Table 3, Material Capital Expenditures

Major Projects	2014
27.6kV Additions	$420,973
Distribution Meters / Wholesale Meter Upgrades	481,706
New Development / Services	1,016,068
Road Widening (Dependent on Road Work - No Hydro Control)	403,115
System Access	**2,321,862**
Alterations and Improvements for Load Transfer and System Security	1,028,655
Rebuild Overhead Distribution System	1,118,877
Rebuild Underground Distribution System	2,017,232
Substations	1,016,763
Supervisory Control and Communications	231,887
Transformer Replacements and Voltage Conversion	566,332
System Renewal	**5,979,745**
Information Technology	452,000
Rebuild Overhead Distribution System	100,000
Supervisory Control and Communications	36,899
Emergency Back-up Transformer	5,000,000
System Service	**5,588,899**
Buildings	341,615
Information Technology	1,897,210
Major Tools and Safety Equipment	93,333
Transportation	384,762
General Plant	**2,716,920**
Grand Total	**$16,607,427**

Regional Planning Process

As discussed earlier, it will take approximately four years to complete the province-wide transition to the Regional Planning Process. Oakville Hydro is not currently aware of specific requirements for investments related to regional planning, at this time, and has not included any investments related to regional planning in its DS Plan. However, the two regional planning groups that Oakville Hydro is a member of, have been identified as being a high priority for regional planning. Oakville Hydro has engaged Hydro One to enable it to gain insight on the current status of the Regional Planning Process as it applies to these two regional planning groups. In the event that Oakville Hydro is required to make material investments as a result of the regional planning process, it will use the appropriate rate adjustment mechanism to seek approval for the recovery of those costs.

As discussed previously, Hydro One provided an update on the status of Regional Planning on September 5, 2013. In its letter, Hydro One confirmed that the Regional Planning Process has not been initiated and a Regional Infrastructure Plan has not been developed within the GTA West region or the Burlington to Nanticoke Region. Hydro One expects that regional planning will be initiated in the fourth quarter of 2013.

Customer Engagement

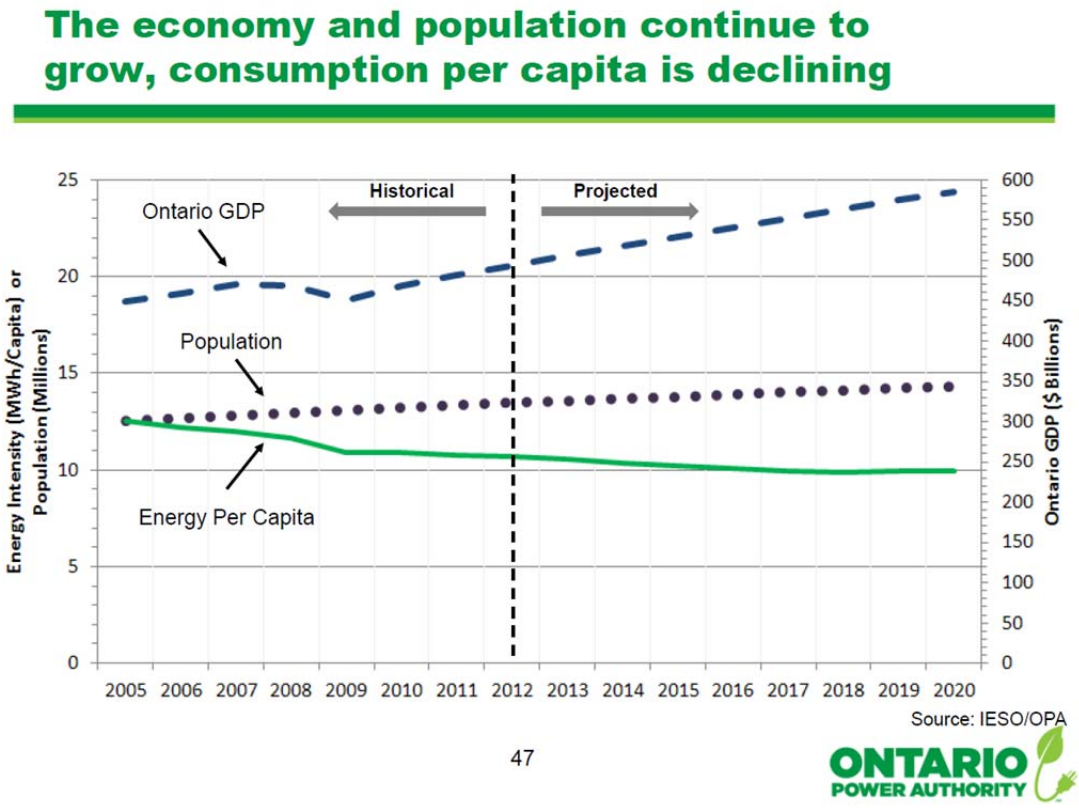
Oakville Hydro conducts a Residential customer satisfaction survey on an annual basis. As part of the customer satisfaction survey, Oakville Hydro asks its customers for their feedback on a number of areas including service reliability, outage management, electrical safety, value for money, cost effectiveness and affordability. In its 2013 customer satisfaction survey, Oakville Hydro's scores in these areas consistently met or exceeded both the Ontario average and the National average. Oakville Hydro's Capital Expenditure Plan balances the need to maintain a safe, reliable distribution system that is affordable to its customers while continuing to make investments to accommodate growth. Oakville Hydro's high scores in the areas of reliability and cost effectiveness are evidence of its ability to manage this balance. Oakville Hydro plans to

enhance its customer satisfaction surveys in the future to enable it to better understand the expectations of its Residential customers.

In addition, Oakville Hydro's Key Account Manager engages commercial customers through site visits and seminars to address customer concerns, provide information to enable customers to enable them to make informed energy decisions and to enable them to run their businesses in a more cost effective manner. In recent years, customer engagement has focused primarily on the achievement of energy efficiencies and reducing costs. Oakville Hydro plans to improve its relationships with commercial and industrial customers through its key account manager.

Development of the Distribution System

Oakville Hydro is forecasting modest growth in its Residential and Small Business customer base during the five-year planning horizon. However, Oakville Hydro, like other jurisdictions, is forecasting that despite the fact that the economy and population continue to grow, consumption per capita is declining and that load growth will be modest. The graph below, prepared by the Ontario Power Authority illustrates the upward trends in economic and population in Ontario and the contrasting downward trend in average energy consumption per capita.



Oakville Hydro's Smart Grid Strategy, as provided in Appendix 5, is to grow and develop Oakville Hydro's distribution grid using a combination of good utility distribution practice coupled with emerging technologies & systems. Oakville Hydro's long term strategy is to evolve its operating distribution system and associated Information Technology ("IT") systems capabilities to align with its three over-arching Smart Grid goals listed below. Oakville Hydro plans to leverage the capabilities of current system assets to enhance future capabilities. For example, Oakville Hydro assessed the costs and outcome value to its customers of the integration of smart meter data into its Outage Management System ("OMS"). In addition, it will continue to make prudent asset management decisions around replacing selected end-of-life equipment and supporting communication infrastructure, with choices that align with this evolving strategy. Oakville Hydro will ensure that all Smart Grid projects align with Oakville Hydro's Investment Objectives, by integrating them into the capital project portfolio to be evaluated and prioritized

as set out in the Exhibit 1.2, Asset Management Strategy. Oakville Hydro's Smart Grid over-arching goals for the ten-year planning horizon are as follows:

Customer Control

a) Enhance customer experience associated with control of energy usage.
b) Increase visibility on system outages
c) Connect renewable generation as required and take advantage of plug-in and hybrid vehicles as choice of transportation

Power System Flexibility

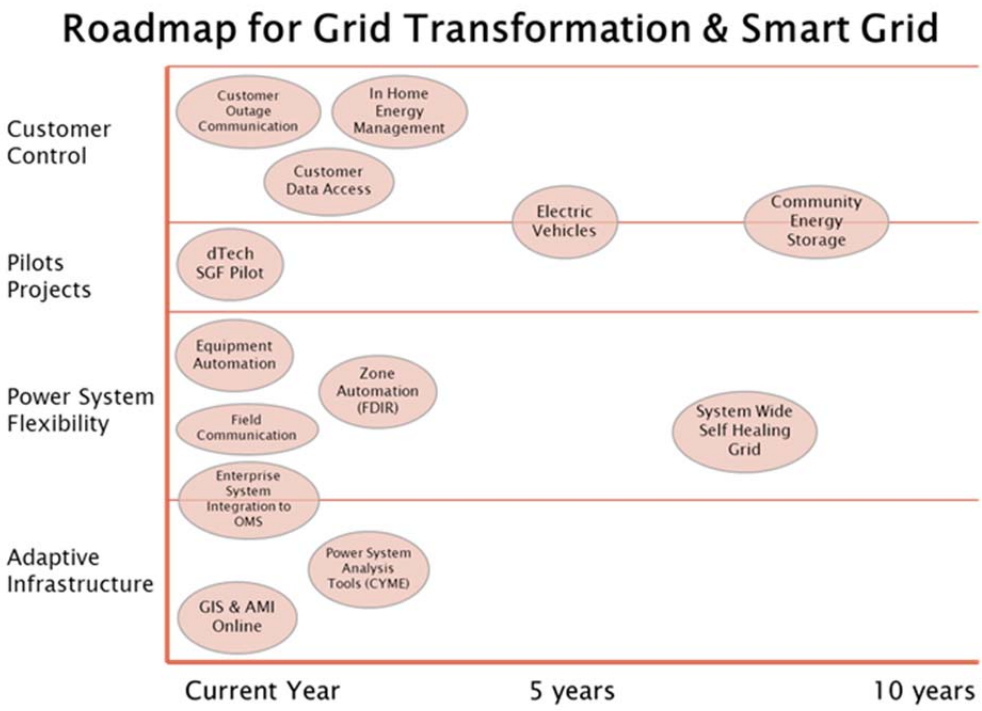
a) Improve distribution system reliability, performance and responsiveness
b) Equip the existing distribution system to enable two-way flow of electricity
c) Improve operating efficiencies through distribution automation, e-mobile capabilities and IT system integration (e.g. Advanced Metering Infrastructure, Geographical Information System, and Outage Management System)

Adaptive Infrastructure

a) Improve power quality and energy efficiency using advanced system tools and controls, to monitor and reduce distribution losses
b) Enhance asset efficiency through system monitoring to fully utilize and extend life of existing assets

Over the next five years, Oakville Hydro will continue to reinforce the foundations of its distribution system (e.g. switching, monitoring and communications infrastructure) and enhance and integrate its operating and information systems in order to achieve these goals. These changes will involve continued enhancements of current engineering and operations technology platforms as well as planned integration into a new Outage Management System currently under

development. A new level of sophisticated operational capabilities is evolving that will accept all forms of distributed generation and provide increased reliability through switching flexibility and automation of features such as self-healing distribution feeders. The following diagram provides more detailed near and long-term plans to operationalize this strategy.



The timing of Smart Grid investments will be, as mentioned, somewhat dependent on upgrades to Oakville Hydro's distribution system facilities through expansion or renewal. The rate of customers' adoption of renewable generation and consumer technologies will also have an impact on Oakville Hydro's anticipation of smart grid investments. The rate of customer adoption will depend on customer education and the perceived value of these smart grid technologies. The results of Oakville Hydro's 2013 customer satisfaction survey show that Oakville Hydro's customers have limited knowledge with respect to Smart Grid. Therefore, Oakville Hydro is in the process of developing communication materials for its customers on the Smart Grid and gathering information regarding their expectations for Smart Grid investments.

This will drive required customer focused investment.

Oakville Hydro is currently participating in an Ontario Smart Grid Fund, a program launched in 2011by the Ministry of Energy to support the growth and advancement of the province's electricity grid, demonstration pilot project in collaboration with a company by the name of dTechs. The dTechs MeterSuite is an advanced wireless metering system created to help distributors address grid management, line-loss reduction and power theft. The dTechs MeterSuite will find, immediately notify and direct Oakville Hydro to the location of atypical consumption. This includes power theft, unsafe high consumption and poor infrastructure areas (e.g. aged transformer equipment and poor distribution lines). This pilot project involved the deployment of 225 units in 2013 to cover 25% of Oakville Hydro's customer base.

Plug-in electric vehicles are starting to enter the market but adoption is slower than anticipated. These entrants, plus the potential for growth in electric public transportation, are expected to be longer term, but none-the-less, a significant aspect of evolving distribution systems. In 2013, Oakville Hydro partnered with Tim Hortons to install vehicle charging stations at two of its locations in the Town of Oakville. Oakville Hydro will continue to monitor the situation and work towards enabling their roll out through collaborative ventures. In the 2013 customer satisfaction survey, the number of customers that were "very interested" in purchasing an electric vehicle declined to 7% from 9% in 2012. This trend may change if oil prices become unstable and climb.

Automation and Innovation

Oakville Hydro has planned a number of projects in response to noted customer preferences, to take advantage of technology-based opportunities, improve operational efficiencies, improve asset management capabilities and study innovative processes, services business models or technologies. For those projects over Oakville Hydro's materiality level in the 2014 Test Year, additional information is provided in Appendix 7, Material Capital Project Templates.

Table 4, Automation and Innovation

Project Number	Project Name	Forecast ($)	Description
16-G2	27.6kV Air insulated switchgear upgrades	$379,340	Automated Restoration
16-U1	Gang-Operated Switch Replacement	$267,139	Remotely operated switches
14-61	Distribution Meters	$15,750	Data access - Zigbee Chips
14-64A1	Outage Management System Improvements	$300,000	Automated Restoration Capabilities
14-64A4	Power System analysis tool - CYME	$152,000	Load Management
14-64C1	Customer Communication improvements	$165,000	Customer Preference - Self Service Options
14-64D1	Microsoft Dynamic GP upgrade to GP2013	$123,000	Provides Asset Management Capabilities
14-64M1	Maximo Phase 3	$100,000	Asset Management

Capital Expenditure Planning Process Overview

Oakville Hydro's Asset Management process is the driver in determining Oakville Hydro's capital expenditures budget. The Asset Management process sets out processes for determining the necessary distribution system investments to ensure safe, reliable and cost-effective delivery of electricity to its customers. Oakville Hydro's Asset Management process accompanies this Exhibit as Appendix 1.

As discussed in the following section, System Capability Assessment for Renewable Energy Generation, Oakville Hydro has sufficient capacity to connect the forecasted future renewable generation projects. Therefore, Oakville Hydro's capital planning process does not currently include objectives for the connection of renewable generation facilities. Should there be a change to the forecast, Oakville Hydro will update its investment objectives and planning processes.

Although regional planning policies are currently not a formal part of Oakville Hydro's Asset Management Process, Oakville Hydro will re-evaluate and update its processes to include regional planning in the assessments of alternatives to relieving system capacity or operational constraints as Oakville Hydro's Regional Planning Process develops.

Oakville Hydro's Asset Management process identifies the capital expenditures required over a 20 year period based on its capital Investment Objectives discussed on page 30. Oakville Hydro's Capital Expenditure Plan identifies the capital projects required to meet the capital

Investment Objectives, showing the detailed current and following year projects, a high level cost for future years two to five, and statements identifying the direction from years six to twenty. The capital budget forecast for the 2013 Bridge Year and the 2014 Test Year is influenced by, among other factors, the highest priority capital requirements, notably - Oakville Hydro's capacity to finance capital projects and the impact on the cost to the customer. All proposed capital projects are assessed within the framework of their capital budget priority. A significant portion of Oakville Hydro's capital investments are customer or municipally driven and are outside of Oakville Hydro's control.

The capital budget is prepared annually by Management before the start of each fiscal year. It encompasses all capital requirements for the distribution system, substations, information technology hardware and software, vehicles and building costs.

Responsibilities

- The Finance department co-ordinates the development of the capital budget.
- Each department is responsible for preparing its respective capital budget; with the VP of Engineering and Operations and COO being responsible for the overall reasonableness of the capital budget expenditures.
- The President & CEO, COO and CFO review the capital budget in conjunction with the operating budget and identify any changes and challenge any alternatives. Once they are satisfied with the capital expenditures, they present and recommend the budget to the Audit and Finance Committee of the Board of Directors.
- The Finance and Audit Committee reviews the capital budget and may make recommendations to Management. Once the Finance and Audit Committee is in agreement, they make a recommendation to the Oakville Hydro Board for approval as part of the entire Business Plan.
- The Oakville Hydro Board of Directors has, on occasion, directed Management to revise a budget following consideration of year-end financial results or major changes in capital

project priorities.

- Each year, the COO, Vice President of Engineering and Operations is responsible for confirming in writing that the capital budget is prudent and satisfies the needs of the customers.
- The Finance Department monitors actual to planned spending on a monthly basis and reports to the Finance and Audit Committee on a quarterly basis.

The Budget is an important planning tool for Oakville Hydro. It puts capital and operational budgets into a common financial plan and allows for the evaluation of the total cost impact to the customer. The final document provides a comprehensive package of departmental budgets that collectively ensure that appropriate resources are designated for the various capital and operational needs of the utility for the coming year to meet customer expectations for service reliability and cost effectiveness.

Based on Oakville Hydro's distribution categories, below is a detailed description of the process followed in identifying capital expenditure needs.

Selection, Prioritization and Pacing of Projects

Distribution System Projects

In the initial phase of the capital budgeting process, Oakville Hydro's Engineering Department receives copies of all developer/site plan submissions from the Town of Oakville. Engineering is given the opportunity to comment on the submissions and determine how electrical demand will be met. Engineering also participates in the five-year plan review with the Town of Oakville, to keep abreast of future major developments.

In addition to incorporating development plans, input is received from internal Subject Matter Experts ("SMEs") incorporating risk areas in order to identify projects required to maintain the reliability and safety of the system. Condition assessments are also a criteria used to identify

future project requirements. Asset condition is assessed and documented noting any urgent issues. In some cases simple maintenance tasks cannot mitigate these issues, prompting the need for a capital replacement project. In these situations a project is initiated, designed, planned and estimated to remedy the outstanding issues.

Oakville Hydro implemented and uses an Optimizer Software package as a systematic tool to assist in the planning and evaluation of its multi-year project portfolio and create a prioritized list of projects that is used as the basis for the capital budget. The optimization of future project portfolios allows Oakville Hydro to ensure that future capital costs are systematically applied to the appropriate areas of the system to mitigate risk and improve value. Future projects are evaluated by considering both their risk and probability of failure if not completed, and their value if completed. More details are provided in the Asset Management Process, filed as Appendix 1 to the DS Plan.

Fleet

The Operations Department reviews the status of all vehicles and the annual maintenance and repair costs and recommends the timing for replacements. Oakville Hydro currently uses an outside consultant who in consultation with the Director of Distribution Operations, determines fleet requirements, obtains quotes and makes recommendations to the Director.

Other

Justification for all other capital projects is provided by the relevant department and approved by the appropriate level of management. Expenditures, where the cost of the individual item is greater than $1,000 are capitalized, and those less the $1,000 are expensed.

Customer Engagement

Over the past three years, Oakville Hydro has and engaged a third party to conduct customer satisfaction surveys. These customer satisfaction surveys provide information that supports

decisions surrounding the improvement of system reliability and customer service. The survey asks customers questions on a wide range of topics, including: overall satisfaction with Oakville Hydro, reliability, trust, customer service, outages, billing and corporate image. In addition, Oakville Hydro has a key account manager to maintain a close relationship with commercial and industrial customers to enable Oakville Hydro to understand the needs and expectations of this customer class.

Oakville Hydro involves customers in special projects where customer input, education and opinion is requested for valued consideration. For example, in 2010 Oakville Hydro held a public session inviting the public to become engaged in the proposal to build the Glenorchy Municipal Transformer Station required to service North Oakville.

Capital Budget Attestation

As part of the budget approval process, the COO, Vice President Engineering and Operations formally confirms that the Capital Investment Plan and associated Operations and Maintenance Programs are adequate to maintain Oakville Hydro's electricity distribution system based on customer requirements. In addition, confirmation is provided that the plan aligns with the goals of prudent Asset Management and has been developed and prioritized to ensure obligations to stakeholders are met and regulatory compliance is assured. This attestation is provided to Oakville Hydro's Board of Directors.

System Capability Assessment for Renewable Energy Generation

Section 5.1.4.2 of the DS Plan Filing Requirements requires that distributors submit information to the Ontario Power Authority (the "OPA") in relation to the Renewable Energy Generation investments identified in their DS Plan. (The OPA is expected to provide a letter of comment with regards to these plans for inclusion in a distributor's cost of service application). Oakville Hydro's renewable energy generation investment plan forms part of its overall Distribution System Plan. Oakville Hydro's Renewable Energy Generation Investment Plan has been created

as a separate document for the purpose of the OPA's review and letter of comment and provided as Appendix 4, Renewable Energy Generation Plan (including a copy of the OPA's letter of comment with regards to Oakville Hydro's Renewable Energy Generation Investment Plan) and summarized in the following paragraphs.

The Renewable Energy Generation Investment Plan assesses the state of Oakville Hydro's existing distribution system, studies the current renewable connected generation and near-term growth forecast, develops a strategy to accommodate the predicted renewable generation growth and describes Oakville Hydro's future Renewable Generation expenditures from 2014 through 2018.

The OPA launched the Feed-In Tariff ("FIT") program in 2009. The FIT/microFIT program generated modest interest in Oakville Hydro's service area. Oakville Hydro's connected renewable generation is 0.49 MW for FIT programs. Currently there are three FIT projects and 32 microFIT projects which have been connected. There are seven FIT applications in Oakville Hydro's territory waiting for a contract with the OPA.

Oakville Hydro's distribution system is a robust, integrated network throughout the Town of Oakville. Adequate planning and proactive infrastructure projects have made the distribution network well-equipped to handle forecasted renewable generation. However, there are two Hydro One owned transformer stations namely, Palermo and Trafalgar where there are short circuit capacity restrictions related to the connection of renewable generation, within the upstream transmission system. However, the remaining stations have sufficient short-circuit capacity to accommodate the type of distributed generation that Oakville Hydro has seen so far. Most of the renewable energy projects proposed in Oakville Hydro's service area are inverter-based with limited fault contribution to Oakville Hydro's distribution system. It is unlikely that the fault contribution from the anticipated distributed generation will cause Hydro One owned transformer stations to reach the short-circuit capacity limits.

Based on Oakville Hydro's 2011 to 2013 FIT/microFIT data and the future assumptions, it is

for renewable energy indicate that Oakville Hydro is ready to connect future renewable generation projects.

Consequently, Oakville Hydro has not included any capital expenditures related to renewable energy generation in its Distribution System Plan. In addition, there are no additional OM&A costs proposed related to renewable energy generation as Oakville Hydro is able to use existing staff to process microFIT/FIT applications and all the related requirements that currently exist.

Capital Expenditure Summary

Oakville Hydro has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through careful capital spending. Capital additions for material 2014 Test Year projects are provided in Appendix 7, Material Capital Project Templates. An overview of Oakville Hydro's capital additions from 2009 to 2018 follows below in Table 5.

Chapter 5 of the DS Plan Filing Requirements issued by the Board on March 28, 2013 requires that a distributor's investment projects and activities be grouped for filing purposes into one of four investment categories: system access, system renewal, system service or general plant. Oakville Hydro has grouped actual expenditures for the Historical Years and forecasted expenditures for the 2013 Bridge Year and the 2014 Test Year in the Board's investment categories.

Distributors are also requested to provide summary information for the last five years prior to the test year as well as historical "previous plan" data if a plan had previously been filed with the Board. Oakville Hydro filed plans with the Board for the year 2010 as part of its 2010 Cost of Service Application. Oakville Hydro has not filed previous plans for the years 2009, 2011, 2012 and 2013 with the Board. Therefore, Oakville Hydro has included it internal capital plans in Table 5.

Oakville Hydro does not have historical capital planning detail broken into the Board's investment categories: System Access, System Renewal, System Service and General Plant. Therefore, Oakville Hydro has provided capital planning data based on its total capital expenditures budget.

Table 5 Capital Expenditure Summary

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

First year of Forecast Period: *2014*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2009			2010			2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*				
System Access		5,782	--		3,307	--		29,215	--		3,090	--	3,291	3,822	16.1%	2,322	2,130	2,448	2,497	2,639
System Renewal		13,001	--		11,146	--		6,939	--		7,571	--	5,573	5,535	-0.7%	5,980	5,436	5,505	5,599	5,599
System Service		1,449	--		916	--		838	--		11,351	--	79	201	155.0%	5,589	559	581	605	629
General Plant		2,535	--		1,247	--		3,055	--		1,984	--	2,549	2,137	-16.2%	2,717	2,126	2,866	2,052	2,063
TOTAL EXPENDITURE	18,232	22,767	24.9%	14,721	16,615	12.9%	29,024	40,046	38.0%	13,562	23,996	76.9%	11,493	11,695	1.8%	16,607	10,251	11,401	10,752	10,931
System O&M	n/a	$ 5,852	--	$ 6,135	$ 5,568	-9.2%	n/a	$ 6,936	--	n/a	$ 7,308	--	$ 10,140	$ 10,394	2.5%	$10,758	n/a	n/a	n/a	n/a

NORMALIZED CAPITAL EXPENDITURES (EXCLUDING GLENORCHY MTS, SMART METERS, 3rd PARTY IRU)

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2009			2010			2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*				
System Access	-	4,967	--	2,372	3,307	39.4%	-	6,354	--	-	2,931	--	3,291	3,822	16.1%	2,322	2,130	2,448	2,497	2,639
System Renewal	-	13,001	--	8,662	11,146	28.7%	-	6,939	--	-	7,571	--	5,573	5,535	-0.7%	5,980	5,436	5,505	5,599	5,599
System Service	-	1,449	--	781	916	17.2%	-	783	--	-	1,232	--	79	201	155.0%	589	559	581	605	629
General Plant	-	1,635	--	2,906	1,247	-57.1%	-	3,055	--	-	1,984	--	2,549	2,137	-16.2%	1,979	2,126	2,380	2,052	2,063
TOTAL NORMALIZED EXPENDITURE	18,232	21,052	15.5%	14,721	16,615	12.9%	17,938	17,132	-4.5%	13,562	13,718	1.1%	11,493	11,695	1.8%	10,869	10,251	10,915	10,752	10,931
Glenorchy MTS/Emergency Back-up Transformer	-	-		-	-		9,186	22,861		-	159		-	-		5,000	-	-	-	-
Smart Meters	-	-		-	-		1,900	54		-	10,119		-	-		-	-	-	-	-
New Customer Information System	-	-		-	-		-	-		-	-		-	-		-	-	486	-	-
Remaining 3rd Tranche CDM Activities	-	1,715		-	-		-	-		-	-		-	-		-	-	-	-	-
3rd Party IRU	-	-		-	-		-	-		-	-		-	-		738	-	-	-	-
TOTAL EXPENDITURE	18,232	22,767	24.9%	14,721	16,615	12.9%	29,024	40,046	38.0%	13,562	23,996	76.9%	11,493	11,695	1.8%	16,607	10,251	11,401	10,752	10,931

Table 5 Capital Expenditure Summary, Continued

CATEGORY	Forecast Period (planned)				
	2014	2015	2016	2017	2018
	$ '000				
System Access	2,322	2,130	2,448	2,497	2,639
System Renewal	5,980	5,436	5,505	5,599	5,599
System Service	5,589	559	581	605	629
General Plant	2,717	2,126	2,866	2,052	2,063
TOTAL EXPENDITURE	16,607	10,251	11,401	10,752	10,931
System O&M	$10,758	n/a	n/a	n/a	n/a

NORMALIZED CAPITAL EXPENDITURES (EXCLUDING GLENORCHY MTS. SMART METERS. 3rd PARTY IRU)

CATEGORY	Forecast Period (planned)				
	2014	2015	2016	2017	2018
	$ '000				
System Access	2,322	2,130	2,448	2,497	2,639
System Renewal	5,980	5,436	5,505	5,599	5,599
System Service	589	559	581	605	629
General Plant	1,979	2,126	2,380	2,052	2,063
TOTAL NORMALIZED EXPENDITURE	10,869	10,251	10,915	10,752	10,931
Glenorchy MTS/Emergency Back-up Transformer	5,000	-	-	-	-
Smart Meters	-	-	-	-	-
New Customer Information System	-	-	486	-	-
CDM Activities	-	-	-	-	-
3rd Party IRU	738	-	-	-	-
TOTAL EXPENDITURE	16,607	10,251	11,401	10,752	10,931

Explanatory Notes on Variance in Capital Expenditure Summary

Shifts in Forecast versus Historical Budgets by Category

Oakville Hydro does not have historical capital planning detail broken into the Board's investment categories: System Access, System Renewal, System Service and General Plant. Therefore, Oakville Hydro has provided notes on shifts by category for the 2013 to 2018 forecast years only.

System Access:

Spending in 2013 is significantly higher than that expected in 2014 through 2018. The 2013 Test Year includes two large system access projects, namely the construction of feeders for the new Oakville Hospital which is currently under construction and expected to be complete at the end of 2015 and the connection of Milton Hydro Electricity Distribution Inc. as an embedded distributor at the Glenorchy Municipal Transformer Station. For the forecast period 2014 through 2018 System Access projects are expected to be between $2.1M and $2.6M. Road widening projects are expected to decrease from 2014 forecasted levels due to an anticipated decline in municipal, regional and provincial projects. Future expenditures for new development/services and meters are expected to increase moderately.

System Renewal:

System access investments are investments in the replacement or refurbishment of the distribution system to extend the original service life of the assets. Expenditures on System Renewal projects are expected to be in the $5.5M to $6.0M range from 2013 to 2018.

System Service:

This category typically includes SCADA enhancements and upgrades, switching improvements and installations at various locations in Oakville, installation of remote fault indicators and repeater site upgrades. In 2013, resources normally allocated to these types of projects are expected to be used for the two large system access projects referenced above -

the construction of feeders to service the new Oakville Regional Hospital and Milton Hydro. Once completed, spending in the system service category is expected to increase and remain relatively consistent through 2014 through 2018.

General Plant:

General Plant projects are forecasted to be in the $2.1M range for the 2013 Bridge Year and the 2014 Test Year with normalized expenditures decreasing to a range between $2.0M and $2.4M from 2015 to 2018. Oakville Hydro has made, and plans to make, system investments in information technology in 2013 to 2014 (CMMS, GIS, Health and Safety). Although upgrades and improvements to these systems are expected in 2015 to 2018, they will not be of the same magnitude as the initial systems cost. The increase in General Plant in 2016 is due to the expected implementation of a new Customer Information System. Expenditures for vehicles, tools and leasehold improvements are expected to be consistent from 2013 onwards.

Notes on Year over Year Plan versus Actual Variances for Total Expenditures

2009 Planned versus 2009 Actual

In 2009, capital additions excluding CDM activities were $21.0M, an increase of $2.8M as compared to the 2009 planned capital additions of $18.2M. The increase in capital additions was primarily due to an increase in new development and services of $1.3M, and increase of $1.0M in the investments in substations as a result of the construction of the new Arkendo Municipal Substation rather than the planned decommissioning of an existing Municipal Substation and the enhancement of the SCADA system at a cost of $0.8M.

2010 Board Approved versus 2010 Actual

In 2010, capital additions were $16.6M, an increase of $1.9M as compared to the 2010 Cost of Service application which projected capital additions of $14.7M. The increase in capital additions were primarily due to increased spending on projects that were beyond the control of Oakville Hydro. Actual expenditures for 27.6kV additions, new development and services, unanticipated road widening and substation equipment refurbishments were $1.3M higher than budgeted. In

addition, Oakville Hydro added a transformer replacement and voltage conversion in the Woodhaven Park area to the 2010 capital plan at a cost of $0.4M. Although this project was not in the 2010 capital plan, conditions were such that the replacement was required in 2010.

2011 Plan versus 2011 Actual

The 2011 actuals, excluding the Glenorchy Municipal Transformer Station and Smart Meters, were $0.8M or 5% lower than Oakville Hydro's 2011 capital plan. The decrease versus budgeted capital additions was due to lower spending on Information Technology projects, replacement of fewer vehicles than anticipated, and lower spending on the Rear Lot Distribution Projects, a multi-year project to remove high voltage lines from rear lot areas. This was partially offset by the costs associated with the re-roofing and renovation of Oakville Hydro's head office at 861 Redwood Square and higher than anticipated cost of the feeders from the Glenorchy Municipal Transformer Station due to higher than predicted ground water flows present on the site which increased the cost and complexity of the construction work.

2012 Plan versus 2012 Actual

Total actual spending in 2012, excluding the Glenorchy Municipal Transformer Station and Smart Meters, was $0.2M or 1% higher than Oakville Hydro's 2012 capital expenditure plan. The difference between planned capital expenditures and actual capital expenditures in 2012 was not material.

Notes on Plan versus Actual Trends for Individual Expenditure Categories

As noted previously, Oakville Hydro has provided its total capital budget for the 2009 to 2012 historical years. Oakville Hydro is not providing notes on plan versus actual trends for individual expenditure categories; instead, Oakville Hydro is providing notes on plan versus actual trends for total expenditures.

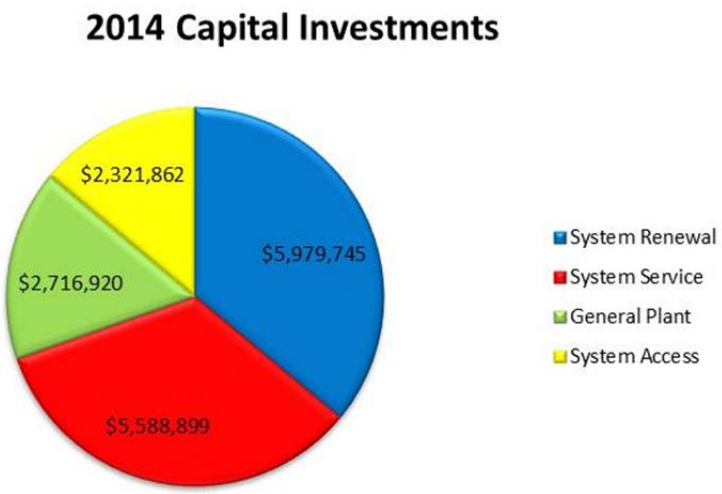
As discussed previously, the variance between planned capital expenditures and actual capital was $2.8M in 2009, $1.9M in 2010, ($0.8M) in 2011 and $0.2M in 2012. This reduction in the

variance between planned and actual capital spending is evidence that Oakville Hydro's planning process has evolved in recent years. Its new Asset Management Process has enabled it to more accurately budget its capital investment requirements. This process is continuing to evolve to provide for better planning over a longer term planning horizon.

Justifying Capital Expenditures – 2014 Test Year

Overall Plan

As stated in the RRFE Report, good planning is necessary to ensure that the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. Consistent with this outcome based approach, Oakville Hydro's Capital Expenditure Plan is designed to provide a distribution system that is efficient, reliable, sustainable, and provides value for customers. Oakville Hydro's historical and planned capital investments are summarized by category in the following chart.



Impact of Capital Investments on Operating and Maintenance Costs

As noted in the individual project details in Appendix 7 - Material Capital Project Templates, there are a number of capital projects that will reduce operating and maintenance costs. These reductions have enabled Oakville Hydro to refine the patrol and maintenance process to ensure that minimum requirements are met, and that follow up maintenance is completed to mitigate the need for capital expenditures to replace equipment prematurely due to failures with existing staff. Advantages that have been realized include:

New or Improved Processes:

- Increased quality and quantity of data collected during patrols of distribution system assets
- Increased infrared thermography to include local feeders instead of just express feeders.
- Increased radio frequency detection to include both local and express feeders.
- New underground cable testing techniques in order to accurately capture condition.
- New process for the investigation of underground cable, splice and device failures.
- New process for rigid washing cycle for commercial vaults to include a washing in the spring to mitigate salt deposited over the winter months, and washing in the fall to mitigate organic debris deposited over the fall months.

Cost Savings:

- Increased interval between maintenance activities for padmount switches – from three to six years.
- New processes to track underground cable failures to allow for faster identification and restoration in order to reduce administrative costs and improve customer satisfaction.
- Installed polymer insulators to reduce failures due to pollution-allowing for the discontinuation of insulator washing.
- Extended the testing and treatment maintenance of wood poles from a three year cycle to a six year cycle.

Capital Expenditures Drivers

The main drivers of capital expenditures are summarized below. As previously noted, investments related to renewable energy generation are not currently a driver of capital investments in Oakville Hydro's service area. The calculated remaining capacity and the projected demand for renewable energy indicate that Oakville Hydro is ready to connect future renewable generation projects. Further details are provided in Appendix 4, Renewable Energy Generation Investments. Therefore, Oakville Hydro has not included any capital expenditures related to renewable energy generation in its DS Plan.

Investments related to System Access are expected to be lower in the near term due to a reduction in road widening projects in the Town of Oakville. As discussed in the section entitled Capital Asset Categories, capital investments are allocated to the remaining investment categories based upon the optimization of risk and value.

Table 7, Summary of Capital expenditure drivers

Drivers	System Access	System Renewal	System Service	General Plant
	New Customer Connections	Equipment Failure	Safety Improvements	Equipment Failure
	Distribution Meters	Equipment Damage	New Technological Advancements	Equipment Damage
	Municipal Road Changes	Reliability Improvemnts	Operational Savings	New Technological Advancements
	Modifications to Connect New Customers	Operational Savings	Reliability Improvements	Operational Savings

Material Investments

Oakville Hydro's 2014 capital projects above its materiality level of $180,000 are listed in Table 8, Material Capital Projects – 2014 Test Year, below and summarized in the following paragraphs. Project details for individual projects over Oakville Hydro's materiality level are also

provided in Appendix 7 – Material Capital Project Templates and, in accordance with the DS Plan Filing Requirements, include the following (where applicable):

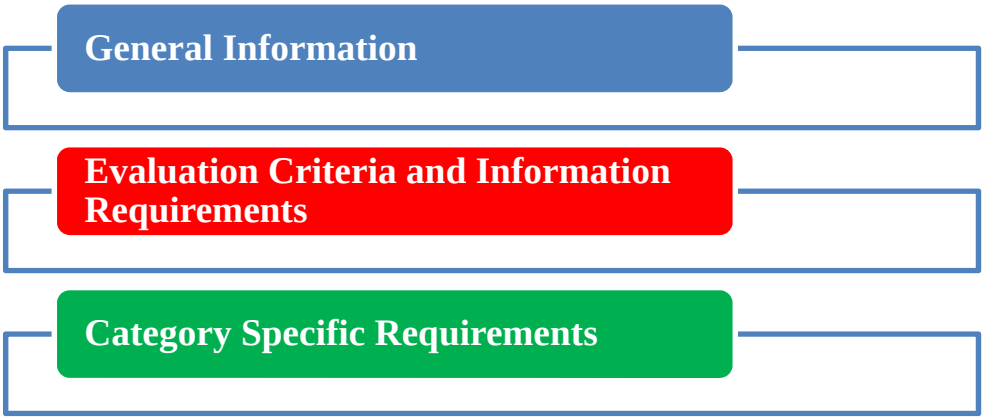


Table 8, Material Capital Projects – 2014 Test Year

Project #	Description	System Type	Total Project Cost	Contributed Capital	Oakville Hydro Project Cost
05-N	Onsite Emergency Back-up Transformer for Glenorchy MTS	System Service	$5,000,000	$0	$5,000,000
14-64A1	SCADA Enhancements in Loadflow, Contingency Analysis, FDIR	System Service	300,000	0	300,000
16-G2	27.6kV Air insulated switchgear upgrades to G&W	System Renewal	379,340	0	379,340
16-U1	Gang-Op Switch Replacement Program	System Renewal	267,139	0	267,139
05-P2	Power Transformer Replacement Program	System Renewal	268,190	0	268,190
05-Q2	Victoria MS Low Voltage Breaker Replacement Program	System Renewal	547,715	0	547,715
46-A	Replace Overhead Assets on John Street	System Renewal	207,270	0	207,270
46-B	Replace Overhead Assets on Queen Mary, Bond and Chisholm	System Renewal	358,919	0	358,919
46-C	Replace Overhead Assets on Robinson St.	System Renewal	458,981	0	458,981
45-A	Vault Transformer Replacements	System Renewal	316,241	0	316,241
45-D	Poletran Removals and Replace U/G Assets Various Locations	System Renewal	292,164	0	292,164
45-Q	Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion	System Renewal	385,205	0	385,205
45-X	Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln	System Renewal	184,665	0	184,665
42-B	Live front Padmount Transformer Replacements	System Renewal	275,730	0	275,730
44-H	27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403	System Access	420,973	0	420,973
14-50C	New Development Investment	System Access	2,280,508	1,856,780	423,729
14-54	New General Services	System Access	598,945	247,341	351,604
14-61	Distribution Meters	System Access	481,706	0	481,706
15-E	North Service Rd Widening, 8th Line to Iroquois Shore Rd	System Access	244,991	91,191	153,800
15-I	Road Widening TBD	System Access	309,752	106,518	203,234
14-62	2014 Fleet	General Plant	384,762	0	384,762
14-64D	ERP - GP & Business Intelligence	General Plant	203,000	0	203,000
14-64F	IT Infrastructure	General Plant	420,000	0	420,000
LSHOLD	HVAC upgrade - 5 year replacement program	General Plant	230,000	0	230,000
	3rd Party Indefeasible Right of Use	General Plant	738,210	0	738,210
	Material Capital Projects		**15,554,406**	**2,301,829**	**13,252,577**
	Other Non-Material Total		**4,352,301**	**997,452**	**3,354,850**
	Total		**$19,906,708**	**$3,299,281**	**$16,607,427**

System Access

The system access investment category includes the capital investments associated with the connection of new customers and distribution meters in Oakville Hydro's service area. Seven projects have been identified for the 2014 Test Year. These projects are non-discretionary.

Project 15-E Widening of North Service Road and 15-I Miscellaneous Road Widening

Oakville Hydro's 2014 Capital Expenditure Plan includes the costs associated with the widening of North Service Road and other miscellaneous road widening projects. North Service Road will be widened from the existing two lanes into four lanes from 8th Line to Iroquois Shore Rd. This represents one km of roadway and at least 20 new poles. This project will require relocation of poles and associated distribution equipment to make room for the new lanes.

14-50C New Development Investment and 14-54 New General Services

Oakville Hydro's 2014 Capital Expenditure Plan includes the estimated costs associated with the connection of new residential and commercial customers.

14-61 Distribution Meters

Oakville Hydro's 2014 Capital Expenditure Plan includes the estimated costs associated with distribution meters. This project includes the costs of new residential meters equipped with Zigbee to facilitate real-time access to smart meter data, multi-residential meters, commercial meters, and a new Tower Gateway Base ("TGB") station to support increased smart meter data collection.



44-H Additional 27.6kV feeder

Oakville Hydro's 2014 Capital Expenditure Plan includes the costs associated with the addition of an additional 27.6kV feeder on Upper Middle Road E, from Ninth Line to Highway #403, to support load growth in the Winston Business Park. This will also support future load growth in the next phase of new development in the area (Winston Park West).

System Renewal

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.

Project 16-G2 27.6kV Air Insulated Switchgear Upgrade Program

Oakville Hydro's 2014 Capital Expenditure Plan includes the costs associated with the replacement of 27.6kV air insulated style padmount switchgear. The 27.6kV air insulated style padmount switchgear is at a risk due to contamination and flashovers. The insulators inside of these switchgears are susceptible to salt spray contamination during the winter. When located in a high traffic area, the contamination builds up and can cause flashovers. In these cases the switchgear needs to be removed and either refurbished or scrapped depending on the level of damage. If replaced with deadfront switchgear, the salt spray does not affect the unit, mitigating the risk of the flashovers. The existing switchgear is also subject to accelerated aging due to adverse weather conditions and road salt. The new switchgears are easier to operate, have an electronic trip and do not require fuse replacements, and dry ice cleaning is required only every six years.



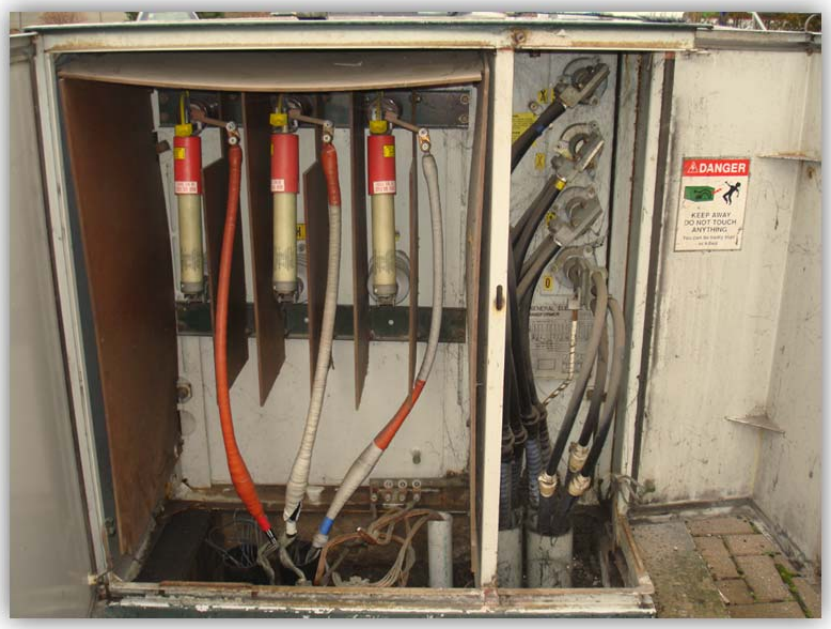
Project 16-U1 Gang-Operated Switch Replacement Program

Vacuum gang-operated switches tend to fail without warning, and there is little to no maintenance that can be performed in order to keep them in working order. Upon failure they are replaced with newer style remote operated switches. In order to mitigate this risk, Oakville Hydro has implemented a gang-operated switch replacement program to prioritize the replacement of the switches based upon the risk of failure. Replacement of these switches before failure reduces the risk of outages, customer or employee injury and fire, and improves reliability and performance measures.



Project 42-B Livefront Transformer Replacement Program

Oakville Hydro has phased these transformers out over time and only a handful remains in the field with no straight replacement stock available. The units are typically installed without proper foundations causing issues during replacement with newer units that require foundations. On average these units are 40 years old. The 2014 Capital Expenditure Plan provides for the replacement of the remaining livefront transformers at 1027 Speers Road. The replacement of these transformers reduces the risk of outages, equipment failures and employee injury, while protecting the environment from the release of toxic materials and improving reliability and performance.



Project 45-A Vault Transformer Replacement Program

These transformers typically service residential apartment buildings or commercial plazas. There are numerous instances where current limiting style fuses are installed that are difficult to operate and replace safely. Many of these locations are difficult to access and pose safety issues due to open air live parts. The replacement of these transformers reduces the risk of outages, equipment failures and employee injury, while protecting the environment from the release of toxic materials and improving reliability and performance.



Project 45-Q Replace Underground and Overhead Assets in Colchester Area and Project 45-X Replace Underground and Overhead Assets in Willowbrook Area

A number of areas with aging underground distribution have been identified for replacement including the Colchester area and Willowbrook areas. Typically in these older areas the cables are direct buried, causing replacement challenges. If one of these cables were to fail, the fault will have to be located, and excavated. Once the fault is isolated, a splice can be added in order to use the cable again. Rebuilding of these areas with ducts will provide a means to remove the cables when they are failing. These areas typically have non-vented bushing inserts and elbows which can allow flashovers to occur when switching takes place. The replacement of these assets reduces the risk of outages and equipment failures, reduces the risk of employee and customer injury, protects the environment from the release of toxic materials and improves reliability performance.

Project 46-A Replace Overhead Assets on John Street Project

Project 46-B Replace Overhead Assets in Queen Mary Area

The John Street and Queen Mary areas have been patrolled and the assets have been identified in poor and degrading condition. The replacement of these assets reduces the risk of outages and equipment failures, reduces the risk of employee injury, protects the environment from the release of toxic materials and improves reliability performance.

05-P2 Power Transformer Replacement Program

Oakville Hydro plans to replace Power Transformer Loc-B at Woodhaven Municipal Station, which is the oldest power transformer in Oakville Hydro's distribution system, unless another deteriorates rapidly resulting in a lower health index. The replacement of these assets reduces the risk of outages and equipment failures. Deferral of the replacement until failure results in increased maintenance costs and leads to transfer of the financial costs to future customers as well as the increased risk of significant outages. Substation power transformers are especially critical due to their role in supplying hundreds of customer in the surrounding area.



Project 05-Q2 Victoria Municipal Substation Low Voltage Breaker Replacement Program

Oakville Hydro plans to replace the Low Voltage Breaker lineup at Victoria MS, which is the oldest Low Voltage Breaker lineup in Oakville Hydro's distribution system, unless there is a rapid deterioration or failure of another low voltage breaker. The replacement of these breakers reduces the risk of outages and equipment failures. Substation breakers are especially critical due to their role in supplying power to hundreds of customers per feeder.



System Service

Project 05-N On-site Emergency Back-up Transformer for Glenorchy Municipal Transformer Station

On September 17, 2010, Oakville Hydro filed an ICM application, EB-2010-0104 which included a request for the recovery of the capital costs associated with the design and construction of Oakville Hydro's Glenorchy Municipal Transformer Station. On March 14, 2011, the Board approved Oakville Hydro's application and the associated rate rider. In 2011, Oakville Hydro completed the project of building its Glenorchy Municipal Transformer Station in order to service the customers of Oakville.

In July of 2011, this municipal transformer station realized a peak load level of 44MW supplied to the north-central area of Oakville. In August 2013, Milton Hydro connected to Oakville Hydro's distribution system and became an embedded distributor. With the connection of Milton Hydro, the transformer station's utilisation is increased by 6 MW from Milton Hydro. Further load will be added to the Glenorchy Municipal Transformer Station when the new Regional hospital is connected to the distribution system in late 2015. These customers will be Oakville Hydro's two largest customers and the criticality of maintaining reliable service to these two customers is increasing.

The acquisition of the emergency back-up transformer could also benefit the Board's Regional Planning process in that it could be made available to other transmitters or distributors in the same geographical area. In addition, as previously discussed, Oakville Hydro is unique in that it is fed by three separate transmission supplies and Oakville Hydro is often called upon by Hydro One to perform short-term load transfers among its distribution stations to alleviate capacity constraints within the region. A prolonged failure at the Glenorchy Municipal Transformer Station would severely compromise Oakville Hydro's ability to assist Hydro One which may result in greater challenges in the region.



The Glenorchy Municipal Transformer Station does not have an on-site emergency back-up transformer for use in event of a failure. Therefore, Oakville Hydro believes it is imperative and critical to the customers it serves to have this capability on hand. Oakville Hydro has included the estimated cost of $5.0 M in its capital expenditure plan in the 2014 Test Year. Table 9, Components of the On-site Emergency back-up Transformer, provides a breakdown of the costs by component.

Table 9, Components of the On-site Emergency Back-up Transformer

Type	CGAAP ($)
Equipment	3.6M
Construction	1.0M
Design	0.2M
Commissioning	0.2M
Total Costs	5.0M

In preparing its DS Plan, Oakville Hydro explored a number of alternatives for the acquisition of an emergency back-up transformer for the Glenorchy Municipal Transformer Station as discussed below.

ALTERNATIVES

Collaboration with Hydro One

In keeping with the Board's focus on regional planning, Oakville Hydro approached Hydro One to determine whether there was an opportunity to share their inventory of spare transformers with Oakville Hydro. On June 7, 2012 Hydro One advised Oakville Hydro that they were not interested in sharing their back-up transformers. Although Hydro One had been approached by several distributors to discuss the feasibility of entering into an arrangement to share backup transformers, including Hydro One Brampton, Hydro One advised that they had concerns regarding "numerous procurement, logistical, accounting and pricing issues" associated with the sharing of back-up transformers. On August 19, 2013, Oakville Hydro contacted Hydro One who confirmed that its position of not being able to provide an

emergency back-up transformer had not changed.

Collaboration with Neighbouring Electricity Distributors

Oakville Hydro contacted PowerStream, its closest neighbouring distributor with a back-up transformer in its inventory that meets the design specifications of the Glenorchy Municipal Transformer Station, to explore the potential for sharing the costs associated with the ownership of a back-up transformer. On November 12, 2012, PowerStream advised Oakville Hydro that they would be interested in sharing their back-up transformer with Oakville Hydro. At that time, PowerStream advised that they would require an annual standby fee for potential access and a monthly fee to lease the transformer if Oakville Hydro required the use of the back-up transformer. Costs would continue until the spare or a replacement unit was returned to the pool.

Having received this response, Oakville Hydro approached ABB (the transformer supplier) for information on the feasibility of transporting the PowerStream back-up transformer from their Greenwood Transformer Station where it is stored, to Oakville Hydro's Glenorchy Municipal Transformer Station in the event of a failure. ABB supplied and installed both of the existing power transformers at Glenorchy Municipal Transformer Station, and also supplied both the spare and in-service transformers to PowerStream. In addition, ABB has prepared a preparedness plan for PowerStream that details how their spare transformer will be mobilized to each of their transformer stations if required in the event of a failure. Given this experience, Oakville Hydro believes that ABB is well-equipped with the technical expertise to advise Oakville Hydro on the feasibility of using the PowerStream back-up transformer.

On February 14, 2013, ABB provided Oakville Hydro with their findings regarding the feasibility of Oakville Hydro using the PowerStream back-up transformer. ABB found that, although it is possible to transport the PowerStream spare transformer to Glenorchy Municipal Transformer Station, it would be both complicated and time consuming. Successful transportation to site depends on railcar arrangements, use of the Hydro One's rail siding near

the Trafalgar Transformer Station in Oakville and road route surveys. In addition, there is a half load restriction from March until May on some of the roadways over which the back-up transformer would be required to travel in order to reach the Glenorchy Municipal Transformer Station. A further complication would be the time required to transport and install PowerStream's back-up transformer to the Glenorchy Municipal Transformer Station which ABB has estimated to be between 35 and 40 days.

The half-load restrictions would present a significant service risk to the customers serviced from Glenorchy Municipal Transformer Station during the period in which the half-load restrictions are in effect. In the event of a transformer failure in this period, it would take the remainder of the half-load season and then the full time required to transport and install the spare transformer, which could be in excess of three months. This significantly exceeds the Ontario best utility practice of 10 days to replace a damaged transformer. This 10-day requirement is built into the Long Time Rating ("LTR") that is assigned to each transformer station in Ontario. Oakville Hydro is committed to following best utility practices, and believes it would not be prudent to subjecting customers to increased levels of service risk.

Based on these restrictions, the opportunity for sharing an emergency back-up transformer with others is not a feasible solution.

Transfer of load away from Glenorchy Municipal Transformer Station in the event of failure

In the event of a substantial power failure at the Glenorchy Transformer Station, only Hydro One's Palermo Transformer Station and Trafalgar Transformer Station would be left to supply power to the North Oakville service area. In July 2011 the load levels in North Oakville reached a peak of 178.7 MW. According to Oakville Hydro's Connection and Cost Recovery Agreement with Hydro One dated October 5, 2010, Oakville Hydro has been allocated a total of 149.7 MW supply in the North Oakville area from Hydro One's Palermo Transformer Station and Trafalgar Transformer Station. Based on the load levels from July 2011 there would be 29 MW of stranded load in North Oakville, and this load level will continue to grow

as Oakville develops and takes on new customers. Milton Hydro's customers would be at risk as well.

If there was an outage on only one of the two in-service transformers at Glenorchy Municipal Transformer Station during this peak demand period, Oakville Hydro would be at risk of a second failure that would leave this 29MW of load stranded. It is Oakville Hydro's view that this poses an unacceptable risk to manage.

Conclusion

Oakville Hydro has been prudent and thorough in assessing the alternatives for the acquisition of an emergency back-up transformer for its Glenorchy Municipal Transformer Station and has concluded that the on-site emergency back-up transformer is required in order to minimize risk of disruption to the customers this transformer station currently serves and will serve in the future including. As discussed previously, there are also be two feeders supplying load to Milton Hydro, and one additional feeder which will supply load to the new Oakville Regional Hospital in 2015. Coincident with these new loads, Oakville Hydro requires an emergency back-up transformer that will be sited at Glenorchy Municipal Transformer Station that can be used to replace a damaged transformer within 10 days as per best utility practice. In addition, the emergency back-up transformer would be available to other distributors in these regions, including Hydro One, in the event that they experience a failure.

Therefore, Oakville Hydro has included $5.0 M of capital in its DS Plan in the 2014 Test Year for the on-site emergency back-up transformer.

General Plant

The "Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements" issued on March 28, 2013 by the Board defines the asset category, General Plant, as investments or modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities.

Project 14-62 2014 Fleet

Oakville Hydro has the included costs associated with the procurement of eight vehicles in its 2014 Capital Expenditure Plan. Four existing pickup trucks and an existing van are proposed to be replaced with new 2014 vehicles. One existing blocker truck chassis is proposed to be replaced with a large used truck chassis. One existing warehouse forklift is proposed for replacement. The procurement of vehicles that better suit the job requirement will reduce fuel costs, reduce maintenance costs, and reduce overall costs through "right sizing" the vehicle for the job. The replacement of these vehicles will improve response times, improve employee safety and reduce harmful emissions. The vehicles to be replaced and their ages are provided in the following table.

Truck #	Year Make and Type
69	2004 Chevy Crew Cab
75	2005 Chevy Crew Cab
80	2006 Chevy Pickup
65	2003 Chevy Pickup
68	2004 Chevy Malibu
77	2005 Chevy Van
20	1990 International Blocker Truck
406	1991 Forklift


TOYO

Project 14-64A1 SCADA Enhancements in Loadflow, Contingency Analysis, Fault Detection Isolation Restoration ("FDIR")

The following functional upgrades will be added to the existing SCADA system:

- Loadflow will provide the Control Room Operators with an analysis tool to simulate the impact of system loading levels in order to drive the right solutions.
- Contingency Analysis is a complementary module to Loadflow, and will provide the Control Room Operators with information that highlights critical components in the distribution system, allowing the Operator to reconfigure the system as necessary.
- Fault Detection Isolation Restoration ("FDIR") is also a module that is complementary to Loadflow, and is an element of smart grid transformation that builds a level of automation into the SCADA system. Existing field sensors and controllable switches are leveraged, and the SCADA system is able to take action without Operator intervention to begin system restoral following an outage. A photograph of Oakville Hydro's GIS is provided below.



14-64F Information Technology Infrastructure

The ongoing maintenance of Oakville Hydro's IT infrastructure is core to maintaining the systems the business requires. Asset plans in the IT Strategy define a good basis for a plan that makes sense from a system and cost point of view. The IT strategy is provided as Appendix 6 to the DS Plan. In 2011 and 2012 there was a decrease in the maintenance of the systems due to reorganization in the department. In 2014 there are many systems that require upgrading but only the critical systems are being addressed in the 2014 Capital Expenditure Plan.

16-64D Enterprise Resource Planning ("ERP") & Customer Information System

This project is comprised of a number of upgrades to Oakville Hydro's existing Customer Information System and an upgrade to its Enterprise Resource Planning ("ERP") System, Great Plains – Microsoft Dynamics.

- **Enterprise Resource Planning System ("ERP")**

  Great Plains, Microsoft Dynamics is Oakville Hydro's ERP system and support on the existing GP 2010 will end Oct 2015. Oakville Hydro will implement an upgrade in 2014 in order to ensure that there is no risk of increased costs from vendors to support the system after Microsoft has completed its support. In addition, the upgrade will provide features that will assist in the development of asset management strategies

- **Customer Information System ("Harris")**

  In 2014, Oakville Hydro will automate the collection process to increase efficiency, and reduce bad debt. Oakville Hydro Has received a number of complaints regarding its current process and the automation of the collection process will increase the level of customer satisfaction. In addition, Oakville Hydro will automate service orders and processes to reduce manual processes. This will help reduce billing errors, delayed bills, and improve utilization of resources, which will serve to benefit Oakville customers.

Leasehold HVAC Upgrade

This project is part of a plan to replace HVAC units at Oakville Hydro's corporate office located at 861 Redwood Square in the Town of Oakville. These units were installed in 1994 and have reached the end of their life cycle. Oakville Hydro is experiencing more frequent breakdowns of units requiring replacement, particularly with units that are rooftop and exposed to the elements. Lead time for replacement units on an emergency basis varies from four to ten weeks depending on make and model type/size. Repair costs on these aging units continue to increase. Newer technology and more energy efficient products will result in improved operations, improved reliability and decreased maintenance costs.

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Appendix 1

Asset Management Process

2013/14

Oakville Hydro Electricity Distribution Inc.

Asset Management Process Overview

03/09/2013

Version 1D

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Asset Management Process Overview Purpose and Objective

Oakville Hydro Electricity Distribution Incorporated (OHEDI) produced this Asset Management Process Overview to be a document that provides relevant basic information about the utility, such as area served, customers mix, reliability performance, etc., as well as provide a preamble to the Asset Management Process (AMP) which includes the AM Policy, Strategy, and Objectives and to the Capital Expenditure Plan and Maintenance Expenditure Plan, all of which drive development of investment requirements and ultimately translate into a Business Plan. The AMP will be reviewed and updated on a yearly basis

The purpose of an AMP is to provide a succinct version of what the utility is all about to its shareholders, rate payers, Regulator, employees and general public. The AMP is also used to support Rate Application and to furnish new members of the Senior Management team or Board of Directors with essential background information about the utility.

Corporate Information

As the provider of energy services to the Town of Oakville, Oakville Hydro Corporation (OHC), and its subsidiary OHEDI, envisions itself as being a key facilitator of the growth of the Town of Oakville.

Vision Statement

We energize you

Mission Statement

We provide your best energy and conservation solutions

Corporate Principles

The following set of principles was developed in acknowledgement of a need to augment the ways in which OHC operates, and to reflect the ways in which the Corporation wishes to alter its positioning with its shareholders, customers, suppliers and communities. The foundations for the successful execution of the strategic plan are embodied in the following principles:

- Safety
- Customer focus
- Accountability
- Innovation
- Teamwork
- Communications
- Integrity/Respect

About Oakville Hydro Electricity Distribution Inc.

Utility Overview

OHEDI is Oakville Hydro Corporation's (OHC's) electricity distribution company. Using a network of remotely switched power lines of approximately 1,529 circuit km, 55% of the system underground and 45% overhead, OHEDI has reliably delivered energy to homes and businesses for over a century within the Town of Oakville in the Region of Halton. The service area is approximately 143 square kilometers. OHEDI has gross assets of $227 million and net capital assets of $169 million and a peak demand of 380.1MW. OHEDI offers customer service to developers and consumers, as well as designs, builds and maintains Oakville's power distribution system. OHEDI's customer base includes:

- Almost fifty-eight thousand residential customers;
- Almost five thousand general service customers that require less than 50kW of electrical demand; and
- Almost nine hundred general service customers that require more than 50kW of electrical demand.

Geographical Area Served

Oakville Hydro Electricity Distribution Incorporated (OHEDI) distributes electricity to the Town of Oakville located in the Region of Halton. OHEDI shares borders with Enersource, Burlington Hydro, Milton Hydro, and has its south east border defined by Lake Ontario. The following geographical map provides reference.

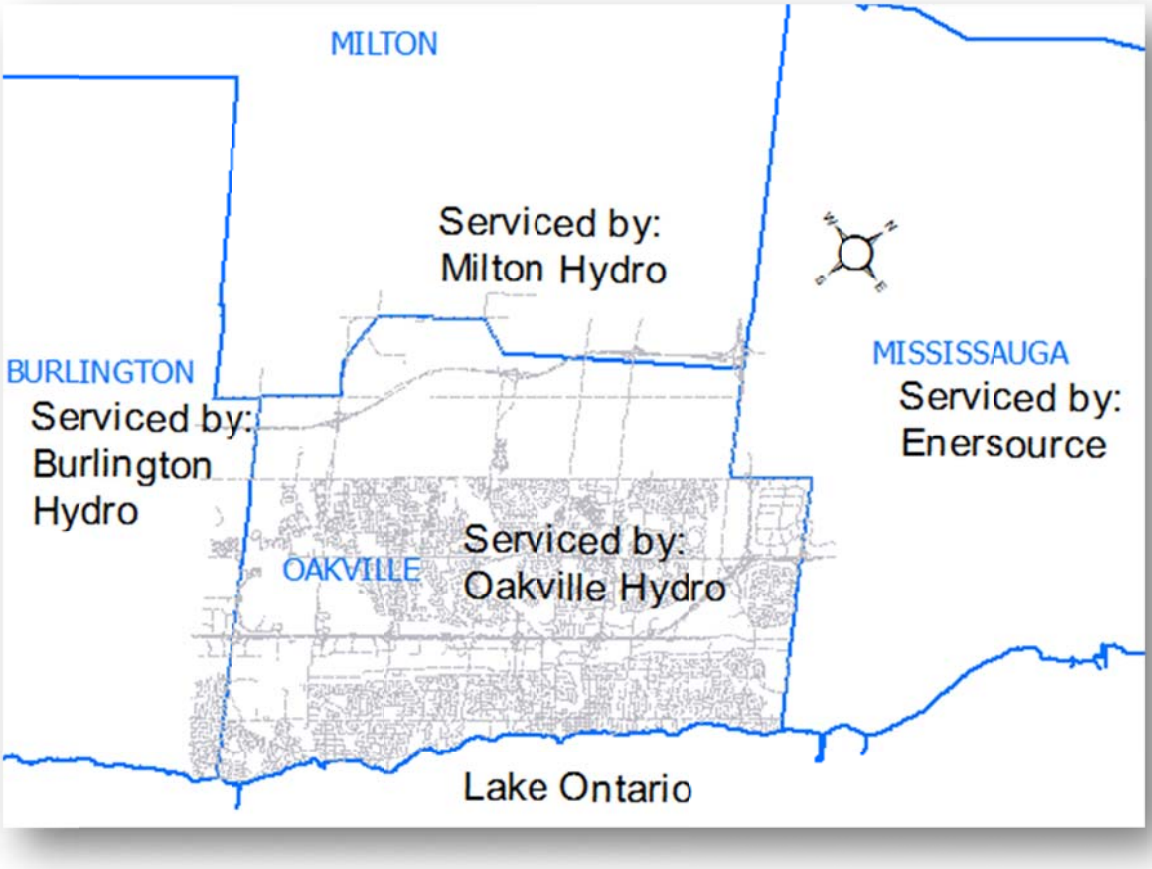


Figure 1

Population Served

OHEDI services 41 sq. km of rural area and 102 sq. km of urban area for a total service area of 143 sq. km. Over the next twenty years OHEDI expects the increase of urban area to encompass most, if not all of the distribution territory.

Climate

Oakville Ontario is considered in the "Dfb" or "Warm Summer Continental" climate of the Köppen climate classification. Extreme minimum temperature recorded at -30°C and extreme maximum temperature recorded at 38°C with average temperatures ranging between -4.9°C and 20.7°C. Seasonal precipitation ranges between 44.2mm to 78.5mm. The Town of Oakville expects an increase of temperature between 2 to 2.6 degrees and an increase of 5.1% precipitation by 2050.

Number of Customers by Segment

OHEDI's customer breakdown as of July 2013 is as follows:

Table 1

Res.	Gen. Serv. <50kW	Unmetered	Gen. Serv. >50kW	Gen. Serv. >1000kW	Gen. Serv. >5MW	Streetlight Accounts	Sentinel Light Accounts	Standard Offer Program Customers	Micro FIT	FIT	Total
58,673	4,941	675	899	16	1	3	25	1	17	3	65,232

Net Book Value of Total Assets

As of December 31, 2012 OHEDI's net book value of assets is $227,537,702 which is comprised of distribution, fleet, building, IT, and Call Centre assets, of which distribution assets account for $153,505,603.

Peak Load and Energy Delivered

The following charts shows OHEDI's peak load and energy delivered, both historical and forecast. OHEDI's peak load was reached in July 2013, of 382MW and the highest energy demand of 1,728,259,011 kWh was in 2004.

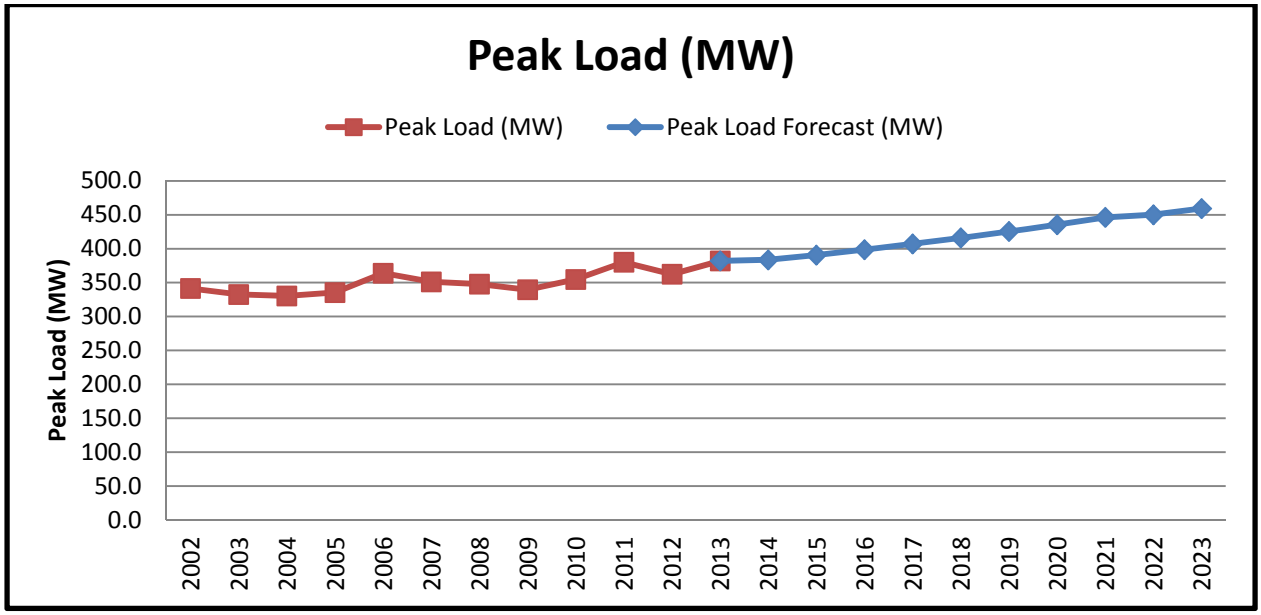


Figure 2

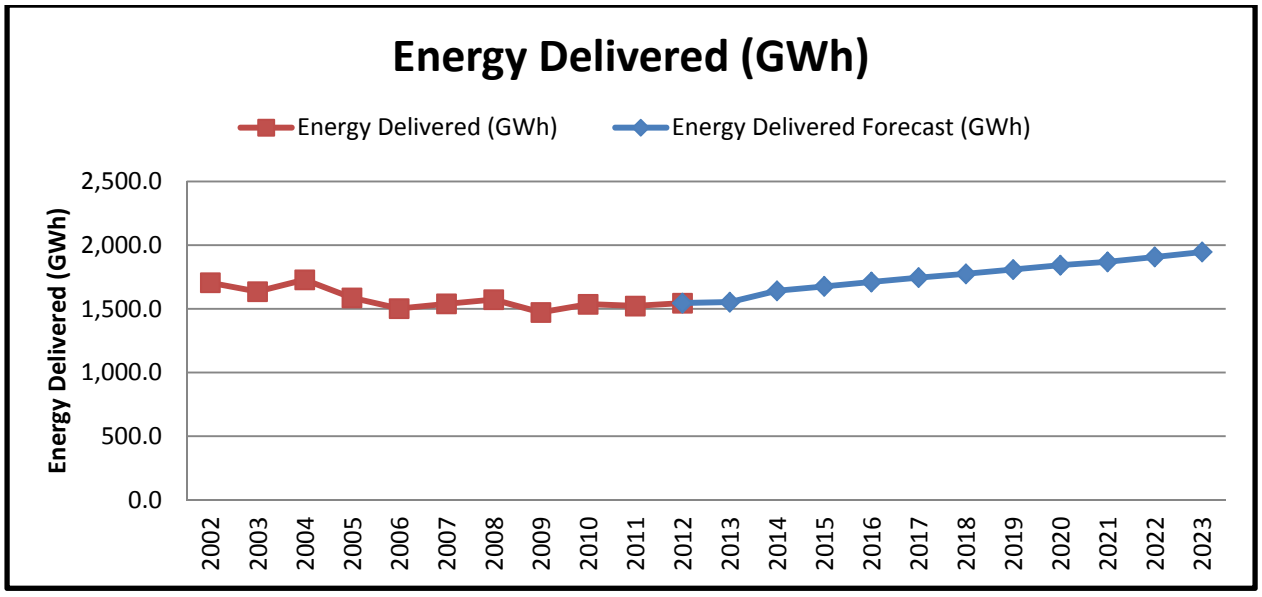


Figure 3

OHEDI's Provincial Ranking

The following table shows OHEDI's overall provincial ranking for number of customers, netbook value of assets, and area served based upon the 2011 Yearbook of Electricity Distributors published on September 13, 2012 by the OEB.

Table 2

	# of Customers	NBV, $M Total Assets	Area served, sq. km
Oakville Hydro	63,614	$218	143
Rank (#1 indicates the most)	Burlington Hydro #12	EnWin Utilities #11	Lakeland Power #33
	Oakville Hydro #13	Oakville Hydro #12	Oakville Hydro #34
	Oshawa PUC #14	Waterloo North #13	Niagara-on-the-Lake #35

Network Configuration & System Description

Supply Points

OHEDI's distribution system is supplied from four Hydro One owned transformer stations (TS), and one municipal transformer station (MTS) as shown in the following table.

Table 3

Name	Owner	Voltage	Area Serviced	Capacity MVA
Bronte TS	Hydro One Networks	115kV to 27.6kV	South West/Central Oakville	(ONAN/ONAF/ONAF) T2 – 50/67/83 (ONAN/ONAF/OFAF) T5 – 56/75/93 T6 – 56/75/93
Palermo TS	Hydro One Networks	230kV to 27.6kV	North West Oakville	(ONAN/ONAF/OFAF) T3 – 50/67/83 T4 – 50/67/83
Oakville TS	Hydro One Networks	230kV to 27.6kV	South East/Central Oakville	(ONAN/ODAN/ODAF) T5 – 75/100/125 T6 – 75/100/125
Trafalgar TS	Hydro One Networks	230kV to 27.6kV	North East Oakville	(ONAN/ODAN/ODAF) T1 – 50/67/83 T2 – 50/67/83
Glenorchy MTS	OHEDI	230kV to 27.6kV	North Central Oakville	(ONAN/ONAF/ONAF) T1 – 75/100/125 T2 – 75/100/125

OHEDI's distribution system is designed to enable the control of load flow in response to changing demand in the Town of Oakville. Hydro One's four transformer stations that supply OHEDI's distribution system are connected to three different transmission circuits. Due to this configuration, OHEDI is called on frequently by Hydro One to shift load in its distribution system to assist Hydro One in managing both the transformer station load levels and the transmission circuit load levels.

System Configuration

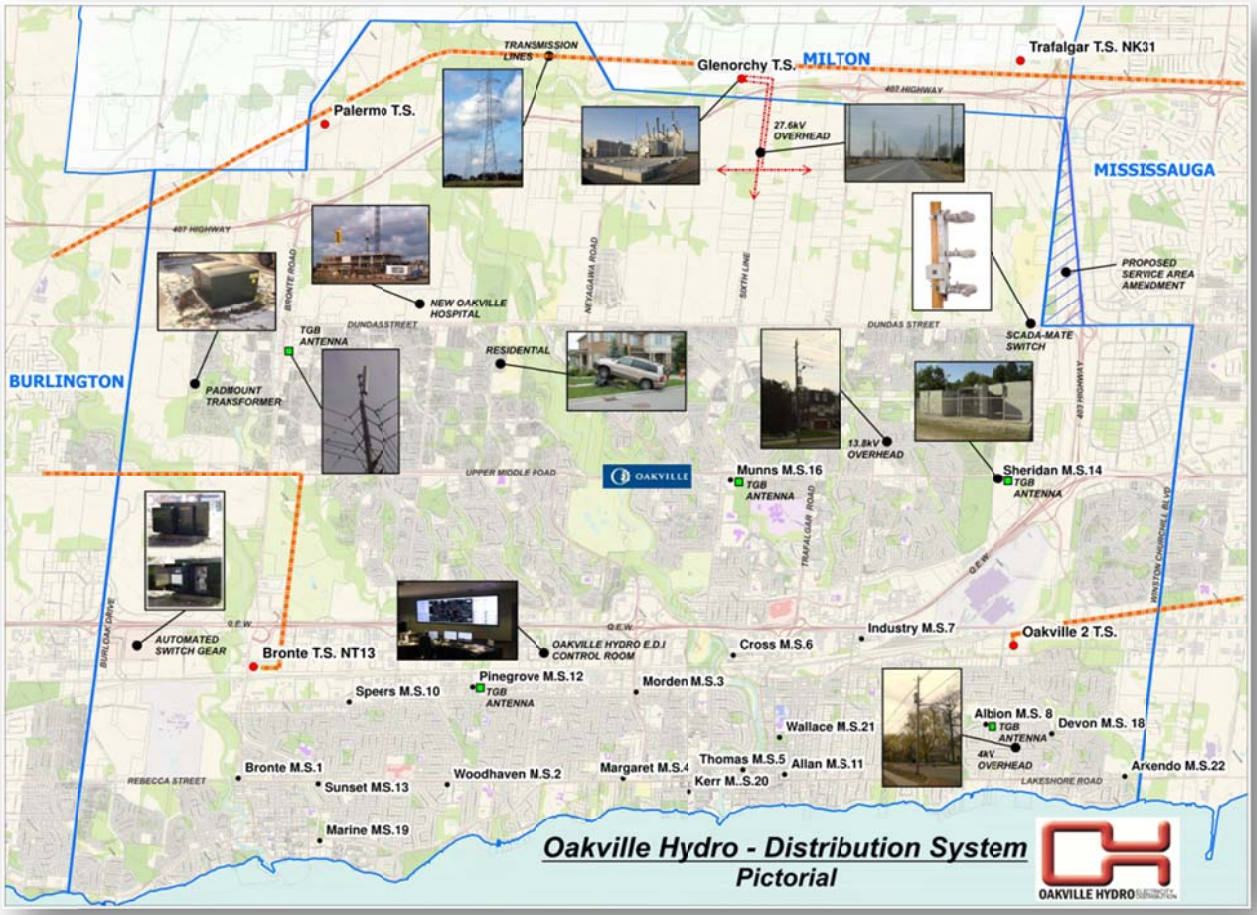


Figure 4

27.6kV Circuits

Table 4

Feeder	Transformer Station Supply	OH Wire Lengths (m)	UG Cable Length (m)
13M1	Bronte T.S.	24,224	9,054
13M2	Bronte T.S.	10,085	28,240
13M23	Bronte T.S.	11,035	10,844
13M24	Bronte T.S.	28,548	35,365
13M25	Bronte T.S.	15,388	0
13M26	Bronte T.S.	15,800	0
13M3	Bronte T.S.	22,803	24,391
13M4	Bronte T.S.	14,820	11,828
13M5	Bronte T.S.	13,574	4,533
13M6	Bronte T.S.	4,768	0
13M7	Bronte T.S.	4,484	0
13M8	Bronte T.S.	38,814	20,494
1M14	Glenorchy M.T.S.	15,370	920
1M15	Glenorchy M.T.S.	30,830	82,059
1M16	Glenorchy M.T.S.	8,215	910
1M17	Glenorchy M.T.S.	15,337	24,656
1M18	Glenorchy M.T.S.	30,719	84,493
1M19	Glenorchy M.T.S.	8,525	806
22M43	Oakville T.S.	38,164	84,941
22M44	Oakville T.S.	36,388	14,189
22M49	Oakville T.S.	24,060	1,657
22M50	Oakville T.S.	38,166	15,223
22M51	Oakville T.S.	12,926	16,630
22M52	Oakville T.S.	60,937	36,044
4-M2	Palermo T.S.	14,301	18,366
4-M4	Palermo T.S.	28,388	92,493
4-M7	Palermo T.S.	32,446	185,282
4-M8	Palermo T.S.	46,649	125,047
31M4	Trafalgar T.S.	27,185	32,040
31M5	Trafalgar T.S.	38,123	35,631
31M6	Trafalgar T.S.	38,203	8,126
31M7	Trafalgar T.S.	66,821	94,905
31M8	Trafalgar T.S.	17,054	108,176
Total		**883,214**	**1,208,184**

Information on Oakville T.S. feeder 22M45(Hydro One), Palermo T.S. feeders 4-M1 (Milton), 4-M3 (Milton), 4-M5 (Burlington), and 4-M6 (Burlington) removed from table.

Municipal Substations

OHEDI owns and operates 19 municipal stations, two at 13.8kV and 17 at 4.16kV. The municipal station information is shown in the following table.

Table 5

Name	Voltage	Area Serviced	Capacity (ONAN/ONAF) kVA
Bronte MS 1	27.6kV to 4.16kV	South West Oakville	T1 – 6000/8000 T2 – 6000/8000
Woodhaven MS 2	27.6kV to 4.16kV	South West Oakville	5000/6667
Morden MS 3	27.6kV to 4.16kV	South Central Oakville	6000/8000
Margaret MS 4	27.6kV to 4.16kV	South Central Oakville	6000/8000
Thomas MS 5	27.6kV to 4.16kV	South Central Oakville	6000/7998
Cross MS 6	27.6kV to 4.16kV	South Central Oakville	5000/6666
Industry MS 7	27.6kV to 4.16kV	South East Oakville	6000/8000
Albion MS 8	27.6kV to 4.16kV	South East Oakville	5000/6667
Speers MS 10	27.6kV to 4.16kV	South Central Oakville	6000/8000
Pinegrove MS 12	27.6kV to 4.16kV	South West Oakville	6000/8000
Sunset MS 13	27.6kV to 4.16kV	South West Oakville	6000/8000
Sheridan MS 14	27.6kV to 13.8kV	North East Oakville	T1 – 10000/13330 T2 – 10000/13330
Munns MS 16	27.6kV to 13.8kV	North Central Oakville	T1 – 10000/13300 T2 – 10000/13300
Victoria MS 17	27.6kV to 4.16kV	South Central Oakville	5000/6667
Devon MS 18	27.6kV to 4.16kV	South East Oakville	6000/8960
Marine MS 19	27.6kV to 4.16kV	South West Oakville	6000/7998
Kerr MS 20	27.6kV to 4.16kV	South Central Oakville	6000/8000
Wallace MS 21	27.6kV to 4.16kV	South Central Oakville	6000/8960
Arkendo MS 22	27.6kV to 4.16kV	South East Oakville	6000/8000

13.8kV Circuits

Table 6

Feeder	Municipal Station Supply	OH Circuit Lengths (m)	UG Circuit Length (m)
14F1	Sheridan MS14	17,284	9,178
14F3	Sheridan MS14	3,997	26,054
14F4	Sheridan MS14	8,389	10,397
16F1	Munns MS16	9,955	22,165
16F3	Munns MS16	5,777	15,675
16F4	Munns MS16	11,442	18,381
Total		**56,844**	**101,873**

Information on Sheridan MS14 F2 and Munns MS16 F2 removed from this table.

8.32kV Circuits

There are two areas of OHEDI's distribution system that are fed at 8.32kV, one serviced from Milton Hydro feeders, and the other serviced from OHEDI's 27.6kV system through a set of "Rabbit" step down/up transformers.

4.16kV Circuits

Table 7

Feeder ID	Municipal Station Supply	OH Wire Lengths (m)	UG Cable Length (m)
MS10-F1	Speers MS10	10,476	457
MS10-F2	Speers MS10	12,408	229
MS10-F3	Speers MS10	1,248	13,574
MS10-F4	Speers MS10	4,322	728
MS12-F1	Pinegrove MS12	2,152	892
MS12-F2	Pinegrove MS12	13,132	1,010
MS12-F3	Pinegrove MS12	13,231	1,041
MS12-F4	Pinegrove MS12	2,103	1,044
MS13-F1	Sunset MS13	5,087	3,804
MS13-F2	Sunset MS13	0	6,527
MS13-F3	Sunset MS13	1,847	1,996
MS13-F4	Sunset MS13	8,228	739
MS17-F1	Victoria MS17	3,163	2,831
MS17-F2	Victoria MS17	1,535	7,304
MS17-F3	Victoria MS17	3,581	1,065
MS17-F4	Victoria MS17	2,003	1,867
MS18-F1	Devon MS18	2,719	6,870
MS18-F2	Devon MS18	0	12,429
MS18-F3	Devon MS18	1,277	9,196
MS18-F4	Devon MS18	0	8,425
MS19-F1	Marine MS19	1,700	5,075
MS19-F2	Marine MS19	0	3,865
MS19-F3	Marine MS19	3,828	8,354
MS19-F4	Marine MS19	3,419	2,677
MS1-F1	Bronte MS1	5,686	7,812
MS1-F2	Bronte MS1	7,144	2,154
MS1-F3	Bronte MS1	3,168	8,782
MS1-F4	Bronte MS1	9,890	7,507
MS1-F5	Bronte MS1	2,981	8,335
MS20-F1	Kerr MS20	387	6,991
MS20-F2	Kerr MS20	3,638	2,245
MS20-F3	Kerr MS20	3,369	2,869

Feeder ID	Municipal Station Supply	OH Wire Lengths (m)	UG Cable Length (m)
MS21-F1	Wallace MS21	4,414	652
MS21-F2	Wallace MS21	7,161	973
MS21-F3	Wallace MS21	3,557	1,641
MS21-F4	Wallace MS21	3,893	3,346
MS22-F1	Arkendo MS22	1,430	7,887
MS22-F2	Arkendo MS22	3,451	12,837
MS22-F3	Arkendo MS22	3,259	4,606
MS2-F1	Woodhaven MS2	5,075	2,785
MS2-F2	Woodhaven MS2	4,236	281
MS2-F3	Woodhaven MS2	8,236	1,134
MS2-F4	Woodhaven MS2	5,998	1,393
MS3-F1	Morden MS3	961	4,248
MS3-F2	Morden MS3	4,599	1,609
MS3-F3	Morden MS3	11,933	1,130
MS3-F4	Morden MS3	2,777	5,314
MS4-F1	Margaret MS4	3,525	4,584
MS4-F2	Margaret MS4	6,788	3,719
MS4-F3	Margaret MS4	10,004	6,221
MS4-F4	Margaret MS4	8,326	1,643
MS5-F1	Thomas MS5	8,326	1,948
MS5-F2	Thomas MS5	4,594	1,452
MS5-F3	Thomas MS5	0	6,611
MS5-F4	Thomas MS5	806	6,457
MS6-F2	Cross MS6	5,388	1,377
MS6-F3	Cross MS6	188	4,981
MS6-F4	Cross MS6	6,823	2,933
MS7-F1	Industry MS7	9,577	4,409
MS7-F2	Industry MS7	11,723	1,297
MS7-F3	Industry MS7	18,043	4,419
MS7-F4	Industry MS7	7,329	209
MS8-F1	Albion MS8	6,470	1,781
MS8-F2	Albion MS8	9,197	4,086
MS8-F3	Albion MS8	10,896	605
MS8-F4	Albion MS8	523	1,005
Total		**333,228**	**261,882**

Information on Allan MS11 F1, F2, F3, Arkendo MS22 F4, Cross MS6 F1, and F5 removed from this table.

Major Distribution Assets

OHEDI's major distribution assets and quantities are shown in the following table.

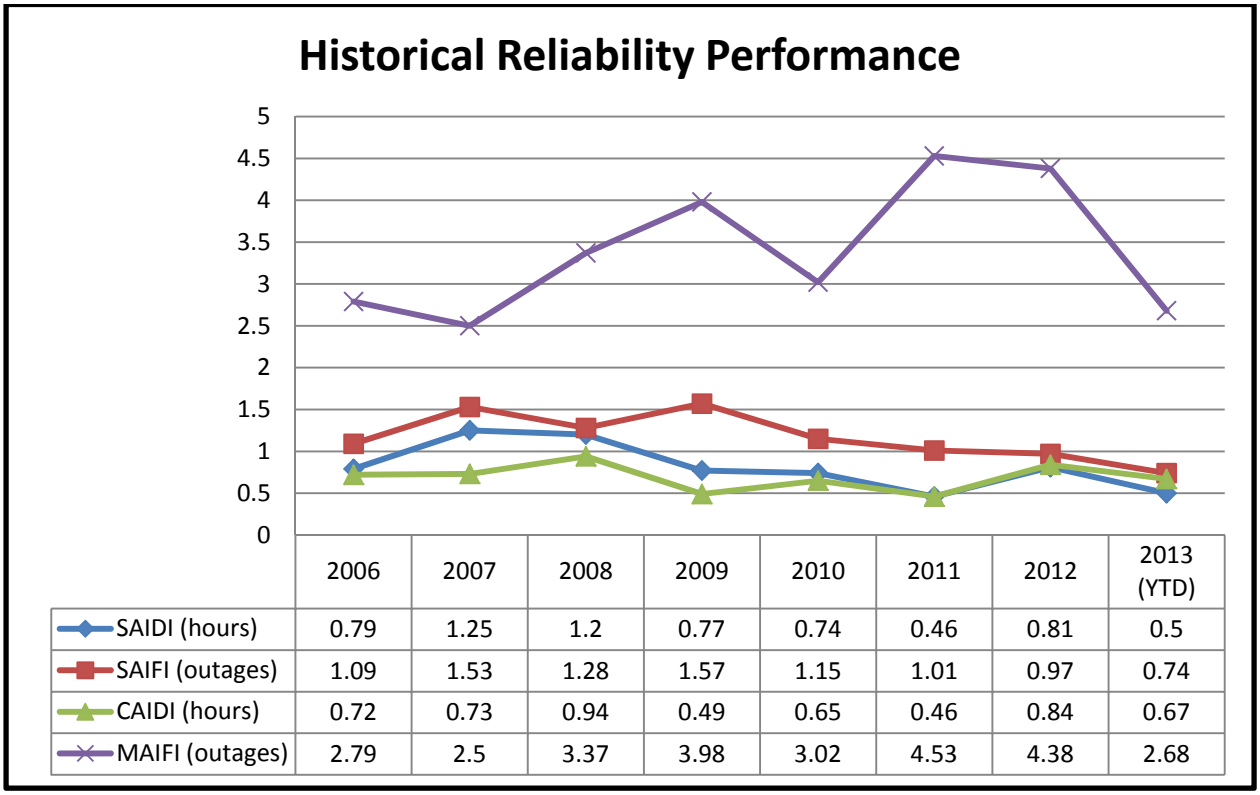
Table 8

Asset	Quantity	Average Age (Yrs.)	Age Range (Yrs.)	Average Condition
MTS Power Transformer (Glenorchy)	2	2	2	Very Good
MS & Customer Specific Power Transformer (CSPT)	36	35.5	1 – 56	Good
Low Voltage Station Switches (4.16 & 13.8kV)	20	3.4	2 – 4	Very Good
Low Voltage Station Breakers (4.16 & 13.8kV)	87	27.2	1 - 44	Good
High Voltage Station Switches (27.6kV Open Air)	38	36.5	1 – 56	Good
High Voltage Station Switches (27.6kV GIS)	46	2	2	Very Good
High Voltage Station Breakers (27.6kV)	21	2	2	Very Good
High Voltage Station Switches (230kV)	2	2	2	Very Good
Overhead Distribution Transformer	1759	26.9	1 – 73	Very Good
Padmount Distribution Transformer	4713	17.8	1 – 50	Very Good
Submersible Distribution Transformer	1243	17.1	1 – 47	Very Good
Vault-style Distribution Transformer	231	39.5	13 – 64	Good
Padmount Switchgear	173	24	1 – 43	Good
Vault-style Switchgear	11	13	6 – 43	Fair
Overhead Gang-Operated Switch	123	29	1 – 32	Good
Overhead Primary Wire Circuit Kilometers	688	29	1 – 72	Good
Underground Primary Cable Circuit Kilometers	840	23	1 – 44	Good
Poles – Mostly wood	8991	26	1 – 72	Good
Secondary Cable Kilometers	1067	23	1 – 72	Fair
Residential Meters	58,720	2.5	1 – 11	Very Good
General Service <50kW Meters	5,014	2	1 – 11	Very Good
General Service >50kW Meters	878	11	1 – 31	Good
General Service >1000kW Meters	16	11	1 – 31	Good
Microfit Meters	24	2.5	1 – 3	Very Good
Primary Meters	44	21	1 – 43	Good
Remote Terminal Units (RTUs)	116	11	1 – 21	Good

*The average age of OHEDI's Distribution System is approximately 25 years old.

The quantities shown are as of August 27, 2013.

Historical Reliability Performance



	2006	2007	2008	2009	2010	2011	2012	2013 (YTD)
SAIDI (hours)	0.79	1.25	1.2	0.77	0.74	0.46	0.81	0.5
SAIFI (outages)	1.09	1.53	1.28	1.57	1.15	1.01	0.97	0.74
CAIDI (hours)	0.72	0.73	0.94	0.49	0.65	0.46	0.84	0.67
MAIFI (outages)	2.79	2.5	3.37	3.98	3.02	4.53	4.38	2.68

Figure 5 – As of July 31, 2013

SAIDI is the average sustained interruption duration per customer served per year (measured in hours). Calculation is "Total Customer Hours of Interruptions" divided by "Total Number of Customers".

SAIFI is the average number of sustained interruptions experienced per customer served per year (measured in outages). Calculation is the "Total Customer Interruptions" divided by "Total Number of Customers".

CAIDI is the average sustained interruption duration experienced by interrupted customers per year (measured in hours). Calculation is SAIDI divided by SAIFI.

MAIFI is the average number of momentary interruptions less than 60 seconds experienced per customer served per year (measured in outages). Calculation is the "Total Momentary Customer Interruptions" divided by the "Total Number of Customers".

The historical reliability performance graph includes issues/events attributable to OHEDI's distribution system and MTS, and does not include external factors such as loss of supply from Hydro One.

Asset Management Process Documents

Asset Management Policy

OHEDI has adopted an Asset Management Policy (AMPo) to help staff support OHC's & OHEDI's vision, goals and objectives. The AMPo contains information such as the asset management policy statements, background and purpose of the policy, the policy principles, guidelines and integration, and key roles & responsibilities for the asset management policy.

Asset Management Strategy

OHEDI has created an Asset Management Strategy (AMS) which was derived from the AMPo, and the OHEDI Strategy. The AMS contains information such as the asset management guiding principles, asset management framework, a 20-Year capital asset view, information regarding major external challenges and commitments, the asset maintenance strategy, and the major distribution assets and replacement criteria.

Asset Management Objectives

OHEDI's Asset Management Objectives (AMO) was derived from the AMS and the OHEDI Objectives. The AMO contains information such as OHEDI's main objectives, asset risk management, performance reporting frameworks, 20-year capital asset view, inspection, condition assessments & health index, asset management system, procurement efficiency and PAS 55.

Capital Expenditure Plan

OHEDI's Capital Expenditure Plan (CEP) was derived from the AMO and the OHEDI Objectives. The CEP contains key information about OHEDI's capital expenditures including, by category, significant projects and activities to be undertaken and their respective key drivers; the relationship between investments in each category, and OHEDI's objectives and targests.

Maintenance Expenditure Plan

OHEDI's Maintenance Expenditure Plan (MEP) was derived from the AMO and the OHEDI Objectives. The MEP contains information such a description of maintenance planning criteria and assumptions and a description of routine and preventative inspection and maintenance policies, practices and programmes.

OEB Chapter 5 Consolidated Distribution System Plan Filing Requirements

Section 5.2 of the Consolidated Distribution System Plan Filing Requirement (CDSPFR) states: *Distributors are encouraged to organize the required information using the section headings indicated. If a distributor's application uses alternative section headings and/or arranges the information in a different order, the distributor shall demonstrate that these requirements are met by providing a table that clearly cross-references the headings/subheadings used in the application.* The following table provides that clarity.

Table 9

CDSPFR Section	OHEDI Document	OHEDI Heading
5.3.1.a ***a description of the distributor's asset management objectives and related corporate goals, and the relationships between them; where applicable, show and explain how the distributor ranks asset management objectives for the purpose of prioritizing investments;***	AMO	OHEDI Capital Investment Objectives And OHEDI Capital Investment Objective Weighting
5.3.1.b ***information regarding the components (inputs/outputs) of the asset management process used to prepare a capital expenditure plan, identify and briefly explain the data sets, primary process steps, and information flows used by the distributor to identify, select, prioritize and/or pace investments; e.g.*** • ***asset register*** • ***asset condition assessment*** • ***asset capacity utilization/constraint assessment*** • ***historical period data on customer interruptions caused by equipment failure*** • ***reliability-based 'worst performing feeder' information and analysis*** • ***reliability risk/consequence of failure analyses.***	AMO	Major Distribution Asset Replacement
5.3.2.a ***a description and explanation of the features of the distribution service area (e.g. urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent for asset management purposes, highlighting where applicable expectations for the evolution of these features over the forecast period that have affected elements of the DS Plan;***	This document	About Oakville Hydro Electricity Distribution Inc.
5.3.2.b ***a summary description of the system configuration, including length (km) of underground and overhead systems; number and length of circuits by voltage level; number and capacity of transformer stations;***	This document	Network Configuration and System description
5.3.2.c ***information (in tables and/or figures) by asset type (where available) on the quantity/years in service profile and condition of the distributor's system assets, including the date(s) the data was compiled;***	This document	Major Distribution Assets

CDSPFR Section	OHEDI Document	OHEDI Heading
5.3.2.d ***an assessment of the degree to which the capacity of existing system assets is utilized relative to planning criteria, referencing the distributor's asset related objectives and targets*** • ***where cited as a 'driver' of a material investment(s) included in the capital expenditure plan, provide a level of detail sufficient to understand the influence of this factor on the scope and value of the investment.***	CEP	System Access System Renewal System Service General Plant
5.3.3.a ***description of asset lifecycle optimization policies and practices, including but not necessarily limited to:*** • ***a description of asset replacement and refurbishment policies, including an explanation of how (e.g. processes; tools) system renewal program spending is optimized, prioritized and scheduled to align with budget envelopes; and how the impact of system renewal investments on routine system O&M is assessed;*** • ***a description of maintenance planning criteria and assumptions; and*** • ***a description of routine and preventative inspection and maintenance policies, practices and programmes (can include references to the DSC).***	AMO	Major Distribution Asset Replacement
5.3.3.b ***A description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation, including but not necessarily limited to the methods used; types of information inputs and outputs; and how conclusions of risk analyses are used to select and prioritize capital expenditures.***	AMO	Major Distribution Asset Replacement

Oakville Hydro Electricity Distribution Inc. Asset Management Policy

OAKVILLE HYDRO

Policy Number:	AM2012-001	Supersedes Numbers:
Authority to Implement & Manage:	VP-Engineering and Operations & Chief Operating Officer (COO)	
Approval:	CEO	
Approval Date:	03/12/2012	
Effective Date:	03/12/2012	

1 ASSET MANAGEMENT POLICY STATEMENTS

Asset management is a broad strategic framework that encompasses many disciplines and involves the entire organization. The term "asset management", as used in this document, is defined as "the application of sound technical, social and economic principles that considers present and future needs of users, and the service from the asset". To guide Oakville Hydro Electricity Distribution Inc. (OHEDI), the following policy statements have been developed:

a) OHEDI will continuously refine its asset management program to meet system capacity, reliability, security and operating requirements while ensuring long term affordability and responsible stewardship of the distribution system.
b) OHEDI will continue to meet and maintain regulatory and service requirements, employing good utility practices, while balancing between customer expectations and lifecycle costs.
c) OHEDI will maintain compliance to health and safety policies, environmental regulations, and electricity rates and filing requirements.
d) OHEDI will optimize capital and maintenance costs throughout the lifecycle of the asset, and corporate value will be enhanced through timely asset renewal.
e) OHEDI will drive asset investment decisions through condition-based system analysis with a goal to extend asset useful life, as appropriate.
f) OHEDI will incorporate the requirements for system growth and asset replacement or renewal decisions as noted in OHEDI's Smart Grid Strategy and Ontario's Green Energy Act.
g) OHEDI will incorporate the elements of the Asset Management Strategy in long term distribution system planning.
h) OHEDI will continually assess evolving technologies for consideration and potential application.

2 BACKGROUND AND PURPOSE OF POLICY

As the leading provider of energy services to the Town of Oakville, Oakville Hydro Corporation (OHC) envisions itself as being a key facilitator of the growth of the Town of Oakville. This is captured in the corporate vision statement "We energize you". In order to guide staff with the effective implementation of that vision, OHEDI develops policies in key areas of the business that are intended to support OHC's Vision, Goals and Objectives, and provide guidance to staff.

2.1 OHEDI's Vision and Goals for Infrastructure Assets

OHEDI's vision and goal is to develop & manage a safe, reliable, secure, and economically viable distribution system underpinned by well managed and maintained infrastructure assets. These assets include, but are not limited to efficient, economical and reliable electricity distribution networks, safe and reliable support structures, reliable information technology systems, and a productive fleet.

Though these assets age and deteriorate, by using sound asset management practices, OHEDI and OHC can be assured that the assets maintain performance levels, required to deliver the desired service standards in the long term and are managed for present and future users.

The intent of this policy is to articulate OHEDI's commitment to asset management, and provide guidance for implementation. This policy also outlines the manner by which it will be integrated within the organization to be coordinated, cost effective and organizationally sustainable. This policy also demonstrates to the Community that OHEDI is exercising good stewardship, and is delivering affordable services while considering its legacy to future customers.

Staff will implement the policy through the development and use of asset management guidelines and practices. The performance of asset management is organization-specific, reflective of knowledge, technologies, and available tools, and will continue to evolve over time.

3 POLICY PRINCIPLES, GUIDELINES AND INTEGRATION

The key principles of the asset management policy are outlined in the following list.

The organization shall:

- Make informed decisions, identifying all revenues and costs (including operation, maintenance, replacement and decommission) associated with infrastructure asset decisions, including additions and deletions. Trade-offs will be articulated and evaluated, and the basis for the decision recorded
- Integrate corporate, financial, business, technical and budgetary planning for infrastructure assets
- Establish organizational accountability and responsibility for asset inventory, condition, use and performance
- Consult with stakeholders where appropriate
- Define and articulate service, maintenance and replacement levels/outcomes

- Use available resources effectively
- Manage assets to be economically sustainable through condition based maintenance
- Minimize total life cycle costs of assets
- Consider environmental goals
- Consider social and sustainability goals
- Minimize risks to users and risks associated with failure
- Pursue best practices where available
- Establish the capability to report on portions of the asset management program as required

3.1 Guidelines and Practices

This policy shall be implemented by staff using accepted industry guidelines and practices. Staff shall utilize the approved asset management strategy and asset management plans.

The organization will also comply with required capital asset reporting requirements, and integrate the Asset Management program into operational plans throughout the organization.

Strategic asset management plans may be developed for a specific class of assets, or be generic for all assets, and will outline long term goals, processes and steps toward how they will be achieved. The asset management plans will be based on current inventories and condition (acquired or derived), projected performance and remaining service life and consequences of losses (e.g., vulnerability assessments). Operational plans will reflect these details. Replacement portfolios and associated financial plans will consider alternative scenarios and risks, as well as include Executive Management Team consultation.

3.2 Context and Integration of Asset Management within Organization

The context and integration of asset management throughout the organization's lines of business is typically formalized through references and linkages between corporate documents. Where possible and appropriate, OHEDI and its staff will incorporate the essence of this policy in the development of such corporate documents as:

- Smart Grid plan
- Business plans
- Corporate strategic plan
- Corporate financial plan
- Capital Budget plan
- Operational plans and budgets (including fleet and IT)
- Design criteria and specifications
- Infrastructure servicing, management and replacement plans
- Regional system planning

4 KEY ROLES & RESPONSIBILITIES IN SUPPORT OF THE ASSET MANAGEMENT POLICY

OHEDI policies are approved by the Chief Executive Officer (CEO). While staff and other agencies may provide input on the nature and text of the policy, the CEO retains the authority to approve, update, amend or rescind policies.

Role	Responsibility
Identification of issues, and development of policy updates	CEO and staff
Establish levels of service	CEO, staff and public
Exercise stewardship of assets, adopt policy and budgets	VP-Engineering and Operations/COO and staff
Implementation of policy	VP-Engineering and Operations/COO and staff
Development of guidelines and practices	VP-Engineering and Operations/COO and staff
On-going review of policies	CEO and staff

4.1 Implementation, Review and Reporting of Asset Management Work

The implementation, review and reporting back regarding this policy shall be integrated within the organization. Due to the importance of this policy, the organization's asset management program shall be reported annually to the Board, and implementation of this policy reviewed by the CEO.

Actions	Responsibility
Adopt Asset Management Policy	Board and CEO
Monitor and review infrastructure standards and service levels at established intervals	CEO and VP-Engineering and Operations/COO
Develop and maintain infrastructure strategies including development and service plans	Engineering, Asset & Control, and Finance departments
Develop and maintain asset inventories	Asset & Control department
Assess infrastructure condition and service levels	Asset & Control department
Establish and monitor infrastructure replacement levels through the use of full life cycle costing principles	Asset & Control department
Develop and maintain financial plans for the appropriate level of maintenance, rehabilitation, extension and decommission of assets	Engineering, Asset & Control, and Finance departments
Report to Board on status of OHEDI's infrastructure assets and asset management program. The channels include business plans, etc.	CEO, VP-Engineering and Operations/COO

Endorsed: Mike Brown, VP-Engineering and Operations/COO — Date: 2012/12/03

Approved: Rob Lister, President & CEO — Date: 2012/12/03

2013/14

Oakville Hydro Electricity Distribution Inc.

Asset Management Strategy

02/08/2013

Version 1J

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Introduction

The Oakville Hydro Electricity Distribution Inc. (OHEDI) Asset Management Strategy encompasses relevant strategies associated with integrated capital investment, asset maintenance and asset retirement. It covers all distribution assets including power transformers, station switches and breakers, distribution transformers, switchgears, overhead switches, primary wire and cable, secondary wire and cable, poles and meters. It is derived from, and consistent with the goals of OHEDI's strategic plan.

Asset Management Strategy

The following guiding principles define the over-arching strategy for managing assets at OHEDI. Each principle is internally consistent with, and contributes to achieving OHEDI's values:

- Refine continuously the asset management program to meet reliability, demand, security and capacity requirements while ensuring long term affordability and responsible stewardship of the distribution system.
- Continue to meet and maintain regulatory and service requirements employing good utility practices while balancing between customer expectations and lifecycle costs.
- Compliance to health and safety policies, environmental regulations, electricity rates and filing requirements.
- Capital and maintenance costs optimized throughout the lifecycle of the asset, and corporate value enhanced through asset renewal.
- Condition-based system analysis to drive asset investment decisions, with a goal to extend asset useful life, as appropriate.
- System growth and asset replacement or renewal decisions incorporating requirements as identified in OHEDI's Smart Grid Strategy and Ontario's Green Energy Act.
- Longer term distribution system planning incorporating the elements of this asset management strategy.
- Regional system planning with IESO/OPA/Hydro One and neighbouring LDCs factored into this asset management strategy.
- Evolving technologies continually assessed for consideration and potential application.

Asset Management Framework

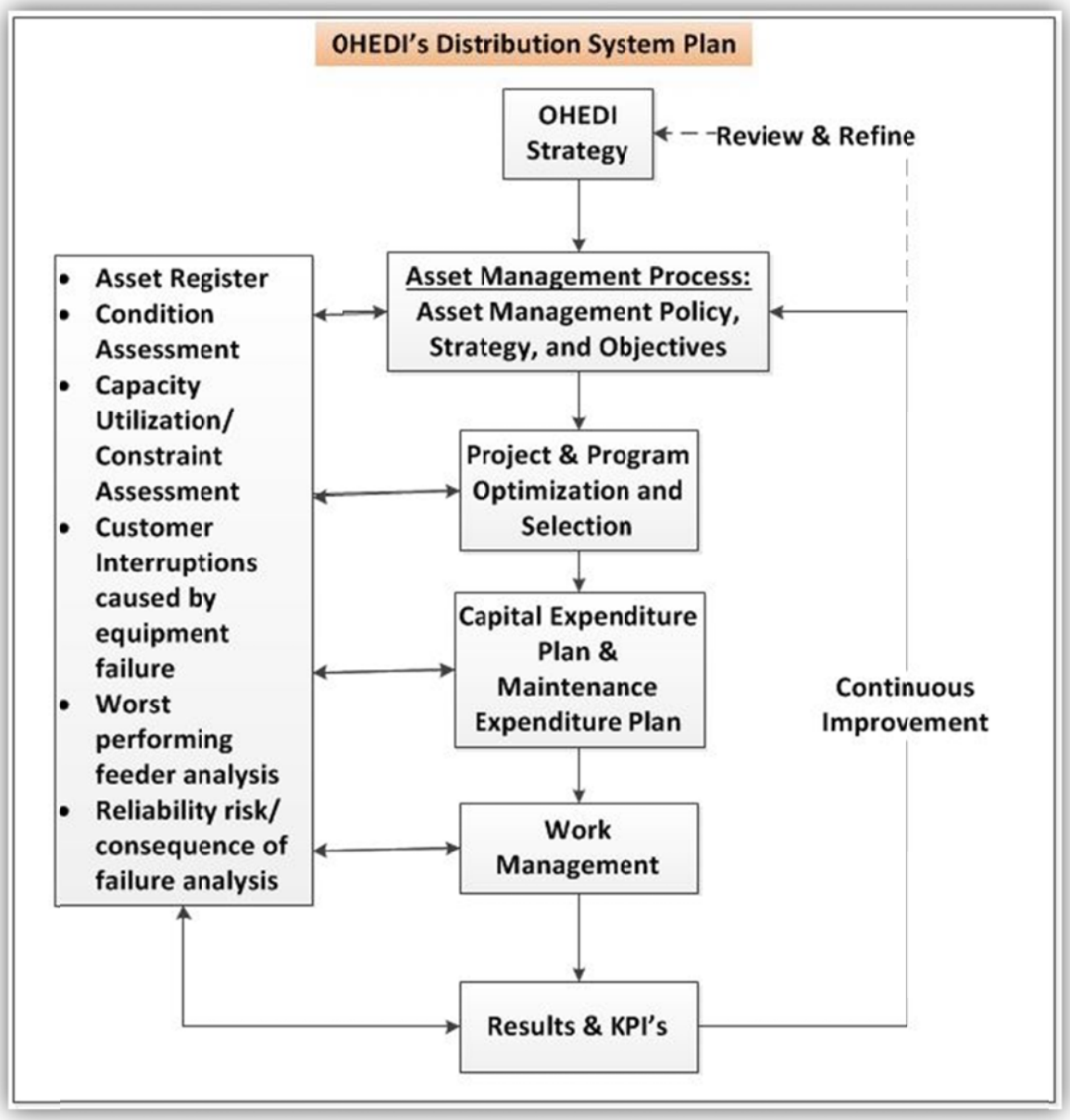


Figure 1

20-Year Capital Asset View

OHEDI has reviewed the Major External Challenges and Commitments, Asset Maintenance Strategy and Major Distribution Asset Replacement topics in order to confirm that all asset replacement activities are done in a long-term sustainable and affordable manner. This approach will prevent 'peaks and valleys' of asset renewal, and allow for a more consistent and relatively steady capital investment over the long-term.

OHEDI has compiled a capital view for the next 20 years using load forecasts, condition/age assessments, and system planning requirements. OHEDI has a number of assets which have passed their typical useful life (TUL). Certain types of assets in our system, based on critical role, implications to service and timelines to replace, have been identified as 'proactive' replacement candidates. These assets will be prioritized for replacement, and are incorporated into OHEDI's multi-year capital plan. There are also assets which are approaching their TUL within this 20 year timeframe as well. OHEDI's intent is to plan replacement of certain assets proactively, based on current condition-based assessments and their role in the system. This approach will assist in mitigating 'spikes' in capital requirements over this period, allowing OHEDI to effectively manage this risk.

Additional assets have been designated as 'run to failure' entities (e.g. distribution transformers) based on localized impacts and ability to efficiently replace. Processes are in-place to manage these cases expediently.

Major External Challenges and Commitments

OHEDI is required to make investments necessitated by external challenges and commitments, which are non-discretionary in nature. These investments include:

- Relocation resulting from municipal/regional/provincial road widening or intersection improvement projects.
- Implementation of Smart Grid initiatives.
- Enhancement of the system to accommodate load growth from new subdivisions or large individual customers.
- Incorporation of distributed generators.

Road widening/intersection improvement projects can be initiated by the Town of Oakville, Halton Region, or the Ministry of Transportation Ontario. These projects are mandatory. OHEDI expects a downward trend in these types of projects over the next 20 years.

OHEDI will actively collaborate in Smart Grid Pilot demonstration projects that have been appropriately funded through the Ministry of Energy and, in addition, approved by the Ontario Energy Board (OEB). Oakville Hydro will ensure that all other smart grid or grid transformation initiatives align with Oakville Hydro's current Strategic Plan by including them in the capital project portfolio to be evaluated (including business case assessment) and prioritized as set out in this Asset Management Strategy.

Customer connection projects can be initiated through the building of a new lot or subdivision, and/or re-building of a currently serviced property. These projects are mandatory as part of our obligation to serve. OHEDI expects an upward trend in these type projects in the next 18 years, at which time it will peak and then decline.

Asset Maintenance Strategy

The OEB outlines the minimum inspection and interval requirement in the Distribution System Code (DSC). The Town of Oakville is considered an urban area therefore the OEB minimum inspection cycle requirements for all transformers, switches, cables, poles, and civil infrastructure is once every three years. The OEB definition of this requirement is as follows:

"Patrol or simple visual inspections consists of walking, driving or flying by equipment to identify obvious structural problems and hazards such as leaning power poles, damaged equipment enclosures, and vandalism. In cases where a patrol notices that a problem exists or identifies a condition that warrants a more thorough or rigorous inspection, patrol may then include situations where structures are opened as necessary, and individual pieces of equipment carefully observed and their condition noted and recorded. The specifics of these inspections are recorded, and a summary document prepared in the distributor's annual reports as part of their rates or licensing submissions."

OHEDI utilizes a combination of patrols and maintenance activities to complete these inspection requirements, and records information regarding the condition of distribution assets. A minimum of one-third of each major asset is either patrolled or has maintenance performed each year in order to ensure all assets are inspected a minimum of once every three years. During the patrol, minor maintenance or critical items, that may be immediately addressed, are resolved and reported. Major maintenance that requires more complex coordination is subsequently scheduled for completion within the year, or planned for future years.

OHEDI analyzes the feedback from inspection and maintenance routines, as part of condition-based asset assessments. Decisions to replace assets versus proceeding with ongoing maintenance (to extend life), are determined based on a business case assessment.

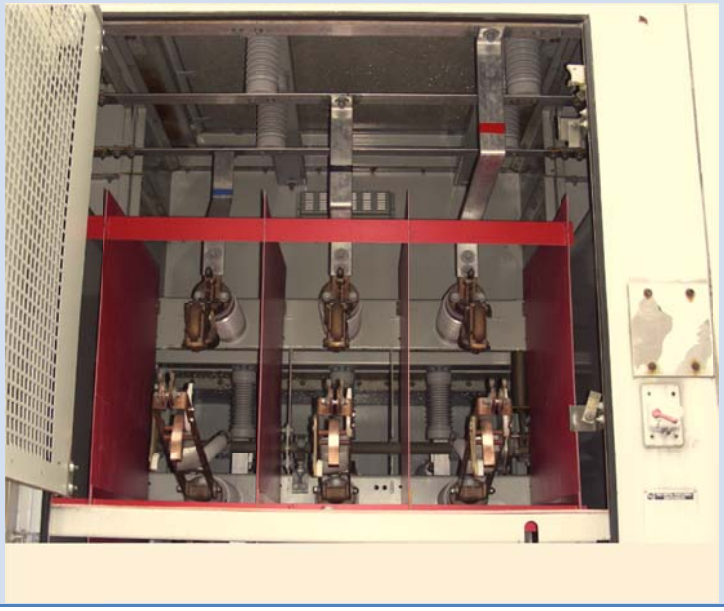
In addition, OHEDI has a Municipal Transformer Station (MTS) – Glenorchy - connected to the grid, which has specific inspection and maintenance standards identified in the OEB Transmission Code.

Major Distribution Assets and Replacement Criteria

Generally speaking, assets labeled with a 'proactive' strategy will be replaced when their age reaches the Typical Useful Life (TUL) and a pre-set condition. Assets labeled with a 'run-to-failure' strategy are allowed to pass their TUL and will only be replaced upon failure. The table below shows how OHEDI treats each major asset class.

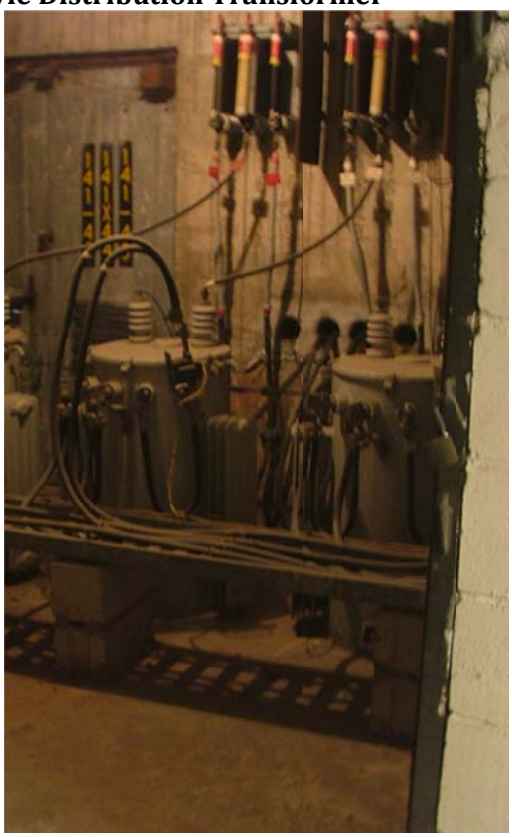
Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
Municipal Transformer Station - Power Transformer (Glenorchy) 	2	1 [1]	Proactive
Municipal Sub-station & Customer Specific Power Transformer (CSPT)  	36	34.5 [1 - 55]	Proactive

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
Low Voltage Station Switches (4.16 & 13.8kV) 	20	2.4 [2 - 3]	Proactive
Low Voltage Station Breakers (4.16 & 13.8kV) 	87	26.2 [1 - 43]	Proactive

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
High Voltage Station Switches (27.6kV Open Air) 	38	35.5 [1 - 55]	Proactive
High Voltage Station Switches (27.6kV GIS) 	46	1 [1]	Proactive
High Voltage Station Breakers (27.6kV)	21	1 [1]	Proactive

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
High Voltage Station Switches (230kV) 	2	1 [1]	Proactive

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
Overhead Distribution Transformer 	1812	25.9 [1 - 72]	Run-To Failure
Padmount Distribution Transformer 	4857	16.8 [1 - 49]	Run-To Failure

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
Submersible Distribution Transformer 	1235	18.1 [1 - 46]	Run-To Failure
Vault-style Distribution Transformer 	223	38.5 [13 - 63]	Proactive

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
Padmount Switchgear 	170	23 [1 - 42]	Proactive
Vault-style Switchgear 	11	12 [6 - 42]	Proactive

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
Overhead Gang-Operated Switch 	123	28 [1 - 31]	Proactive
Overhead Primary Wire Circuit Kilometers 	561	28 [1 - 71]	Run-To Failure
Underground Primary Cable Circuit Kilometers 	894	22 [1 - 43]	Proactive
Poles – Mostly wood	8004	25 [1 - 71]	Proactive

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
Secondary Cable Kilometers 	1067	22 [1 - 71]	Run-To Failure
Residential Meters. 	58,720	1.5 [1 - 10]	Proactive
General Service <50kW Meters	5,014	1 [1 - 10]	Proactive
General Service >50kW Meters	878	10 [1 - 30]	Proactive
General Service >1000kW Meters	16	10 [1 - 30]	Proactive
Microfit Meters	24	1.5 [1 - 2]	Proactive
Primary Meters 	44	20 [1 - 42]	Run-To Failure

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
Remote Terminal Units (RTUs) 	116	10 [1 - 20]	Proactive

Summary

This document provides sufficient information, guidance and direction for the development and ongoing management of the Capital Expenditure Plan and Maintenance Expenditure Plan, separate documents which contain the detailed plans to achieve the outcomes of the Asset Management Strategy.

2013/14

Oakville Hydro Electricity Distribution Inc.

Asset Management Objectives

03/09/2013

Version 1I

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Introduction

The Oakville Hydro Electricity Distribution Inc. (OHEDI) Asset Management Objectives encompass relevant objectives associated with integrated capital investment, asset maintenance and asset retirement. It covers all distribution assets including power transformers, station switches and breakers, distribution transformers, switchgears, overhead switches, primary wire and cable, secondary wire and cable, poles and meters. It is derived from, and consistent with the OHEDI objectives.

OHEDI Capital Investment Objectives

The optimization of future programs and project portfolios allows OHEDI to ensure that future expenditures will be applied effectively to the appropriate areas of the system to mitigate risk to OHEDI Objectives described below. The risk is assessed by considering probability and consequence to these Objectives if a project or a program is not completed. The following are OHEDI's Objectives:

Financial

Value

This value deals with ensuring efficient spending of capital and maintenance costs. When assessing the impact on the financial value, OHEDI must consider the mitigation of maintenance expenditures, mitigation of lost revenue due to decreasing reliability, and mitigation of future capital expenditures, through the completion of the proposed projects and programs package, replacement of ageing assets, and maintenance practices.

Risk

Financial risk is measured by lost revenue due to lower reliability, and/or cost avoidance, and its measures are: 1) increased/decreased costs over a 10 year period, and 2) lost revenue or cost avoidance ranging from <$1,000 in lost revenue and/or cost avoidance to >$50,000 in lost revenue and/or cost avoidance.

Goal

The goal is to reduce costs associated with maintaining aging equipment and to mitigate, to the extent possible, future lost revenue due to lower reliability.

Service Quality

Service quality is currently split into two areas of focus. The first is SAIFI which stands for the System Average Interruption Frequency Index. SAIFI is impacted by the number of times a customer experiences a power interruption. The second is SAIDI which stands for the System Average Interruption Duration Index. SAIDI is impacted by the amount of time in which a customer experiences a power interruption.

SAIFI

Value

This value deals with ensuring that frequency of interruption to customers is not increasing. When assessing risk to the SAIFI value, OHEDI considers the impact on SAIFI through completion of the proposed projects and programs-package, replacement of ageing assets, and maintenance practices.

Risk

SAIFI risk is measured by the number of customers that will be without power due to failure of the assets included within the proposed projects and programs package, and its measures are: 1) types of customers affected, ranging from Individual Customer (<50kW) affected to Multiple TS Feeders (>20,000kW) affected, and 2) SAIFI improvements ranging from SAIFI<0.001 Improvement in SAIFI

(approximately 60 customer outages) to <0.030 Improvement in SAIFI (approximately 1800 customer outages).

Goal

Goal is to establish a downward trend in OHEDI's SAIFI, and mitigation of potential issues that could cause an increase in SAIFI.

SAIDI

Value

This value deals with ensuring that duration of interruption to customers is not increasing. When assessing risk to the SAIDI value, OHEDI considers the impact on SAIDI through completion of the proposed projects and programs package, replacement of ageing assets, and maintenance practices.

Risk

SAIDI risk is noted by the interruption duration. This risk will come from the amount of time customers could be without power due to the failure of the assets within the proposed project and programs package and its measures are: 1) Interruption duration ranging from Momentary <3 minutes to Outage >12 hours, and 2) SAIDI improvement raging from <0.001 Improvement in SAIDI (approximately 60 customer hours) to <0.030 Improvement in SAIDI (approximately 1800 customer hours).

Goal

Goal is to establish a downward trend in OHEDI's SAIDI, and mitigation of potential issues that could cause an increase in SAIDI.

Socio-Political

Value

This value deals with maintaining and enhancing the brand name and reputation of OHEDI. When assessing impact to the community image value, OHEDI considers the mitigation of written or verbal complaints to the company, through the completion of the proposed projects and programs package, replacement of ageing assets, and maintenance practices.

Risk

Socio-Political risk is measured by the number of written or verbal complaints ranging from <1 written or 5 verbal to >4 written or 20 verbal. The risk is also measured by the complaint escalation level, ranging from Individual concerns made to the company to General public outcry – national media coverage.

Goal

Goal is reduction in existing customer concerns and media focus, and minimizing complaints escalation.

Legal

Value

This value deals with managing cost and number of potential litigations brought against OHEDI by customers and also minimizing legal fees associated with OHEDI's business, e.g. acquiring easement rights.

Risk

Legal risk is measured by litigation costs that could be incurred due to the assets within the proposed projects and programs package. The risk measures are ranging from Litigation costs <$1,000 to Litigation costs >$500,000.

Goal

Goal is reduction in existing litigation costs, and minimizing to the extent possible legal costs associated with OHEDI's business.

Regulatory

Value

This value deals with ensuring compliance with directives/standards/regulations etc. issued by various regulatory bodies, such as OEB, ESA, OSHA, CSA, etc.

Risk

Regulatory risk is measured by severity of possible non-compliance that could occur due to assets within the proposed projects and programs package. The risk measures are ranging from OEB/ESA non-reportable compliance issues to OEB/ESA damaging regulatory impacts – loss of licence/franchise.

Goal

Goal is reduction in existing regulatory compliance issues, and mitigation of potential future regulatory non-compliance situations.

Safety

The safety is currently split into two areas of focus. The first is Employee Safety. The second is Public Safety.

Employee Safety

Value

This value deals with ensuring that OHEDI's employees work in a safe environment and that potential known safety hazards are eliminated or minimized to the extent possible.

Risk

Employee safety risk is measured by assessing potential severity of the safety issue that could occur due to the assets within the projects and programs package ranging from Minor Injury to Multiple loss time incidents and/or fatality.

Goal

Goal is the reduction in existing employee safety issues, and mitigation of employees' exposure to potential safety hazards.

Public Safety

Value

This value deals with public safety hazards associated with OHEDI's assets and is aimed at minimizing to the extent possible public exposure to such hazards.

Risk

Public safety risk is measured by assessing potential consequences of public exposure that could occur due to the assets within the projects and programs package, ranging from Potential for injury with no history, not life threatening to known hazard with history, possibly life threatening.

Goal

Goal is reduction in existing public safety incidents and mitigation of potential future safety hazards.

Environmental

Value

This value deals with managing and mitigating environmental issues to ensure that potential environmental hazards are minimized to the extent possible and that all environmental regulatory requirements are met.

Risk

Environmental risk is measured by the potential severity of environmental issues due to the assets within the proposed projects and programs package, ranging from minor disturbance, documentation not necessary to disturbance requiring Ministry of Environment assistance and public evacuation.

Goal

Goal is reduction in existing environmental incidents and mitigation of potential future incidents.

OHEDI Capital Investment Objective Weighting

In order to provide value added risk disciplined decision making OHEDI has assigned weightings to the above noted Capital Investment Objectives. The weightings ensure that capital investments are prioritized appropriately to mitigate the highest risks. The following figure shows the weighting of each of the objectives.

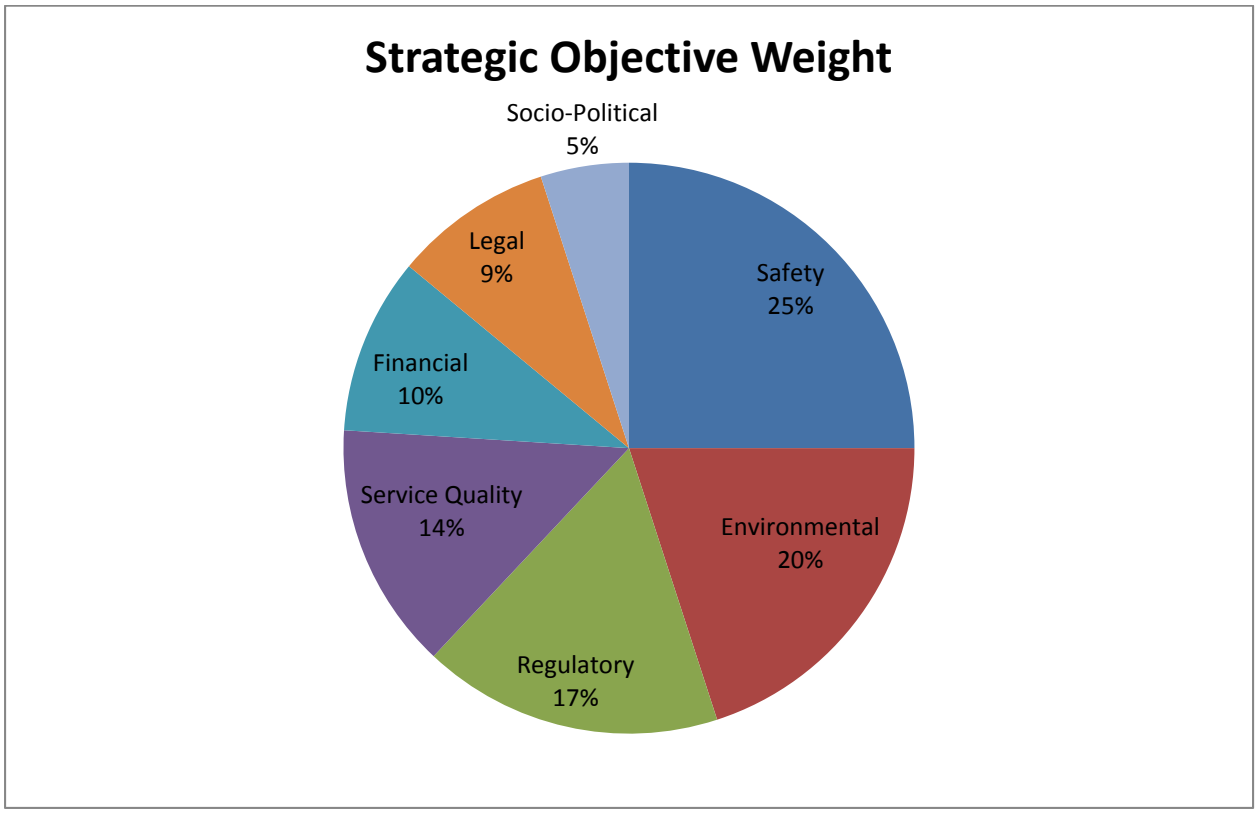


Figure 1

Safety, OHEDI's highest weighted Strategic Objective, is a combination of both employee safety and public safety sub criteria. Employee safety represents 12.5% and public safety represents 12.5% for a total of 25% weighting. Service quality is a combination of both SAIFI and SAIDI sub criteria. SAIFI represents 8.4% and SAIDI represents 5.6% for a total of 14% weighting.

Asset Risk Management

Risk Management is reviewed regularly by Senior Management with oversight from the Board's Governance and Risk Committee. The executive accountable for facilitating Corporate Risk is the Vice President - Engineering and Operations / COO. In Q3 2010, Oakville Hydro engaged an independent consultant (AESI – Acumen Engineered Solutions International Inc.) to conduct a detailed enterprise-wide risk assessment and assist in the development of a Risk Management framework.

The initial Risk Management review identified, at a high level, the wide range of risk areas to which the complete organization may be exposed. These risk areas were documented on the basis of – risk profile, current state, and control framework. The ten risk areas or categories identified were:

- Safety
- Reliability of Supply
- Customer Expectations
- Workforce Sustainability
- Reputational
- Financial
- Technology
- Cyber Security
- Regulatory and Policy
- Environmental

Each of these corporate Risk Areas, has been assigned to a member of the Executive Management Team for ongoing review and management. Within these areas or categories of risk, there were specific, high priority risks that surfaced as individual priorities or specific risks of greater concern. Based on this outcome, a Risk Management framework was put in-place that defined responsible resource for each specific risk. It focuses in on potential severity and probability as well as process steps to either eliminate, mitigate or manage these specific risks.

Quarterly update meetings are held to discuss each specific risk, in order to have updates provided which include noting any changes to the severity and probability of the risk occurring. It is during these meetings where any contingency arrangements and mitigation techniques are discussed and implemented. The updates are provided to the Executive Management Team (EMT) and then further reported quarterly to both the Board and the Board's Governance and Risk Committee.

Two asset-specific risks were identified in the above-noted process, which were:

- Localized outages due to underground cable faults and;
- Oil Spills from transformers, and oil entering waterways

Other asset specific risks are identified by conducting Subject Matter Expert (SME) interviews in which meetings are conducted with Supervisors and Lead Line Technicians from the company to identify areas of concerns in OHEDI's distribution system.

Specific risks identified were:

- Delta Transformers, which are typically over 40 years old and service Regional waste water treatment pumping stations. These transformers are not easily replaceable, and if they fail could cause flooding in the general vicinity due to the shutdown of the pumping stations they service.
- Poletran Transformers, which are typically over 44 years old and are difficult to operate due to insufficient access. They are also difficult to maintain due to limited availability of parts. Since the transformer are not a standard install, once failed, replacement would not be easy or quick and the customers fed from these locations could experience a lengthy outage.
- Porcelain insulators, which have tended to cause OHEDI issues in the past due to cracking and shattering. There have been a number of documented incidents where porcelain insulators have broken while being used, or have broken on their own, causing issues. These insulators are also more susceptible to contamination causing arcing across them which can turn into a flashover over time.
- Air Insulated 27.6kV Switchgears, which are at risk due to flashovers caused by contamination. The insulators inside of these switchgears are susceptible to salt spray contamination during the winter. When located in a high traffic area the contamination builds up and can cause arcing leading to flashovers. In these cases, typically the switchgear needs to be removed and either refurbished or scrapped entirely depending on the level of damage. Maintenance costs are higher with this type of switchgear due to the level of cleaning required to keep the insulators performing as they should.
- Rear Lot Primary, which is high voltage lines located in the backyards of customers properties. These lines are susceptible to falling tree limbs. Access to repair or replace the equipment in backyards is difficult, and any patrols following an outage are lengthy and cumbersome in order to locate issues.
- Vacuum Switches, which are typically over 30 years old and are prone to sudden failure without warning. There is no maintenance that can be performed in order to prevent these switches from failing, and there are no spare parts in order to have them fixed once failed.
- Submersible Switches, which are typically over 30 years old. There is no maintenance that can be performed in order to prevent these switches from failing, and there are no spare parts in order to have them fixed once failed.
- Livefront Transformers, which are typically over 40 years old. These transformers are not easily replaceable when failed as connections have to be changed from live front construction to dead front construction (terminators to elbows) and most current installations are slab on grade and must be converted to vaults to allow for proper termination of cables. Since the transformers are not a standard install, once failed, replacement would not be easy or quick and the customers fed from these locations could experience a lengthy outage.
- Vault Room Transformers, which are typically over 40 years old. These transformers are located inside buildings, and are typically live front construction. They pose a safety risk to crews performing patrols and maintenance due to their construction style. Typically the

cables servicing these transformers are direct buried, or have three cables installed in a single pipe which would pose a significant issue if the cables were to fail.

- Padmount transformer bushing and elbow replacements in non-vented areas. Older styles of inserts and elbows on padmount transformers do not have venting. The venting helps prevent electrical flashovers from occurring while line forces are isolating these transformers. Without venting present, larger outages are required in order to safely operate the transformers.
- Municipal station ground grid upgrades. The existing ground grids at some of the MS's have mechanical connections instead of compression and some of the metal fixtures within the station grounds are not properly connected to the ground grids.
- Municipal station service upgrades. The existing station services need improvements in order to meet ESA regulations.
- Repeater site upgrades. The current common communication repeater site requires upgrade to latest software/hardware for the OHEDI voice and RTU communication systems.
- Neutral substation protection. The protection schemes on our MS's and TS's and remote switches need to be enabled for neutral overcurrent protection.
- Municipal station fan and fan control upgrades. Existing fans do not have reporting capabilities, nor can be controlled from the OHEDI control room. There is no offsite ability to exercise the fans and to test functionality.
- Intelligent Electronic Device (IED) replacements. The older IED's in the OHEDI system are known to lose their settings requiring them to be reset manually.
- Remote fault indicators. Some areas of OHEDI's distribution system still do not have remote fault indicators. Without these indicators, it takes a longer time to identify the source of outages on the system.

Yearly SME meetings are held in order to capture additional risks that may become prevalent in the distribution system.

Performance Reporting Frameworks

In addition to the enterprise or corporate Risk Management framework and reporting structure notated above, OHEDI has other performance reporting frameworks in-place. This section describes in more detail how OHEDI receives updates regarding the risk position, key performance indicators, and investment requirements.

Financial Risk Reporting

An Internal Auditor conducts a comprehensive financial risk assessment audit using the Committee of Sponsoring Organizations (COSO) model approach. The findings from this audit are reviewed with the Board's Finance and Audit Committee. The Finance department compiles a report each month and forwards it to each department and to the Executives showing the OM&A spending for the previous month, and year-to-date. A detailed capital report is compiled monthly by the Finance department and is forwarded to each department and to the Executives. Both reports are then reviewed to ensure that overspending does not take place in any one area of the business, and appropriate measures can be taken in the case spending is trending too high.

Service Quality Risk Reporting

Monthly Service Quality Indicators (SQI) are published internally and submitted to the OEB annually. In addition, each month, an interruption report is produced which states the current and year-to-date values of System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI), and Momentary Average Interruption Frequency Index (MAIFI). The report also includes information regarding significant interruption causes. This report is then used to identify specific areas of investment and maintenance concentration within the OHEDI distribution system.

Community Image Risk Reporting

OHEDI engages an external consultant (UtilityPULSE) to conduct surveys of its customers annually, measuring respondents' feedback from over 20+ attributes that a customer could use to describe their thinking about how satisfied and loyal they might be towards their utility. The categories were split between customer care, company image, and management operations. The primary goal of really listening to customers and responding effectively to them is to create a higher level of affinity with our organization. With higher levels of affinity come higher levels of confidence that employees will handle their problems with speed and professionalism. This process results in less stress on our Customer Call-Centre. It also results in higher levels of acceptance of various communication bulletins and marketing messages which we send to our customers.

By effectively leveraging the findings from the customer survey, OHEDI can have meaningful conversations with staff about customers' – satisfaction, concerns, suggestions, etc. Utilities with a constructive employee culture with high levels of employee engagement will have an easier time navigating the choppy waters of the current environment. The reason is simple, everything OHEDI does and everyone in OHEDI represents the brand – hence its perceived value.

Regulatory Risk Reporting

One of OHEDIs key initiatives is the review of processes relating to compliance with laws and regulations. An inventory of compliance requirements has been compiled and the appropriate executive for each compliance requirement has identified a Departmental resource. The Departmental Resources are responsible for reporting on compliance and for monitoring and communicating any changes in compliance status to Regulatory Affairs for tracking purposes. Compliance status is reviewed on a quarterly basis and presented to the Board's Governance and Risk Committee. Changes to regulatory requirements or compliance status are used to prioritize areas of investment that enable regulatory compliance.

Safety Risk Reporting

An intranet Sharepoint site has been established for OHEDI to track safety issues within the organization. Topics include accident and incident investigation, contractor safety audits, employee injury and illness reports, joint health and safety committee corrective management, safety meeting minutes, management inspection forms, safety hazard notices, and safety tasks.

OHEDI uses another system, called Springboard, where reporting for training accumulation, competency required vs. actual competency, and custom KPIs are tracked.

Ministry of Labour, Canadian Electricity Association, and MEARIE tracking are also completed for benchmarking purposes. The benchmarks are reported to the Board and the Board's Human Resources Committee quarterly, and include loss time injuries, medical aids and hours of training for safety.

Environmental Risk Reporting

Environmental risk reporting is covered under regulatory risk reporting, as it is applicable to Ontario and Canadian regulations. In addition, it is highlighted within the Enterprise Risk framework.

20-Year Capital Asset View

OHEDI has reviewed the Major External Challenges and Commitments, Asset Maintenance Strategy and Major Distribution Asset Replacement topics in order to confirm that all asset replacement activities are done in a long-term sustainable and affordable manner. This approach will prevent 'peaks and valleys' of asset renewal, and allow for a more consistent and relatively steady capital investment over the long-term.

OHEDI has compiled a capital view for the next 20 years using load forecasts, condition/age assessments, and system planning requirements. OHEDI has a number of assets which have passed their typical useful life (TUL). Certain types of assets in our system, based on critical role, implications to service and timelines to replace, have been identified as 'proactive' replacement candidates. These assets will be prioritized for replacement, and are incorporated into OHEDI's multi-year capital plan. There are also assets which will reach their TUL within this 20 year timeframe. OHEDI's intent is to plan replacement of some assets proactively based on current condition-based assessments and the criticality of their role in the system. This approach will help level the capital requirements over this period, and effectively mitigate the risk of critical asset failure.

Additional assets have been designated as 'run to failure' entities (e.g. distribution transformers) based on localized impacts and ability to replace in a timely manner in the event of failure. Processes are in-place to manage these cases expediently.

Major External Challenges and Commitments

OHEDI is required to make investments necessitated by external challenges and commitments, which are non-discretionary in nature. These investments include:

- Relocation of assets resulting from municipal/regional/provincial road widening or intersection improvement projects.
- Enhancement of the system to accommodate load growth from new subdivisions or large individual customers.
- Installation of new residential, commercial and condo meters.
- Incorporation of distributed generators.
- Meeting minimum OEB inspection and testing requirements

Road Widening/Intersection Improvements

Road widening/intersection improvement projects can be initiated by the Town of Oakville, Halton Region, or the Ministry of Transportation Ontario. These are mandatory projects. Over the last several years MTO, Region & the Town increased their spending on infrastructure in part due to government incentives for infrastructure spending. This is tailing off now, although there are talks of more infrastructure spending incentives. In Oakville, the QEW widening and HOV lane projects are complete with no anticipated further projects in the foreseeable future. For the Region, Bronte Road/Highway 25 has been completed, Ninth Line up to Dundas Street will be completed in 2013, Neyagawa Boulevard will be completed in 2013 and Dundas Street widening will be completed in the 2013-2014 period. Trafalgar Road and Ninth Line, north of Dundas Street, have not had impact assessments completed at this time. A lot of the major Town widening have been completed to-date. Two grade separations may have an impact, one being on Kerr St. and the other on Burloak Drive. The original lines were designed with this in mind so minimal impact is anticipated. The circuits constructed in north Oakville for Glenorchy MTS were positioned to have minimal impact if road widening occurs, with the best planning information available at the time. For these noted reasons, OHEDI expects a downward trend in these types of projects over the next 20 years.

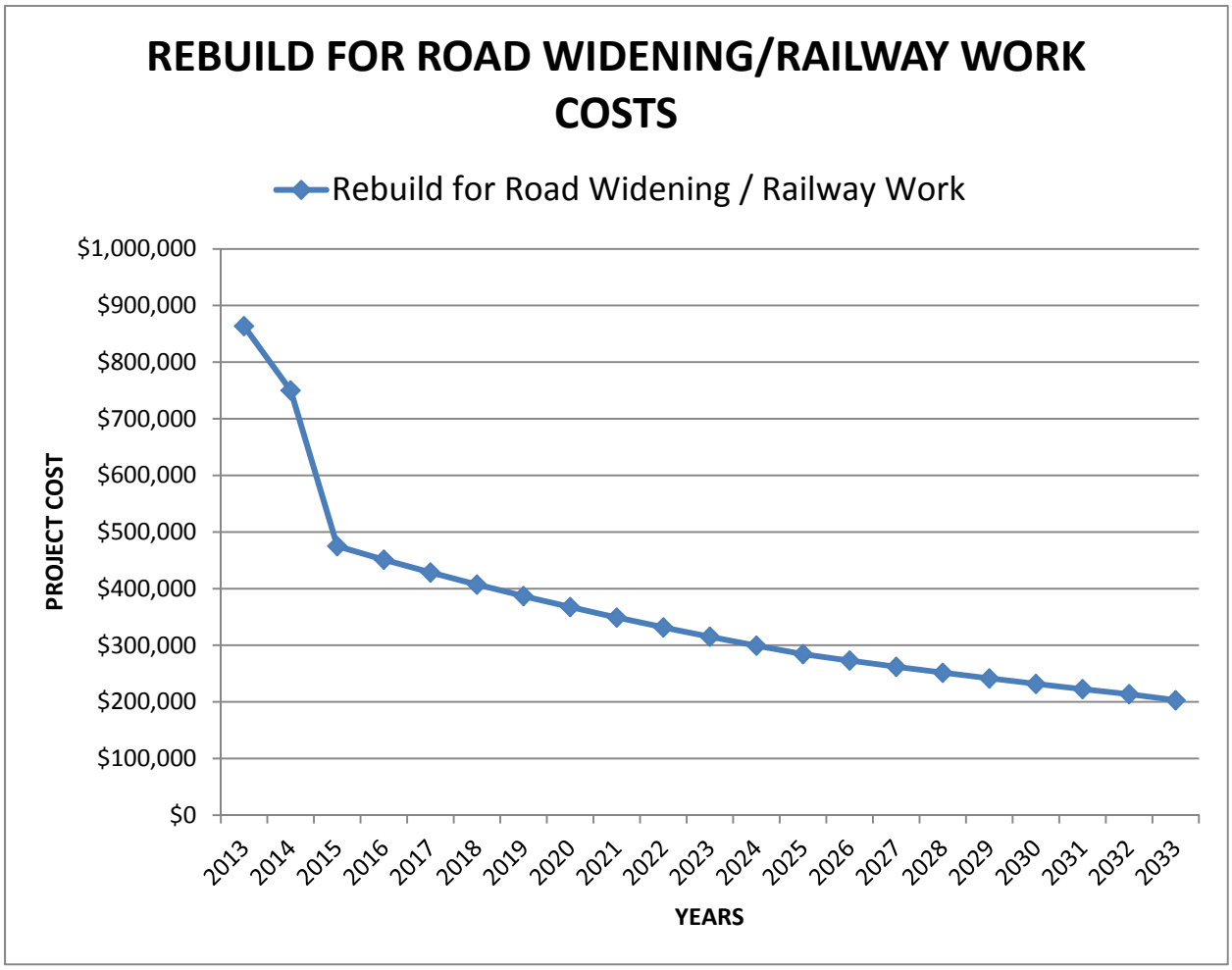


Figure 2

SMART Grid

OHEDI will actively collaborate in Smart Grid Pilot demonstration projects that have been appropriately funded through the Ministry of Energy and, in addition, approved by the Ontario Energy Board (OEB). OHEDI will ensure that all other smart grid or grid transformation initiatives align with Oakville Hydro's current Strategic Plan by including them in the capital project portfolio to be evaluated (including business case assessment) and prioritized as set out in these Asset Management Objectives.

Customer Enhancement

Customer connection projects are initiated through the building of a new lot or subdivision, and/or re-building of a currently serviced property. These projects are mandatory as part of our obligation to serve. OHEDI expects an upward trend in these type projects in the next nine years, at which time it will have some stability.

In the 27.6kV Additions category, OHEDI required additional funding in 2013 to allow for the building of two required projects. The first project was the addition of two feeders from the Glenorchy MTS to supply Milton Hydro. The second project was a feeder addition to supply the new Oakville Hospital.

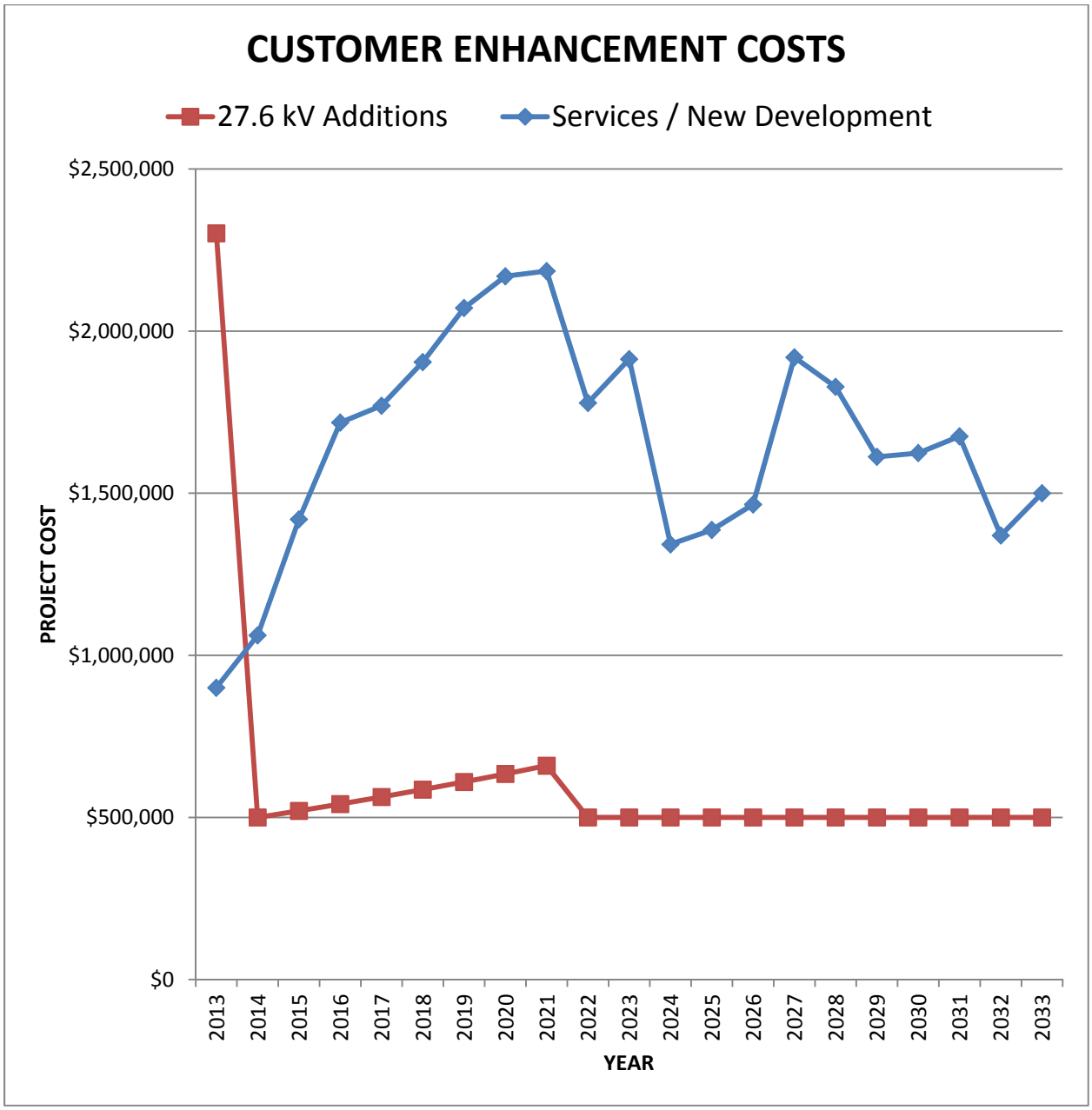


Figure 3

Installation of new meters has three major components. Residential meter installation requirements typically follow the costs for services/new development, as shown in the previous figure. Commercial meters have been known to flat line trend and should only represent a pillowing factor to the overall budget. Residential condo meters are unpredictable past approximately two years, however OHEDI does not expect a significant increase in these meters over the next 20 years.

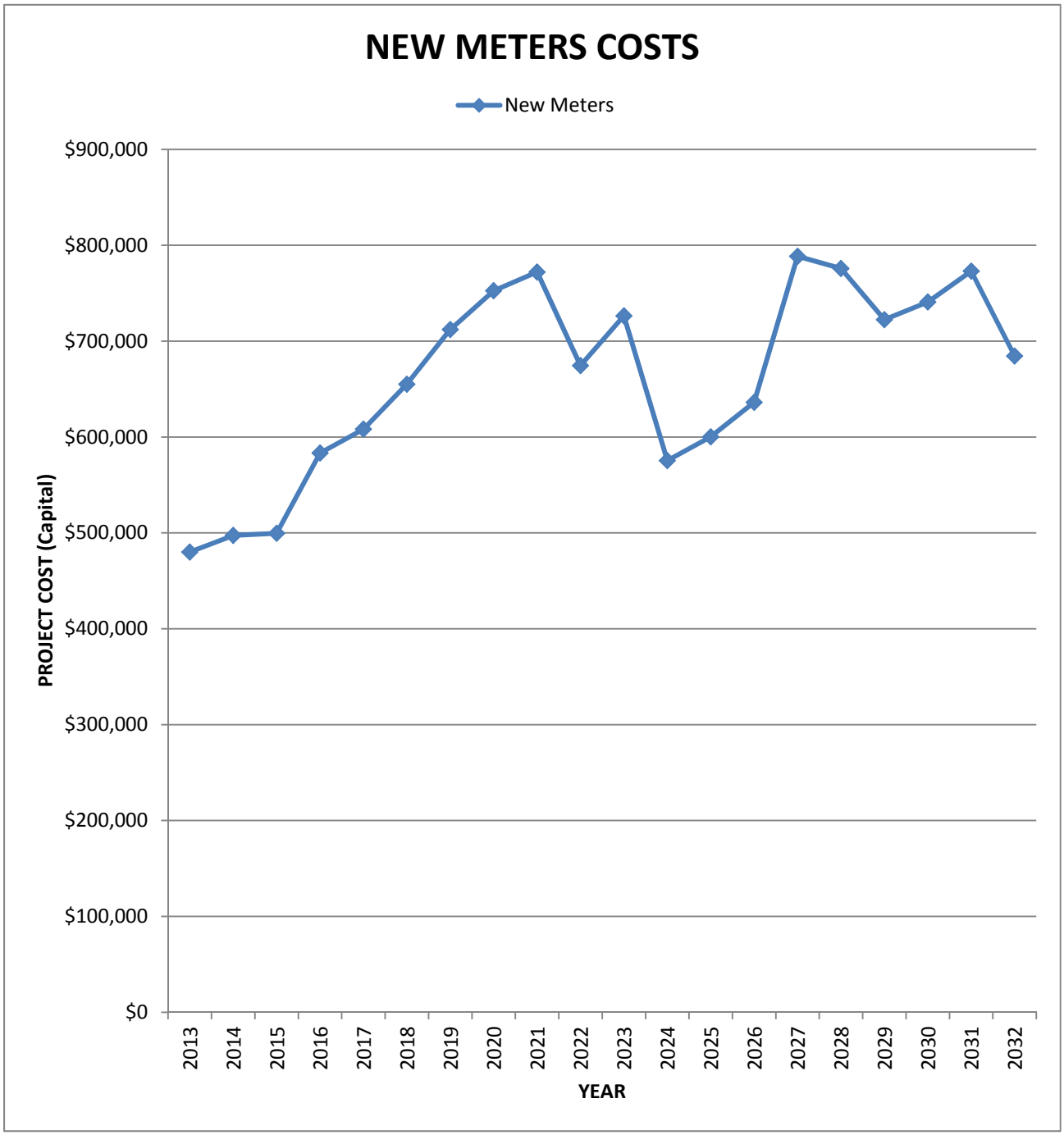


Figure 4

Inspection and Testing Requirements Distribution Assets

Inspection and testing requirements are internally scheduled, and involve the maintenance and patrols of the distribution infrastructure. The patrols and associated maintenance to address defects, are mandated by regulatory standards. OHEDI expects an upwards trend in inspection and testing requirements over the next 20 years.

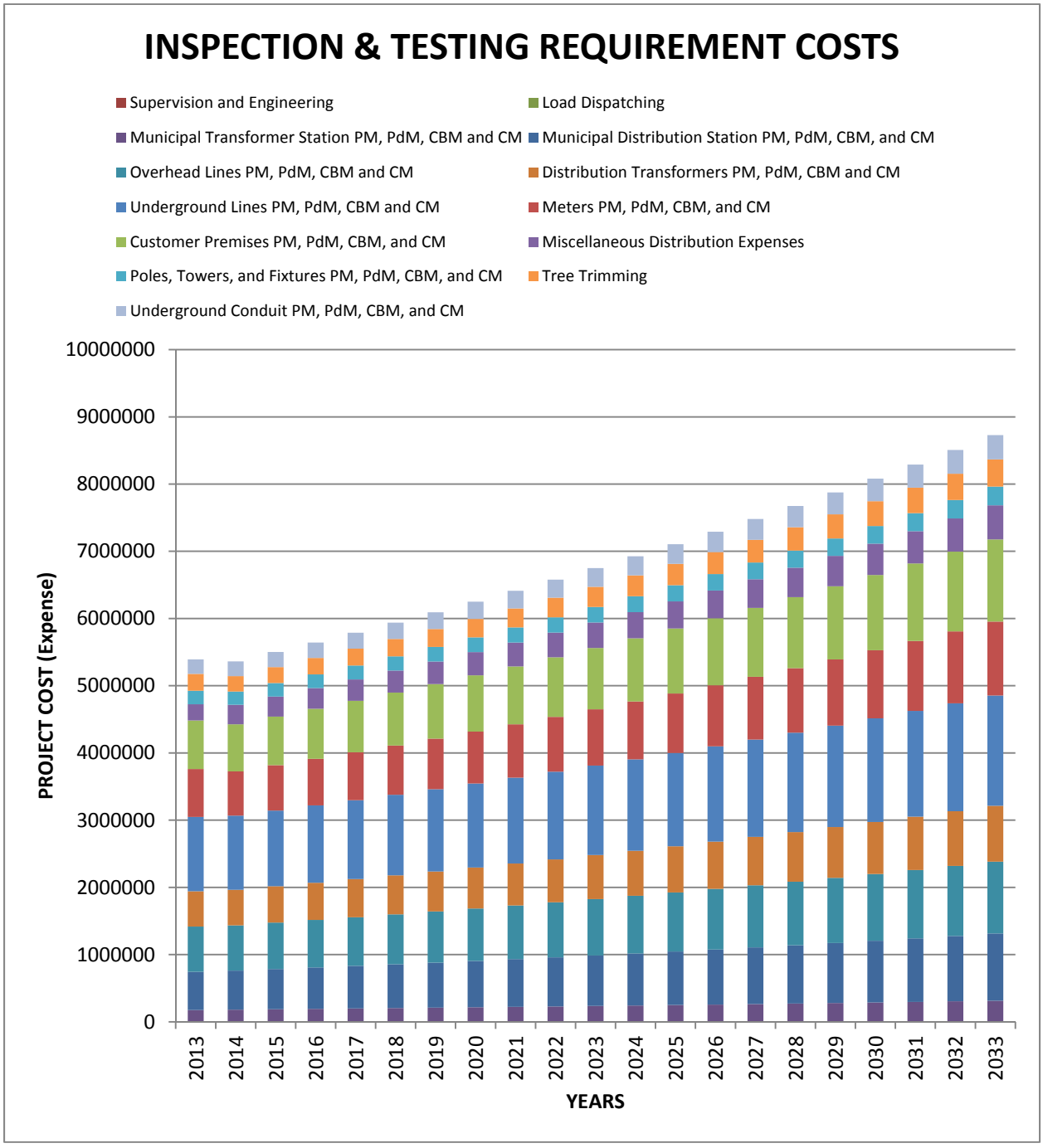


Figure 5

Major Distribution Asset Replacement

A number of inputs are used in order to select major distribution assets for replacement.

Asset Register

Major distribution asset records currently reside in various locations. Power and distribution transformer records are kept in OHEDI's Microsoft Dynamics GP program, low voltage breakers and high voltage switch records are mainly kept in paper format with some information stored in Microsoft Excel files, switchgear and switch records are kept in a Microsoft Access database, overhead wire and underground cable records are kept in paper format with some information stored in the ESRI Geographic Information System (GIS), pole records are kept in a Microsoft Access database, meter records are kept in the North Star Harris Customer Information System, and primary meter records are kept in a Microsoft Excel file.

Most records contain asset:

- Tracking numbers
- Descriptions
- Quantities
- Manufacturers
- Serial numbers
- Warranty information (where applicable)
- Acquisition dates
- Service dates
- Physical locations
- Disposal dates

OHEDI is striving to also include the acquisition cost of the asset, the assets salvage value, the asset's useful life, the depreciation method, and the current book value with the individual asset registers as sometimes this information is kept in other locations, or not kept at all.

OHEDI is in the process of establishing a single centralized location (Maximo System) for the Asset Register for all major distribution assets which will include all the above record attributes. See the "Asset Management Systems" section of this document for details.

Condition Assessments & Recommendations

Asset condition is assessed & documented noting any urgent issues. In some cases simple maintenance tasks cannot mitigate these issues, prompting the need for a capital replacement project. In these situations a project is initiated, designed, planned & estimated to remedy the outstanding issues. It is preferable to group like assets together for replacement in these situations to reduce the number of project packages.

Conditions of assets are kept in various locations like described in the equipment register information above, and each major distribution asset has various conditions noted in order to determine follow-up maintenance or capital expenditure.

OHEDI is striving to have a single centralized location for the Condition Assessments for all major distribution assets which will include all noted condition attributes. See the "Asset Management Systems" section of this document for details.

Asset Capacity Utilization/Constraint Assessment

OHEDI annually reviews capacity utilization at the transformer station connection points (at 27.6kV) and at the 27.6 kV feeder level, on an individual feeder basis. The review is normally done at the time of the annual system peak, to most accurately determine the system capacity utilization. The SCADA (System Control and Data Acquisition System) is used to monitor feeder loads and assists in the capacity utilization review. For newly added loads, capacity utilization and constraint assessment is done on a project by project basis. For new developments in North Oakville, at present, the assessment is very straightforward due to the recent addition of the OHEDI owned Glenorchy MTS transformer station and associated new 27.6kV feeders. At present there is substantial available capacity for new loads in this area. For new load additions in other established areas, capacity utilization and constraint assessment is done on a project by project basis to determine if upgrades or load transfers to other feeders are necessary.

Reliability-Based 'Worst Performing Feeder" Information and Analysis

Worst Performing Feeder analysis is performed on a yearly basis. Each feeder is reviewed for their SAIDI, CAIDI, and SAIFI metrics. The Control Room Supervisor compiles the report from information that is available in the current outage reporting system. This analysis helps identify possible areas for capital expenditure.

Reliability Risk/Consequence of Failure Analyses

Currently these analyses are being completed for individual projects selected for replacement. Each project is reviewed by its impact to the OHEDI Capital Investment Objectives, and prioritized as such. OHEDI is looking to assign risk to all major distribution assets in order to identify the risk level and consequence of failure of the entire system.

Interviews

Annual interviews are conducted with internal Subject Matter Experts (SMEs) and risk management primes at OHEDI in order to identify future project requirements. Condition assessments do not necessarily cover the full extent of projects that should be considered. These interviews will capture a wider range of projects, including those that are safety and operations related.

Optimization of Project Portfolios

The Optimizer software was obtained from UMS through Abicus Management Solutions Inc. in 2009. This software package enables the evaluation of a multi-year project portfolio, and optimizes the project selection based on a set of weighted criteria.

The optimization of future project portfolios allows OHEDI to ensure that future capital costs will be applied to the appropriate areas of the system to mitigate risk and improve value. Future projects are evaluated by considering both their risk and probability if not completed, and their value if completed. Projects are evaluated based upon the risk and value associated with the capital investment objectives and weightings.

The optimization of these project portfolios will produce a prioritized list of projects to be completed in future years. The optimizer will prioritize this list of projects based upon the individual effects each has on the capital investment objectives and weighting. When applying the projected annual capital budget amount to the optimization, a list of projects to be executed by year will be produced. This list can be modified by either increasing or decreasing the capital budget amounts if required.

Typical Useful Lives(TUL)

The figures in the following sections illustrate the differences between a proactive capital replacement program, and a replacement program based upon TUL. Obviously, OHEDI does not expect every asset to fail at the exact TUL date; these metrics are used as a baseline to illustrate the feasibility of a proactive replacement program for distribution assets to mitigate peaks and valleys in capital expenditure over a 20 year timeframe. To establish the TUL expectations, OHEDI has considered current asset age data and the Kinectrics Inc. Report titled "Asset Depreciation Study for the Ontario Energy Board" number K-418033-RA-001-R000 dated July 8, 2010.

The following cost estimates were created using a 2% inflation increase per year over a 20 year timeframe in order to accurately reflect capital costs over time.

Municipal Substation and Customer Specific Power Transformers

Asset Evaluation

Power Transformers form a relatively small asset base. Year of manufacture ranges from 1957 to 2011 with the average age being 35 years old. OHEDI uses a TUL of 45 years. Based upon this timeframe, currently 5 transformers have exceeded the TUL of 45 years.

The following bar graph shows the number of Power Transformers by year that will exceed this TUL within the next 20 years.

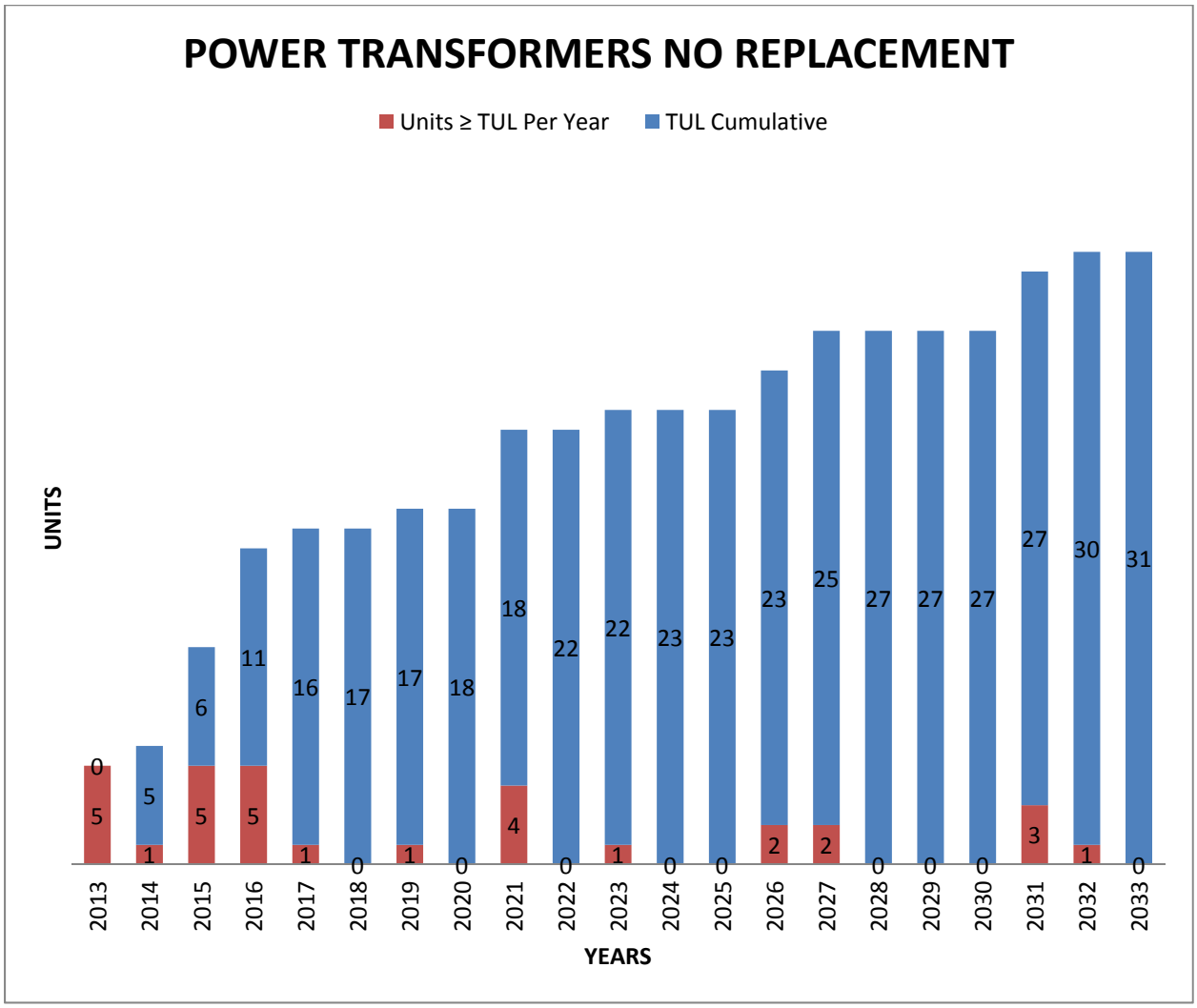


Figure 6

Investment Optimization

For Customer Specific Power Transformers the customers load will be reviewed to determine if it can be serviced from a standard three phase padmount transformer. Utilizing a standard three phase padmount transformer will reduce both material and installation cost, and decreases spare inventory requirements.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace one power transformer per year for the next 10 years and two power transformers for the following 10 years.

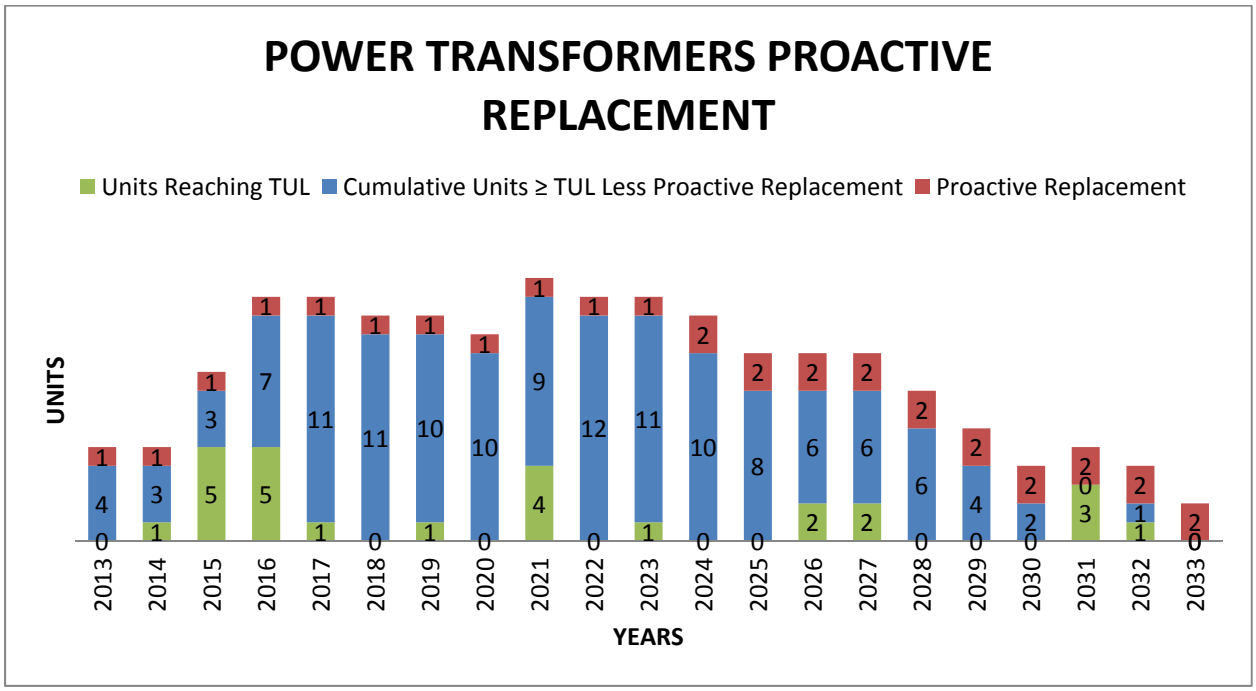


Figure 7

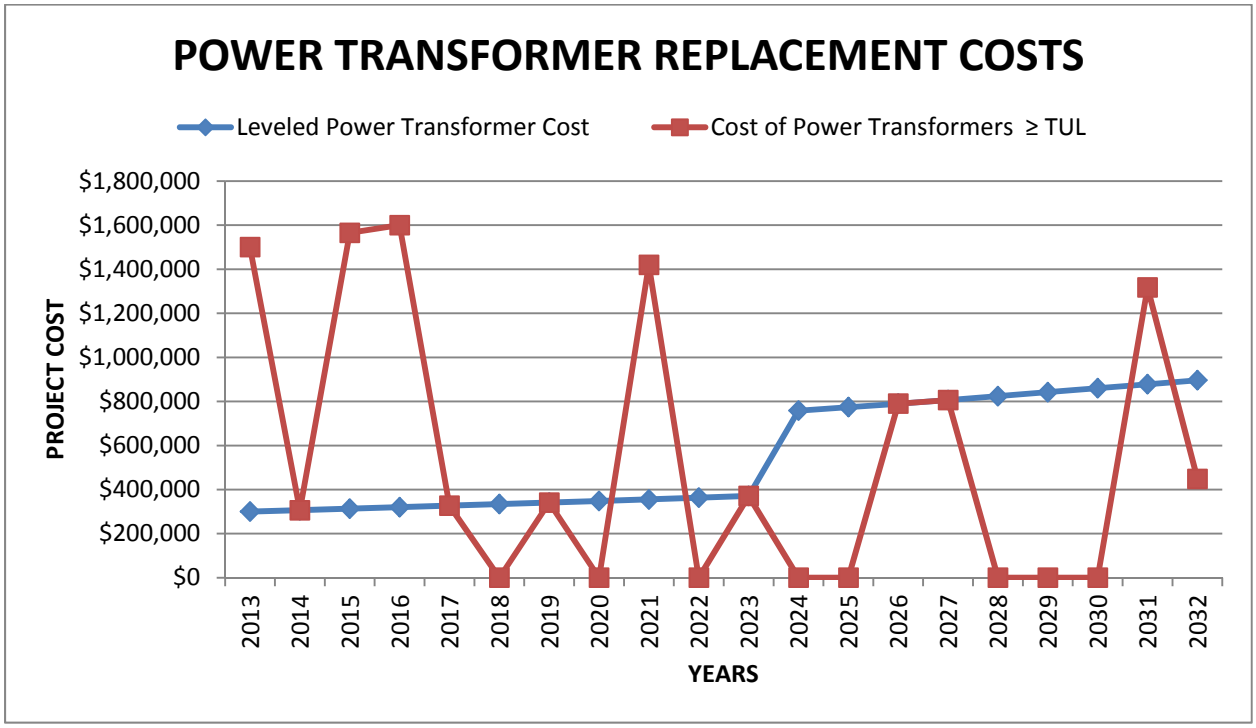


Figure 8

Low Voltage Station Switches and Breaker Line-ups

Asset Evaluation

Low voltage station switches and breaker line-ups form a small asset base. Year of manufacture ranges from 1969 to 2010 with the average age being 25 years old. OHEDI uses a Typical Useful Life (TUL) of 25 years. Based upon this timeframe, currently 11 low voltage switches and breaker line-ups have exceeded this TUL of 25 years.

The following bar graph shows the quantity of low voltage station switches and breaker line-ups that will exceed this TUL within the next 20 years.

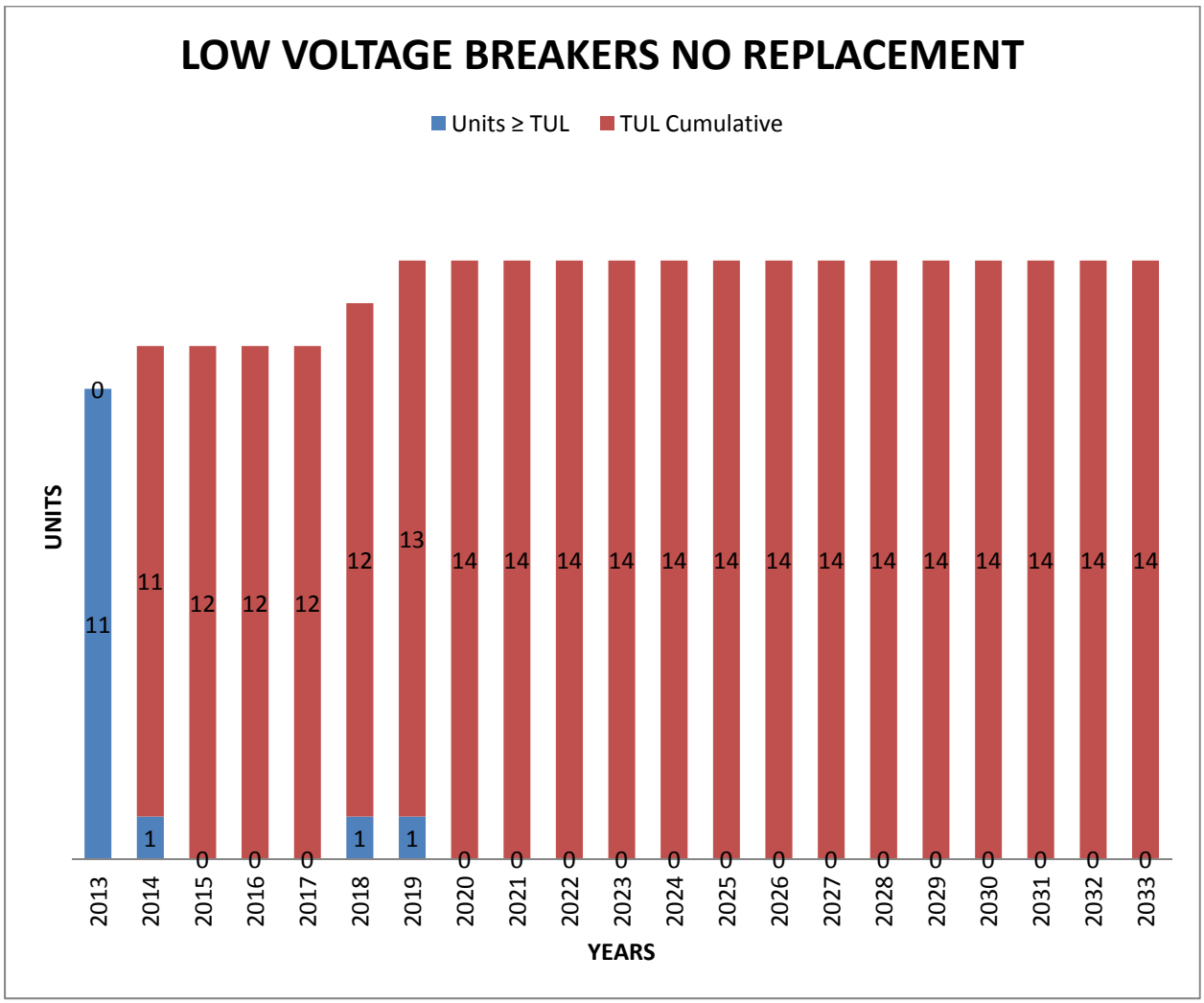


Figure 9

Investment Optimization

Utilizing standard padmount switchgear will reduce both material and installation cost, and allows for spare inventory in the case of equipment failure. Future investigations into this will take place to determine the feasibility of this option.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace one low voltage switch and breaker line-up per year for the next 13 years.

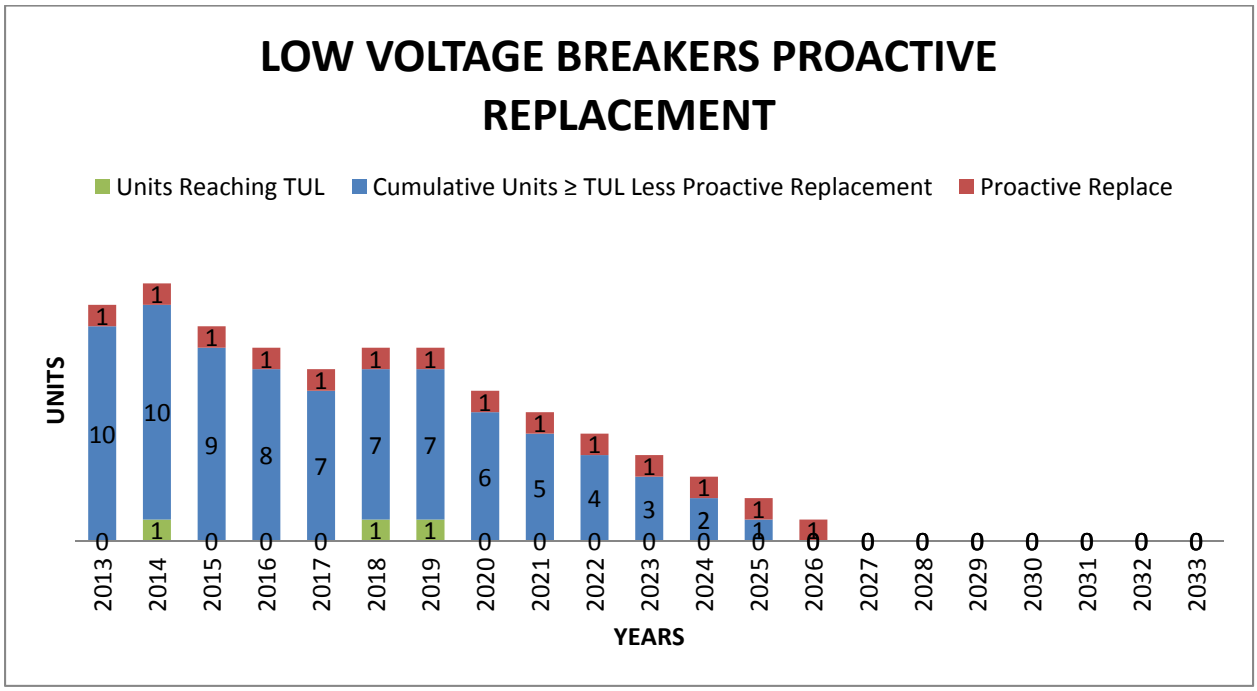


Figure 10

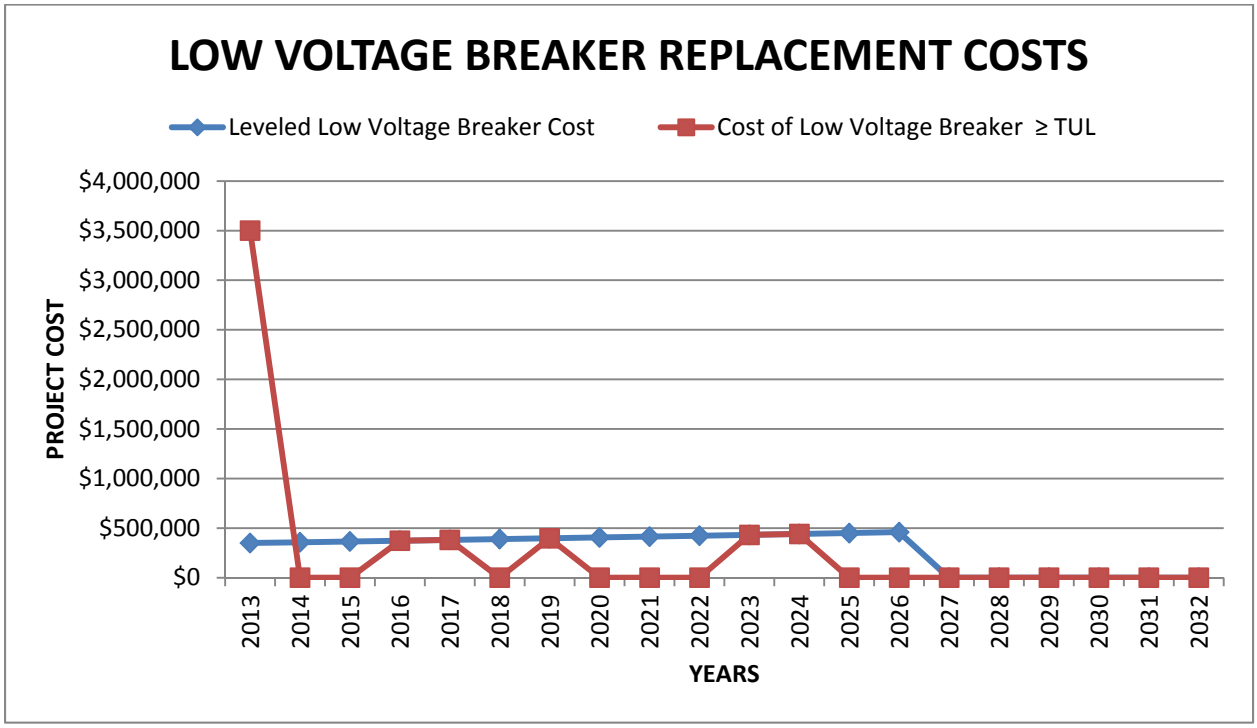


Figure 11

High Voltage Station Switches

Asset Evaluation

High voltage station switches form a small asset base. Year of manufacture ranges from 1957 to 2011 with the average age being 36 years old. OHEDI uses a Typical Useful Life (TUL) of 55 years. Based upon this timeframe, currently two high voltage station switches have exceeded the TUL of 55 years.

The following bar graph shows the quantity of high voltage station switches that will exceed this TUL within the next 20 years.

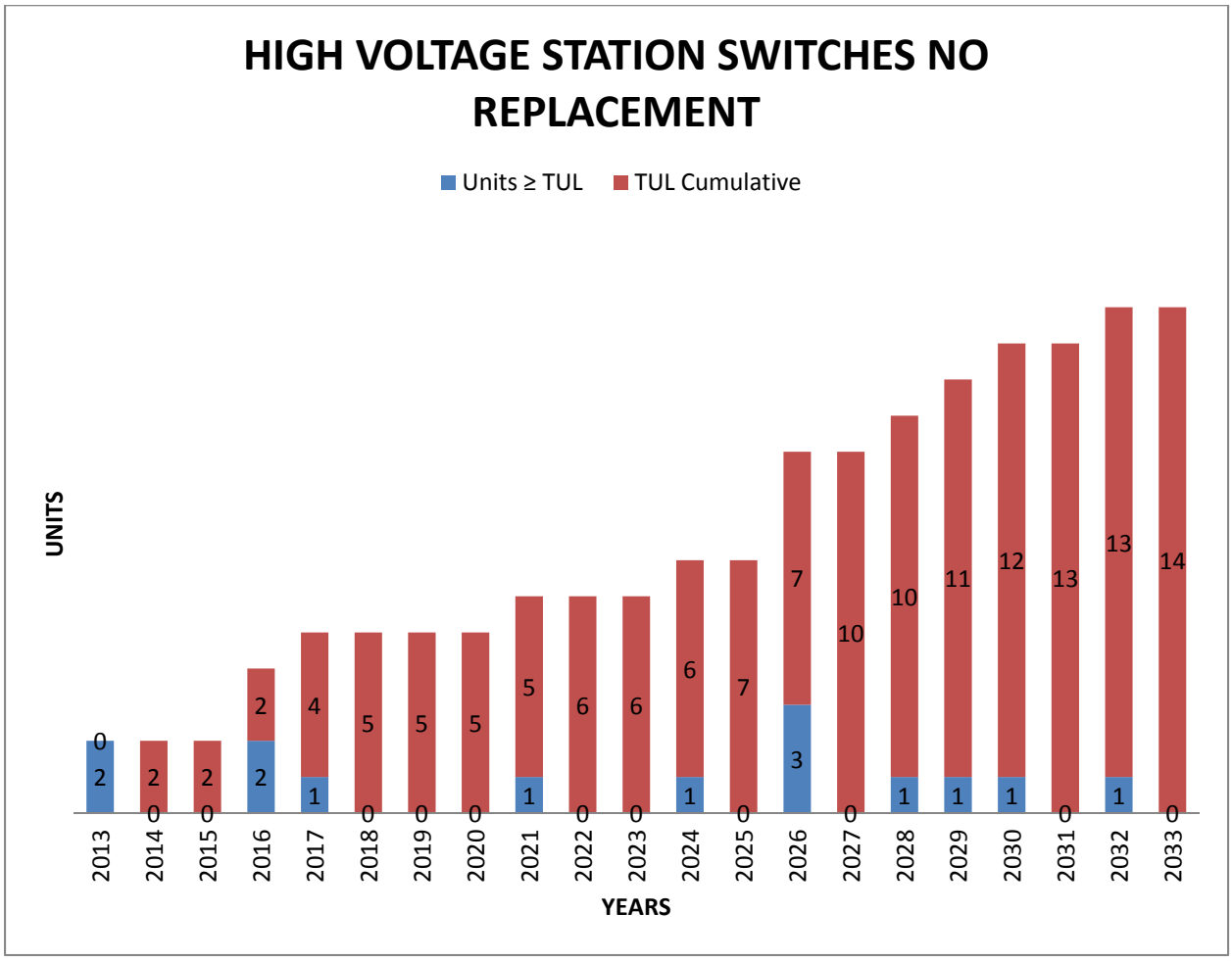


Figure 12

Investment Optimization

The station load will be reviewed to determine if it can be serviced from standard padmount switchgear. Utilizing standard padmount switchgear will reduce both material and installation cost, and allows for spare inventory in the case of equipment failure.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace one high voltage station switch in each of the following years: 2013 to 2014, 2016 to 2018, 2021, 2024, and 2026 to 2032.

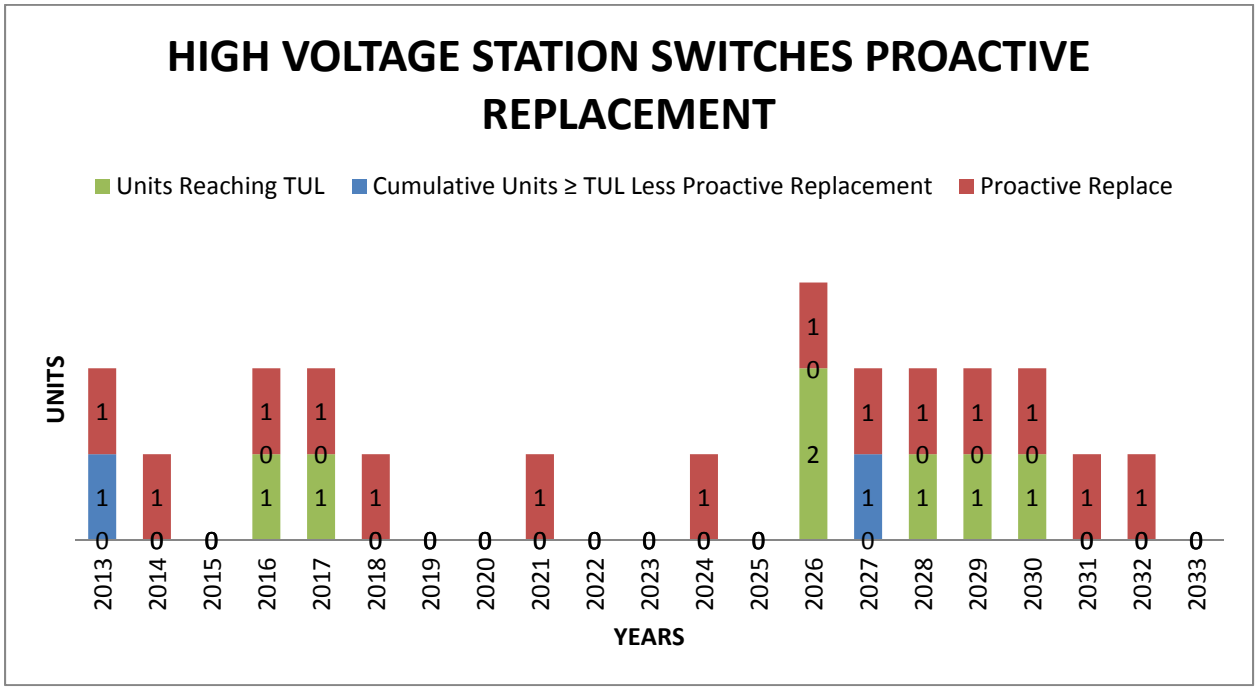


Figure 13

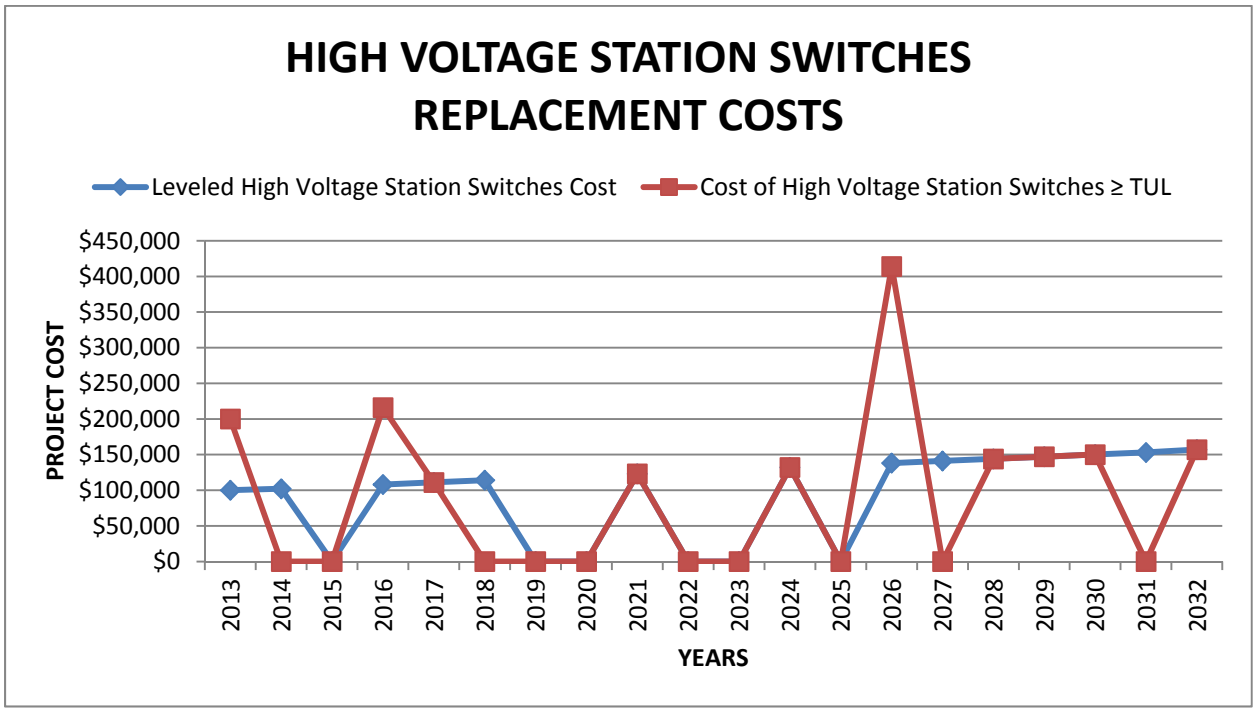


Figure 14

Overhead Distribution Transformers

Asset Evaluation

Overhead distribution transformers form a large asset base. Year of manufacture ranges from 1940 to 2012 with the average age being 24 years old. OHEDI uses a Typical Useful Life (TUL) of 35 years. Based upon this timeframe, currently 508 overhead distribution transformers have exceeded the TUL of 35 years. OHEDI has chosen a run-to-failure strategy for overhead distribution transformers, and will replace upon failure, or ten years after the TUL, whichever comes first.

The following bar graph shows the quantity of overhead distribution transformers that will exceed this TUL within the next 20 years.

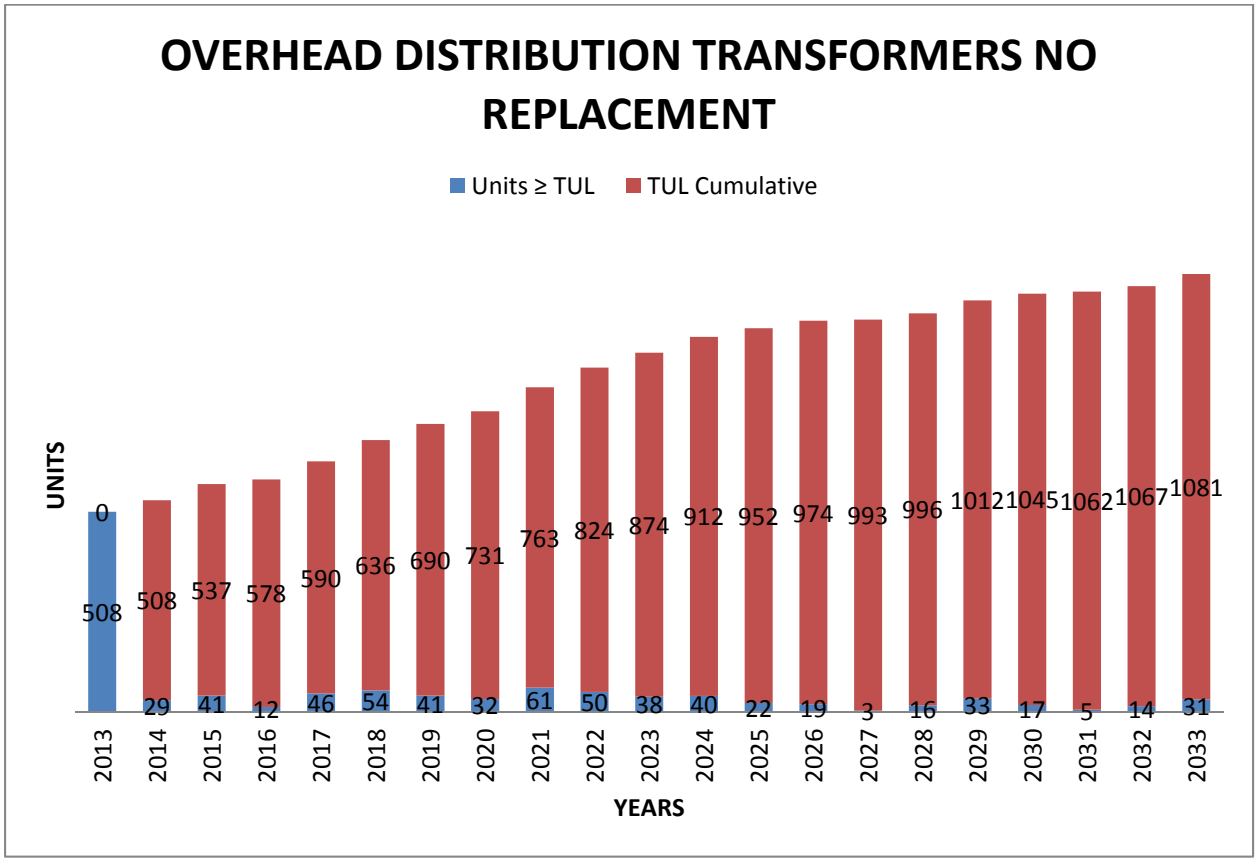


Figure 15

Investment Optimization

Prior to replacement of overhead distribution transformers the distribution area will be reviewed to determine if the transformer is still required. In the case it is not, the project will include transference of load to adjacent transformers, and decommissioning of the existing piece of equipment. Any non-standard transformers will be replaced with standard transformers where possible to lower material costs and decrease spare inventory requirements. Voltage conversion will be considered in order to reduce losses, cost of losses, CO_2 emissions created by fossil fuel fired generating stations due to losses, and voltage drop levels.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace 53 overhead distribution transformers per year for the next 20 years.

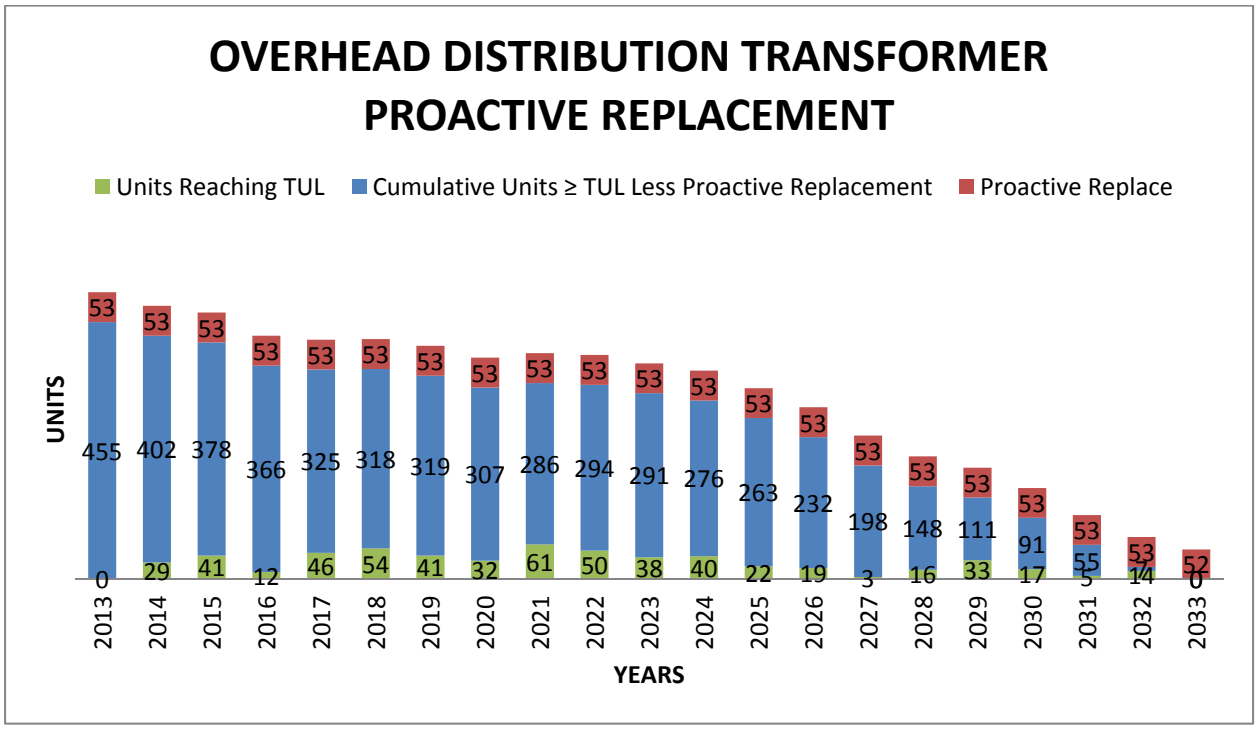


Figure 16

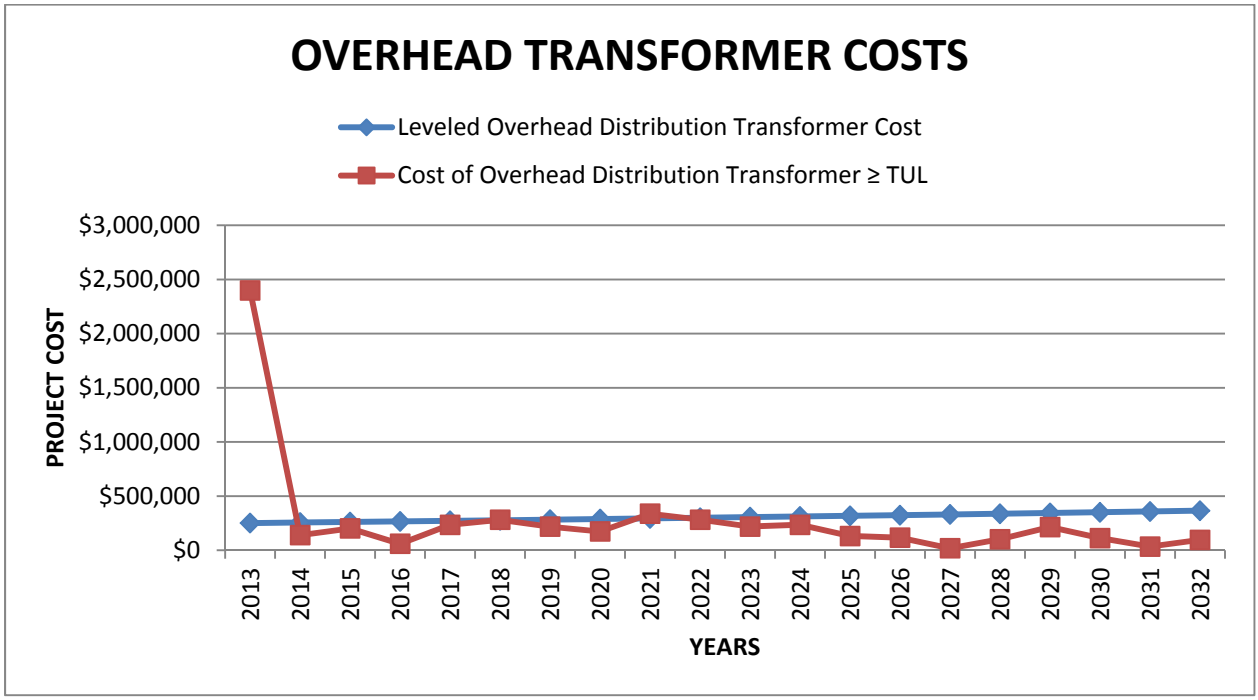


Figure 17

Padmount Distribution Transformers

Asset Evaluation

Padmount distribution transformers form a large asset base. Year of manufacture ranges from 1963 to 2012 with the average age being 17 years old. OHEDI uses a Typical Useful Life (TUL) of 35 years. Based upon this timeframe, currently 45 padmount distribution transformers have exceeded the TUL of 35 years. OHEDI has chosen a run-to-failure strategy for padmount distribution transformers, and will replace upon failure, or ten years after the TUL, whichever comes first.

The following bar graph shows the quantity of padmount distribution transformers that will exceed this TUL within the next 20 years.

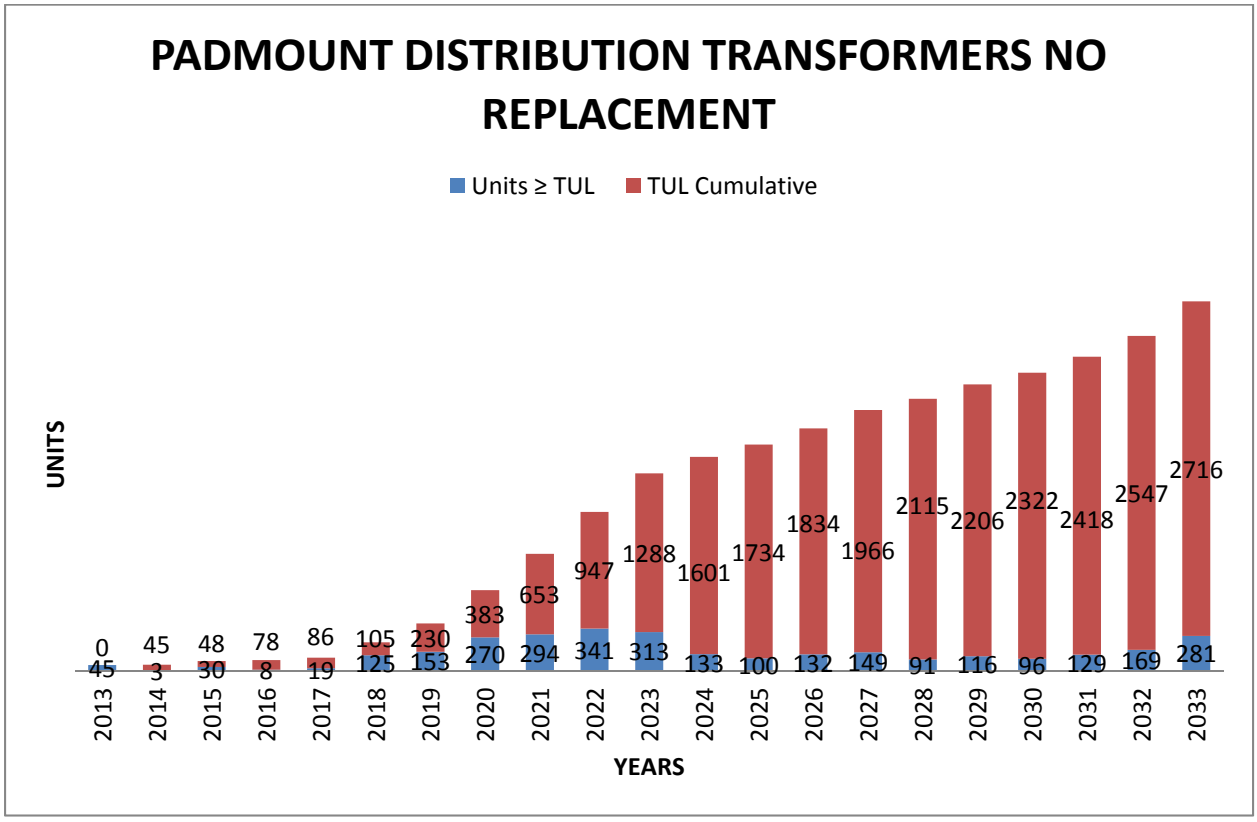


Figure 18

Investment Optimization

Prior to replacement of padmount distribution transformers the distribution area will be reviewed to determine if the transformer is still required. In the case it is not, the project will include transference of load to adjacent transformers, and decommissioning of the existing piece of equipment. Any non-standard transformers will be replaced with standard transformers where possible to lower material costs and decrease spare inventory requirements. Voltage conversion will be considered in order to reduce losses, cost of losses, CO_2 emissions created by fossil fuel fired generating stations due to losses, and voltage drop levels. Looping of radial fed padmount distribution transformers will also be considered to improve operational costs and customer downtime.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace four padmount distribution transformers in 2013 and 2014, then 20 transformers between 2015 to 2017, with an additional 20 transformers added per year until 2030. The costs for the first five years are expected to be a higher unit cost as replacements will consist of livefront three phase padmounts, which are more costly, and require new concrete pads to be installed.

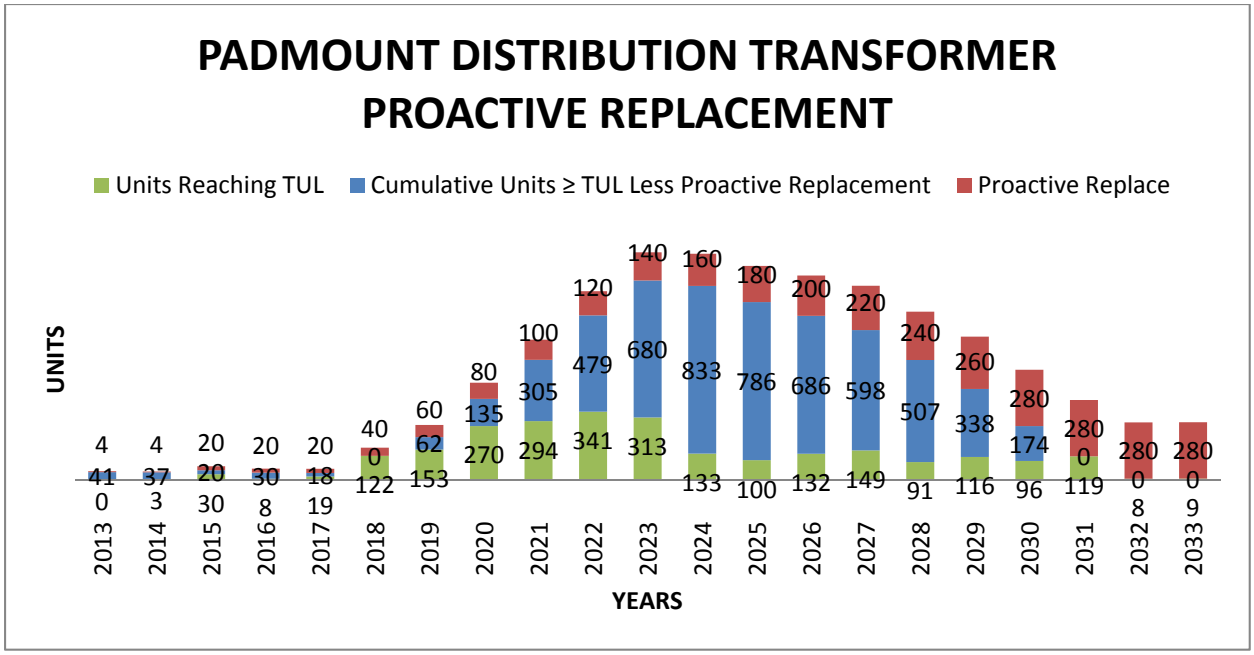


Figure 19

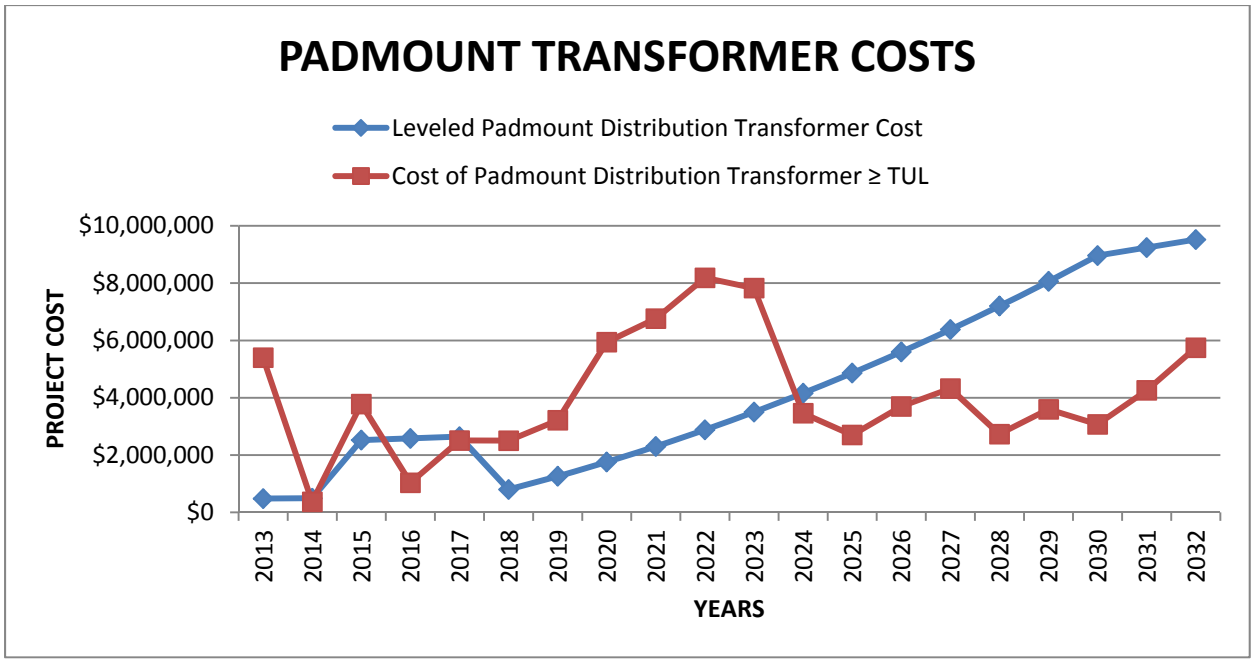


Figure 20

Submersible Distribution Transformers

Asset Evaluation

Submersible distribution transformers form a large asset base. Year of manufacture ranges from 1966 to 2012 with the average age being 17 years old. OHEDI uses a Typical Useful Life (TUL) of 35 years. Based upon this timeframe, currently 107 submersible distribution transformers have exceeded the TUL of 35 years. OHEDI has chosen a run-to-failure strategy for submersible distribution transformers, and will replace upon failure, or ten years after the TUL, whichever comes first.

The following bar graph shows the quantity of submersible distribution transformers that will exceed this TUL within the next 20 years.

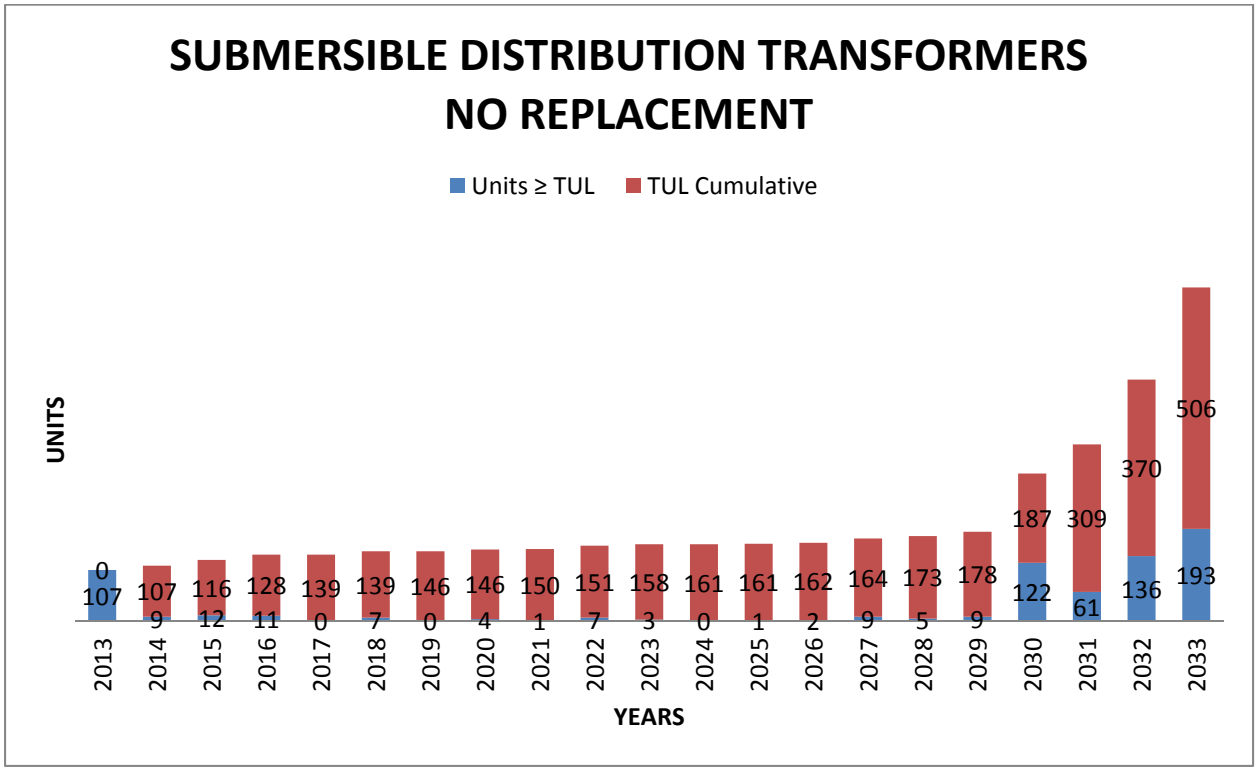


Figure 21

Investment Optimization

Prior to replacement of submersible distribution transformers the distribution area will be reviewed to determine if the transformer is still required. In the case it is not, the project will include transference of load to adjacent transformers, and decommissioning of the existing piece of equipment. Any non-standard transformers will be replaced with standard transformers where possible to lower material costs and decrease spare inventory requirements. Installation of padmount distribution transformers will be considered, as the change will allow for easier voltage conversion, as the current submersible vault structures are too small to accommodate higher voltage transformers. Voltage conversion will be considered in order to reduce losses, cost of losses, CO_2 emissions created by fossil fuel fired generating stations due to losses, and voltage drop levels.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace 11 submersible distribution transformers per year until 2029, 50 in 2030, and an additional 50 per year until 2033.

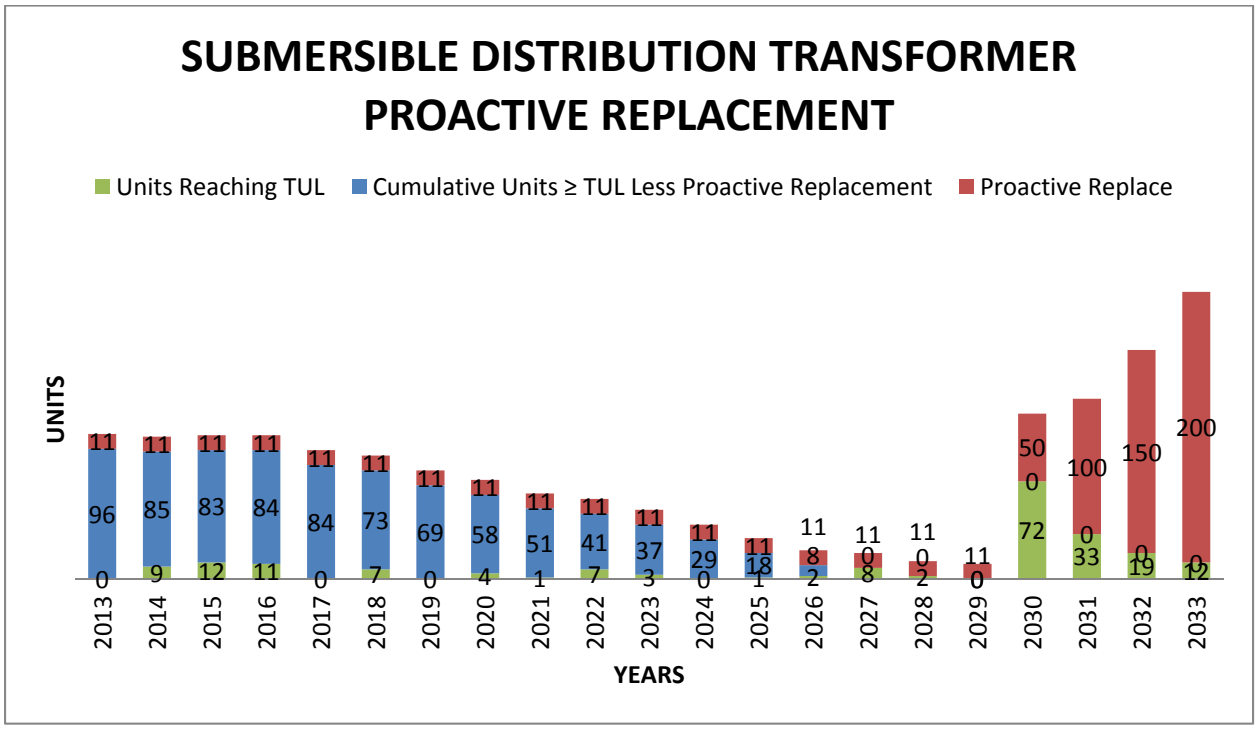


Figure 22

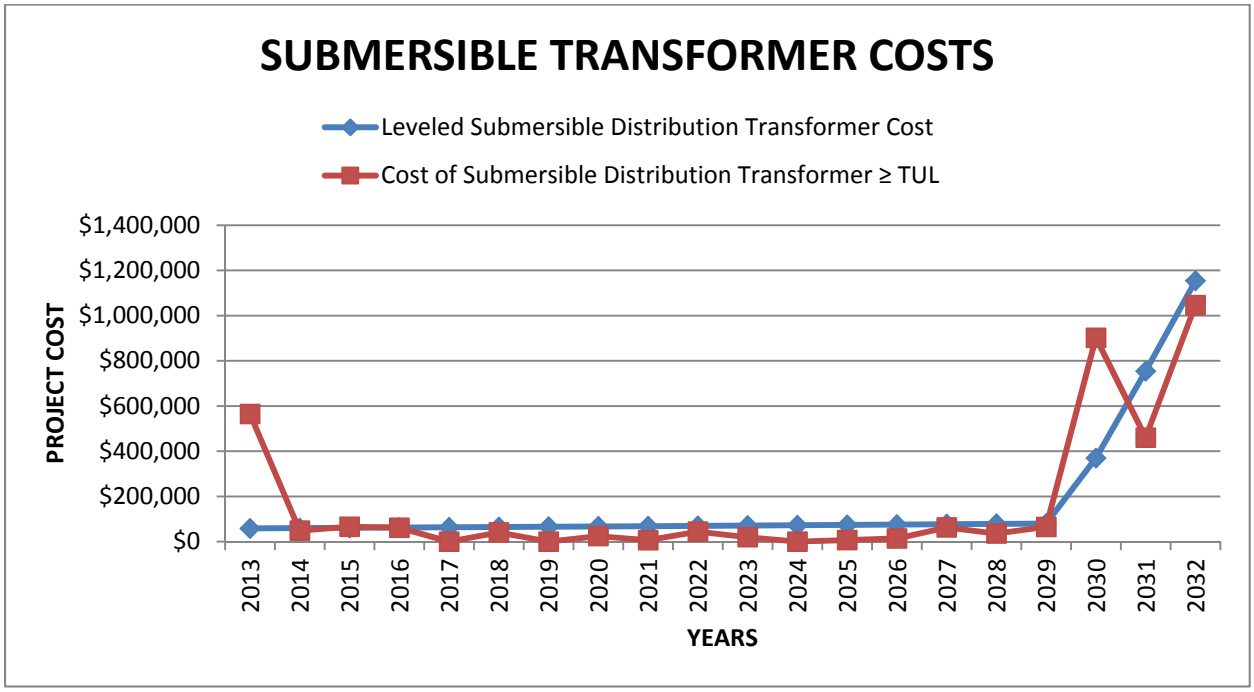


Figure 23

Vault-Style Distribution Transformers

Asset Evaluation

Vault-style distribution transformers form a large asset base. Year of manufacture ranges from 1949 to 1999 with the average age being 38 years old. OHEDI uses a Typical Useful Life (TUL) of 35 years. Based upon this timeframe, currently 164 vault-style distribution transformers have exceeded the TUL of 35 years.

The following bar graph shows the quantity of vault-style distribution transformers that will exceed this TUL within the next 20 years.

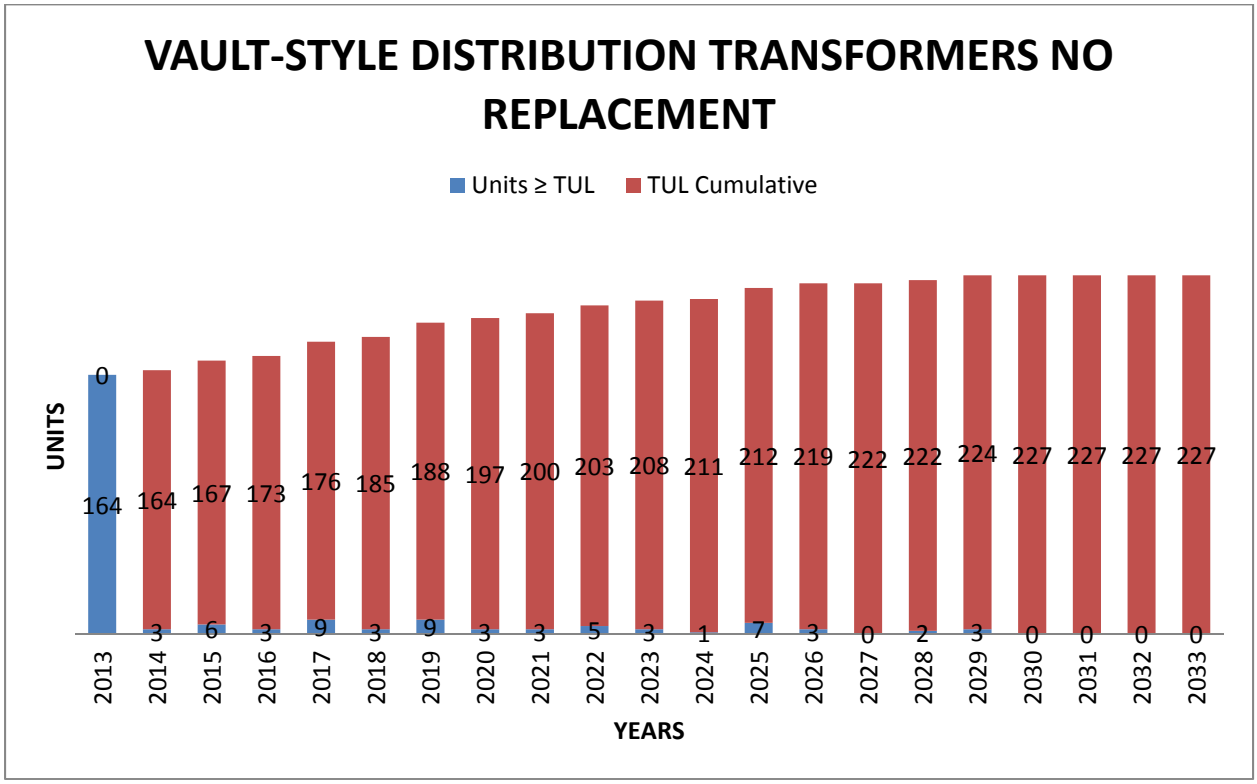


Figure 24

Investment Optimization

Prior to replacement of vault-style distribution transformers the distribution area will be reviewed to determine if the transformer is still required. In the case it is not, the project will include transference of load to adjacent transformers, and decommissioning of the existing piece of equipment. Any non-standard transformers will be replaced with standard transformers where possible to lower material costs and decrease spare inventory requirements. Installation of padmount distribution transformers located outside of the vault rooms will be considered as the change will allow easier access for operational purposes. In the case a padmount transformer cannot be installed, submersible style distribution transformers will be placed in the vault rooms. Voltage conversion will be considered in order to reduce losses, cost of losses, CO_2 emissions created by fossil fuel fired generating stations due to losses, and voltage drop levels

20 Year Forecast

There are many assets in this category past their TUL, however these transformers are kept indoors and not subjected to weather elements. With OEB minimum inspection requirements we ensure the transformers in these rooms do not have any issues causing disruption to OHEDI customers. In order to keep distribution rates down OHEDI only plans the replacement of 9 vault-style distribution transformers per year for the next 20 years. If these transformers are found to be failing at a faster rate than they are replaced the capital replacement program will be modified accordingly.

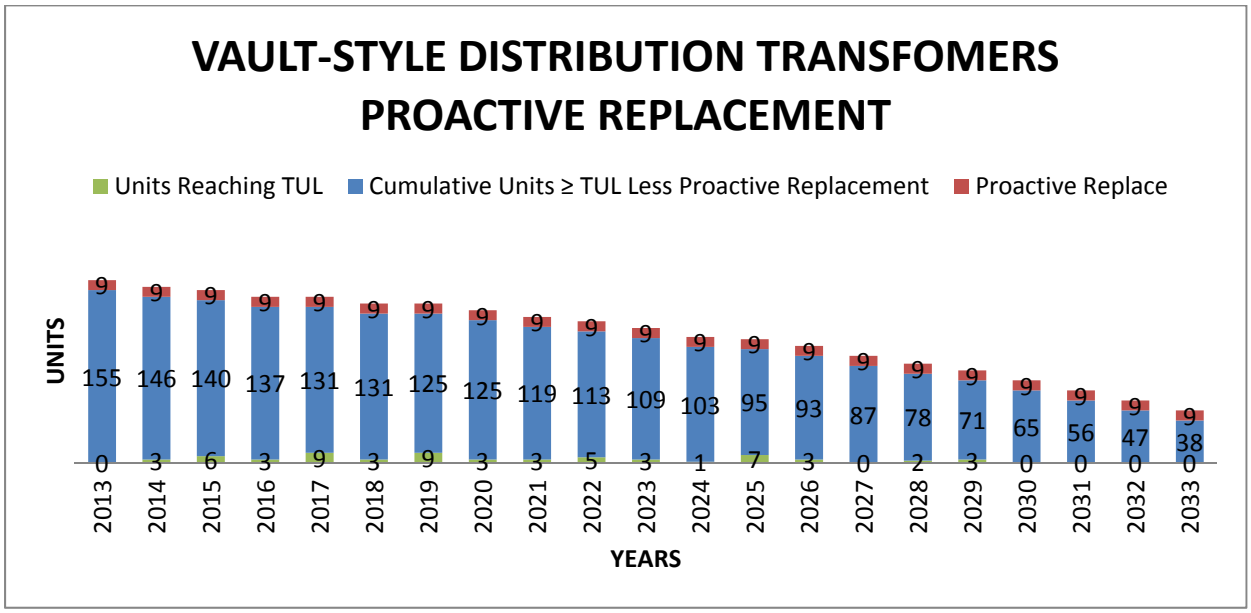


Figure 25

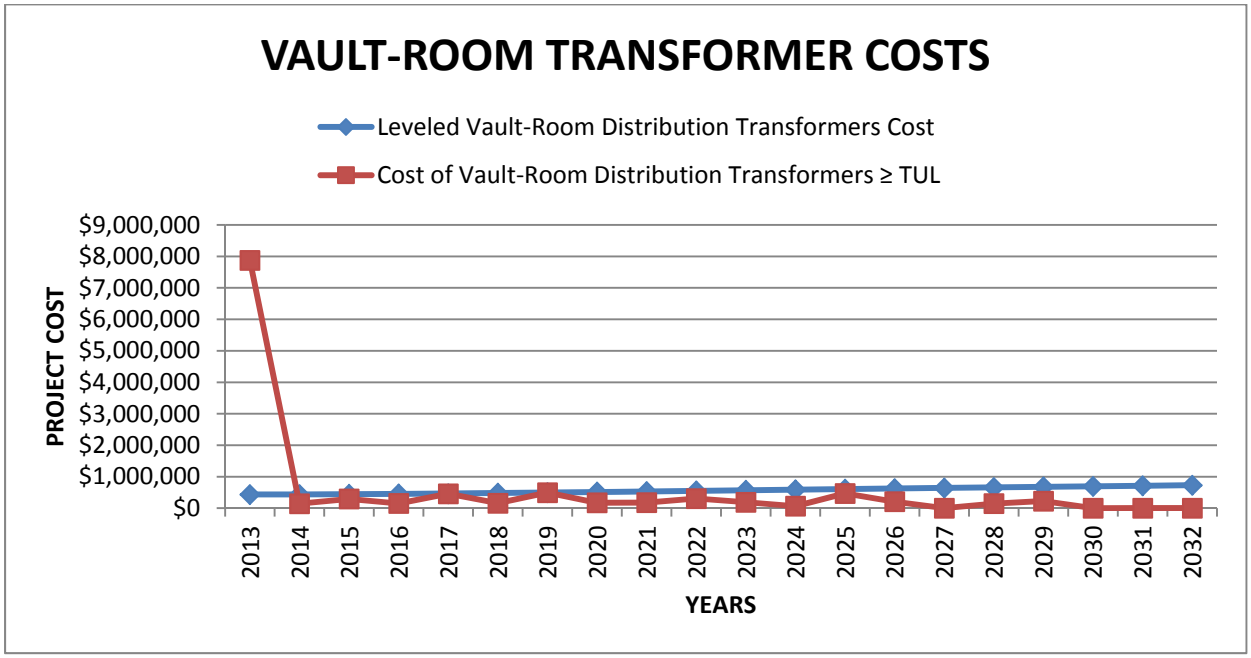


Figure 26

Padmount Switchgears

Asset Evaluation

Padmount switchgears form a large asset base. Year of manufacture ranges from 1970 to 2012 with the average age being 16 years old. OHEDI uses a Typical Useful Life (TUL) of 30 years. Based upon this timeframe, currently 11 padmount switchgears have exceeded the TUL of 30 years.

The following bar graph shows the quantity of padmount switchgears that will exceed this TUL within the next 20 years.

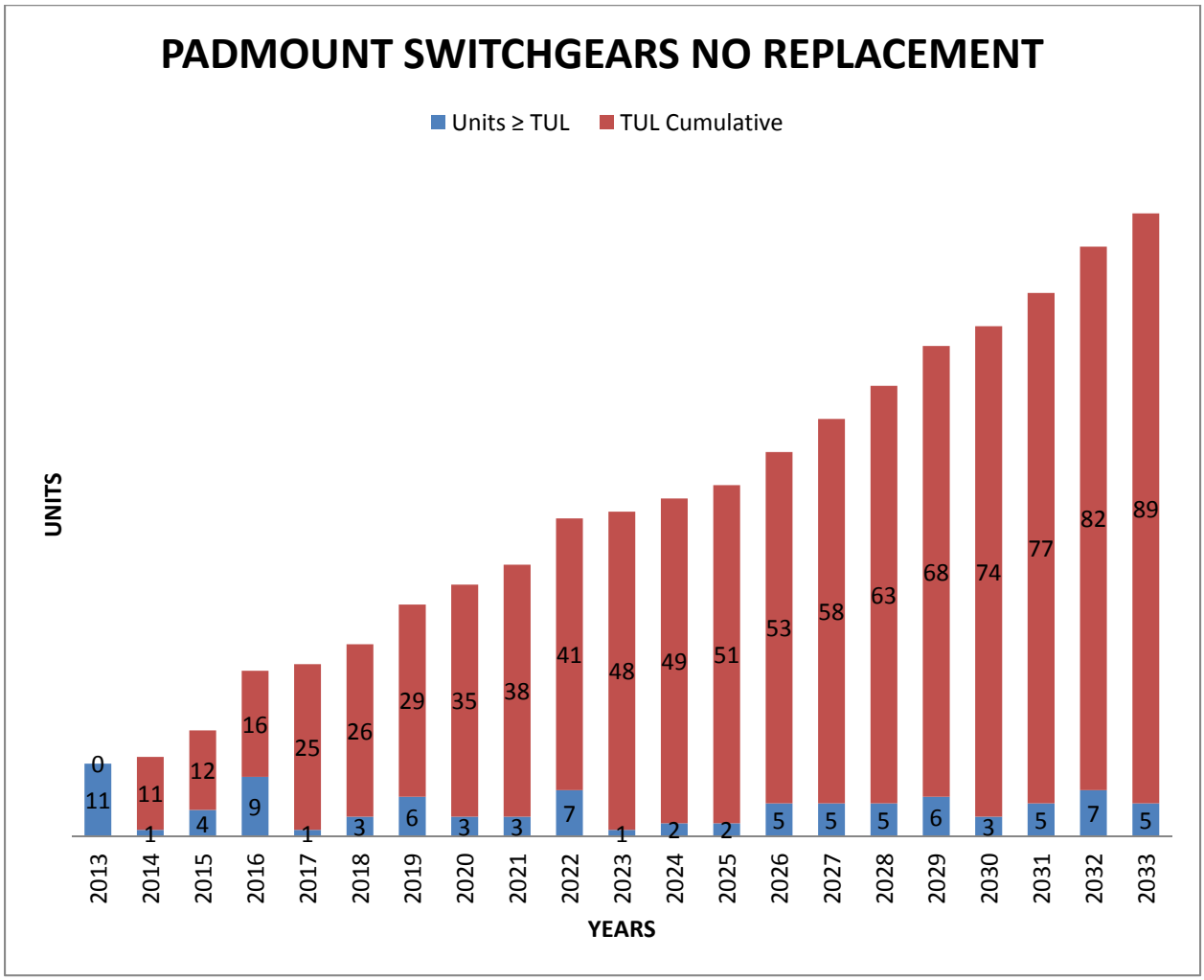


Figure 27

Investment Optimization

Any non-standard padmount switchgears will be replaced with standard padmount switchgears where possible to lower material costs and decrease spare inventory requirements. Livefront padmount switchgears will be replaced with deadfront padmount switchgears in order to lower the required maintenance costs over time. Switchgears will also be reviewed to determine if installation of motor operated controls will improve switching time and decrease operational costs.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace 4 padmount switchgear per year for the next 12 years, and 5 padmount switchgear per year thereafter.

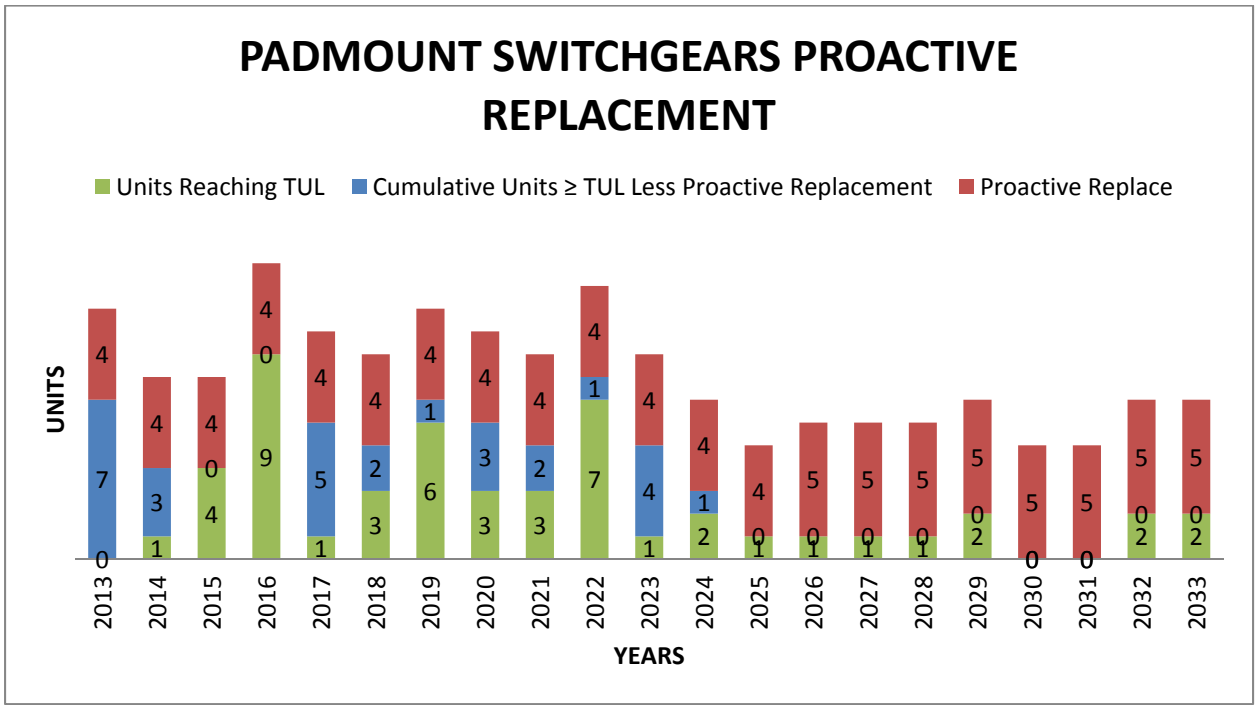


Figure 28

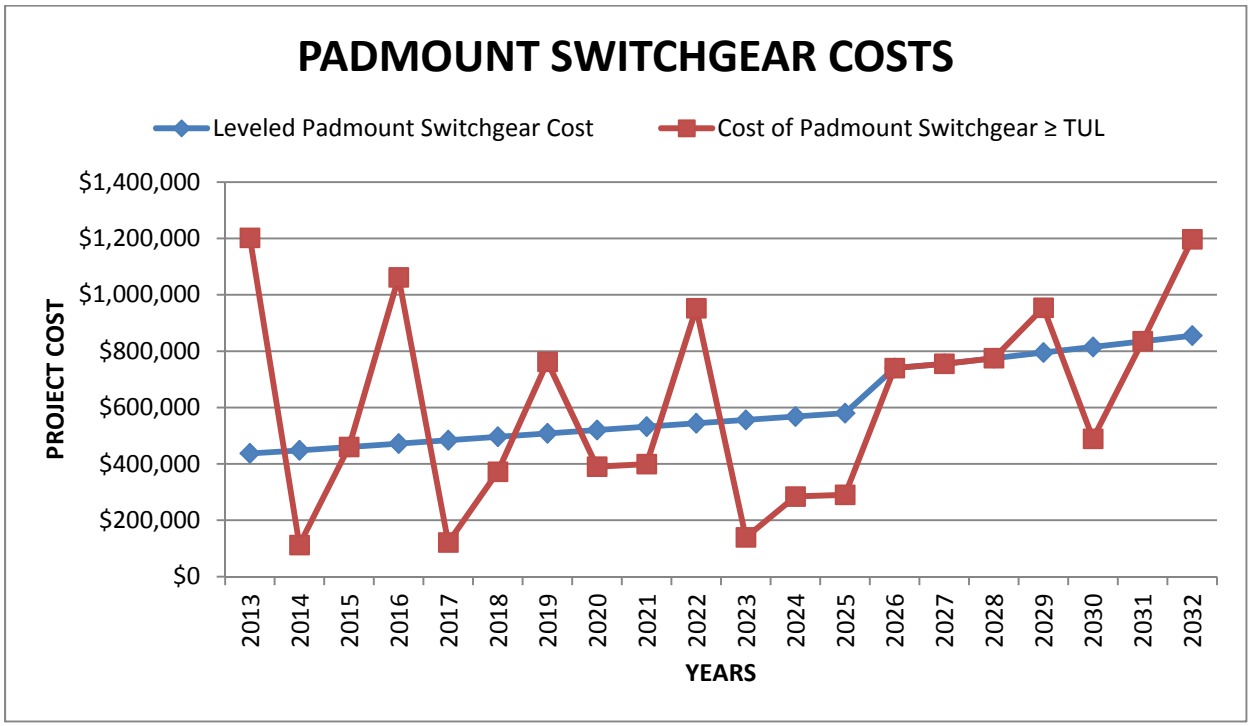


Figure 29

Vault-Style Switchgears

Asset Evaluation

Vault-style switchgears form a small asset base. Year of manufacture ranges from 1970 to 2006 with the average age being 21 years old. OHEDI uses a Typical Useful Life (TUL) of 30 years. Based upon this timeframe, currently four vault-style switchgears have exceeded the TUL of 30 years.

The following bar graph shows the quantity of vault-style switchgears that will exceed this TUL within the next 20 years.

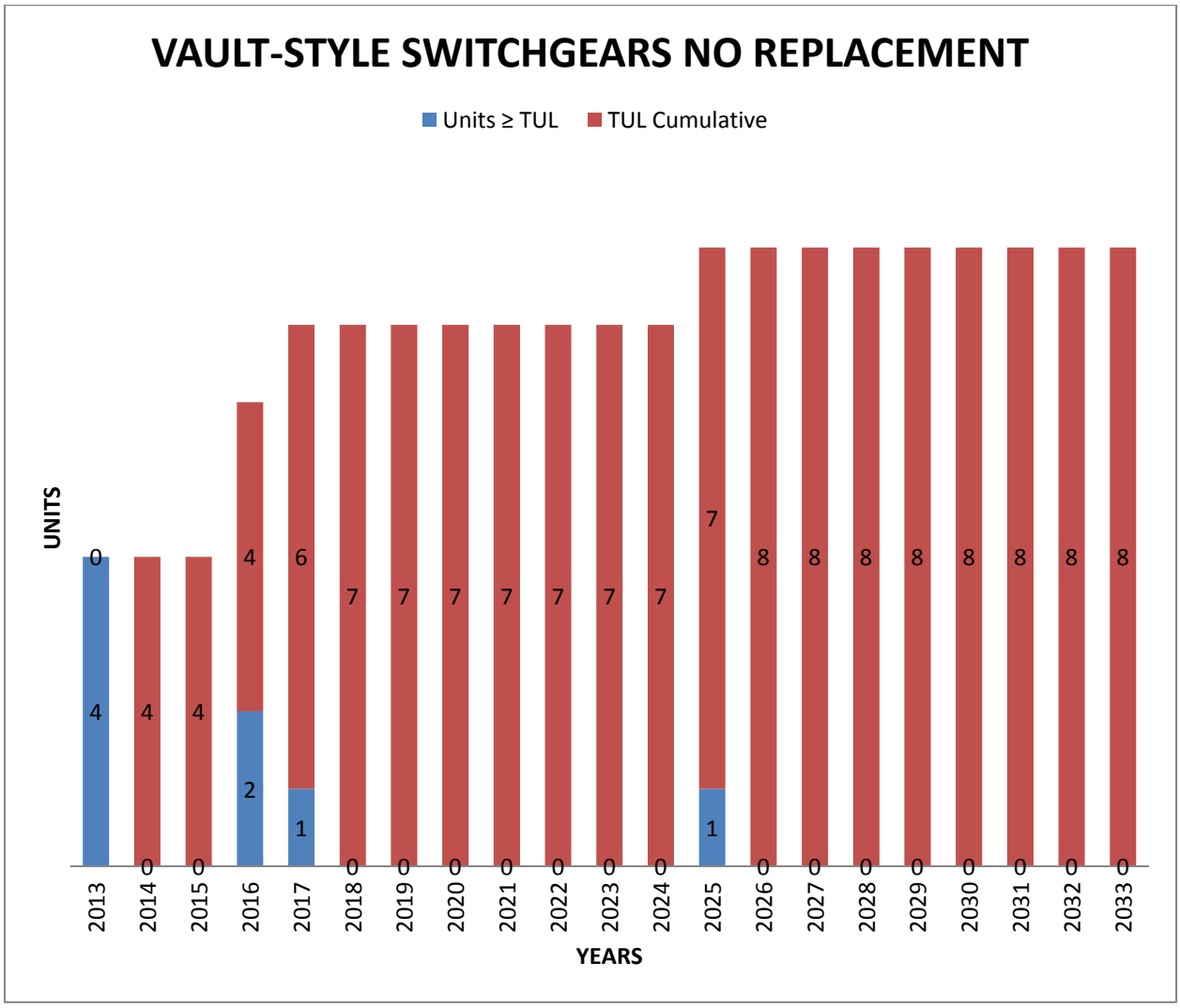


Figure 30

Investment Optimization

Any non-standard vault-style switchgears will be replaced with standard vault-style switchgears where possible to lower maintenance costs and decrease spare inventory requirements. Switchgears will also be reviewed to determine if installation of motor operated controls will improve switching time and decrease operational costs.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace one vault-style switchgear per year from 2014 to 2020 and in 2025.

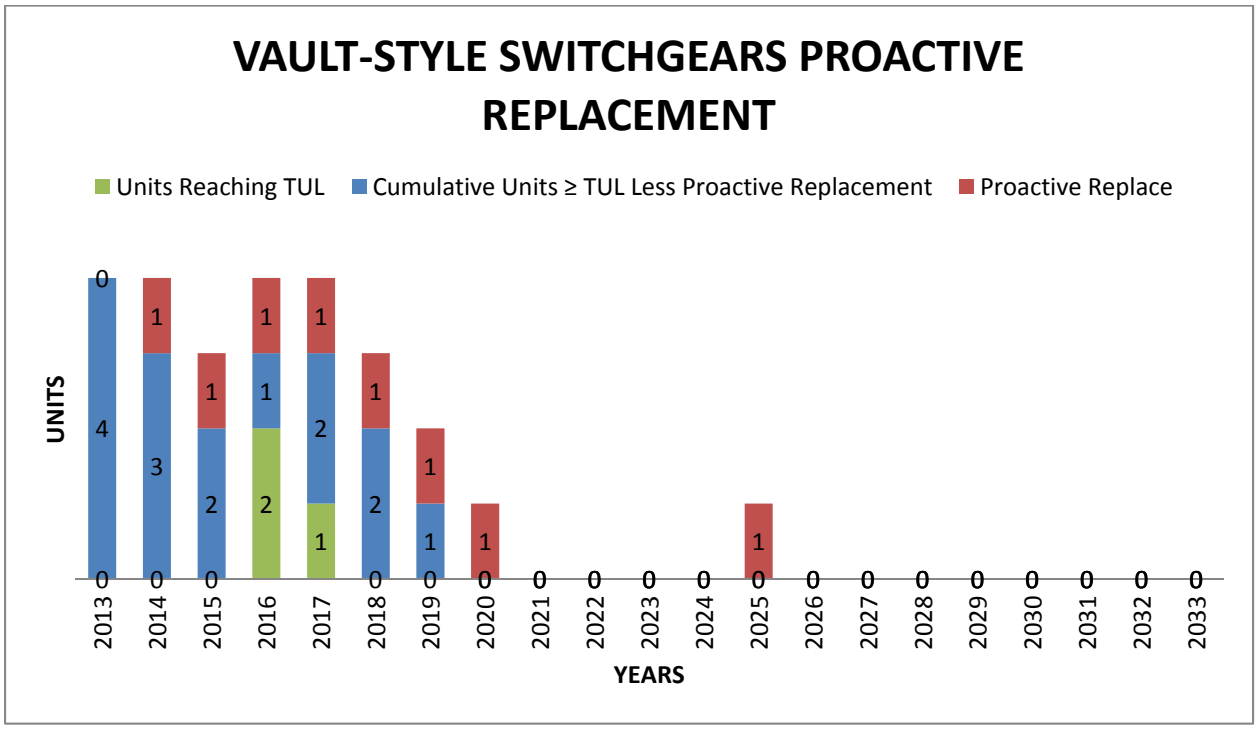


Figure 31

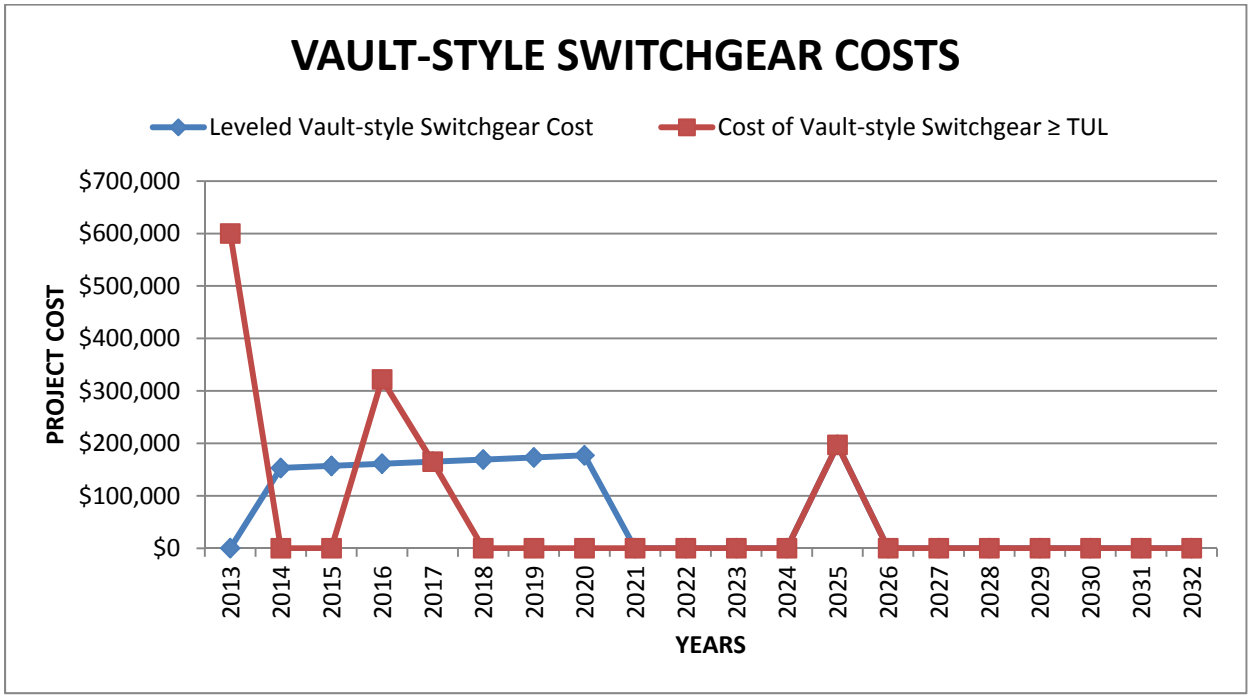


Figure 32

Gang-Operated Switches

Asset Evaluation

Gang-operated switches are switching devices used in overhead power lines. They are called gang-operated as they are single phase devices mechanically coupled and operated all at the same time. Gang-operated switches form a large asset base. Year of manufacture ranges from 1981 to 2012 with the average age being 15 years old. OHEDI uses a Typical Useful Life (TUL) of 25 years for motorized and 45 years for non-motorized. Based upon this timeframe, currently 21 gang-operated switches have exceeded the TUL of 25 or 45 years.

The following bar graph shows the quantity of gang-operated switches that will exceed this TUL within the next 20 years.

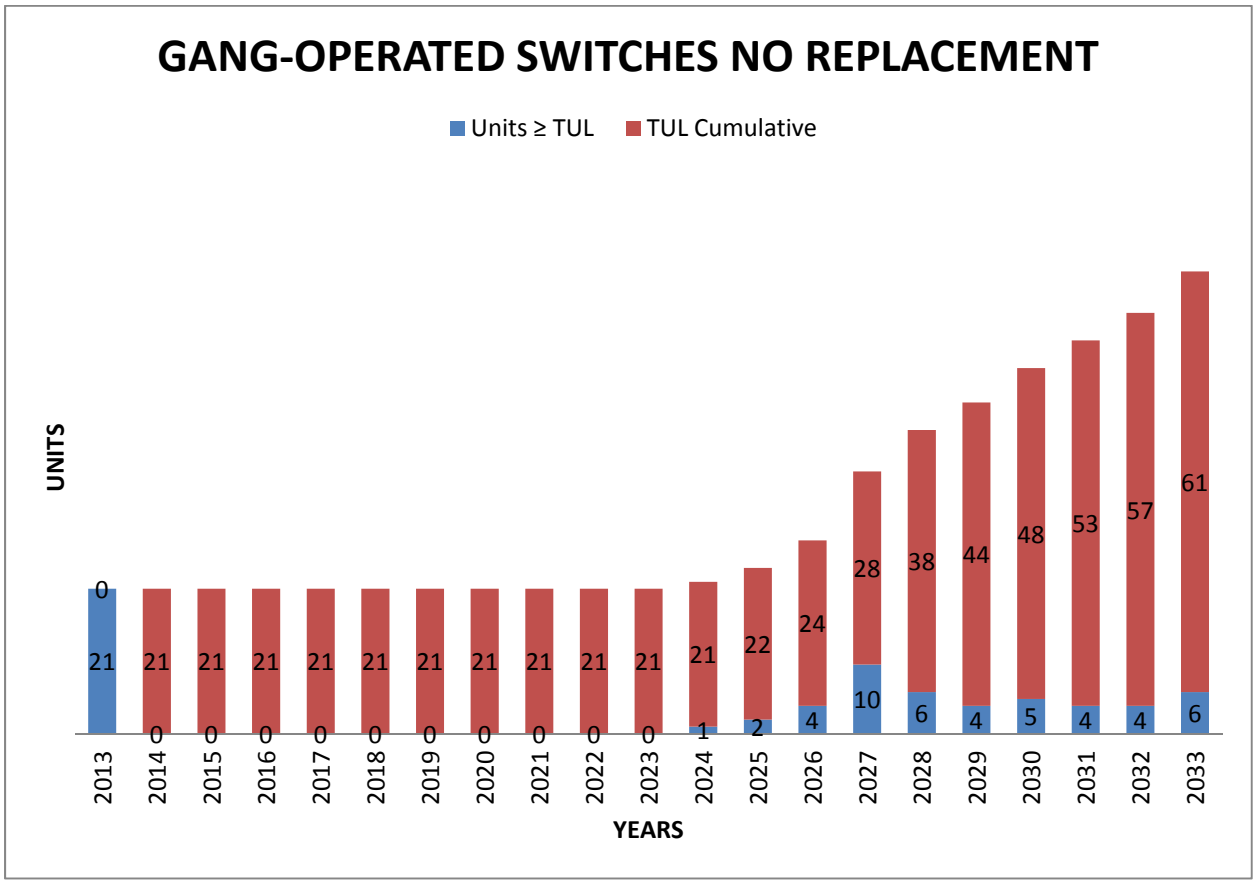


Figure 33

Investment Optimization

Prior to replacement of gang-operated switches the distribution area will be reviewed to determine if the gang-operated switch is still required. Any non-standard gang-operated switches will be replaced with standard gang-operated switches where possible to lower maintenance costs and decrease spare inventory requirements. Gang-operated switches will also be reviewed to determine if installation of motor operated controls will improve switching time and decrease operational costs.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace two gang-operated switches per year for the next 13 years and five per year thereafter.

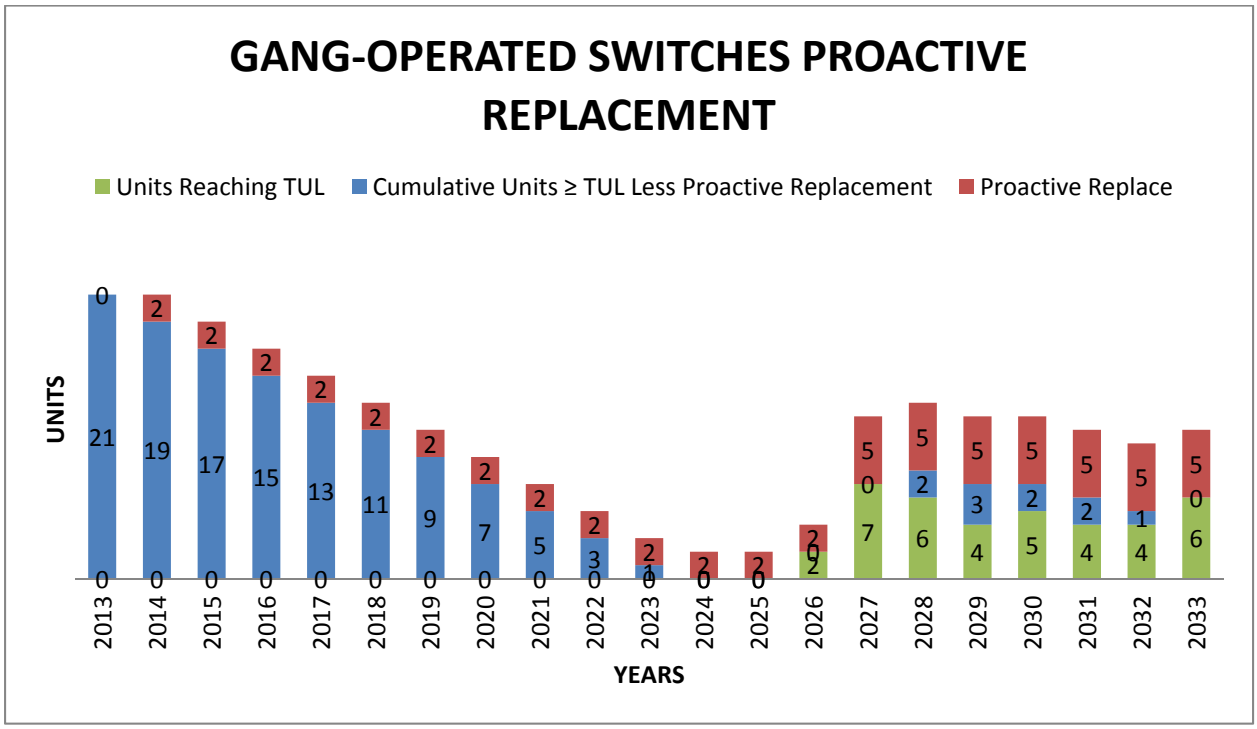


Figure 34

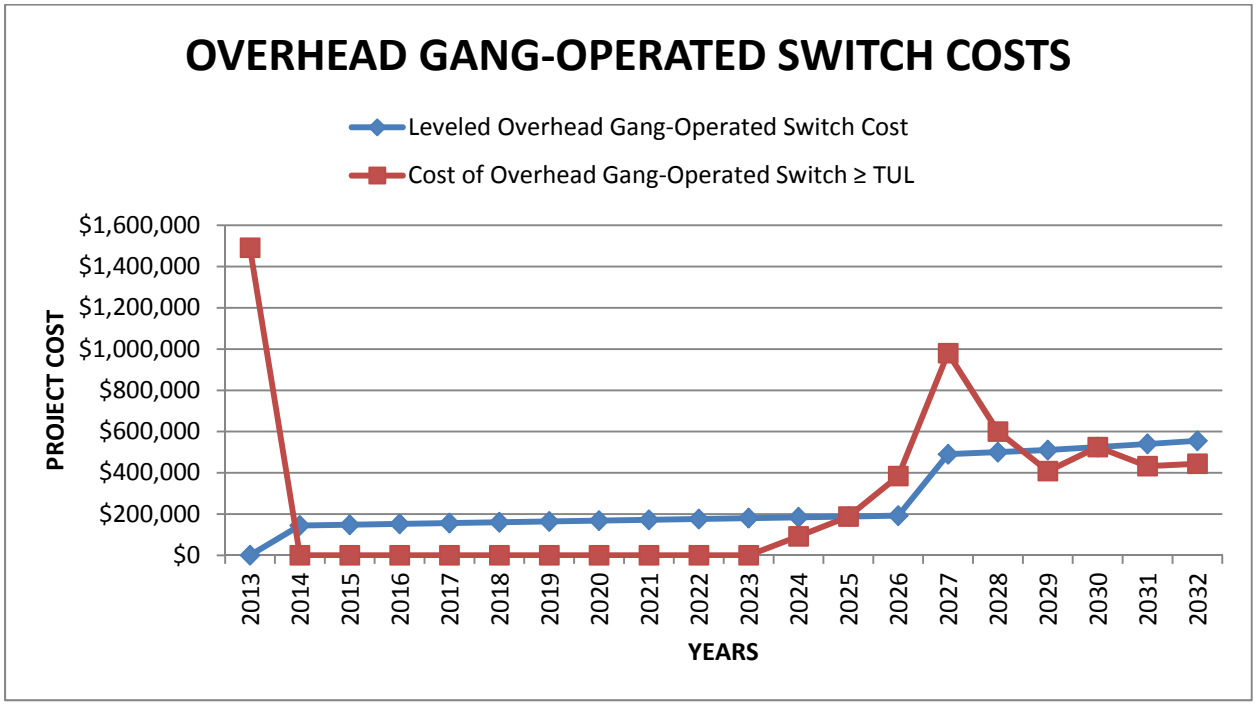


Figure 35

Overhead Primary Wires

Asset Evaluation

Overhead primary wires form a large asset base. Year of manufacture ranges from 1941 to 2012 with the average age being 47 years old. OHEDI uses a Typical Useful Life (TUL) of 60 years. Based upon this timeframe, currently 313km of overhead primary wire has exceeded the TUL of 60 years. OHEDI has chosen a run-to-failure strategy for overhead primary wires, and will replace upon failure, or ten years after the TUL, whichever comes first.

The following bar graph shows the quantity of overhead primary wire that will exceed this TUL within the next 20 years.

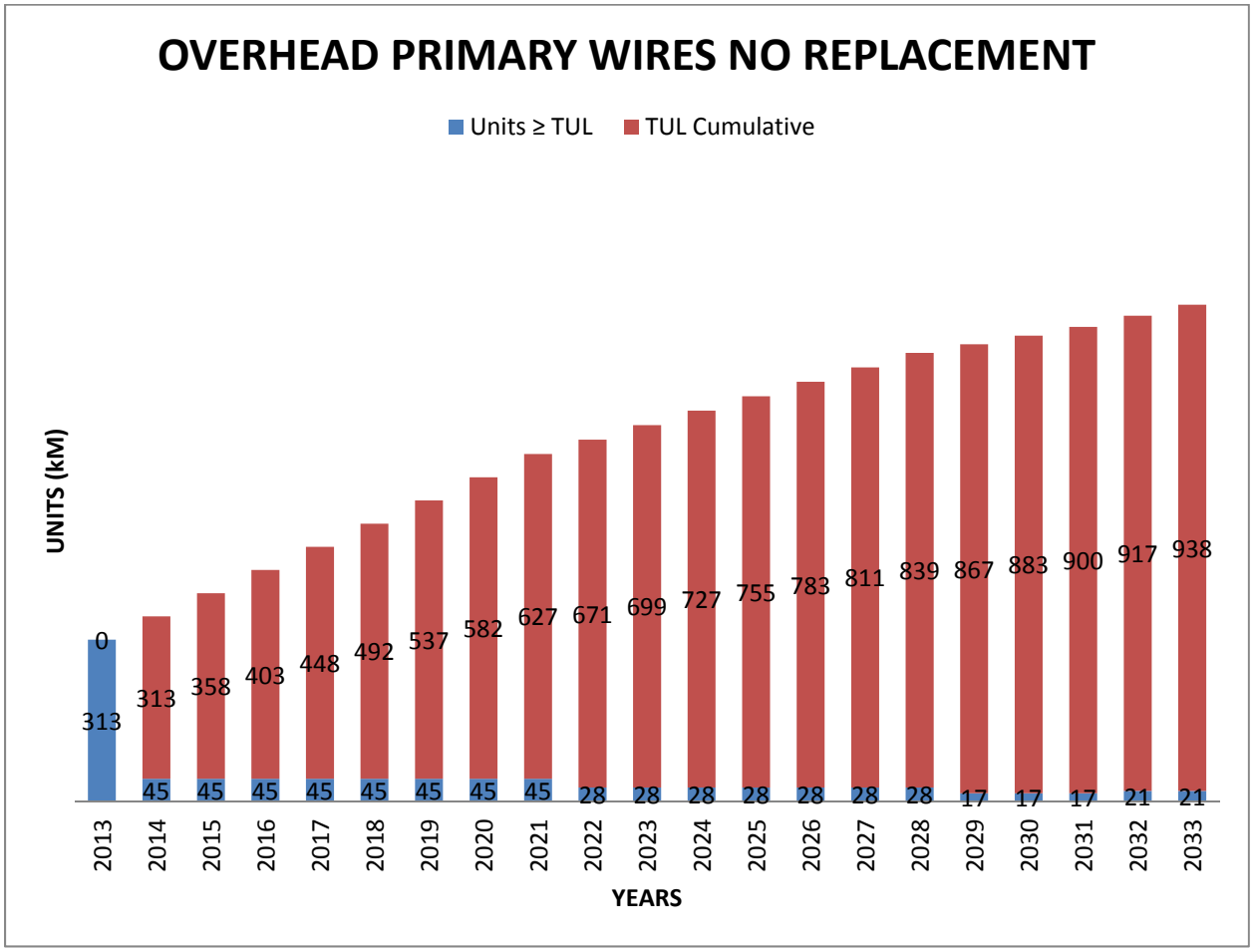


Figure 36

Investment Optimization

Any non-standard overhead primary wires will be replaced with standard wires where possible to lower material costs and decrease spare inventory requirements. Voltage conversion will be considered in order to reduce losses, cost of losses, CO_2 emissions created by fossil fuel fired generating stations due to losses, and voltage drop levels.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace 45km of overhead primary wire per year for the next 20 years.

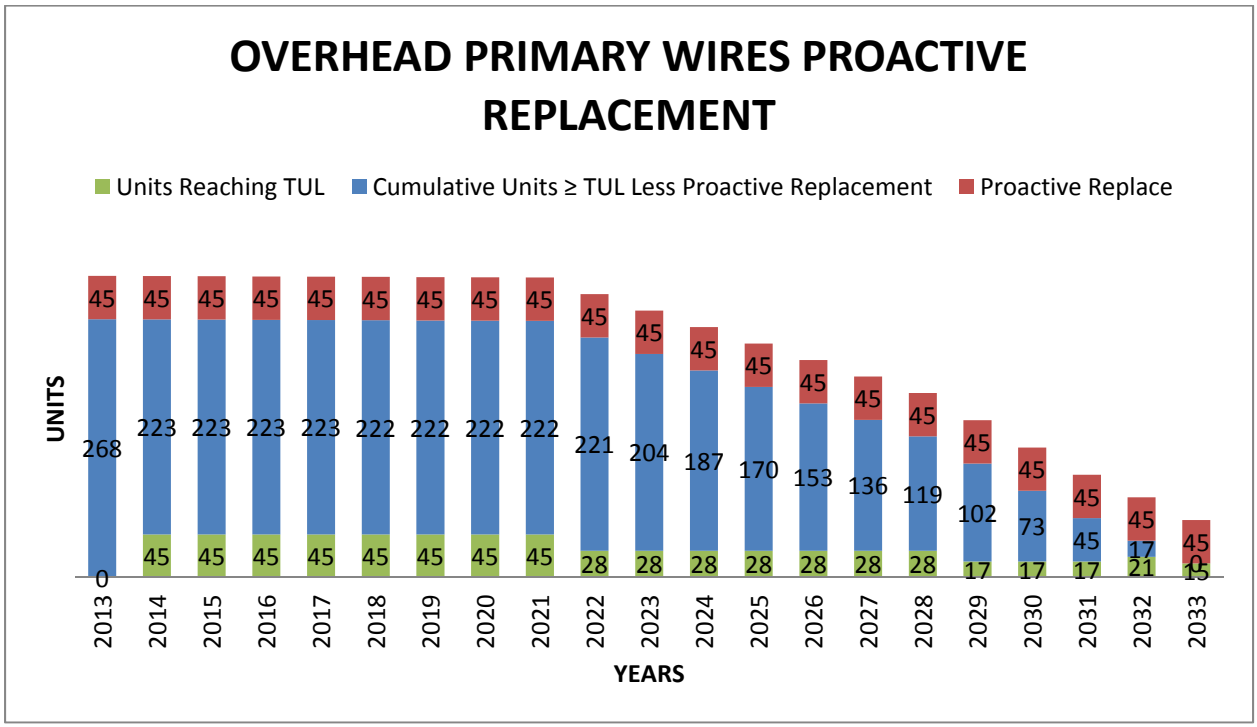


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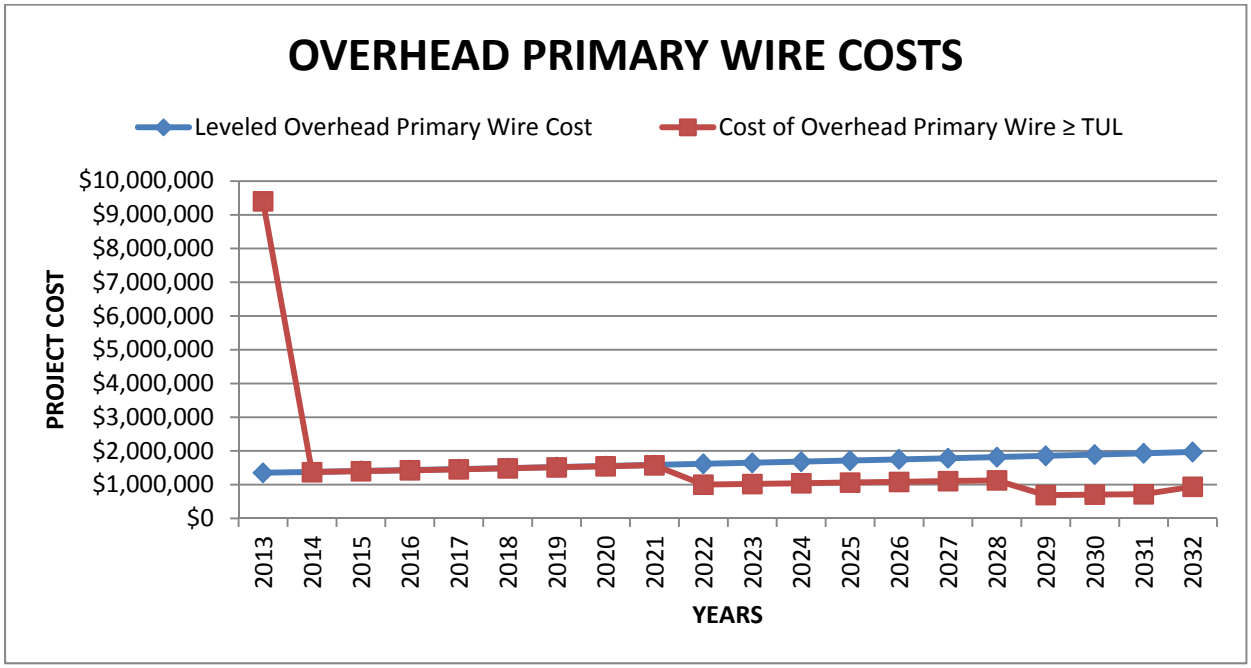


Figure 38

Underground Primary Cables

Asset Evaluation

Underground primary cables form a large asset base. Year of manufacture ranges from 1969 to 2012 with the average age being 17 years old. OHEDI uses a Typical Useful Life (TUL) of 35 years. Based upon this timeframe, currently 57km of underground primary cables have exceeded the TUL of 35 years.

The following bar graph shows the quantity of underground primary cables that will exceed this TUL within the next 20 years.

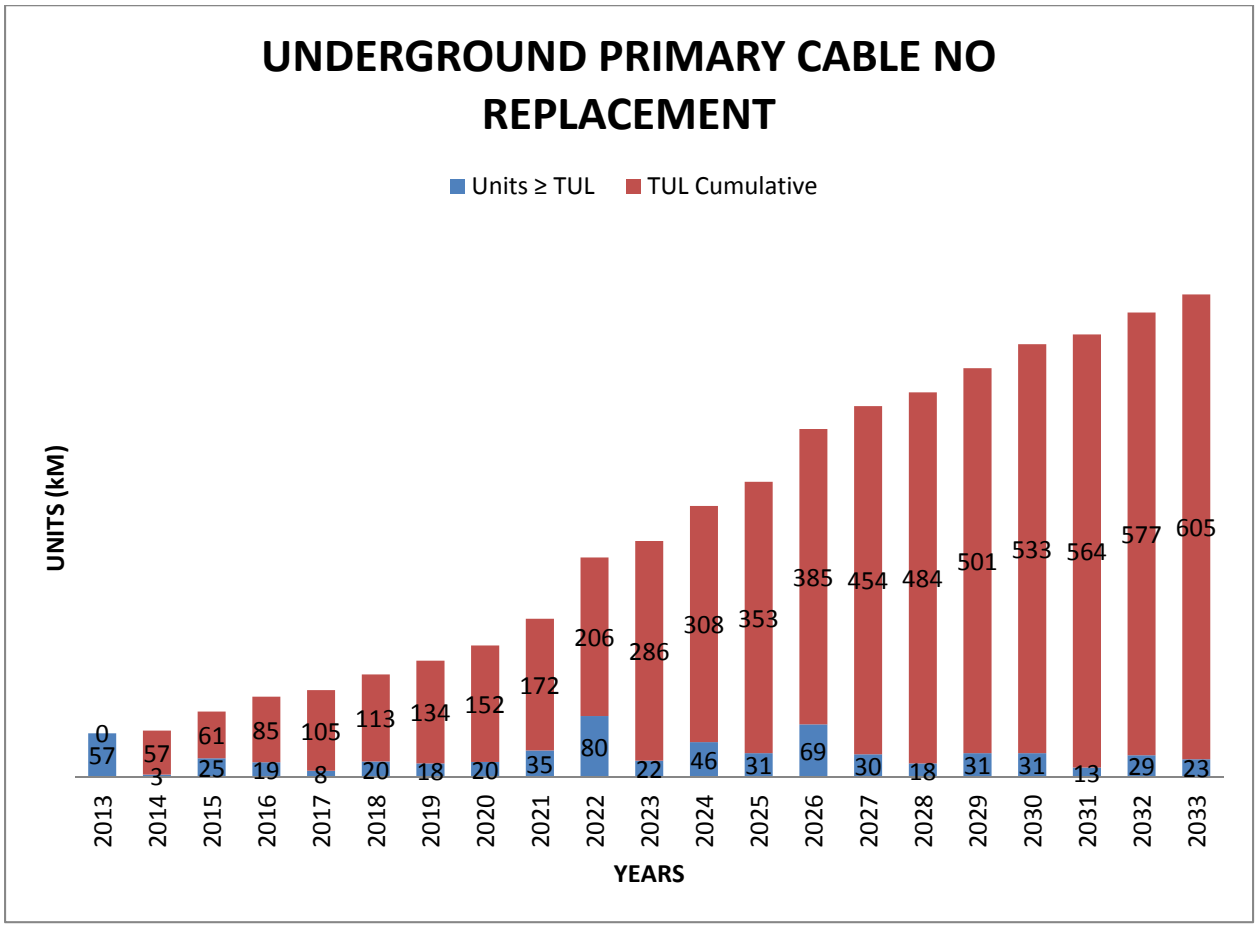


Figure 39

Investment Optimization

Any non-standard underground primary cables will be replaced with standard cables where possible to lower material costs and decrease spare inventory requirements. Areas with existing direct buried cables will be reviewed to determine if cable injection is an adequate solution to extend the useful life of the cables. For those areas where cable injection is not an option new ducts will be installed complete with new primary cables. The installation of these ducts will allow for easier replacement for future rebuilds. Voltage conversion will be considered in order to reduce losses, cost of losses, CO_2 emissions created by fossil fuel fired generating stations due to losses, and voltage drop levels.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace 21km of underground primary cable per year until 2018 and one additional km per year thereafter.

OHEDI predicts the capital expenditure required in this area may increase even more due to increasing failures of the underground primary cables. Failure investigation is being performed and based upon the results OHEDI may determine to expedite the replacement of these cables sooner than their TUL to mitigate operational expenditures.

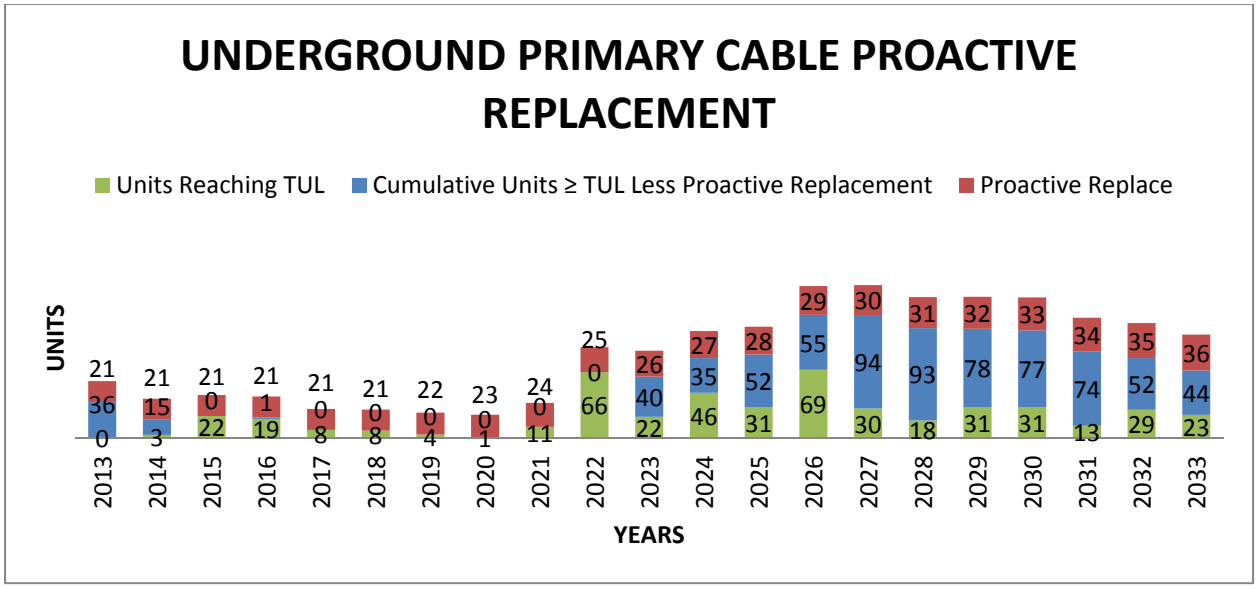


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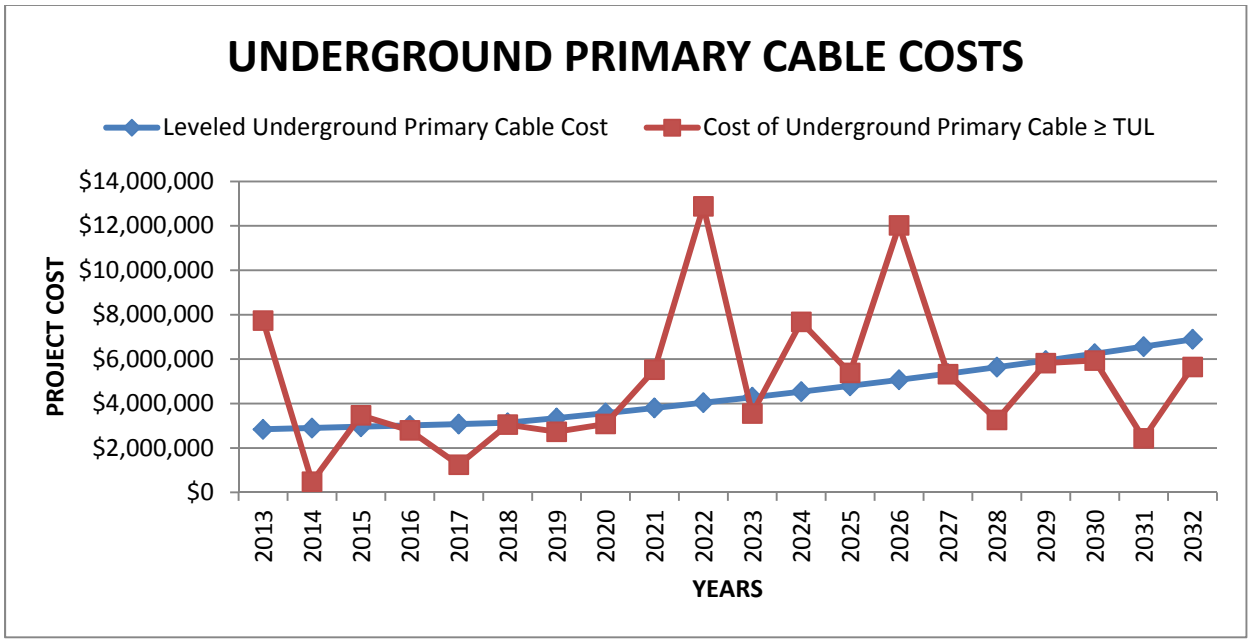


Figure 41

Poles

Asset Evaluation

Poles form a large asset base. Year of manufacture ranges from 1941 to 2012 with the average age being 26 years old. OHEDI uses a Typical Useful Life (TUL) of 45 years. Based upon this timeframe, currently 2059 poles have exceeded the TUL of 45 years.

The following bar graph shows the quantity of poles that will exceed this TUL within the next 20 years.

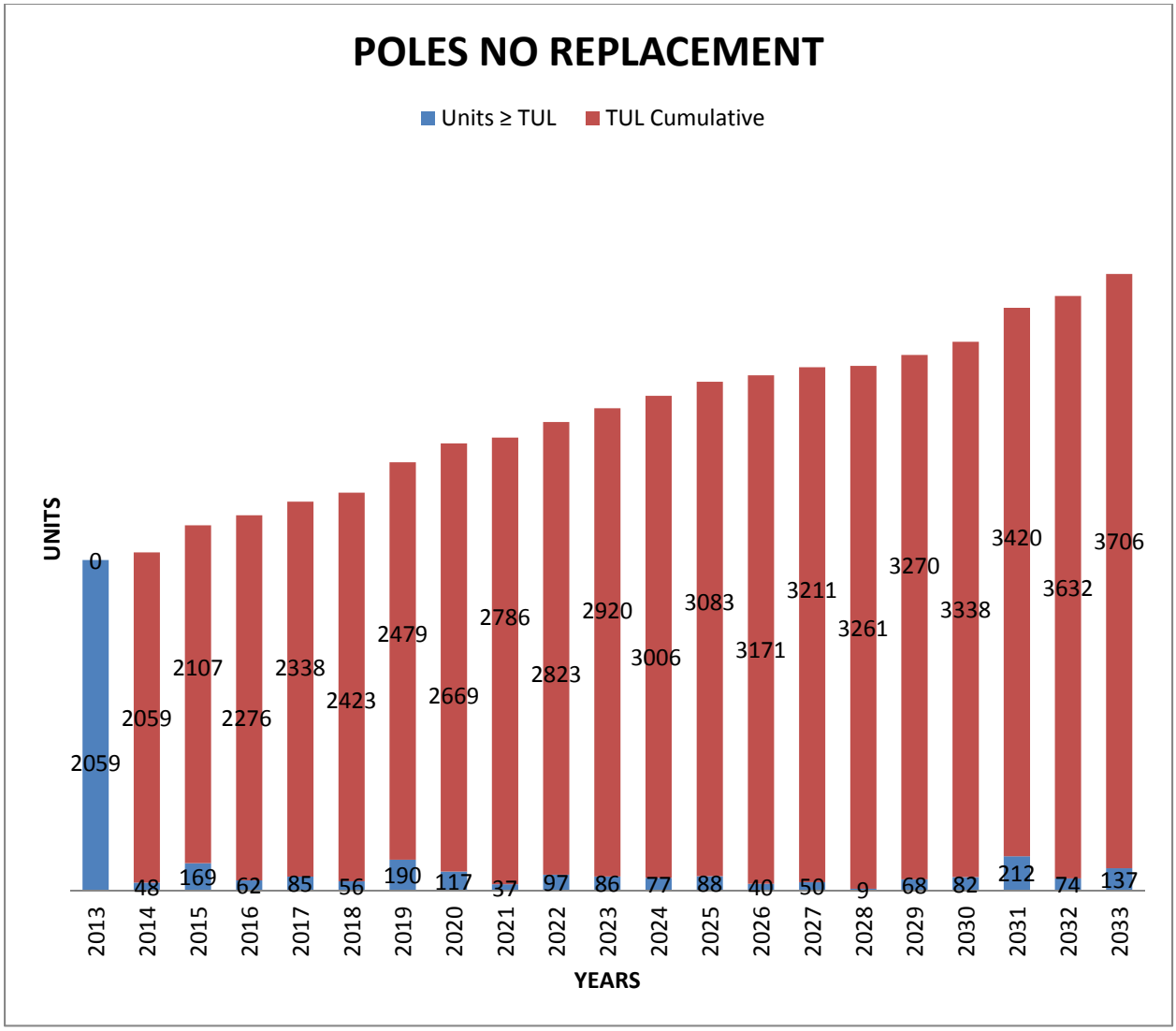


Figure 42

Investment Optimization

Prior to replacement of poles, a review is completed to determine the size and type of new pole to be installed. Future area requirements are taken into account in order to proactively increase the height of poles when required. Any non-standard poles will be replaced with standard poles where possible to lower material costs and decrease spare inventory requirements.

20 Year Forecast

There are many assets in this category past their TUL, however these poles are subject to a rigorous inspection and treatment program once every six years to keep them from failing and catch those assets in a mode of failure before they do fail. In order to keep distribution rates down, OHEDI forecasts the requirement to replace 183 poles per year for the next 20 years. A number of these poles are typically replaced due to findings from the system-wide wood pole inspection program. The others are replaced due to a combination of required replacement for overhead rebuild projects, or infill service upgrades.

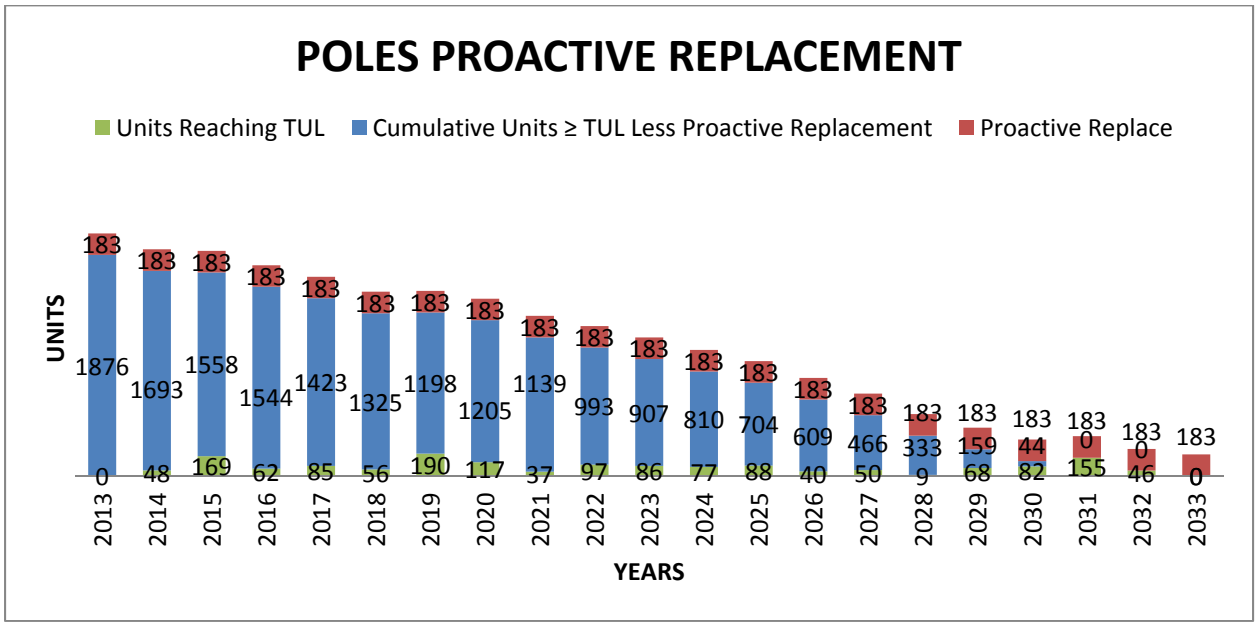


Figure 43

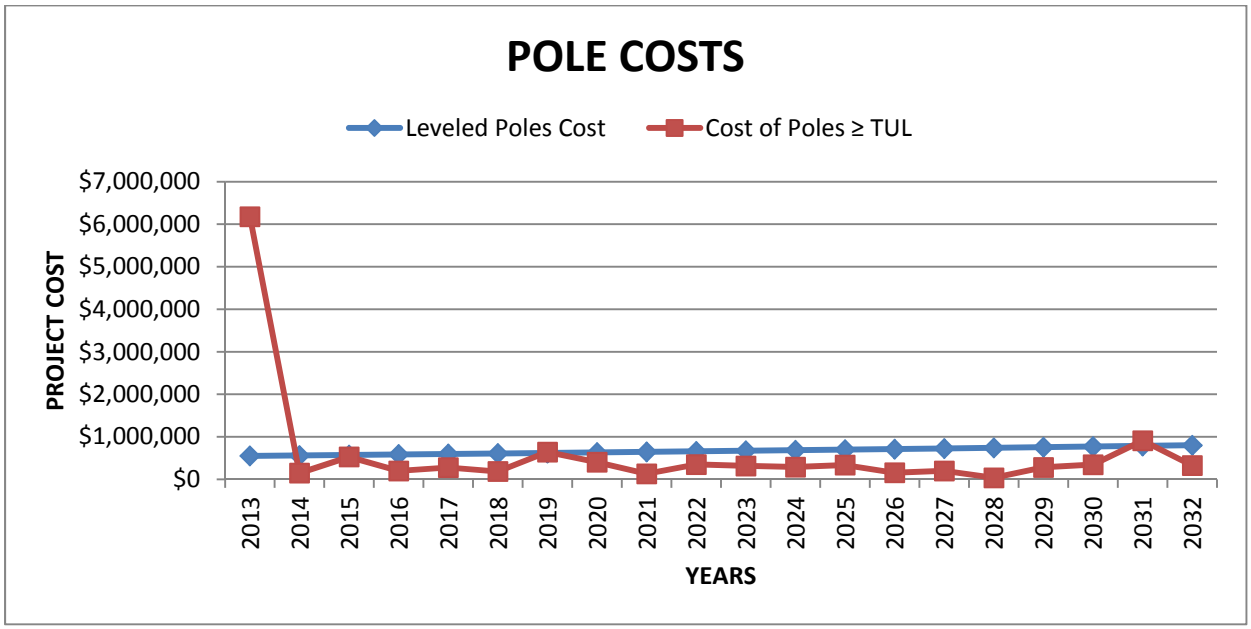


Figure 44

Overhead Secondary Wire

Asset Evaluation

Overhead secondary wires form a large asset base. Year of manufacture ranges from 1941 to 2012 with the average age being 51 years old. OHEDI uses a Typical Useful Life (TUL) of 60 years. Based upon this timeframe, currently 177km of overhead secondary wire has exceeded the TUL of 60 years. OHEDI has chosen a run-to-failure strategy for overhead secondary wire, and will replace upon failure, or ten years after the TUL, whichever comes first.

The following bar graph shows the quantity of overhead secondary wire that will exceed this TUL within the next 20 years.

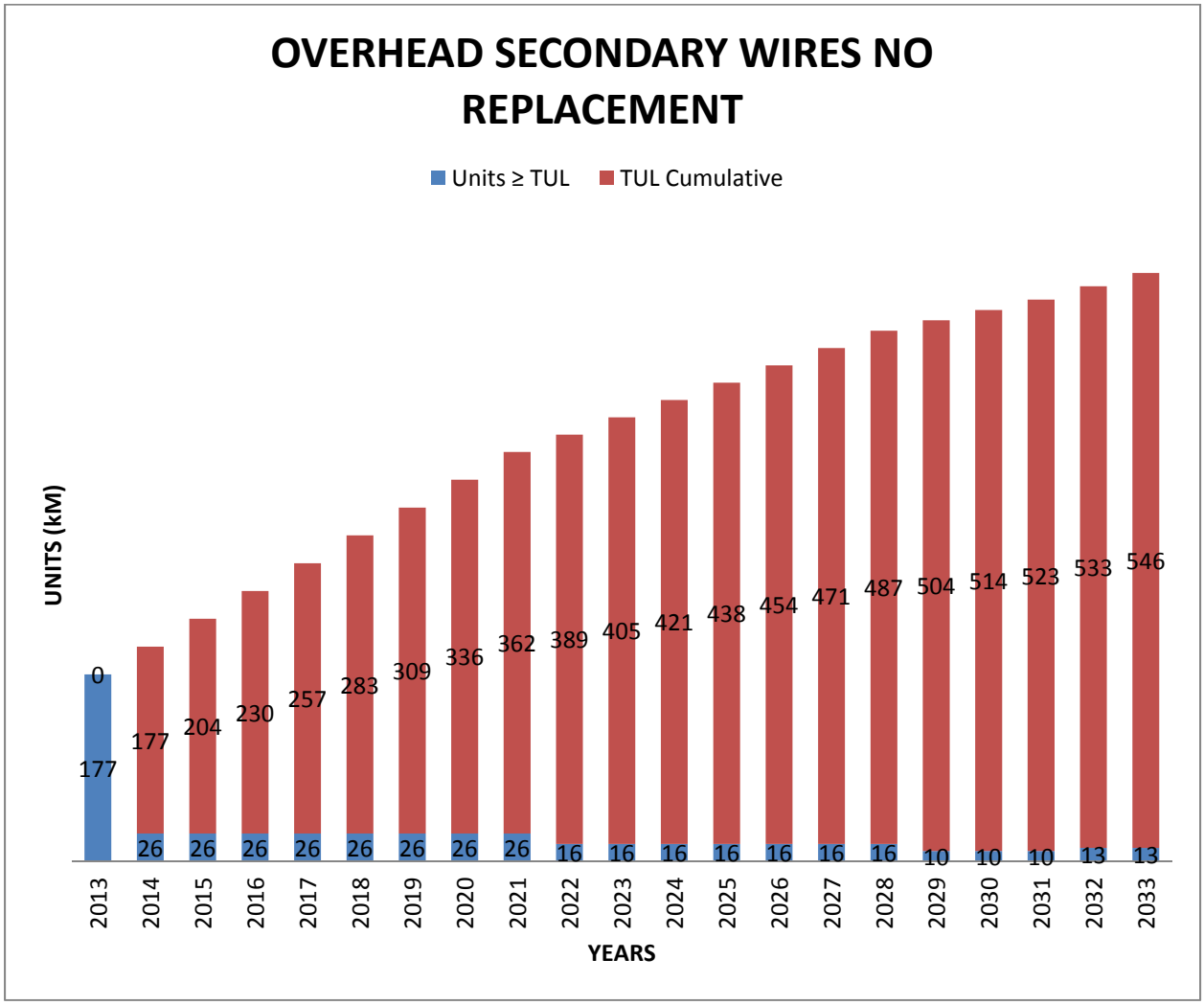


Figure 45

Investment Optimization

Any non-standard overhead secondary wires will be replaced with standard wires where possible to lower material costs and decrease spare inventory requirements.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace 26km of overhead secondary wire per year for the next 20 years.

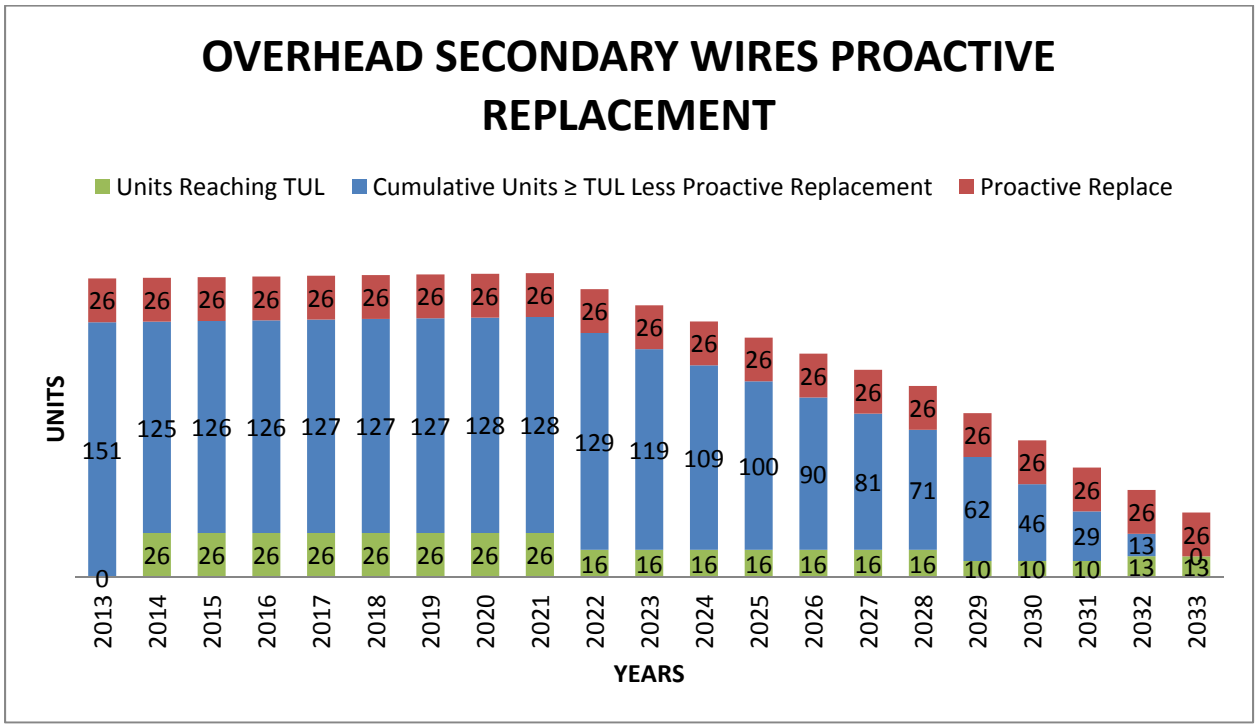


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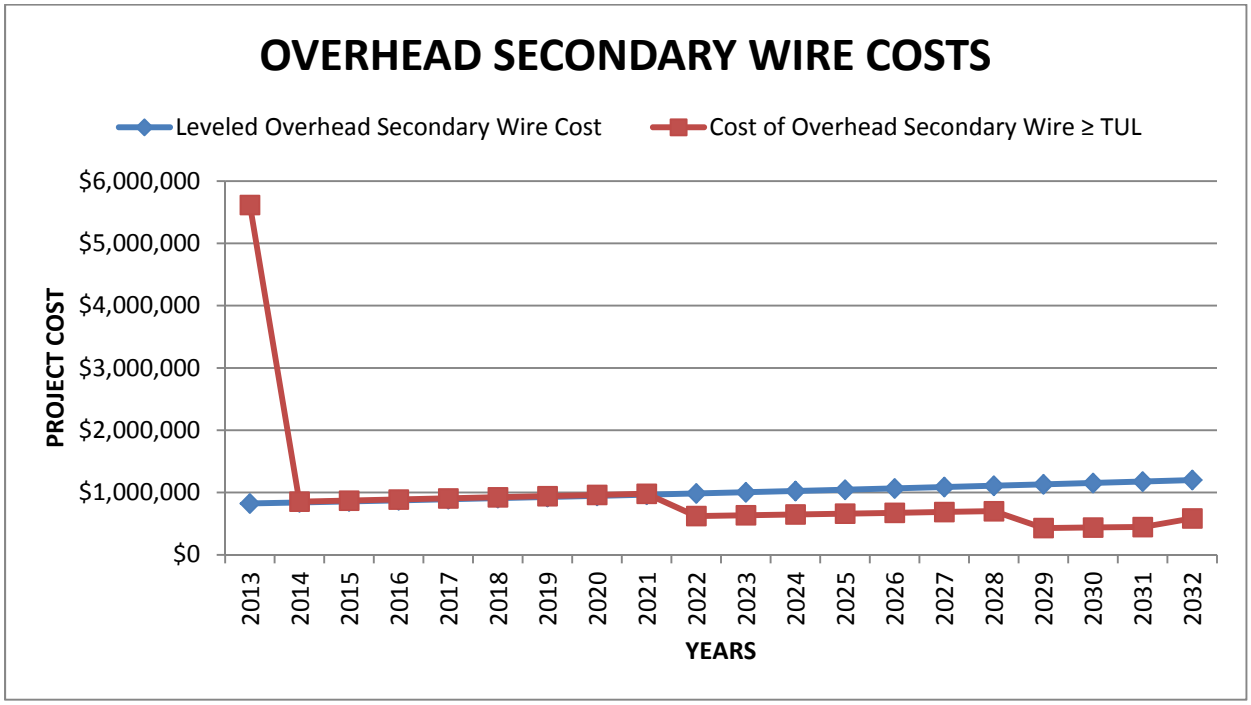


Figure 47

Underground Secondary Cable

Asset Evaluation

Underground secondary cables form a large asset base. Year of manufacture ranges from 1969 to 2012 with the average age being 17 years old. OHEDI uses a Typical Useful Life (TUL) of 35 years. Based upon this timeframe, currently 58km of underground secondary cables have exceeded the TUL of 35 years. OHEDI has chosen a run-to-failure strategy for underground secondary cable, and will replace upon failure, or ten years after the TUL, whichever comes first.

The following bar graph shows the quantity of underground secondary cables that will exceed this TUL within the next 20 years.

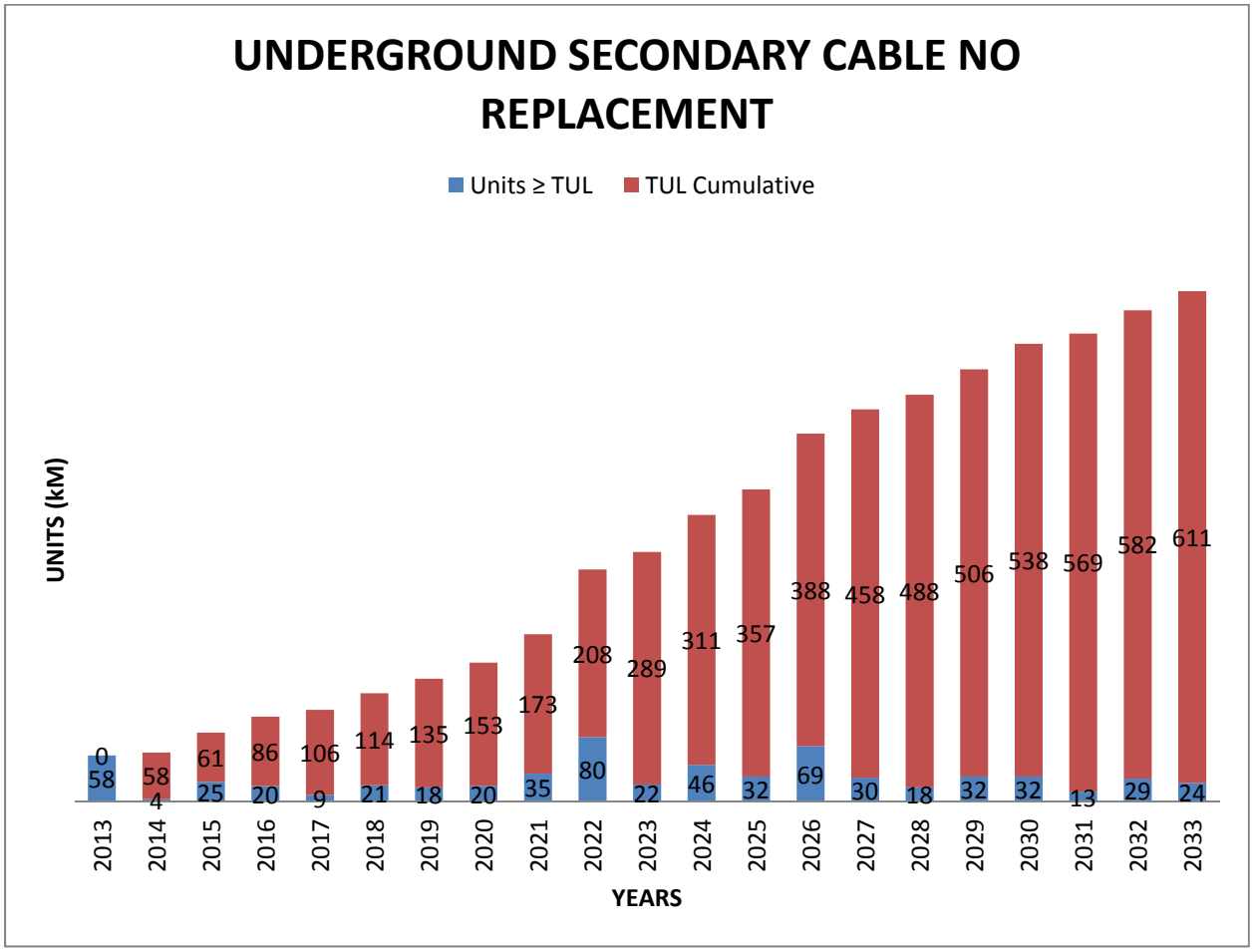


Figure 48

Investment Optimization

Any non-standard underground secondary cables will be replaced with standard cables where possible to lower material costs and decrease spare inventory requirements. Areas with existing direct buried cables will have new ducts installed complete with new secondary cables. The installation of these ducts will allow for easier replacement for future rebuilds.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace 21km of underground secondary cable per year until 2018 and one additional km per year thereafter.

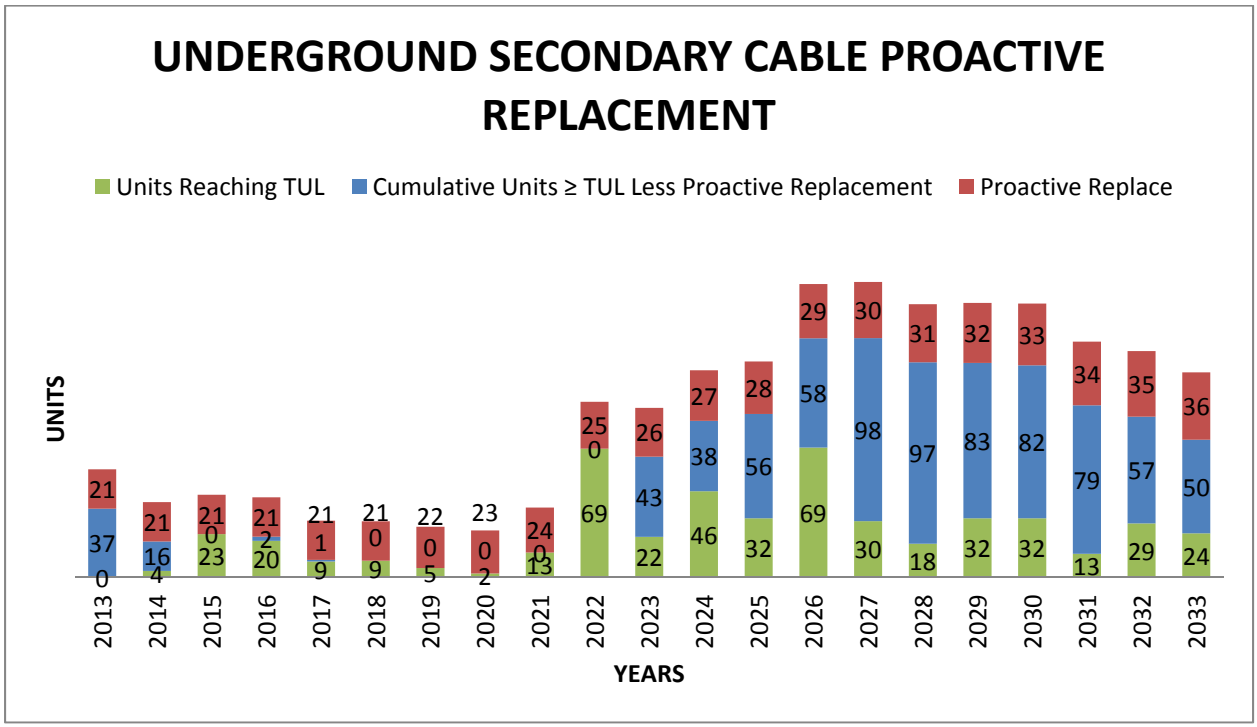


Figure 49

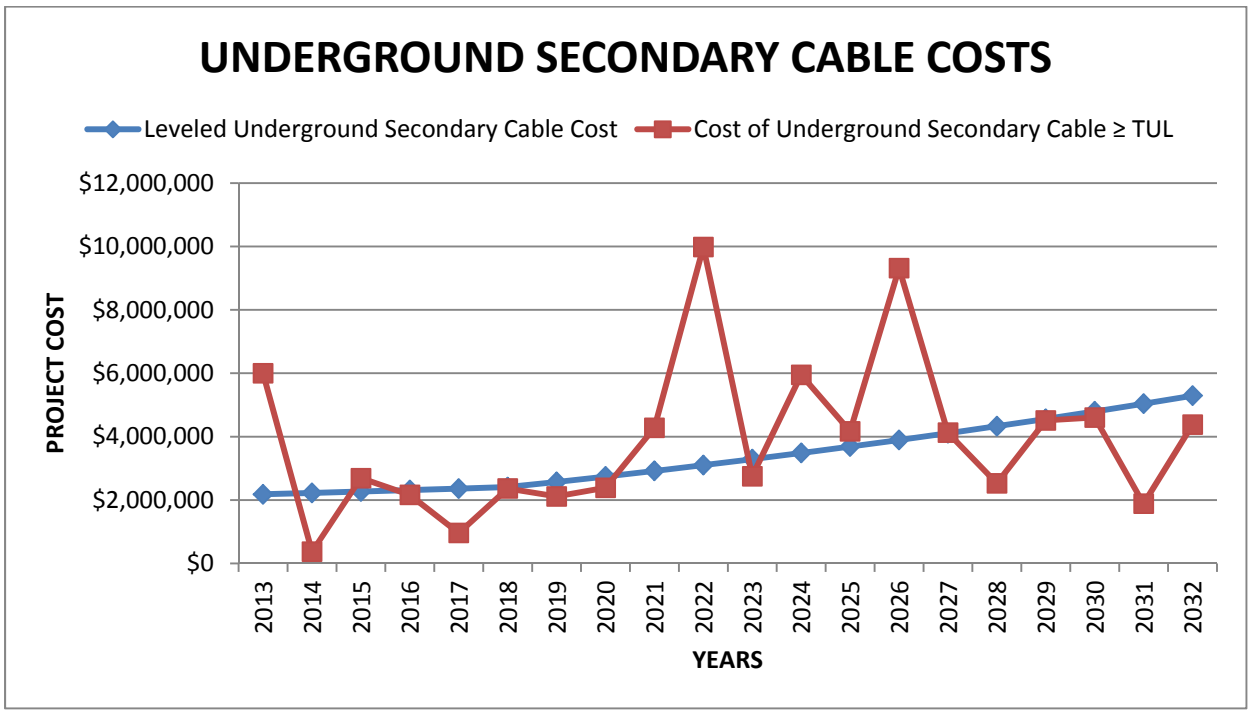


Figure 50

Residential Meters

Asset Evaluation

Residential Meters form a large asset base. In 2011 OHEDI completed a full conversion of all residential meters to next generation AMI meters. Year of manufacture ranges from 1981 to 2012 with the average age being 2 years old. OHEDI uses a Typical Useful Life (TUL) of 15 years. Based upon this timeframe, currently 111 residential meters have exceeded the TUL of 15 years.

The following bar graph shows the quantity of residential meters that will exceed this TUL within the next 20 years.

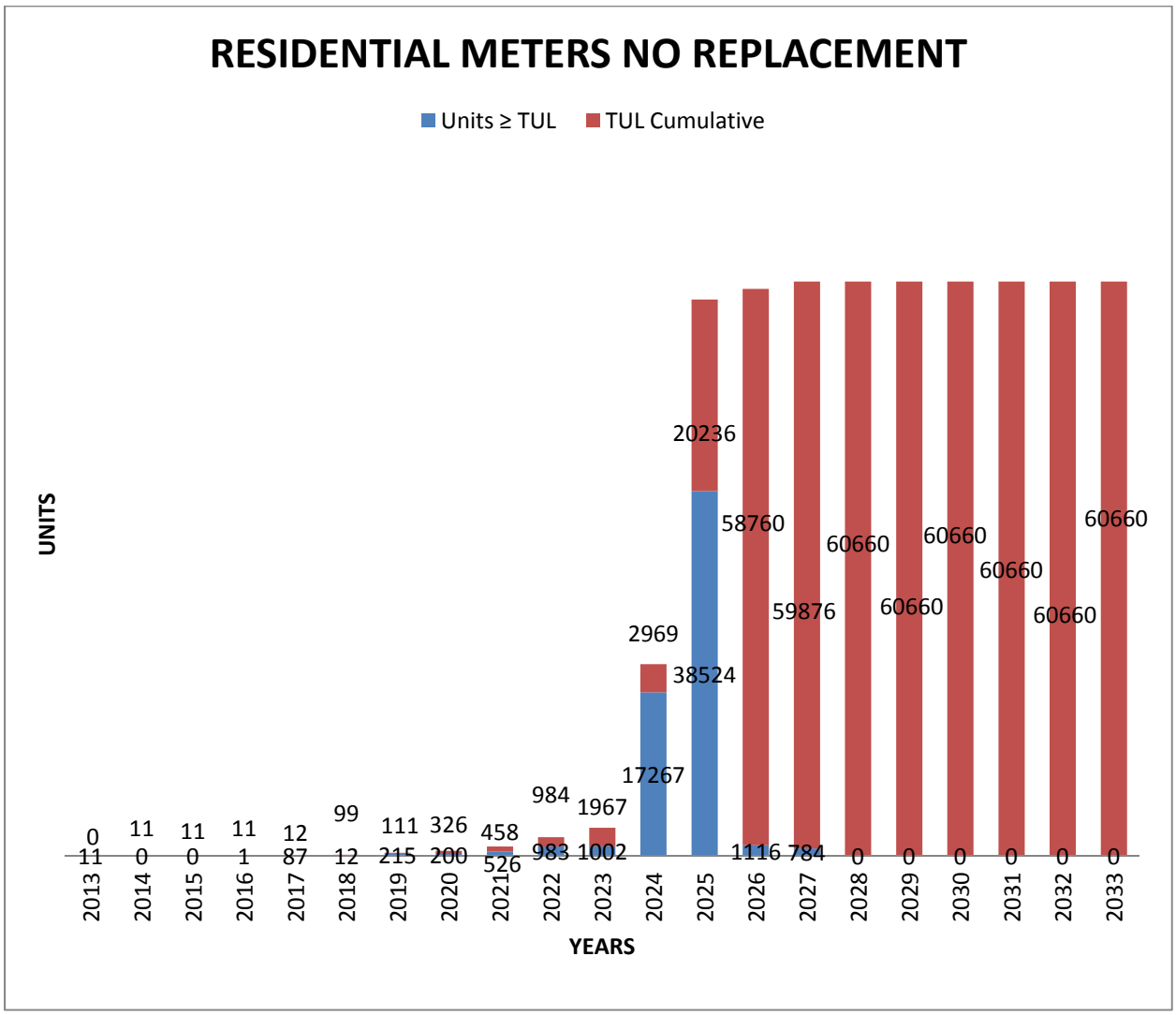


Figure 51

Investment Optimization

Any non-standard residential meters will be replaced with meters where possible to lower material costs and decrease spare inventory requirements.

20 Year Forecast

In order to level capital replacement costs, OHEDI forecasts the requirement to replace an increasing amount of residential meters per year until 2027, at which time replacements will remain at a constant level. Replacements will be driven by the sealing/re-certification plan as detailed in the Maintenance Expenditure Plan

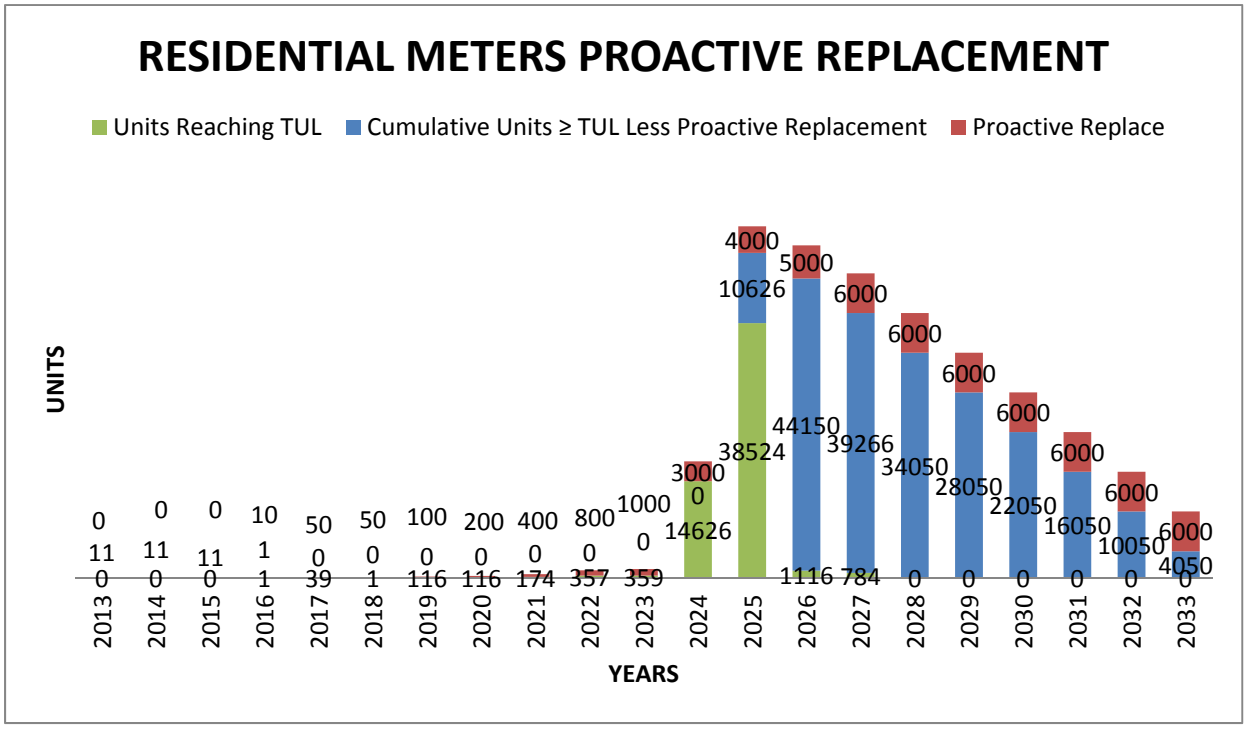


Figure 52

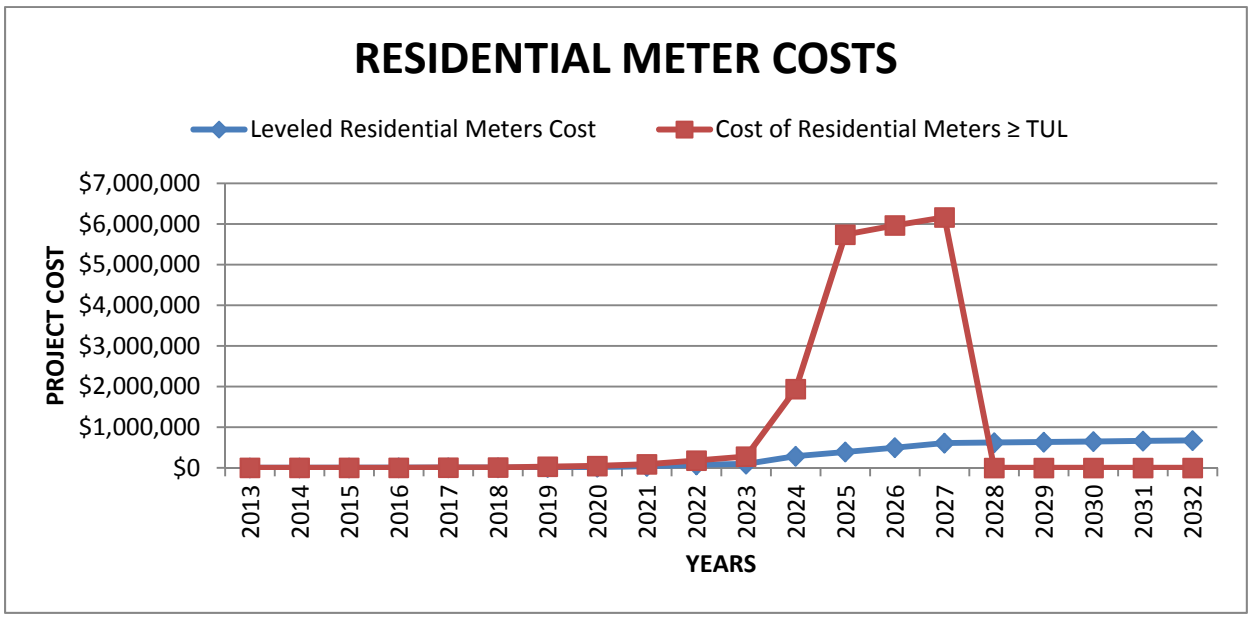


Figure 53

Commercial Meters

Asset Evaluation

Commercial meters form a small asset base. Year of manufacture ranges from 1982 to 2012 with the average age being 10 years old. OHEDI uses a Typical Useful Life (TUL) of 25 years. Based upon this timeframe, currently 20 commercial meters have exceeded the TUL of 25 years.

The following bar graph shows the quantity of commercial meters that will exceed this TUL within the next 20 years.

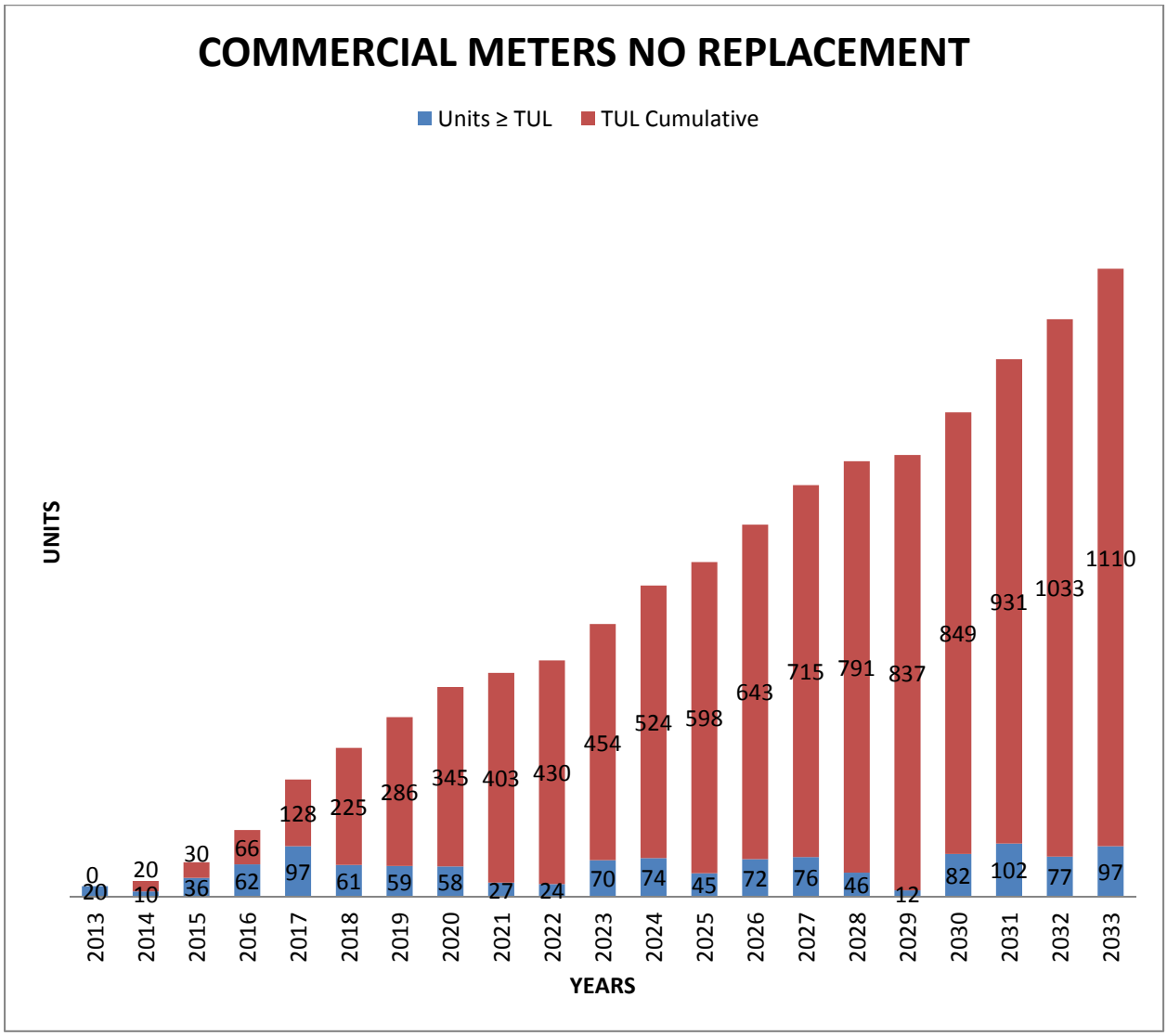


Figure 54

Investment Optimization

Any non-standard commercial meters will be replaced with meters where possible to lower material costs and decrease spare inventory requirements.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace 10 in 2014, an additional 10 per year until 2019, 60 per year until 2026, and 70 per year thereafter.

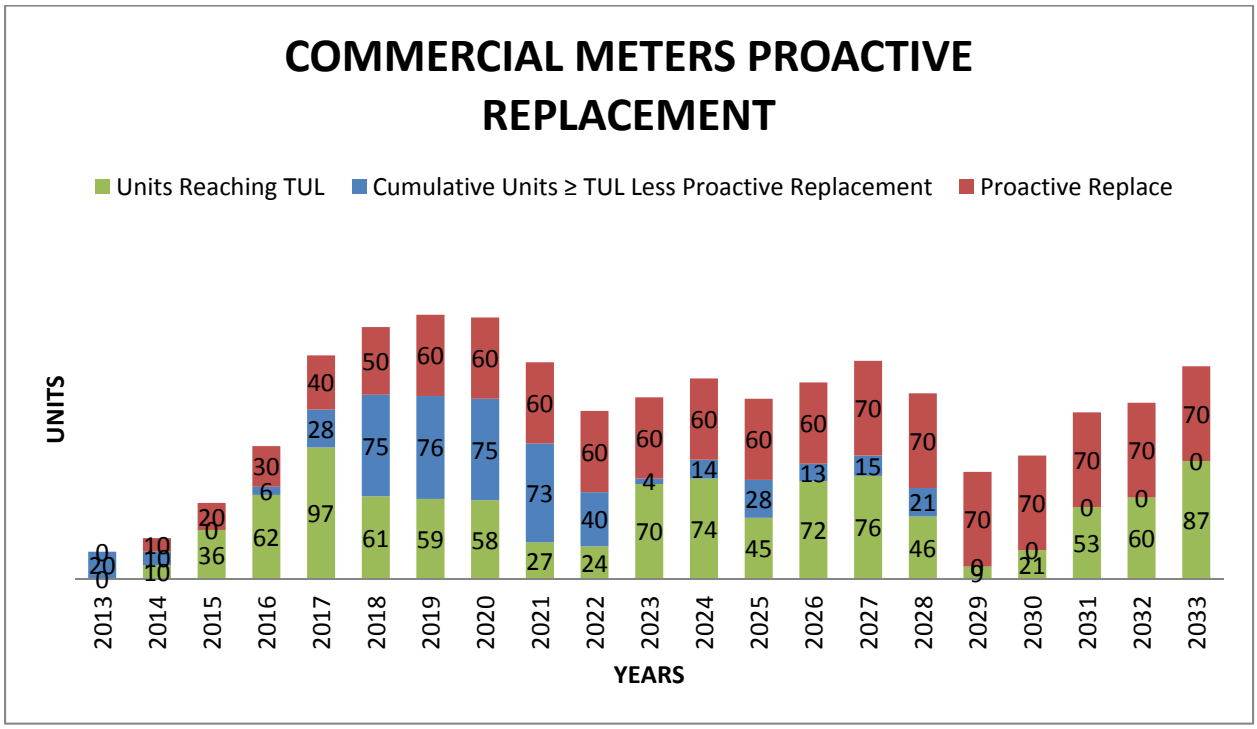


Figure 55

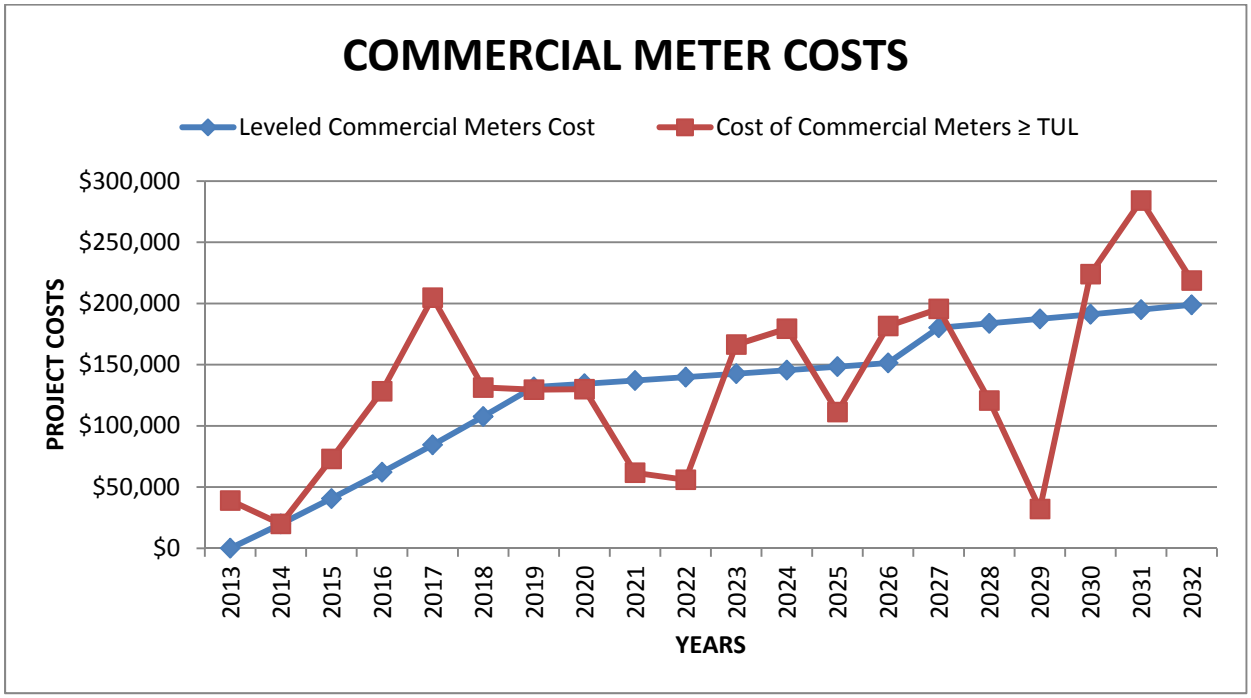


Figure 56

Primary Meters

Asset Evaluation

Primary meters form a small asset base. Year of manufacture ranges from 1970 to 2012 with the average age being 20 years old. OHEDI uses a Typical Useful Life (TUL) of 25 years. Based upon this timeframe, currently 15 primary meters have exceeded the TUL of 25 years. OHEDI has chosen a run-to-failure strategy for primary meters, and will replace upon failure, or ten years after the TUL, whichever comes first.

The following bar graph shows the quantity of primary meters that will exceed this TUL within the next 20 years.

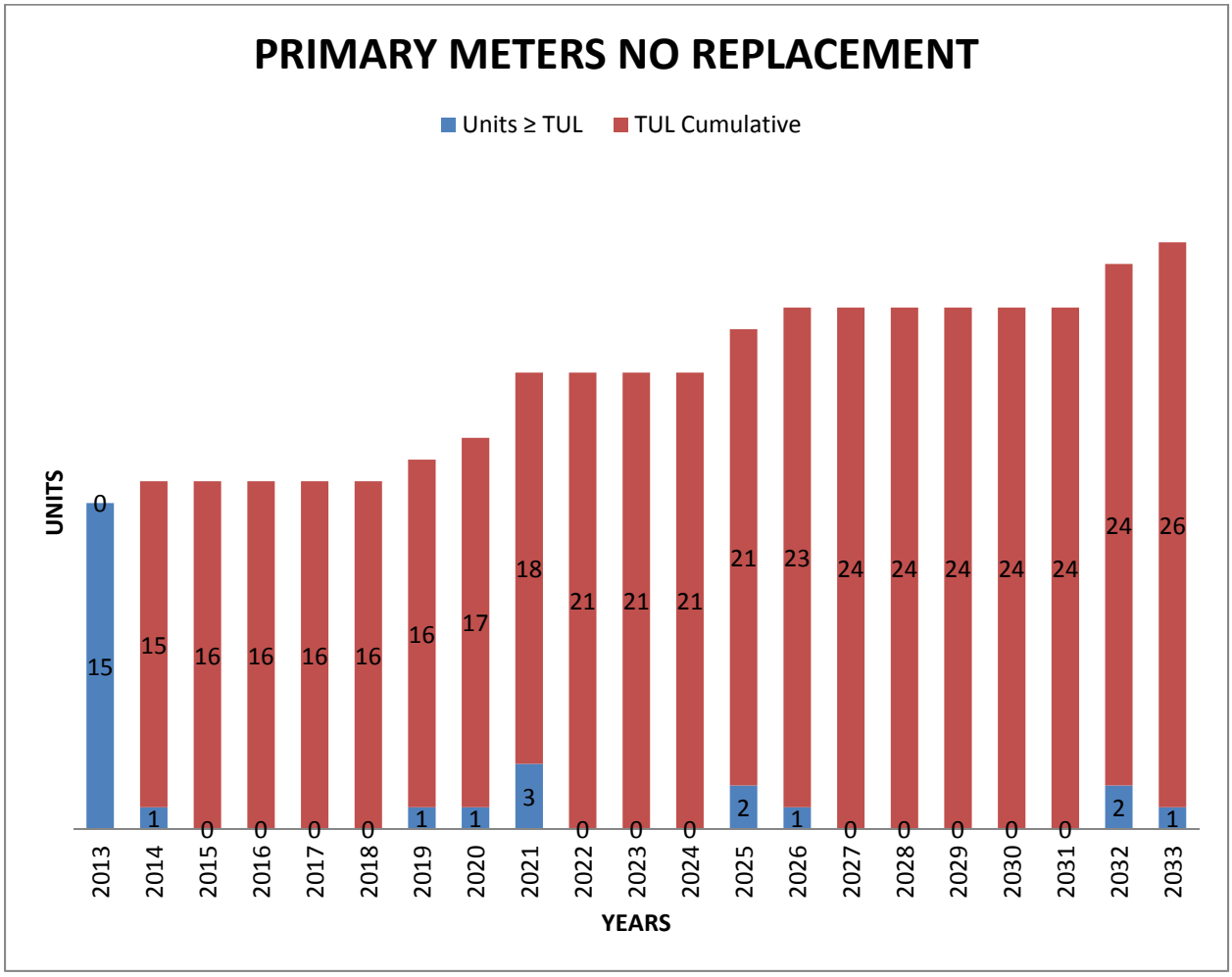


Figure 57

Investment Optimization

Any non-standard primary meters will be replaced with standard primary meters where possible to lower material costs and decrease spare inventory requirements.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace two primary meters per year starting in 2015 until 2021, and one per year thereafter.

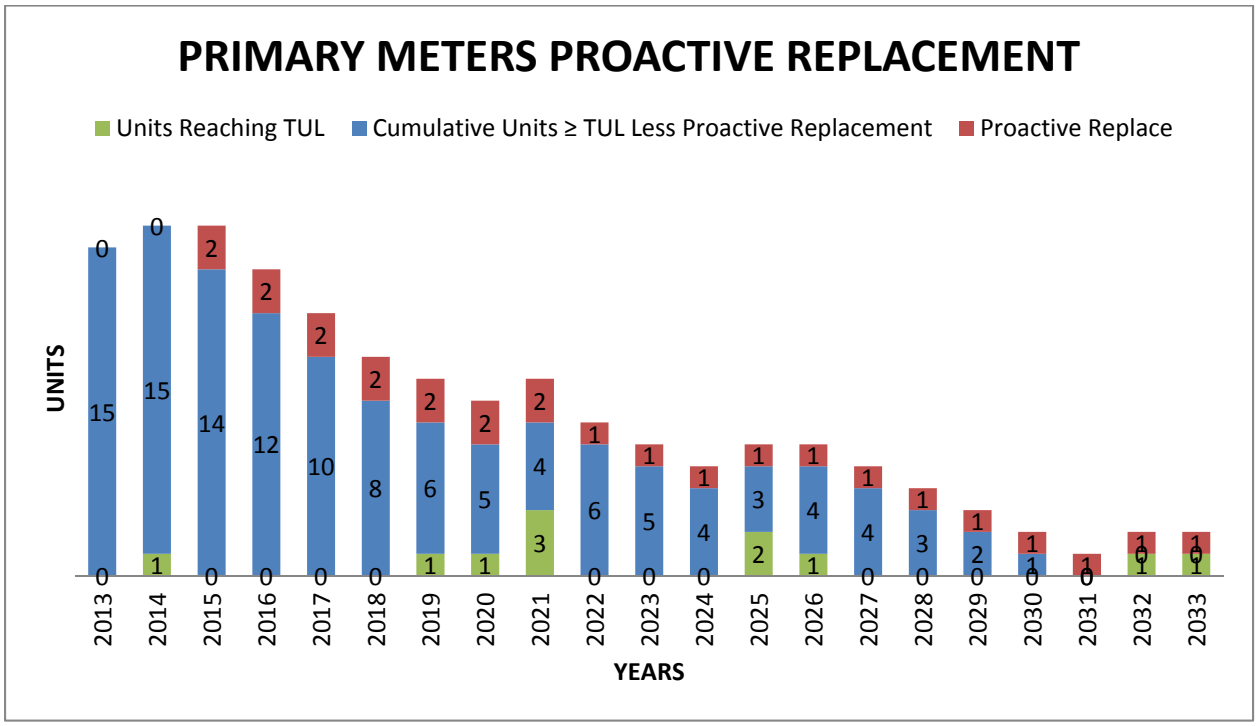


Figure 58

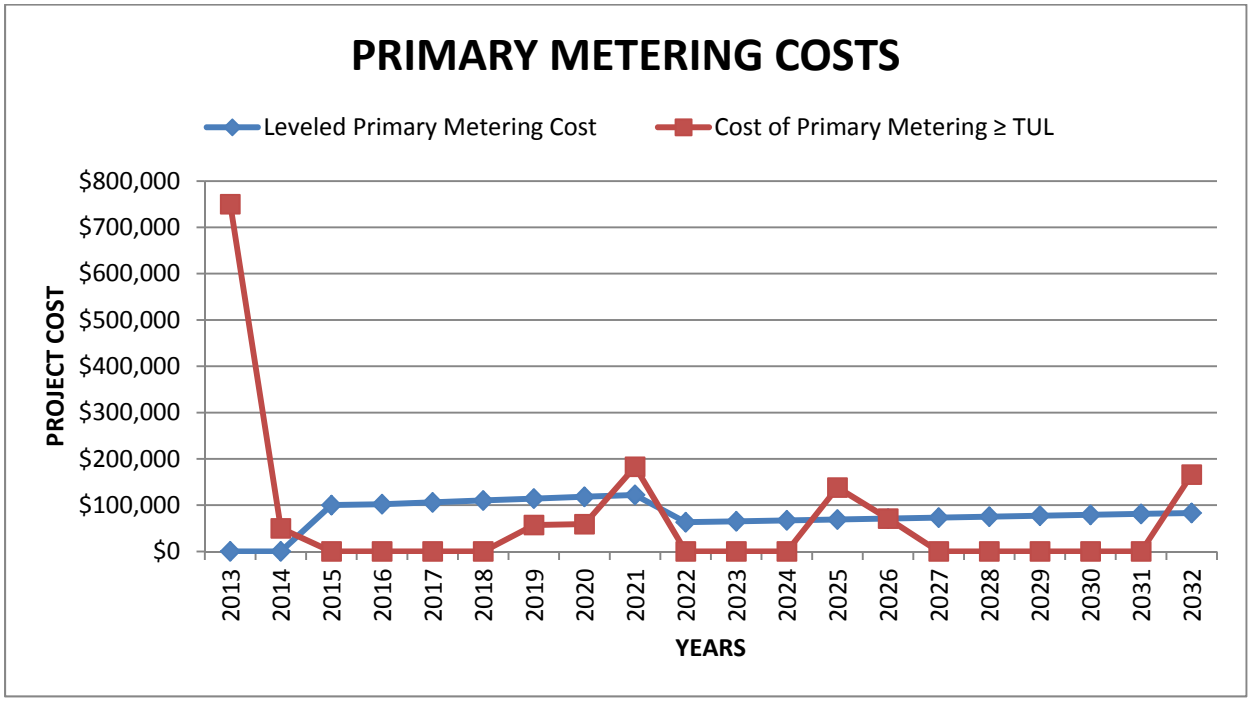


Figure 59

Total Major Distribution Assets

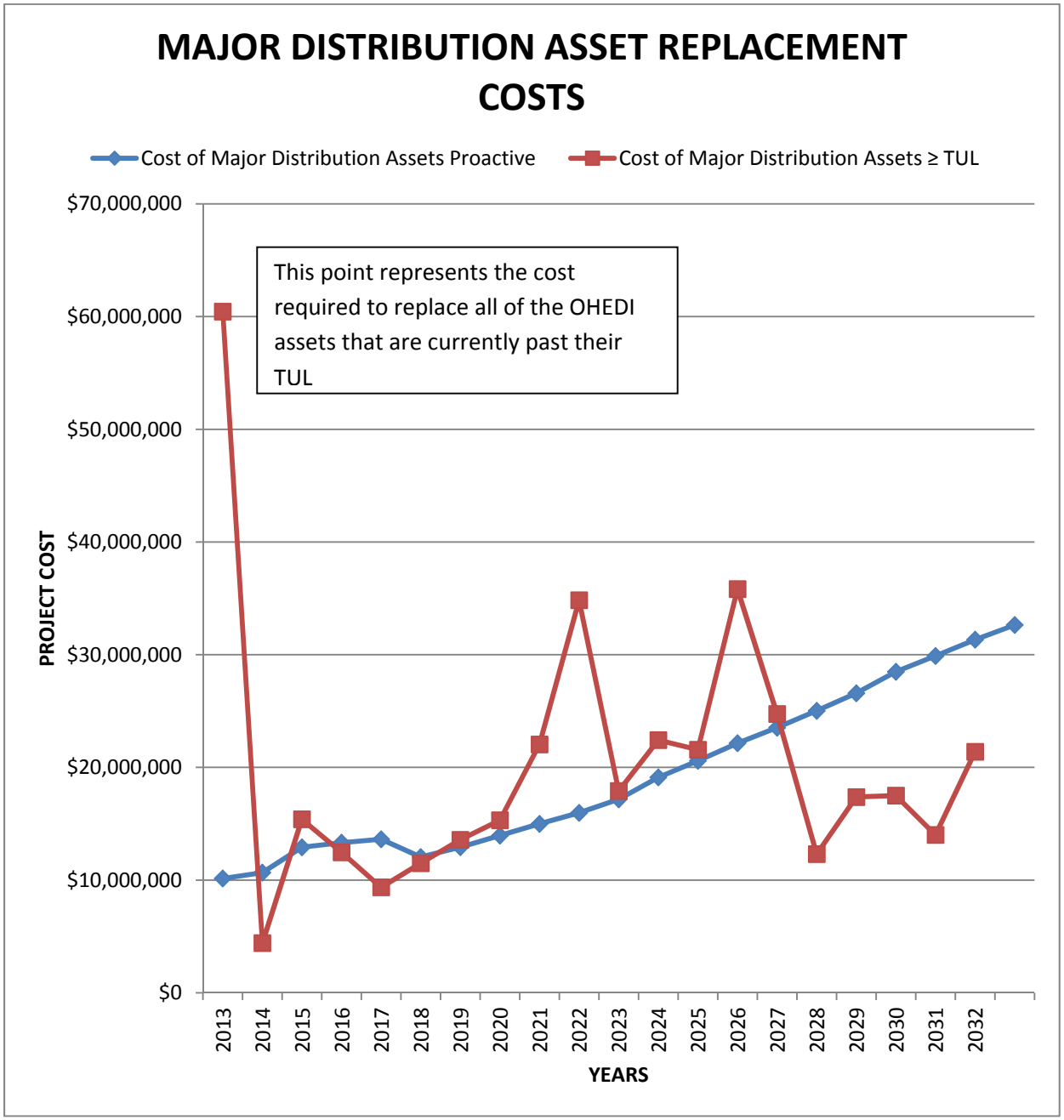


Figure 60

The above graph represents two capital forecasts. The blue, level, line represents a proactive replacement strategy in order to slowly increase capital spending over the next 20 years. The red, jagged, line represents a replacement strategy where most assets are replaced at the end of their typical useful lives, and in the case of an asset categorized as a run to failure asset, the typical useful life plus an additional ten years. To be noted is the large amount of capital required in 2013 in order to replace assets that have already passed their typical useful life.

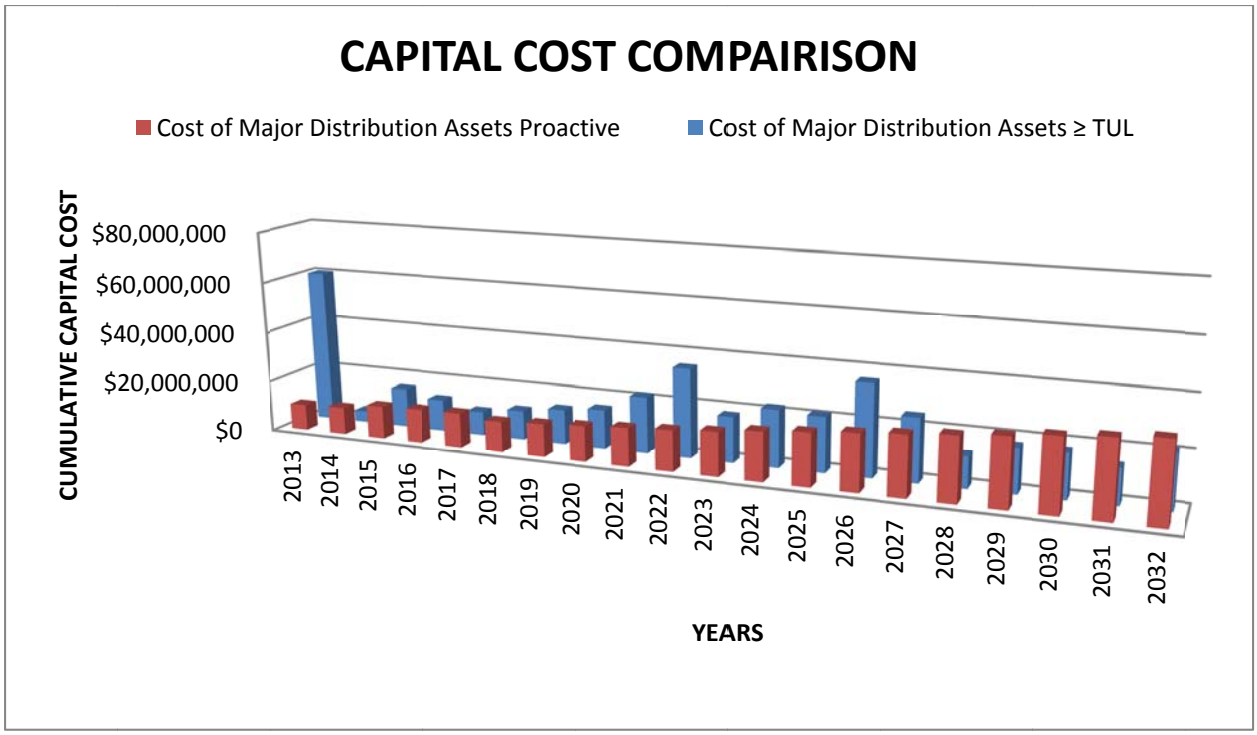


Figure 61

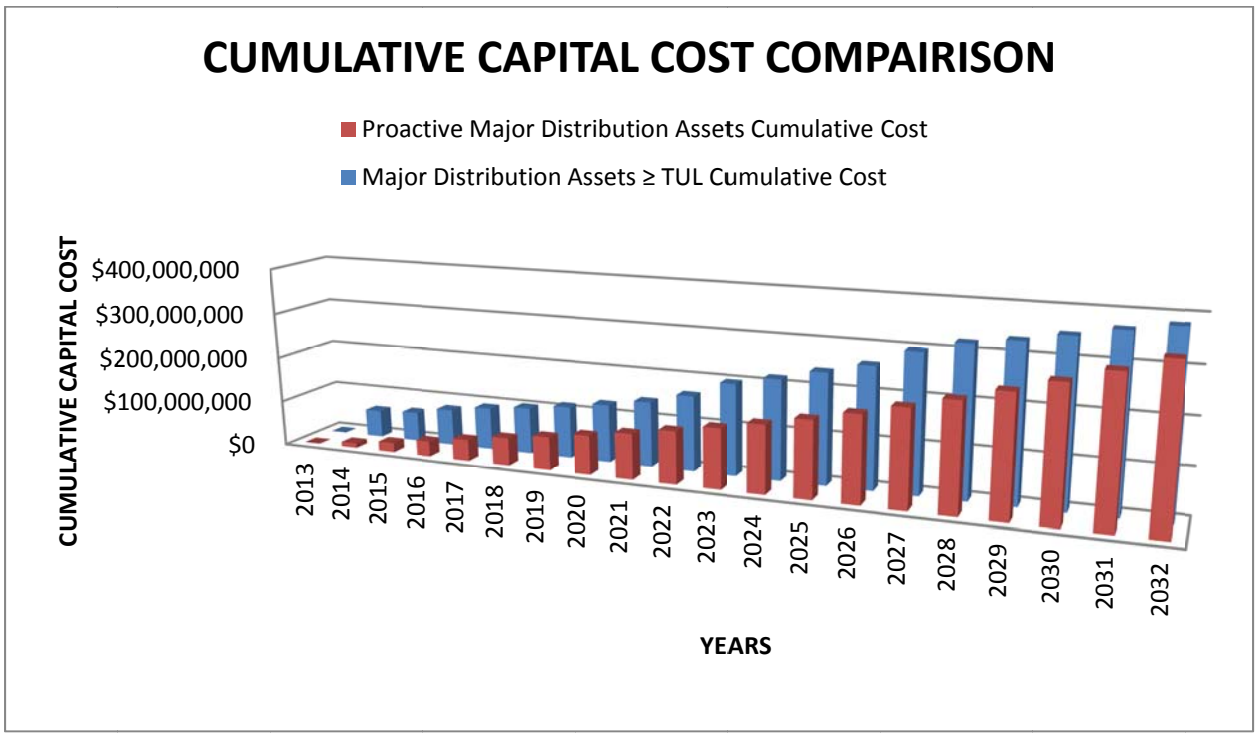


Figure 62

The above graphs represent the two capital forecasts, and the cumulative capital costs required to run both strategies.

Inspection, Condition Assessments, and Health Index

Inspection

The OEB outlines the minimum inspection and interval requirement in the Distribution System Code (DSC). The Town of Oakville is considered an urban area therefore the OEB minimum inspection cycle requirements for all transformers, switches, cables, poles, and civil infrastructure is once every three years. The OEB definition of this requirement is as follows:

"Patrol or simple visual inspections consists of walking, driving or flying by equipment to identify obvious structural problems and hazards such as leaning power poles, damaged equipment enclosures, and vandalism. In cases where a patrol notices that a problem exists or identifies a condition that warrants a more thorough or rigorous inspection, patrol may then include situations where structures are opened as necessary, and individual pieces of equipment carefully observed and their condition noted and recorded. The specifics of these inspections are recorded, and a summary document prepared in the distributor's annual reports as part of their rates or licensing submissions."

OHEDI utilizes a combination of patrols and maintenance activities to complete these inspection requirements, and records information regarding the condition of distribution assets. A minimum of one-third of each major asset is either patrolled or has maintenance performed each year in order to ensure all assets are inspected a minimum of once every three years. During the patrol, minor maintenance or critical items, that may be immediately addressed, are resolved and reported. Major maintenance that requires more complex coordination is subsequently scheduled for completion within the year, or planned for future years.

OHEDI analyzes the feedback from inspection and maintenance routines, as part of condition-based asset assessments. Decisions to replace assets versus proceeding with ongoing maintenance (to extend life), are determined based on a business case assessment.

In addition, OHEDI has a Municipal Transformer Station (MTS) – Glenorchy - connected to the grid, which has specific inspection and maintenance standards identified in the OEB Transmission Code.

Condition Assessments

Conditions of the assets are captured during line patrols and maintenance. In 2011 OHEDI initiated an aggressive and comprehensive 3 year program to review and assess all assets in the system. A total of one-third of all asset conditions were captured at the end of 2011. Two-thirds of all asset condition assessments will be captured by the end of 2012, with the remaining asset conditions to be identified in 2013.

Asset Condition Assessment (ACA) and Risk Assessment (RA) methodologies are used by utilities to develop a Capital Replacement Plan based on both asset condition and criticality. This approach represents a cornerstone of leading Asset Management practices and produces consistent and defensible results that allow for optimal long-term planning, more effective investment practices, and transparent decision making.

Each year ACA information will be collected from assets and calculations are performed in order to generate asset health index.

Health Index

OHEDI has contracted Kinectrics Inc (Kinectrics), a leading provider of asset management services in North America, to recommend Health Index formulations and Condition Criteria for selected distribution asset categories, as well as describe Risk Assessment and Capital Replacement Planning approaches.

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Heath Indexing provides a measure of long-term degradation and thus differs from defect management, whose objective is finding defects and deficiencies that need correction or remediation in order to keep an asset operating prior to reaching its end of life.

By the end of 2013, we expect to have placed all paper condition assessments into an electronic format which will allow us to perform Health Index calculations. This will allow us to begin to develop a condition based Capital Replacement Plan based on condition distribution and criticality of assets. It will produce consistent and defensible results that will allow for optimal long-term planning, more effective investment practices, and transparent decision making.

Asset Management Systems

OHEDI has a number of identified system initiatives which will provide enhancements to allow more scientific and fact based evaluation of our distribution system. These include:

- GIS System
- Asset Management Data Model and Computerized Maintenance Management System (CMMS)
- Business Excellence Program
- SCADA and Outage Management System (OMS)
- Mobile Business Enablement (eMobile)

The current equipment maintenance and management activities co-ordinated by the Asset Management group at OHEDI are done manually. Optimization of this process requires a CMMS (Computerized Maintenance Management System). The purpose of a CMMS is to bring value-added service to a maintenance/asset management department and to a company as a whole. CMMS is the foundation platform for effective and comprehensive asset management.

Preliminary research was conducted with various vendors to determine what capabilities a CMMS would have and how it would provide a value-added service to OHEDI.

CMMS adds value by automating and providing increased sophistication as follows:

- Moves us towards a condition based maintenance plan that focuses investments in the right areas to achieve optimal value
- Cost Management for equipment and labour, with tracking ability.
- Minimized maintenance and patrol labour and equipment costs (vehicles), with automatic scheduling and the ability for powerline technicians to complete patrols and maintenance on assets in the area where they are already working.
- Reduced duplication of data via links to other enterprise programs and databases.
- Advanced data analysis capabilities
- Asset history
- Optimized asset reinvestment using asset history tracking. Issues with an asset can be caught and resolved before the asset fails, mitigating safety concerns, system outages, or secondary damage to Oakville Hydro distribution system.

Maximo (by IBM) has been selected and is being implemented to satisfy the CMMS requirements. Along with the above mentioned values, it also allows provides the following additional functionality:

- Paperless documentation of condition assessments by means of mobile deployment to field crews
- Automatic Health Index calculations to determine the remaining health of assets based upon the collected condition information by field crews
    - Health Index can be used to prioritize investments based upon the condition of assets in the system
    - Health Index can be used in order to obtain an overall picture of the health of all system assets, or health of a certain class of asset
- Failure tracking of assets in order to build a repository of past failures and failure modes.

Procurement Efficiency

OHEDI employs a number of cost effective solutions to ensure procurement efficiency once the need for asset replacement has been established. Each major distribution asset listed above includes investment optimization information in order to ensure efficiency.

As part of the asset replacement decision process, OHEDI is reviewing the standardization of equipment for replacement. The standardization will allow for minimized inventory holdings, as fewer types of equipment are required to be kept in spare inventory for emergency replacement purposes. The standardization will also provide the ability to purchase more equipment in bulk, possibly decreasing overall material costs and allowing for long-term relationships with suppliers.

Over time, the implementation of this strategy into the Asset Management Plan will allow for forecasting of equipment requirements, which will allow for establishment of additional long-term

relationships with suppliers and provide us an outlook of the required capital expenditures on materials over a yearly time frame.

Publicly Available Specification (PAS) 55

OHEDI has obtained and reviewed PAS 55-1:2008 and PAS 55-2:2008 to help implement the asset management policy, strategy, objectives and plans. Although OHEDI does not have any current plans to certify its Asset Management System in accordance with PAS 55, it is prudent to ensure that the approach does align with industry frameworks for asset management.

Summary

This document provides sufficient information, guidance and direction for the development and ongoing management of the Capital Expenditure Plan and Maintenance Expenditure Plan, separate documents which contain the detailed plans to achieve the outcomes of the Asset Management Objectives. It will be communicated to all relevant stakeholders, and will be reviewed regularly to ensure currency, consistency and effectiveness.

2013

Oakville Hydro Electricity Distribution Inc.

Maintenance Expenditure Plan

12/07/2013

Version 1A

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1 Maintenance Expenditure Plan Purpose and Objective

The purpose of the Maintenance Expenditure Plan (MEP) is to provide a description of maintenance planning criteria and assumptions. It also describes routine and preventative inspection and maintenance policies, practices and programmes. This document will be reviewed and updated on a yearly basis.

2 Inspections and Patrols

2.1 Due Diligence Inspections - Municipal Substations

Each year the ESA conducts a Due Diligence Inspections (DDIs) of the Municipal Substations. Due Diligence Inspections are inspections of LDC electrical distribution installations and are performed by ESA Inspectors. DDIs were created in order for ESA to carry out its due diligence with respect to regulating to O. Reg. 22/04. These inspections are complimentary to the Auditor reports, the Declaration of Compliance, Serious Incident Reports and any Public Safety Concerns. When combined, these compliance measures provide ESA with appropriate information to adequately assess compliance with O. Reg. 22/04. DDIs provide a means of assessing whether LDCs are following their safety regulatory obligations at the site of the installation.

Scope: ESA Inspector's schedule visits with the LDCs to review a sample set of new construction, maintenance, repair, temporary services and/or replacement work of electrical equipment owned by the LDC or attachments by a 3rd party to the LDC's asset (ie. pole). Construction consists of Underground, Overhead or Substation sites. Inspectors are given comprehensive guides (developed by the Utility Regulations Department), and Plans or Work Instructions (created by the LDC) to follow.

Inspection Process: The Inspectors schedule DDI appointments with the LDCs and while onsite Inspectors observe and record adherence to the Plans, Work Instructions and construction verification procedures. The Inspector acts as an observer and documents the observations in comprehensive guides. If the construction does not match the Plan or Work Instruction supplied to the Inspector they will make note of the differences and whether the installation change has been recorded. Any additional safety concerns or hazards an Inspector notes are also included in the guides. Any installations deemed, by the Inspector, to be an imminent fire, shock or explosion hazard the Inspector is to ensure the site is made safe before leaving the site.

Reporting: The ESA Inspector submits the guides to the Utility Regulations Department which in turn assesses the information based on O. Reg. 22/04 and discusses the findings with the LDCs. Utility Regulations produces a report documenting the findings and reviews the LDC action plan and follows up with the LDC for the parts of the installation or processes where the LDC was not in compliance with O. Reg. 22/04. The report also confirms those installations that are in compliance

2.2 Protection & Control Inspections - Glenorchy

An extensive inspection of all station equipment both high and low voltage is conducted weekly with any deficiencies reported using the inspection form, and corrective action carried out accordingly. Testing includes the following activities:

1. Locate the ground grid at the station (rods, conductors, and fence).
2. Check on the bonding from grid to fence and equipment.
3. Perform soil resistivity and gravel assessment.
4. Measure potential gradient across the property.
5. Measure step Potential value for safety.
6. Measure touch Potential value for safety.

7. Measure ground Potential Rise (GPR) value for safety.
8. Zone of Influence (ZOI) value for communication equipment.
9. 2D and 3D model created for simulating different scenarios.
10. Recommendation and findings for the existing ground grid.

2.3 Municipal Stations Patrol

MS's are patrolled on a monthly schedule which involves inspection of the compound, transformers, relays, batteries, insulators/arresters, switches/fuses and terminations/grounds. Any deficiencies are reported using an inspection form, and corrective action is carried out accordingly. .

2.4 CSS Line Inspections

Customer Specific Substations (CSS). CSS's are patrolled by operations crews once per year. They confirm issues and conditions for areas such as: Signs, access, interior, oil temp, winding temp, oil level, oil pressure, leaks, switchgear cabinet, fuses, arresters, switches, terminations, and grounds.

2.5 Operations O/H Switch Patrols

Overhead switching and protective device patrols consisting of at least one-sixth of the installed overhead switches, is completed by operations. Operation provides a visual inspection of the overhead switches and their conditions. They confirm issues and conditions for areas such as: Accessibility, grade, blade/fuse, arrester, brackets, connections, grounding, identification, terminations, cable guards, check and record ground resistance, perform an infrared scan, and note presence of fault indicators. They also confirm if the switch is shown correctly on the grid maps with the correct address and information shown on the switch sheets.

Overhead conductor patrols are completed each year. Two different scanning methods are used. The first method is an infrared scan of overhead conductors to identify any heat issues that may be present due to poor connections or failing equipment. The second method employs a radio frequency scan of the streets the overhead conductors are on to identify any issues that may not be picked up by the infrared scanning. A minimum of one-third of the overhead lines will be scanned each year to identify issues that may be present.

2.6 O/H Tx Patrol

Overhead distribution transformer patrols consisting of at least one-sixth of the installed overhead transformers, is completed by operations. Operation provides a close up visual inspection of the overhead distribution transformers and their conditions using bucket trucks. They confirm issues and conditions for areas such as: Accessibility, grade, tank, paint, cutout, arrester, brackets, bushings, connections, grounding, identification, and check for oil leaks. They also confirm if the transformer is shown correctly on the grid maps with the correct address and information shown on the existing transformer spec sheets. The second section, consisting of the other one-sixth of the installed pole mounted transformers, is maintained by operations crews. Along with this review they also check and record secondary voltage levels, confirm ground resistance, ensure the phase connection matches that shown on the grids, perform an infrared scan, and note any additional issues.

2.7 U/G Line Patrols

Switches installed in vault structures are patrolled by operations crews every three years. Due to the limited number of these style switches it is not feasible to split the patrols into separate years. They confirm issues and conditions for areas such as: tank, paint, elbows, fault indicators, motor operators, foundation, identification, grounding, RTU, and AC service. Along with this review they also check and record ground resistance, perform an infrared scan, and note any additional issues. Pad mounted switching and protective device patrols consist of at least one-sixth of the installed pad mounted switches, is completed by operations crews. The operations crews will open up the enclosure and confirm issues and conditions for areas such as: Obstructions, grade, accessibility, security, tank, paint, current sensors, terminations, housekeeping, motor operator, fault indicator, foundation, identification, insulators, grounding, AC service, and sump pump. Along with this review they also check and record ground resistance, perform an infrared scan, and note any additional issues.

2.8 U/G Cable Testing

The primary goal of any preventive maintenance plan for Medium Voltage (MV) power cables is to test and analyze the overall insulation of the cable as well as to determine the serviceability of the accessories through data trending to prevent catastrophic failures. Testing technologies being considered are DC hi-potential testing, AC hi-potential testing, very low-frequency (VLF) testing, power factor/dissipation factor testing, VLF dissipation factor testing, off-line partial discharge testing, and online partial discharge testing.

2.9 U/G Pad Tx Patrol

Padmount distribution transformer patrols consisting of at least one-sixth of the installed padmount transformers, is completed by operations. Operation provides an interior and exterior visual inspection, of the pad mounted distribution transformers and their conditions. They confirm issues and conditions for areas such as: Accessibility, grade, obstructions, security, tank, paint, foundation, bollards, identification, and check for oil leaks. They also confirm if the transformer is shown correctly on the grid maps with the correct address and information shown on the existing transformer spec sheets. Along with this review they also check and record secondary voltage levels, confirm ground resistance, ensure the phase connection matches that shown on the grids, review and record elbow, insert, arrester and cable tag conditions, perform an infrared scan, and note any additional issues.

2.10 U/G Tx Patrol

Submersible distribution transformer patrols consisting of at least one-sixth of the installed submersible transformers, is completed by operations. The operations crews will open the submersible enclosures and confirm issues and conditions for areas such as: Accessibility, grade, obstructions, location, security, grounding, lid, vault, tank, inserts, bushings, elbows, connections, and they check and record information on ground wire resistance, types of fuses used in the transformers, amount of oil, weight, secondary voltages, and if there are any heat issues found. .

Vault distribution transformer patrols consisting of at least one-third of the installed vault transformers, is completed by operations. Operations crews will enter the vault rooms and confirm issues and

conditions for areas such as: Accessibility, obstructions, security, signage, tank, transformer type, bushings, elbows, inserts, junctions, fuses, grounding, LV electrical, and they check and record information on ground wire resistance, amount of oil in the transformers, the weight of the transformers, secondary voltages, housekeeping issues, and if there are any heat issues found.

Padmount distribution transformer patrols consisting of at least one-sixth of the installed padmount transformers, is completed by a contractor. The contractor provides an exterior visual inspection, of the pad mounted distribution transformers and their conditions. They confirm issues and conditions for areas such as: Accessibility, grade, obstructions, security, tank, paint, foundation, bollards, identification, and check for oil leaks. They also confirm if the transformer is shown correctly on the grid maps with the correct address and information shown on the existing transformer spec sheets.

2.11 Meter Maintenance

This covers the cost for meter expenses. Measurement Canada regulations require that all meters be calibrated and sealed prior to being used to for revenue metering. Meters are assigned different seal periods based on type and manufacture. Typically, commercial meters have a 6 year seal period and residential meters have 10 years. This can vary dependent on performance level of meters over time. If accuracy of meters decreases, meters can have their seal period reduced by Measurement Canada. When residential meter seals expire a sample group of the meters is re-verified by an accredited meter service organization. Based on the results of the testing, the complete lot of meters installed in the field can have their seal periods extended for a specific number of years at which time sample testing reoccurs. Eventually all meter must be removed for testing. If a sample group of meters fails re-verification then the total population of meters in the lot must be removed for recalibration. Measurement Canada has introduced a new regulation which requires interim sample testing of residential smart meters 5 years in advance of their seal expiry. This regulation is meant to provide increased monitoring of new smart meters that do not have a performance history.

2.12 Cable Failure Testing

When primary cables fail they are sent to a third party laboratory to investigate the root cause of the failure, receive comment on the aging of the cables, and have suggestions provided regarding future inspection/diagnostics for similar cables under operation. Testing and analysis will include, but will not be limited to:

- autopsy of the cable including jacket, semicon, and insulator
- measurement of dimensions and comparison with the standard recommendations
- microscopic analysis of insulation samples to observe water tree, void and contamination
- investigation of the failure mode and probable cause of the failure

A report will be issued to OHEDI with the results of the above work.

3 Asset Maintenance

3.1 Maintenance of Transformer Station Equipment

Yearly maintenance will include visual inspection, infrared survey, insulator washing, transformer fluid analysis, and the complete maintenance of power systems connected to circuit (T36B & T37B) every alternative year.

Equipment and tests include:

- 230kV Disconnect Switch – Visual inspection, operational verification, contact resistance in micro-ohms, and insulation resistance in mega-ohms.
- 230kV Surge/Lightning Arrestors – Visual inspection, counter check, and insulation resistance in mega-ohms.
- 230kV / 28kV Transformers – Visual inspection, ratio test, capacitance and dissipation factor test, insulation resistance of all windings in mega-ohms, auxiliary device confirmation, and sampling & analysis of main tank fluid & TLTC for:
    - 5-Part oil screen (ASTM D-877)
    - Moisture content
    - Dissolved gas-in-oil analysis
- 28kV Surge/Lightning Arrestors – Visual inspection, counter check, insulation resistance in mega-ohms
- 28kV Siemens GIS – Visual inspection, operational verification, verify gas pressure levels
- Structure Components Misc. (Lightning arresters, potential transformers, etc.) Substation Yard – Visual inspection, insulation resistance in mega-ohms, ground grid resistance test
- Automatic transfer switches – Visual inspection and operational test
- Batteries & charger – Visual inspection, battery cell voltage measurement, battery cell link resistance measurement, battery cell impedance measurement, charger output level confirmation
- Insulator Washing – Water washing of all exposed 34.5/69/230kV apparatus (where accessible for truck)
- Relays T60(HV), SEL487E (HV), D60(HV), D60(LV), C60(LV) – Visual inspection, confirmation of relay settings, calibration test, and functional test.

3.2 Maintenance of Distribution Station Equipment

Batteries are subjected to a shallow drain once every two months to check capacity. Battery problems and hazards are remedied as found, if possible, and larger repairs are reported and scheduled accordingly. If the batteries need to be taken out of service immediately a spare set of batteries with a charger are put into place.

Transformer oil testing is completed by a third party on an annual basis. Results are trended and analysed to identify potential transformer problems or requirements for transformer replacement. A

report is issued to OHEDI that includes the test results, recommendations for follow up testing, and any general transformer deficiencies that were noted during the course of the oil sampling.

An extensive two to three week outage is required every three years to perform maintenance on both high and low voltage systems. During substation maintenance, problems and hazards are remedied before the equipment is put back in service. Specific tasks include visual inspection, shutdown tests, electrical integrity tests, station service transformer reports and secondary switchgear reports. Maintenance for rackable substation breakers involves removing them from service and conducting a visual inspection, mechanical testing, and a timing test. Problems and hazards are remedied as found if possible, and larger repairs requiring assistance from the manufacturer are scheduled and remedied before putting the breaker back into service. The protection relays are tested and calibrated during the time that the associated breaker is out of service. Test results are recorded for equipment 'as found' prior to maintenance in addition to the results 'as left' after completing all maintenance tasks. Outsourcing of the full station maintenance to a third party contractor is performed as required to meet all of the distribution station maintenance targets.

3.3 Maintenance of Poles, Towers and Fixtures

3.3.1 Wood Pole Test/Treat

Wood pole patrols are completed in two sections each year. The first section, consisting of at least one-sixth of the installed wood poles, is patrolled currently by a subcontractor. The subcontractor will visit each pole location and confirm issues and conditions for areas such as: Obstructions, grade, accessibility, rot, cracks, infestations, identification, insulators, feathering, down guys, span guys, mounted equipment, and third party attachments. The second section, consisting of one-sixth of the wood poles, is patrolled by a contracting crew which performs testing and treatments. Along with checking the above noted conditions, they will check the pole above and below ground for rot, voids, and infestations. If any adverse conditions are found, chemical treatments are applied to mitigate further damage to the pole. A list of poles beyond treatment is provided at the end of the patrol, these poles are recommended for replacement. OHEDI has considered performing the wood pole testing every seven years; however, this has been modified to six years in order to coordinate with the three year patrol cycle. This cycle is cost effective because it satisfies both the maintenance and patrol requirements.

3.3.2 Pole Contractor Patrol

Other poles are patrolled by a subcontractor every three years. Due to the limited number of poles in this category it is not feasible to split the patrols into separate years. They confirm issues and conditions for areas such as: Obstructions, grade, accessibility, cracks, rust, crumbling, identification, insulators, down guys, span guys, mounted equipment, and third party attachments.

3.4 Overhead Distribution Lines and Feeders – Right of Way

3.4.1 Tree Trimming

Trees contribute greatly to the natural beauty of the Town. But, if not properly managed, they can create power outages and/or hazardous situations by touching or even falling on the power lines. OHEDI has contracted the Town of Oakville's Urban Forestry Services to conduct regularly scheduled tree maintenance across Oakville.

3.4.1.1 Pruning Cycle



Map made available by Microsoft Streets & Trips
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The Town ensures that trees in each of the three zones of the service territory are pruned responsibly on a three-year cycle to ensure safety and maintain the integrity of the natural surroundings. To complete all areas in the allotted time, the Town may need to contract the help of private, specialized tree experts. These private contractors will be pruning trees with the same care and precision as the Town.

3.5 Maintenance of Underground Conduit

3.5.1 U/G Con Maintenance Labour

Civil Infrastructure patrols are completed in two ways. The first section, consisting of civil infrastructure installed with other equipment, is patrolled by crews during the same time as the other equipment patrols. Any adverse conditions found will be noted during the other equipment patrols for the civil infrastructure. The second section, consisting of one-third of the civil infrastructure such as service boxes, vacant transformer vaults, manholes, and secondary pull boxes are patrolled by operations crews every year. Operation crews confirm issues and conditions for areas such as: Obstructions, grade,

access, security, lid, grounding, damage, collar, vault, duct entrances, drain, sump pumps, and contents. They will also perform an infrared scan of any installed cables or junctions to identify issues.

3.5.2 Residential Vault Washing

OHEDI classifies submersible distribution transformers into two categories. The first are commercial submersible transformers, which include any transformers installed in densely populated commercial areas of Oakville in large submersible vaults. The second are residential submersible transformers, which include any transformers installed in lightly populated residential areas in Oakville in smaller submersible vaults.

Residential submersible distribution transformers do not require the same level of cleaning that the commercial examples do, as the lids do not allow for the same amount of debris to collect. The patrols of these transformers are completed in two sections each year. The first section, consisting of at least one-sixth of the installed submersible transformers, is patrolled by operations crews. The operations crews will open the submersible enclosures and confirm issues and conditions for areas such as: Accessibility, grade, obstructions, location, security, grounding, lid, vault, tank, inserts, bushings, elbows, connections, and they check and record information on ground wire resistance, types of fuses used in the transformers, amount of oil, weight, secondary voltages, and if there are any heat issues found. The second section, consisting of the other one-sixth of the installed residential submersible transformers, is maintained by a contracting crew. All the same information as above is collected, plus the high pressure washing is performed to ensure any debris that may have accumulated in the vaults over six years is removed. An infrared report is then prepared by the washing crew for any issues noted after the washing has been completed.

3.5.3 Commercial Vault Washing

Commercial submersible distribution transformer patrols are completed twice per year for every installation by a contracting crew which performs high pressure washing. Every spring each commercial submersible transformer location is high pressure washed in order to clean out remaining salt residue which accumulates during winter conditions. The pressure washing mitigates corrosion effects on the equipment installed in the enclosures. Every vault is then washed again at the end of the fall in order to clean out any leaf and plant debris that accumulates in the vaults during the fall. The leaf and plant debris clog up sump pumps installed in the bottom of these vaults. When clogged for an extended period of time the sump pumps burn out and require replacement. If not removed the leaf and plant debris can also cause an accumulation of methane gas. Although not toxic, methane is extremely flammable and may form explosive mixtures with air. Methane is also an asphyxiant, and may displace oxygen in an enclosed space. The cleaning of these vaults will mitigate the accumulation of this gas.

3.6 Maintenance of Underground Conductors and Devices

3.6.1 Switchgear Dry Ice Cleaning

Pad mounted switching and protective device patrols are completed in two sections each year. The first section, consisting of at least one-sixth of the installed pad mounted switches, is patrolled currently by operations crews. The operations crews will open up the enclosure and confirm issues and conditions

for areas such as: Obstructions, grade, accessibility, security, tank, paint, current sensors, terminations, housekeeping, motor operator, fault indicator, foundation, identification, insulators, grounding, AC service, and sump pump. Along with this review they also check and record ground resistance, perform an infrared scan, and note any additional issues. The second section, consisting of one-sixth of the installed pad mounted switches, is patrolled by a contracting crew that performs dry ice cleaning. Along with checking the above noted conditions, they spray dry ice pellets into the switchgear enclosures to clean off any contamination that may be present on the insulators, walls, blades, and barricades. The cleaning is used to help mitigate any issues regarding flashovers caused by contamination on the internal parts of the switchgear.

3.7 Maintenance of Underground Services

This account shall include the cost of labour, materials used and expenses incurred in the maintenance of underground distribution line facilities, the book cost of which is included in the underground portion of Account 1855, Services.

Example items:

Work of the following character on underground services:

1. Cleaning ducts.
2. Repairing any underground service plant.

1855 Services

This account shall include the cost installed of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system or the transformers or manhole, or the top of the pole of the distribution line, to the point of connection with the customer's electrical panel. Conduit used for underground service conductors shall be included herein.

Example items:

1. Brackets.
2. Cables and wires.
3. Conduit.
4. Insulators.
5. Municipal inspection.
6. Overhead to underground, including conduit or standpipe and conductor from last splice on pole to connection with customer's wiring.
7. Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks.
8. Permits.
9. Protection of street openings.
10. Service switch.
11. Suspension wire.

Records shall be maintained providing information on underground and overhead services separately and by capacity and function.

3.8 Maintenance of Line Transformers

This account shall include the cost of labour, materials used and expenses incurred in maintenance of distribution line transformers.

The cost shall include renewing oil, painting and the like, necessary to keep the equipment in service.

Note: All lightning arresters on the distribution system, excluding pothead arresters, are considered to be transformer equipment or devices and the maintenance thereof is chargeable to this account.

Records shall be kept to separately show costs related to overhead and underground transformers.

4 Summary

The maintenance plans contained within ensure that OHEDI meets the minimum requirements set out in the Distribution System Code. This document will be updated yearly to include any additional PM or PdM routines that are identified.

Appendix 2

Regional Planning Letter to Hydro One

Oakville Hydro
Electricity Distribution Inc.
P. O. Box 1900
861 Redwood Square
Oakville ON L6K 0C7
Telephone: 905-825-9400
Fax: 905-825-4447
email: hydro@oakvillehydro.com
www.oakvillehydro.com

June 28, 2013

Arthur Fischer
Account Executive
Hydro One Networks Inc.
PO Box 5700
Markham, Ontario L3R 1C8

Dear Arthur,

Re: Regional Infrastructure Planning in Ontario

As you may be aware, the Ontario Energy Board released *Chapter Five of the Filing Requirements for Electricity Transmission and Distribution Applications, Consolidated Distribution System Plan Filing Requirements* (the "DS Plan Filing Requirements") on March 28, 2013. The DS Plan Filing Requirements set out the information required by the Ontario Energy Board (the "Board") to assess a distributor's application involving planned capital expenditures. The DS Plan Filing Requirements are intended to ensure that, among other things, the Board's expectations for the optimization of investments reflect regional considerations.

The Board has also proposed amendments to the Distribution System Code that would require that distributors request one of three documents regarding the status of regional planning from the lead transmitter in the distributors planning region(s) and file the document(s) in support of an application for an adjustment to its distribution rates. These documents include:

- A Regional Infrastructure Plan; or
- a letter confirming the status of the Regional Infrastructure Plan; or
- a Needs Assessment Report (where participation in a regional planning process is not required).

Oakville Hydro Electricity Distribution Inc. ("Oakville Hydro") will file an application for an adjustment to its distribution rates on October 1, 2013. In accordance with the DS Plan Filing Requirements and the proposed amendments to the Distribution System Code, Oakville Hydro is requesting that Hydro One Networks Inc. ("Hydro One") provide Oakville Hydro with a copy of

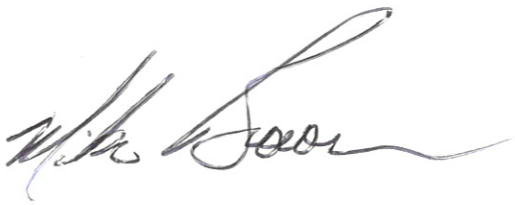
Oakville Hydro
Electricity Distribution Inc.
P. O. Box 1900
861 Redwood Square
Oakville ON L6K 0C7
Telephone: 905-825-9400
Fax: 905-825-4447
email: hydro@oakvillehydro.com
www.oakvillehydro.com

the Regional Infrastructure Plan, a letter confirming the status of the Regional Infrastructure Plan or, if Oakville Hydro is not required to participate in a regional planning process, a Needs Assessment Report for the following planning regions:

- Burlington to Nanticoke Planning Region
- GTA West Planning Region

The DS Plan Filing Requirements also require that distributors consult with regionally interconnected distributors and transmitters in preparing their DS Plan. Oakville Hydro is preparing its DS Plan and would like to suggest that we arrange a meeting the week of August 12, 2013 with the appropriate staff members from Oakville Hydro and Hydro One to discuss regional planning requirements. Please contact me directly so that we can arrange a mutually convenient date and time.

Sincerely



Mike Brown, P.Eng
Vice President - Engineering and Operations
Chief Operating Officer
Oakville Hydro Electricity Distribution Inc.
Direct Line: 905-825-4469
Email: mbrown@oakvillehydro.com

Copy: Brad Colden

Appendix 3

Regional Planning Status Letter

Hydro One Network Inc.
483 Bay Street
15th Floor, South Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345-5420
Fax: (416) 345-4141
ajay.garg@HydroOne.com

September 5, 2013

Mike Brown
VP - Engineering & Operations and COO
Oakville Hydro Electricity Distribution Inc.
P.O. Box 1900
861 Redwood Square
Oakville, Ontario, L6J 5E3

Dear Mr. Brown**:**

Subject: Regional Planning Status

In reference to your request for a regional planning status letter, please note that your Local Distribution Company (LDC) belongs to the a) GTA West and b) Burlington to Nanticoke Region, which are both in Group 1. A map showing details with respect to the 21 Regions/Groups and list of LDCs in each Region is attached in Appendix A and B respectively.

This letter is to confirm that the regional planning process has not been initiated nor has a Regional Infrastructure Plan (RIP) been developed for the sub-region within the GTA West Region or Burlington to Nanticoke Region affecting the Oakville Hydro Region. I am expecting, as per the new process, that the regional planning for the GTA West southern sub-region and the Burlington to Nanticoke Region will be initiated in 4th Qtr. of 2013. Hydro One will formally notify your organization in advance, along with other stakeholders, prior to launching the regional planning process.

The new planning process provides flexibility, during the transition period to the new process, and will ensure that both distribution and transmission planning continue to address any short-term needs, with or without, a formal regional plan. Hydro One looks forward to working with Oakville Hydro Electricity Distribution Inc. in executing the new regional planning process.

If you have any further questions, please feel free to contact me.

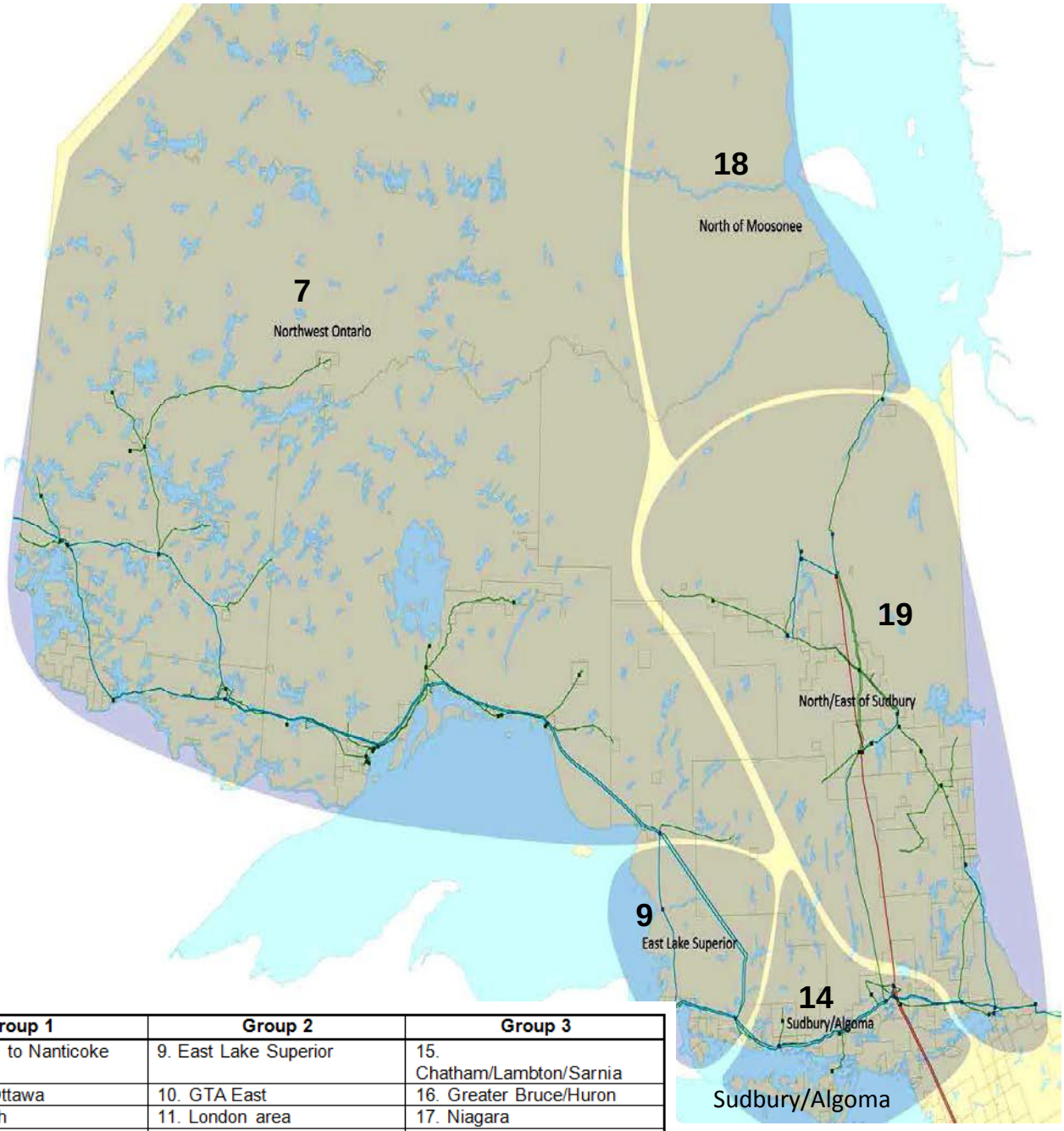
Ajay Garg

Sincerely,
Ajay Garg, P. Eng. |Manager, Regional Planning and Transmission Load Connections|
Hydro One Networks

Cc:
Brad Colden, Manager – Customer Business Relations

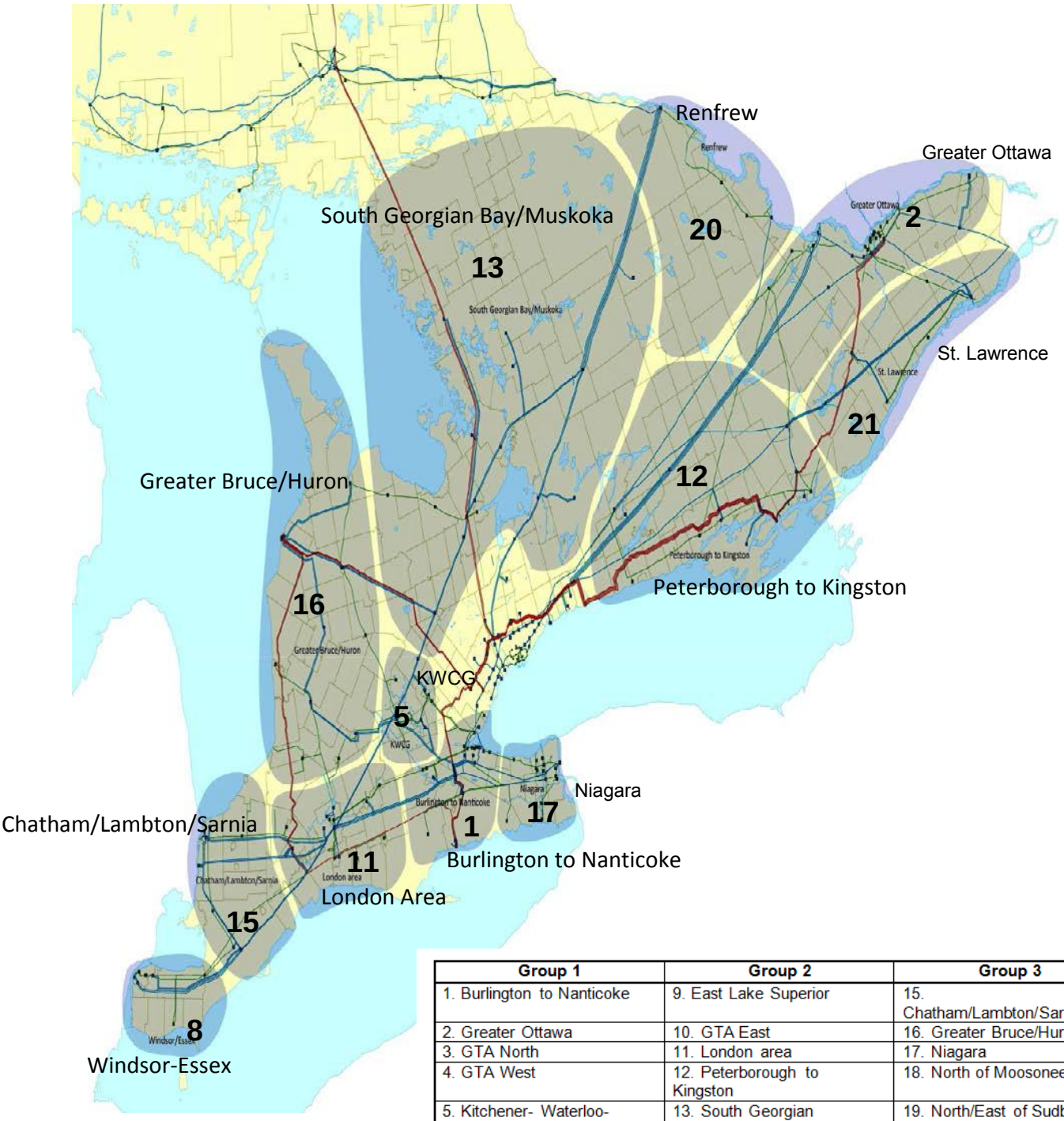
Appendix A: Map of Ontario's Planning Regions

Northern Ontario



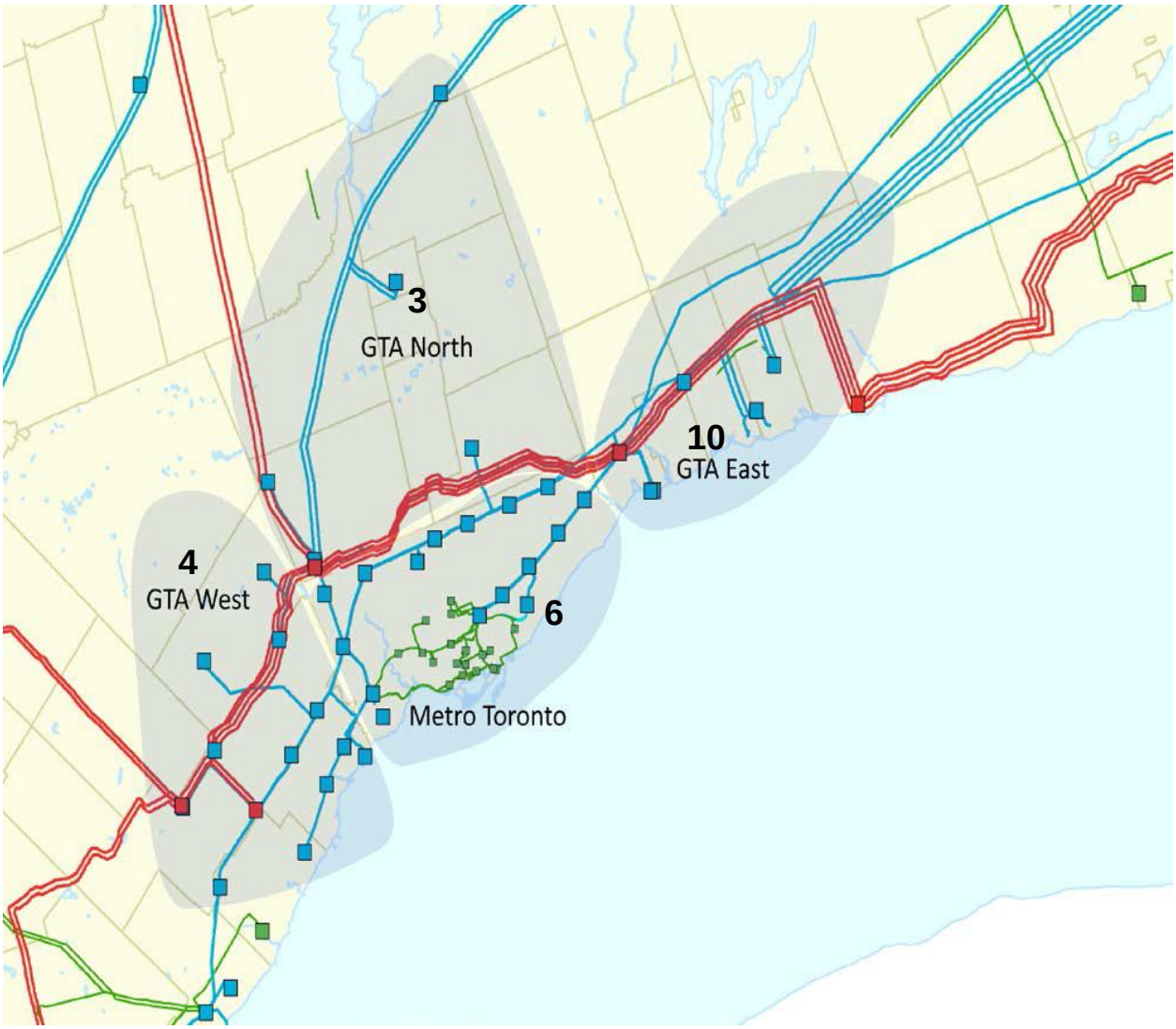
Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
2. Greater Ottawa	10. GTA East	16. Greater Bruce/Huron
3. GTA North	11. London area	17. Niagara
4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Southern Ontario



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
2. Greater Ottawa	10. GTA East	16. Greater Bruce/Huron
3. GTA North	11. London area	17. Niagara
4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Greater Toronto Area (GTA)



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
2. Greater Ottawa	10. GTA East	16. Greater Bruce/Huron
3. GTA North	11. London area	17. Niagara
4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Brant County Power Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc. • Horizon Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Enersource Hydro Mississauga Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • PowerStream Inc. • PowerStream Inc. [Barrie] • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Enersource Hydro Mississauga Inc. • Halton Hills Hydro Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.

5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	• Cambridge and North Dumfries Hydro Inc. • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.
6. Metro Toronto	• Enersource Hydro Mississauga Inc. • Hydro One Networks Inc. • PowerStream Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham-Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	N/A →This region is not within Hydro One's territory

10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation
11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc. • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.
13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • Innisfil Hydro Distribution Systems Limited • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Parry Sound Power Corp. • Powerstream Inc. [Barrie] • Tay Power • Veridian Connections Inc. • Veridian-Gravenhurst Hydro Electric Inc. • Wasaga Distribution Inc.

14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. [Chatham-Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.
17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Horizon Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp.
18. North of Moosonee	N/A →This region is not within Hydro One's territory
19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.

20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

Appendix 4

Renewable Energy Generation Plan

Renewable Energy Generation Investments

2014 - 2018



Oakville Hydro Electricity Distribution Inc.

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1. EXECUTIVE SUMMARY

In its letter dated March 28, 2013, the Ontario Energy Board (the "Board"), stated that "*under the renewed regulatory framework for electricity, a distributor's investments to accommodate and connect renewable energy generation and to develop and implement a smart grid are integral to its overall capital expenditure plan. Consequently, for future distributors filing as indicated above, the Board's Filing Requirements: Distribution System Plans-Filing under Deemed Conditions of Licence – May 17, 2012 will no longer apply*". On March 28, 2013, the Board also issued Chapter 5 of the Board's Filing Requirements for Electricity Transmission and Distribution Applications, entitled Consolidated Distribution System Plan Filing Requirements (the "DS Plan Filing Requirements") which reflect the Board's policy direction on an integrated approach to distribution network planning. Oakville Hydro has prepared its DS Plan in accordance with these DS Plan Filing Requirements.

Section 5.1.4.2 of the DS Plan Filing Requirements requires that distributors submit information to the Ontario Power Authority (the "OPA") in relation to the Renewable Energy Generation investments identified in their DS Plan. The OPA is expected to provide a letter of comment with regards to these plans. Oakville Hydro's Renewable Energy Generation Investment Plan forms part of its overall Distribution System Plan. However, Oakville Hydro has separated its Renewable Energy Generation Investment Plan for the purpose of the obtaining OPA's review and letter of comment. The Board's expectations for the OPA's comment letter are provided in Appendix B.

The Renewable Energy Generation Investment Plan assesses the state of Oakville Hydro's existing distribution system, studies the current renewable-connected generation and near-term growth forecast, defines a strategy to accommodate the predicted renewable generation growth and describes Oakville Hydro's future Renewable Generation expenditures from 2014 through 2018.

The OPA launched the Feed-In Tariff ("FIT") program in 2009. The FIT/microFIT program generated modest interest in Oakville Hydro's service area. Oakville Hydro's connected renewable generation is currently 0.49 MW for FIT programs. Currently there are three FIT projects and 32 microFIT projects which have been connected. There are seven FIT applications in Oakville Hydro's service area waiting for

a contract with the OPA.

Oakville Hydro's distribution system is a robust, integrated network throughout the Town of Oakville. Adequate planning and proactive infrastructure projects have made the distribution network well equipped to handle forecasted renewable generation, except for areas supplied by two Hydro One-owned transmission stations supplying Oakville Hydro which have capacity restrictions due to short circuit levels. Oakville Hydro is working with the transmitter (Hydro One) to alleviate these restrictions, but would have to accept higher short circuit limits than set out in the Transmission System Code. Oakville Hydro plans to study the risk of this change and make a determination to accept, or not accept the higher limits by year end 2013. If this restriction is lifted, Oakville Hydro does not expect a significant increase in FIT applications, based on information currently available.

Based on Oakville Hydro's 2011 to 2013 FIT/microFIT data and the future assumptions, it is estimated that the connection of Renewable Energy projects under FIT and microFIT programs will remain steady between 2014 and 2018. The calculated remaining capacity and the projected demand for renewable energy indicate that Oakville Hydro is ready to connect future renewable generation projects.

Consequently, Oakville Hydro has not included any capital expenditures related to renewable energy generation in its Distribution System Plan. There has been modest interest in the FIT program that would require Renewable Energy Generation Investments. In addition, there are no additional OM&A costs proposed related to renewable energy generation as Oakville Hydro is able to manage workload using existing staff to process microFIT/FIT applications and all the related requirements that currently exist.

2. CURRENT ASSESSMENT

2.1 The Oakville Hydro Distribution System

Oakville Hydro is a local distribution company responsible for the distribution of electricity to approximately 65,000 homes and businesses within the Town of Oakville. It is a subsidiary of Oakville Hydro Corporation whose sole shareholder is the Town of Oakville. Oakville Hydro relies on 1,529 km of circuits to deliver energy and power to its customers. It receives power from Hydro One Networks Inc. and delivers electricity to its customers via five high voltage transformer stations, four owned by Hydro One and one by Oakville Hydro.

2.2 Existing Distributed Generators

As of July 2, 2013, Oakville Hydro has connected three Feed-In Tariff (FIT) projects for a total of 0.49 MW of renewable generation. In addition, Oakville Hydro is aware of seven pending FIT applications from renewable generators over 10 kW in the Oakville service area, totaling 2.075 MW. There are also currently 32 microFIT customers totaling with a total capacity of approximately 200 kW. The total FIT breakdowns by transformer station are shown in Table 1.

Table 1: Oakville Hydro FIT Projects (as at August 12, 2013)

Transformer Station	Bus #	Connected FIT Customers	Connected FIT - Total Capacity (MW)	Pending FIT** Customers	Pending FIT** - Capacity (MW)
Oakville TS (1)	E	1	0.06	2	0.825
Oakville TS (1)	Z	2	0.43	1	0.250
Bronte TS (1)	Q	-	-	1	0.250
Bronte TS DESN1 (1)	BY	-	-	1	0.300
Trafalgar TS(1)	BY	-	-	1	0.250
Palermo TS(1)	BY	-	-	-	-
Glenorchy MTS	J	-	-	-	-
Glenorchy MTS	Q	-	-	1	0.500
TOTAL		3	0.49	7	2.375

(1) Hydro One owned
***Pending applications with the OPA may or may not proceed depending on their eligibility review process.*

2.3 System Capability Assessment for Renewable Energy Generation

The estimated capability of Oakville Hydro's distribution system to accommodate renewable energy generation connection at each transformer station is shown in Table 2 below.

At this time Oakville Hydro is not aware of specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity.

There are two Hydro One-owned transformer stations namely, Palermo and Trafalgar where there are short circuit capacity restrictions related to the connection of renewable generation, within the upstream transmission system. However, the remaining stations have sufficient short-circuit capacity to accommodate the type of distributed generation that Oakville Hydro has seen so far. Most of the renewable energy projects proposed in Oakville Hydro service area are inverter-based with limited fault contribution to Oakville Hydro's distribution system. It is unlikely that the fault contribution from the anticipated distributed generation will cause the transformer stations to reach the short-circuit capacity limits.

Oakville Hydro is working with the transmitter to alleviate the restrictions at Palermo and Trafalgar, but would have to accept higher short circuit limits than set out in the Transmission System Code. Oakville Hydro plans to study the risk of this change and make a determination to accept, or not accept the higher limits by year end 2013. If this restriction is lifted, Oakville Hydro does not expect a significant increase in FIT applications, based on information currently available.

Table 2: The estimated capability of Oakville Hydro's distribution system

Transformer Station	Bus Name	Feeder Name	Voltage (kV)	Capacity for GEN (MW)	Connect GEN (MW)	Remaining Capacity (MW)
Oakville TS (1)	E	M43,M49,M51	27.6	53.10	0.06	53.04
Oakville TS (1)	Z	M44,M50,M52	27.6	49.40	0.43	48.97
Bronte TS (1)	Q	M23,M24	27.6	54.00	0.00	54.00
Bronte TS DESN1(1)	BY	M1,M2,M3,M4,M5,M7,M8	27.6	63.90	0.00	63.90
Trafalgar TS (1) (2)	BY	M4,M5,M6,M7,M8	27.6	0.00	0.00	0.00
Palermo TS (1) (2)	BY	M2,M4,M7,M8	27.6	0.00	0.00	0.00
Glenorchy MTS	J	M15,M17,M19	27.6	17.10	0.00	17.10
Glenorchy MTS	Q	M14,M16,M18	27.6	15.60	0.00	15.60
Total				253.10	0.49	252.60

(1) Hydro One Owned TS

(2) There is No Generator Connection Capacity Due to lack of Short Circuit Capacity

In addition to the above station available capacity information, the cumulative generation connections are limited on an individual feeder basis as follows:

- Feeders operating at 27.6 kV – 19 MW
- Feeders operating at 13.8 kV – 9.6 MW
- Feeders operating at 4.16 kV – 1.45 MW

Based on the low volume of current connections and the volume of existing generators in the application phase, Oakville Hydro does not anticipate or forecast a high volume of connection applications over the 2014 to 2018 planning horizon.

At this time, Oakville Hydro has one potential embedded distributor – Milton Hydro. There are no known constraints for an embedded distributor that may result due to renewable generator connections, other than capacity limitations outlined above.

3. PLANNED DEVELOPMENT

3.1 Projected Renewable Generation Growth

To date, the Renewable Generation installations in Oakville Hydro's service area consist of rooftop solar PV smaller than 500 kW. As indicated by the OPA, there are seven small FIT applications under the FIT 2 program with a total proposed capacity of 2.375 MW (refer to Appendix A). Due to the 200 MW provincial limit for small FIT applications, it is reasonable to estimate that only some of these applications will be awarded a conditional offer under the FIT 2.0 program in 2013. It is also reasonable to expect that the remaining customers who do not receive a FIT contract under FIT 2.0 in 2013 will choose to pursue at a later time.

Based on Oakville Hydro's 2011-2012 FIT/microFIT data and the future assumptions, it is estimated that the connection of Renewable Energy projects under FIT and microFIT programs will remain steady between 2014 and 2018. This estimate assumes that the OPA does not significantly change the program rules and rate calculation methodology.

In general, it is estimated that Oakville Hydro has enough remaining station capacity and distribution infrastructure to accommodate the demand for renewable energy projects under FIT/microFIT program from 2014 to 2018.

3.2 OPA Consultation

Oakville Hydro consults with the OPA on a regular basis as new contracts are approved and will continue to do so in the future. The OPA's letter of comment with respect to Oakville Hydro's Renewable Energy Generation Plan is provided in Appendix B.

4. PLANNED INVESTMENT

Under the rules for connecting renewable energy projects in the Distribution System Code, Oakville Hydro will be responsible for funding new feeder assets required to connect FIT generators to a maximum of $90,000 per MW. To date, there has been limited interest in FIT generation projects that would require construction of new feeder assets. No renewable energy generation investments for the period 2014 - 2018 are expected, in order to accommodate the renewable energy generation connections.

From an OM&A perspective Oakville Hydro has been able to manage the workload related to processing renewable energy applications using existing staff for responding to the microFIT inquiries, conducting the site visits, preparing the offers to connect and microFIT data entries. Oakville Hydro continues to anticipate similar low volume activity of applications in the future and has not included any OM&A costs in the Test year.

4.1 Overall Assessment

Based on a calculated remaining maximum capacity and the projected generation projects Oakville Hydro feels confident that it has capacity in place to accept future renewable generation projects.

Appendix A: Proposed small FIT applications

The proposed small FIT applications in Oakville Hydro service area as provided by the OPA are provided in the following table.

Number of Applications	Capacity (kW)	LDC Name - TS Name, Upstream Feeder Name, Voltage (as indicated by the applicant)
1	300	Oakville Hydro EDI – Bronte TS, M8, 27.6kV
1	250	Oakville Hydro EDI – Oakville TS, M50, 27.6kV
1	250	Oakville Hydro EDI – Trafalgar TS, M5, 27.6kV
2	825	Oakville Hydro EDI – Oakville TS, M43, 27.6kV
1	250	Oakville Hydro EDI – Bronte TS, M24, 27.6kV
1	500	Oakville Hydro EDI – Glenorchy MTS, M14, 27.6kV

Appendix B: OPA Letter

As per Section 5.1.4.2 of the DS Plan Filing Requirements, the Board expects that the OPA comment letter will include:

- The applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- Whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- The potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the Renewable Energy Generation investments; and
- Whether the Renewable Energy Generation investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

The Board may postpone processing an application where a comment letter from the OPA has not been filed in accordance with this requirement.

OPA Letter of Comment:

Oakville Hydro Electricity Distribution Inc.

Renewable Energy Generation Investments











September 12, 2013

ONTARIO POWER AUTHORITY

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Oakville Hydro Electricity Distribution Inc. – Distribution System Plan

The OPA received Renewable Energy Generation Investments Plan ("Plan") from Oakville Hydro Electricity Distribution Inc. ("Oakville Hydro") on August 15, 2013. The OPA has reviewed the Plan and provided its comments below.

OPA FIT/microFIT Applications Received

On page 4 of its Plan, Oakville Hydro indicates that currently it has connected 3 FIT projects totalling 490 kW of renewable generation capacity and 32 microFIT projects totalling 200 kW of capacity. Additionally, Oakville Hydro is aware of 7 pending FIT applications totalling 2,075 kW of capacity that may connect to its distribution system.

According to OPA's information, as of August 30, 2013, the OPA has received and offered contracts to 10 FIT projects, totalling 2,865 kW of capacity, which remain active to date. Of these, 3 FIT projects representing 490 kW have reached commercial operation. Additionally, the OPA has received and offered contracts to 36 microFIT projects, totalling 236 kW of capacity, which remain active to date.

The OPA finds that Oakville Hydro's Plan is reasonably consistent with the OPA's information regarding renewable energy generation applications to date.

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Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

The OPA notes that Oakville Hydro is part of "Group 1" for regional planning prioritization (underway - 2014), and although bulk transmission and regional planning activities have taken place or are currently underway in some parts of the area, neither a Regional Infrastructure Plan, nor an Integrated Regional Resource Plan has been completed for Oakville Hydro's service territory. Oakville Hydro has provided the OPA with long-term load forecasts to support these planning initiatives. As a result, the OPA is unable to comment on whether Oakville Hydro's renewable energy generation investments are consistent with a Regional Infrastructure Plan. In fact, in the section entitled *Planned Investment* on page 9 of the Plan, Oakville Hydro indicates that:

"No renewable energy generation investments for the period 2014 - 2018 are expected, in order to accommodate the renewable energy generation connections." and,

"Based on a calculated remaining maximum capacity and the projected generation projects Oakville Hydro feels confident that it has capacity in place to accept future renewable generation projects."

The OPA also concurs with Oakville Hydro that there is ongoing consultation with the OPA with respect to new contract information to facilitate renewable energy generation connections, and that this will continue.

The OPA looks forward to working with Oakville Hydro in the execution of regional planning once that process is triggered, and appreciates the opportunity to comment on the information provided as part of Oakville Hydro's Renewable Energy Generation Investments Plan.

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Appendix 5

Smart Grid Strategy

Smart Grid Strategy
(Oakville Hydro)

Overview

Developing a 'smart grid' electricity system has been an evolving global vision over the past 15 years. In 2010, the Ontario Smart Grid Forum defined Smart Grid as follows:

- "*A smart grid is a modern electricity system. It uses sensors, monitoring communications, automation and computers to improve the flexibility, security, reliability, efficiency, and safety of the electricity system. It offers consumers increased choice by facilitating opportunities to control their electricity use and respond to electricity price changes by adjusting their consumption. A smart grid includes diverse and dispersed energy resources and accommodates electric vehicle charging. It facilitates connection and integrated operation. In short, it brings all elements of the electricity system – production, delivery and consumption closer together to improve overall system operation for the benefit of consumers and the environment*."

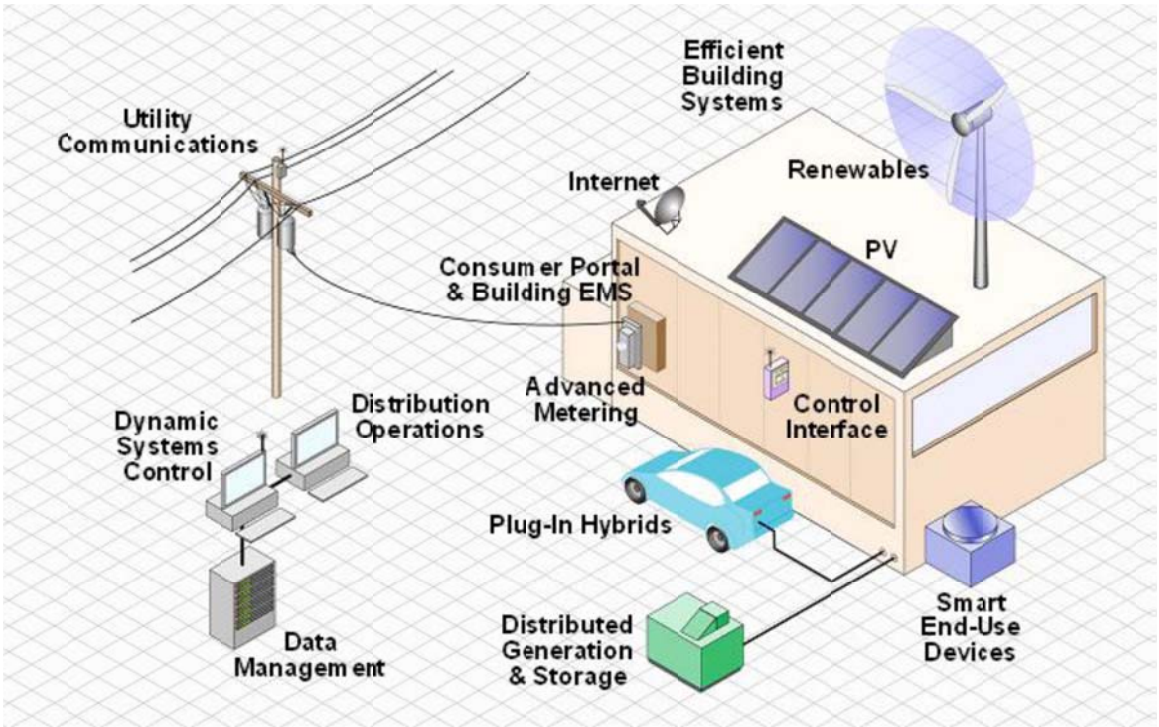
The outcome of this vision being achieved, is dramatically greater visibility and control of the electricity network, support for distributed generation, a more interactive relationship with customers to manage energy use, while maintaining the highest standards for safety and overall system security.

Key Drivers of Smart Grid Evolution (Ontario)

In Ontario, regulatory direction through the Ministry of Energy has initiated and encouraged / mandated significant investment in the operating infrastructure and IT systems in support of an evolving electricity system. The recent implementation of smart meters (Advanced Metering Infrastructure (AMI)) and associated provincial Meter Data Management / Repository (MDM/R) IT system to support Time of Use end user consumption visibility and capabilities is an example of this direction. In addition, Ontario's Green Energy Act promotes and enables renewable energy and distributed generation in all jurisdictions across the province. The Ontario Energy Board (OEB), as part of its Cost of Service (COS) application process by LDCs, requires each LDC to file a Smart Grid Plan as a means to demonstrate its forward-thinking views on distribution system evolution. In 2012 the Ministry of Energy, in an effort to promote technological innovation in the area of smart grid, selectively awarded funds for demonstration / pilot projects (between vendors / LDCs). Increasing consumer expectations around electricity system robustness and reliability, in order to meet their life style needs is another key driver.

Addressing Utility Challenges with Smart Grid	
Challenge	**Smart Grid Benefits**
Customer Control	• Information and Incentives for Reduced or More Intelligent Energy Usage • Real Time Data Access • Behind the Meter Services • Improved Customer Service and Outage Communication
Power System Flexibility	• IT System Integration • Analytics for Decision Support • Connected Mobile Work Force • Self Healing Grid with Automated Switching and Protection Systems
Adaptive Infrastructure	• Balances Supply and Demand • Manages Power Quality • Monitors and Controls Renewable Energy Sources • Maintains Grid Stability as Renewably Energy Sources are Added • Meets Environmental Targets and Regulatory Requirements

Customer-Centric Smart Grid Representation:



Source: Electric Power Research Institute (EPRI – US)

Smart Grid Strategy (Oakville Hydro)

Oakville Hydro's Smart Grid strategy will be to grow and develop the distribution grid utilizing a combination of good utility distribution practice coupled with emerging technologies & systems. Oakville Hydro's long term strategy is to evolve its operating distribution system and associated IT systems capabilities to align with its over-arching smart grid goals. Oakville Hydro plans to leverage the capabilities of current system assets to enhance future capabilities (e.g. smart meters integrated into Outage Management System). In addition, it will make prudent asset management decisions around replacing selected end-of-life equipment and communication infrastructure, with choices that align with this evolving strategy. Oakville Hydro will ensure that all smart grid projects align with Oakville Hydro's Strategic Plan, by including them in the capital project portfolio to be evaluated and prioritized as set out in the Asset Management strategy.

Oakville Hydro's Smart Grid over-arching goals are as follows:

Customer Control

1) Enhance customer experience associated with control of energy usage.
2) Increase visibility / currency on system outages
3) Connect renewable generation (e.g. solar) and take advantage of plug-in and hybrid vehicles as choice of transportation

Power System Flexibility

4) Improve distribution system reliability, performance and responsiveness
5) Equip the distribution system to enable two-way flow of electricity
6) Improve operating efficiencies through distribution automation, e-mobile capabilities and IT system integration (e.g. AMI, GIS, SCADA, OMS)

Adaptive Infrastructure

7) Improve power quality and energy efficiency using advanced system tools and controls, to monitor and reduce distribution losses
8) Enhance asset efficiency through system monitoring to fully utilize and extend life of existing assets

Over the next few years, Oakville Hydro will need to continue to reinforce the foundations of its distribution system (e.g. switching, monitoring and communications infrastructure) and enhance / integrate its operating and information systems in order to achieve these goals. These changes will involve continued enhancements of current engineering and operations technology platforms (GIS and SCADA) as well as planned integration into a new platform (Outage Management System) currently under development. A new level of sophisticated operational capabilities is evolving that will accept all forms of distributed generation and provide increased reliability through switching flexibility and automation features such as self-healing distribution feeders. The attached Appendix, included with this Smart Grid strategy, provides more detailed near and mid-term plans to operationalize this strategy.

Timing of smart grid investments will be, as mentioned, somewhat dependent on upgrades to Oakville Hydro's distribution system facilities through expansion or renewal. The rate of customers' adoption of renewable generation and consumer technologies will also have an impact on Oakville Hydro's anticipation of smart grid investments. Plug-in electric vehicles are starting to enter the market but adoption is slower than anticipated. These entrants, plus the potential for growth in electric public transportation, is expected to be longer term, but none the less, a significant aspect of smart distribution systems. Oakville Hydro will continue to monitor the situation and work towards enabling their roll out through collaborative ventures.

Smart Grid Strategy (Oakville Hydro)
Appendix

Capabilities Assessment (Current and Planned)

Oakville Hydro has many activities and initiatives currently underway and / or in the planning stages that enable the capabilities required to achieve its smart grid goals. They have been categorized as noted below. Each category consists of common themes and contains the associated current state and/or directional plans.

1. **Existing Areas of Operational Excellence** – capabilities that are already present that will be leveraged to enable/deliver on our Smart Grid goals.
2. **Customer Control** – advancements and initiatives that positively impact the customer, providing improvements in both experience and value.
3. **Power System Flexibility** – enhancements made to the distribution system that delivers improved system reliability, problem detection and mitigation.
4. **Adaptive Infrastructure** – equipment or system advancements that optimize business processes, in order to enhance resource effectiveness and/or generate cost efficiencies.
5. **Smart Grid Initiatives** – electric vehicles plus smart grid pilot projects that are funded by the MOE and/or approved by the OEB.

1. Existing Areas of Operational Excellence:

- **Capabilities that are already present that will be leveraged to enable / deliver on Smart Grid goals**

a) Advanced Metering Infrastructure (AMI)

Current State

Oakville Hydro has implemented a Sensus FlexNet AMI network capable of providing remote meter reading to approximately 65,000 smart meters, for the purposes of Time-of-Use billing. Oakville Hydro's AMI network utilizes a licensed radio frequency (RF) network for the collection and transmission of metering information from each meter point to meter data collection and storage systems. Each meter point uses the RF network to wirelessly transmit data to five Tower Gateway Base stations (TGBs) situated throughout Oakville. Once meter data reaches these towers, the data flows into the Regional Network Interface (RNI) via Oakville Hydro dedicated fibre optics. The RNI is the single point of collection for all meter data within the Sensus AMI network. This system is a flexible, multi-application network for Smart Metering with the potential for Distribution Automation and Demand Response. This system is capable of supporting single phase meters, polyphase meters, and additional smart devices. The AMI network will enable the future grid modernization initiatives due to its reliability, availability, scalability, low latency, ability to provide 'over the air' upgrades, and its open standards network architecture.

Oakville Hydro and Sensus have collaborated to ensure that the AMI system is secure. Multi-layered security (from endpoint to user interface) has been a priority since the implementation of AMI. Further measures also include a fully integrated encryption and enhanced key management protocol to safeguard Oakville Hydro's AMI system from external threats.

Directional Plans

All of the information that is harvested from the AMI network resides in the Operational Data Store (ODS). The ODS is a scalable, adaptable system that can meet Oakville Hydro's customer growth and provides customizable options for the addition of future functionality. The ODS currently stores, validates and processes large volumes of data for billing, settlements and other reporting and reconciliation obligations. The ODS is expected to supply meter outage or 'last gasp' information to the Control Room Operator to assist in outage restoration. This outage data will be linked to the Outage Management System (OMS) that is currently in the development stage. Future integration plans with ODS include meter disconnect/reconnect capability linked with the Customer Information System (CIS), transformer to customer network connectivity data linked to the Geographic Information System (GIS), and seasonal load profiles tabulated by transformer and linked to the power engineering software analysis tool (CYME) for load forecasting and analysis.

Timeline

The formatting for outage messaging from the ODS to OMS has been developed and tested using sample data on test servers. This capability is expected to be operational on the live SCADA system in 2013.
Integration to CIS for meter disconnect/reconnect, GIS for customer/transformer network connectivity, and CYME for load forecasting and analysis are planned for 2014.

b) Embedded Field Communications for System Monitoring & Control

Current State

Oakville Hydro first started deploying remotely-operable switches in the early 1980's. Currently there are 120 controllable switches on the 27.6kV distribution system that are used for fault indication, outage restoration, load control and load monitoring. Of these 120 switches, 37 of them have been installed since 2009. These switches are primarily controlled using an Industry Canada licensed 400 MHz radio channel. With 30 separate feeder circuits in service supplying the 27.6kV distribution system, this equates to on average 4 controllable switches per circuit that are used to isolate failures and restore power remotely from the Control Room.

Currently there are 2 Municipal Substations with 13.8kV secondary voltage, 17 Municipal Substations with 4kV secondary voltage, and 1 Transformer Station (Glenorchy MTS) with 27.6kV secondary voltage. All Oakville Hydro substations, as well as Glenorchy MTS, are connected to SCADA via fibre optics.

To enhance fault locating capabilities, Oakville Hydro has installed 7 communicating remote fault indicator collectors that are wirelessly connected to fault indicators that monitor a total of 17 separate primary electrical circuits. For these 17 primary electrical circuits, the fault indicators communicate back to the SCADA system and report instantaneous load information for load control purposes. They also indicate detection of fault current for outage restoration purposes

Directional Plans

Plans are in-place to install more of these remote fault indicator collectors to monitor an additional 11 electrical primary circuits. In addition, there are pilot projects currently underway to trial new overhead and underground indicator technologies such as energy harvesting that eliminate the need for a battery maintenance program. All of Oakville Hydro's communicating fault indicators communicate back to SCADA using an HSPA cellular network.

Timeline

The pilot projects for underground indicators and energy harvesting overhead indicators are currently in place. It is expected that the pilot project findings will be used to drive additional investment in fault indicator technology in 2014.

c) Experience with Modern Intelligent Electronic Device (IED) Technology

Current State

Oakville Hydro was an early adopter of solid state Intelligent Electronic Device (IED) technology. IEDs consist of computerized equipment that is used for system monitoring, operation, and diagnostics. When the first remotely-operable switches were installed in the early 1980's, there wasn't an off the shelf solution for switch control and SCADA (System Control And Data Acquisition) communication, so the required IEDs were wired, commissioned, and installed by Oakville Hydro. Similarly, Oakville Hydro made the switch from electro-mechanical protection relays to three phase solid state IEDs in the late 1980's when the technology became available for substation feeder protection.

In the last three years, Oakville Hydro's capital program has included new remotely-operable switches, municipal substation breaker and transformer replacement projects, and the Glenorchy transformer station, all of which include IED technology with varied requirements. It would be difficult to maintain & operate all of this equipment if there was a different IED technology platform with each project, so Oakville Hydro has standardized on Schweitzer Engineering Laboratories (SEL) and General Electric (GE) IEDs. These two technology platforms are widely

used in the utility industry, and have been used by Oakville Hydro for power transformer monitoring, switch control & monitoring, municipal substation feeder protection, and all of the Glenorchy MTS transformer station protection elements required by the transmission code.

d) 24/7 Operations Control Room

Current State

Oakville Hydro's 24/7 Operations Control Room uses the SCADA (System Control and Data Acquisition) System to both monitor and control all 120 remotely-operable switches, 7 communicating remote fault indicator collectors, 19 Municipal Substations, and the Glenorchy Transformer Station. Considering that the 120 remotely-operable switches are deployed across the entire 27.6kV distribution system which consists of 30 feeders, this equates to on average 4 remotely operated switches per feeder. With the addition of the Glenorchy Municipal Transformer Station (MTS) in 2011, required enhancements to Operator training programs and Operations Control Room operating procedures & policies were made to comply with the strict IESO Transmission System operating requirements. In case of emergency, there is the ability to move these Operations Control Room capabilities from 861 Redwood Square to the Backup Control Room at Glenorchy MTS.

Oakville Hydro is in a unique transmission grid location in that three separate Hydro One transmission lines are utilized to supply electricity to the Town of Oakville. In addition, this supply consists of four Hydro One-owned transformer stations and one Oakville Hydro-owned transformer station. This configuration results in frequent load transfer requests from Hydro One, driven not only by transformer station thermal load, but load restrictions in the transmission system. With these load transfer pressures combined with day-to-day transfers for Oakville Hydro capital projects and maintenance, Oakville Hydro's Operators have become very proficient in using the SCADA system combined with loading data from substations, remote-operable switches, and communicating fault indicators, to maintain the integrity of the distribution system.

Oakville Hydro's Operations Control Room also has a well documented and managed procedure concerning outage restoration and customer communication, implemented in collaboration with the Customer Service Department. In the event of an outage the Operator can forward all phone calls to the Customer Service Representatives and focus on restoration and communication. The Customer Service Representatives receive all phone calls and forward all pertinent information to the Operator. The Operator issues regular outage updates with estimated restoration time to an internal email distribution list, which can then be sent to external contacts as required. Once all power is restored an outage report is both circulated internally and posted to the public website.

Directional Plans

Operator capabilities will continue to grow with respect to system operations and restoration activities with the planned 2013 implementation of OMS. The OMS will bring capabilities that promote outage messages to the Oakville Hydro website and to customer portable electronic devices (PEDs). Also, the establishment of an IVR system will be evaluated to streamline customer service and outage reporting.

e) Geographic Information System (GIS)

Current State

Oakville Hydro initiated the conversion of its auto-cad developed, paper-based distribution system records to an intelligent GIS record in 2010. We achieved all of our key milestones in 2010, 2011, 2012 and on-track for completion in 2013.

Oakville Hydro rolled out a mobile GIS application in February 2013. The initiative reduces the amount of paper prints issued to the field crews and enables redline reporting/communication between Operations and Engineering.

Directional Plans

Going forward, the GIS system offers a variety of productivity features. Some examples are listed below:

- Redline capabilities
- Improving accuracy and currency of distribution system data
- Decrease reconciliation costs between Engineering & Operations for field information
- Ease in locating documents - one repository location for Construction and As-build drawings
- Improved records accuracy will reduce amount of field verification
- Integration of distribution system network model into OMS/SCADA, CYME, and ODS as a valuable information system for Operations Control Room, Engineering Analysis, and Asset Utilization.
- Other operational savings will also be realized in the areas of:
    - Improving information for locates
    - Improving information for asset management & maintenance
    - Locating data and documents
    - Report discrepancies within Network from field vantage
    - Service calls and outage management

Timeline

These productivity features are expected to materialize in 2013.

2. Customer Control

- **Advancements and initiatives that positively impact the customer, providing improvements in both experience and value.**

a) Customer Engagement Strategy

Current State

Oakville Hydro is a customer-centric utility, are constantly working to ensure that our customers have the information they need on various programs and initiatives. Oakville Hydro promotes OPA-Contracted Province-Wide CDM Programs to its customers in a number of ways, including:

- Mass market advertising (newspaper advertising, direct mail, billing inserts, on-bill messaging, on-line advertising, etc.).
- Information concerning CDM programs as well as tips for energy saving on OHEDI's website.
- Sponsorship / participation in local community events such as home / lifestyle shows to promote CDM programs and awareness; flyers describing CDM programs are available at these events.
- Support for public environmental / conservation awareness events such as Earth Day and Eco-Fest.
- For business customers, "lunch & learn" sessions are provided periodically to provide information concerning CDM programs.

Customer feedback is a critical aspect of our strategy, including feedback regarding Smart Grid. A survey was conducted in March 2012 with 1,385 households contacted to take part and provide feedback. Select survey questions focused on smart meters, Smart Grid, and conservation & demand management, with the purpose of determining what customers think about all three categories. In relation to the Smart Grid, we wanted to determine the level of customer knowledge and awareness for Smart Grid, and find out if there is customer support for Oakville Hydro to pursue Smart Grid initiatives.

Oakville Hydro has also engaged the Oakville Town Council on Smart Grid initiatives, including field automation. The Council supported our direction and plans including:

- Acknowledging the number of existing switch locations that are controlled from the Control Room, the use of SCADA, and the role of each in outage restoration.
- Support for continued investment in both remotely controlled switches and switching locations supplied from two sides that automatically operate to select the energized side in the event of an outage (field automation).

Directional Plans

Customer Education will continue to be a focus of our engagement strategy focusing on communicating the features and benefits of Smart Grid to our customers in order to build understanding. A variety of media will be used for this purpose including website, bill inserts, flyers, news release, community events, and customer service representative training.

b) Data Access

Current State

Oakville Hydro has implemented "eCare", an online web presentment service that allows smart metered customers the ability to access their historical meter data. Customers can graph their electricity consumption and monitor energy usage in kWhrs and in cost of energy. Demand side management screens compares customers usage to similar accounts in their neighbourhood and helps customers understand their consumption patterns and load profiles. It also helps them identify which loads/appliances use most electricity so they can practise energy management and conservation. Oakville Hydro also provides on-bill monthly historical energy usage for previous 12 months so customers can readily compare energy usage over a period of time.

Directional Plans

Going forward, we plan to introduce the capability for alert notifications regarding consumption and price, supply charts with weather trends, provide usage comparison information in terms of dollar value, and enable our customers to download their consumptions data.

Timeline

Some of the additional functionality is expected to materialize in 2013, with the remainder in 2014.

c) In-Home Display (IHD)

Current State

The existing in-home displays are limited to the PeakSaver program offering.

Directional Plans

Our AMI system has enabled in-home functionality that ties in with consumption data. We have begun rolling out our PeakSaver+ CDM program which provides all customers who sign up for the program an IHD free of charge. After enrolling in the program the customer owns the IHD with 2 choices:

1. Currently available is a Blueline IHD package which consists of a sensor that mounts on the meter and a Blueline Powercost monitor (IHD).
2. In the near future (potentially 2013), there is an Android tablet to be market-ready pending approval from Sensus that would include a gateway device for web based communications for our customers that would support development of future CDM programs and other potential opportunities.

Timeline

The Peaksaver+ program runs until end of 2014.

d) Energy Management Systems

Current State

The PeakSaver+ CDM program is a demand response program that allows the IESO/OPA to control customer A/C, and /or electric water heaters and/or pool pumps during peak demand periods in the summer months.

Directional Plans

In addition the Android gateway option also supports control of various loads within their home (e.g. appliances). Loads are controlled via paging using switches mounted directly on the loads.

Timeline

The PeakSaver+ program runs until end of 2014.

e) Personal Electronic Devices (PEDs)

Directional Plans

PEDs will have the capability to receive outage status updates once the OMS is operational in 2013.

f) Multifaceted Outage Communications Scheme

Directional Plans

The OMS currently under development will provide improved communications on status of outages to our customers and key stakeholders both for planned and unplanned events. The OMS will be capable of handling call entry either using a call display interface or an Interactive Voice Response (IVR) system to save time for the Operator in taking input from affected customers. Once this information is combined with outage data from the AMI, the system recommends outage cases with the predicted fault locations allowing the Operator to dispatch crews to these key locations to investigate.

With this information, as the outage restoration progresses, Oakville Hydro will be able to provide outage updates and reports using a variety of media outlets including email, twitter, webpage updates, etc. This will serve to keep all stakeholders informed and set appropriate expectations for the restoration of power.

Timeline

These additional outage communications capabilities are expected to start materializing in 2013.

3. Power System Flexibility

- **Enhancements made to the distribution system that deliver improved system reliability, problem detection and mitigation.**

a) Outage Management System (OMS)

Directional Plans

Oakville Hydro is engaged in a joint development project with Survalent (SCADA system vendor) to develop, test and implement a new Outage Management System directly integrated into our existing SCADA system platform with links to GIS, AMI, ODS, and (CIS) customer data. This initiative represents the first OMS system in Ontario to be built directly into the SCADA software already in use by Control Room Operators.

The proposed OMS software will draw on information from the existing Harris CIS, Sensus AMI, and GIS platforms as a powerful tool for the Control Room operators to use when responding to system outages of any magnitude. This will drive more efficient use of resources, improved & more timely communications to customers & stakeholders, and faster restoration times for all distribution system interruptions. Customization specific to customer and stakeholder communication will be available for outage and restoration notification via website, email, or automated phone call.

The planned OMS software is a new subsystem within the Survalent Windows SCADA package. It is designed to run on the SCADA host computers, with a user interface built into the WorldView operator interface. The OMS is therefore fully redundant along with the rest of the SCADA system. The training time for this particular OMS system is minimized because it is integrated directly into the existing SCADA graphical interface that the operator is already familiar with. This system will also capture outage information to drive more accurate and thorough outage reporting for further system analysis and optimization.

Timeline

The OMS is expected to be fully operational in 2013.

b) Communications Infrastructure Solutions

Current State

Oakville Hydro is completed a SCADA Communications Review with a third party to assess the SCADA telecommunications systems and alternatives for future technical field applications. This study supported continuation of a multi-technology approach to SCADA communications and the use of fibre-optic cables, licensed 400 MHz radio, and cellular Ethernet modems. One outcome of this report was the replacement of existing analogue licensed radio equipment in 2012 with digital radio infrastructure, and this was completed as planned.

Directional Plans

Oakville Hydro's SCADA communication scheme is now scalable to accommodate additional grid functionality as it develops.

c) Self Healing Grid

Current State

Oakville Hydro's long term vision is to develop a self healing distribution system grid that leverages automation systems for outage recovery, both centrally located in SCADA, and deployed using IEDs in the field. Distribution switchgear in Oakville has undergone an evolution from fully manually-operated equipment, to motorized and electrically - controllable equipment, and finally to the fully remote-controlled equipment used today that is equipped for automation.
Oakville Hydro's first Equipment Automation deployment is planned for 2013 in the form of padmount switches supplied from two sources that can automatically select the energized side. In existing SCADA-controlled padmount switchgear that is equipped for remote operation of both main incoming switches, the IED will be enabled to detect an outage and automatically shift the supply point over to the energized side. This will energize the local circuits supplied by this switchgear, and turn the power back on without any intervention from Oakville Hydro staff.

Directional Plans

Following the automation of between 2 and 5 isolated equipment locations in 2013, the next step will be Zone Automation. This will be achieved through the SCADA system with a software module for Fault Detection Isolation and Restoration (FDIR). This module will empower Oakville Hydro to set up automation schemes by feeder circuit in the areas that have the required density of automated equipment.

Moving forward, Oakville Hydro is well equipped to leverage its experience in SCADA operations, communication systems, IEDs, and control of field equipment to evaluate self healing grid technologies and develop the distribution system appropriately.

Timeline

Equipment Automation capability for between 2 and 5 padmount switches is planned to be in-place in 2013. Zone Automation (FDIR) capability is expected to be operational in 2014, with full self-healing grid materializing around 2020.

4. Adaptive Infrastructure

- **Equipment or system advancements that optimize business processes, in order to enhance resource effectiveness and/or generate cost efficiencies.**

a) GPS Tracking for Fleet Vehicles

Directional Plans

GPS tracking enables improved dispatching and shorter outage response times. The real-time location information simplifies dispatch decision-making, and identifies which crews are the closest to an outage or critical equipment.

This also drives increased visibility into field operations. The Control Room Operators are able to determine if crews are in the correct location for operating equipment, troubleshooting, line clearing, etc.

In addition, when there is an emergency in or near the vehicle, an emergency button can be pressed that will alert the Control Room Operator to dispatch the emergency services to their location.

Timeline

GPS tracking capability is currently available in Oakville Hydro's newly upgraded mobile radio system in fleet vehicles. Preliminary plans are underway to incorporate these GPS tags into our SCADA system – potentially in 2013.

b) Meter Remote Disconnect Capability

Directional Plans

Meter remote disconnect capability enables more efficient management of non-payment accounts and disconnects for move outs. Reconnect would be performed by the customer using their own television remote control device, which ensures that there is someone home during the reconnect, as a safety measure. Remote disconnect equipped meters will only be installed on a targeted segment of customers where the added cost is justified.

Timeline

This option is currently being developed in the industry and could potentially materialize in 2013-2014 timeframe.

c) Power System Analysis Tools

Directional Plans

Complimentary to the OMS system, a power system analysis tool (CYME) will be implemented to draw in the AMI consumption data and the GIS network model in order to deliver the capability for analysis of voltage drop, system losses, phase balancing, load flow, short circuit levels, protection coordination, arc flash studies, impact of distributed generation and associated connection impact assessments.

Timeline

The CYME software is expected to be operational in 2014.

d) 'Harvester' Solar Panels

Current State

In 2011, Oakville Hydro installed 16 'Harvester' solar panels on poles throughout Oakville as a limited technology trial. This trial involved two locations with eight panels each, one at the South Service Road & Wyecroft, and the other at Joshua's Creek Drive & North Service Road.

Directional Plans

Oakville Hydro plans to continue to evaluate the possibility of installing more 'Harvester' solar panels if appropriate benefits can be validated. The system is based on a single 220 - 280 watt solar panel, a Smart Energy Module with an inverter, two way wireless communications, sensors, digital meter, and a pole mounting system to attach to existing utility poles. The solar unit produces power directly to the secondary voltage lines with the following potential benefits:

- Power system voltage stabilization
- Addition fault locating capabilities for the Control Room
- Reduced line losses

5. Smart Grid Initiatives

- **Electric vehicles plus smart grid pilot projects that are funded by the MOE and/or approved by the OEB.**

a) dTechs Power Loss Monitoring - Smart Grid Fund Round 1 Approved Project

Directional Plans

Oakville Hydro is currently participating in the Ontario Smart Grid Fund demonstration pilot project in collaboration with dTechs for distribution system power loss monitoring and theft detection. This project involves the deployment of 225 units in 2013 to cover 25% of Oakville Hydro's customer base, with outage messages integrated into OMS. These metering units will supplement the fault indicators and AMI meter monitoring, and provide additional overall distribution system monitoring.

The dTechs MeterSuite is an advanced wireless metering system created to help utilities directly address grid management, line-loss reduction and power theft. The system will enable Oakville Hydro to increase its ability to detect, monitor and control technical and non-technical energy losses. The dTechs MeterSuite will find, immediately notify and direct Oakville Hydro to the location of atypical consumption. This includes power theft, unsafe high consumption and poor infrastructure areas (e.g. aged transformer equipment and poor distribution lines). The dTechs metering hardware installs quickly and seamlessly in the grid, measuring flow in real time at the most efficient location (medium voltage); that being the primary/tap line which delivers electricity to an average of 60 to 100 customers. MeterSuite is a one-time permanent deployment installed system-wide in the distribution grid that reconciles with existing smart meter (AMI) endpoint data. This monitoring allows for full system surveillance of power usage, regardless of technical or non-technical loss and the customer endpoint. These metering units will be powered by energy harvesting technology.

The dTechs system will be fully integrated within the IT infrastructure and will provide full usage information within the grid, assisting Oakville Hydro in locating loss areas. The theft detection aspect allows for the permanent termination of high loss endpoints. Coincidental termination of these high loss endpoints increases societal/public safety and reduces fire incidence. Furthermore, by fully monitoring the medium voltage lines, loss from aging infrastructure and proactive locating of poorly performing infrastructure will improve reliability and increase efficiency.

b) Demand Response Transformers - Smart Grid Fund Round 2 Application

Current State

Oakville Hydro is supporting Qurrent Solutions on their Smart Grid Fund round 2 application for "Demand Response Transformer". This demonstration project involves the replacement of approximately 10 utility distribution transformers with the Demand Response Transformer. This demonstration is intended to validate the efficiency outcomes for the Demand Response Transformer. The data received from this demonstration will be analyzed against existing transformer technology in order to compare two components, no-load losses and load factor which are associated with the millions of kilowatt-hours of energy lost annually in the generation and delivery of electricity. A report will then be completed to illustrate the potential savings associated with reduced energy loss including the cost of producing energy and the associated savings in greenhouse gas emissions from burning coal or other fossil fuels.

c) Energy Storage - Smart Grid Fund Round 2 Application

Current State

Oakville Hydro is supporting S&C on their Smart Grid Fund round 2 application for "Community Energy Storage for Microgrid and EV Charging". A number of other LDC's are supporting this application, specifically for Oakville Hydro, this pilot project will demonstrate the value of energy storage deployed in direct support for electric vehicle chargers. This project will also demonstrate how cyber secure wireless connections can be used to conserve electricity during the day by shifting the EV loads to either distributed generation or off-peak generation.

Directional Plans

Situated at the edge of the power grid or distribution system, either at the distribution transformer or at the customer premise, Community Energy Storage (CES) and Home Energy Storage (HES) systems are much smaller than utility-scale or bulk energy storage systems. Currently there are utilities, vendors, and governments testing CES and HES systems for the purposes of smoothing peaks in electricity demand, enabling voltage support and frequency regulation. If EV adoption is high, energy storage may be an important partner technology to lessen impacts on the distribution system. Although CES and HES are still further into the future in terms of commercial deployment, Oakville Hydro plans to monitor and study the progress of this technology.

d) Electric Vehicles (EVs)

i) Member and Active Participant of "Plug'n Drive" and "Charge My Car"

Current State

Plug'n Drive Ontario is a not-for-profit coalition engaging in activities that will accelerate the adoption of electric vehicles and maximize their environmental and economic benefits for consumers and businesses in Ontario. Oakville Hydro is one of several GTA and GHA area LDC members in this coalition. The key priorities are education, awareness, research and infrastructure. The goal is to create a one-stop shop for information on EVs in Ontario to enable easier customer EV adoption. Road shows will be conducted to educate and excite consumers on the benefits of EVs. The group will engage in research that will help fill the gaps needed to advance EV deployment and influence consumer behaviour, as well as promote the development of EV infrastructure. Web development is currently underway to standardize approach and provide assistance to consumers in such areas as power assessments and residential EV charger installations.

ii) Strategic Partnerships

Directional Plans

Oakville Hydro plans to coordinate and align with the Town of Oakville's Environmental Strategic Plan. The current Town Plan focuses primarily on fleet opportunities but is intended to expand to community charging facilities. Being an active partner, will further promote EVs in the community, and contribute to the success of this Environmental Strategic Plan.

In addition, Oakville Hydro is an active player in the GridSmartCity consortium that is currently exploring collaborative opportunities in smart grid technologies and operational efficiency ventures.

It will also be worthwhile to partner with other EV interested parties. Partnering with Metrolinx, and exploring opportunities at GO stations in Oakville, could provide EV solutions to commuters – this promotes Oakville Hydro in the community and could add load to the distribution system.

Developing relationships with dealerships and installers will be helpful in assisting customers, and promoting EVs in the community.

iii) Staff Training

Directional Plans

In order for Oakville Hydro to be successful and ready for the EV evolution, training in various areas will be important. Customer-facing staff will require training about EVs and how to handle customer requests. Distribution planners and engineers will need to know about the possible impacts on the distribution system, and how to plan for deployment. Line & Control staff will require training on field operations, monitoring and control.

iv) Promotion of EVs in the Community

Current State

In 2013, Oakville Hydro partnered with Tim Horton's to install vehicle charging stations at one of its locations in the Town of Oakville. Oakville Hydro will continue to monitor the situation and work towards enabling their roll out through collaborative ventures. In the 2013 customer satisfaction survey, the number of customers that were "very interested" in purchasing an electric vehicle declined to 7% from 10% in 2011.

Directional Plans

Promotion of EVs can be carried out in several ways including advertising with community partners, active participation in Plug'n Drive and Charge My Car, aligning with the Town of Oakville and EV promotion on the website. For EVs to be successful in Oakville, Oakville Hydro should play an active role in the community and with customers.

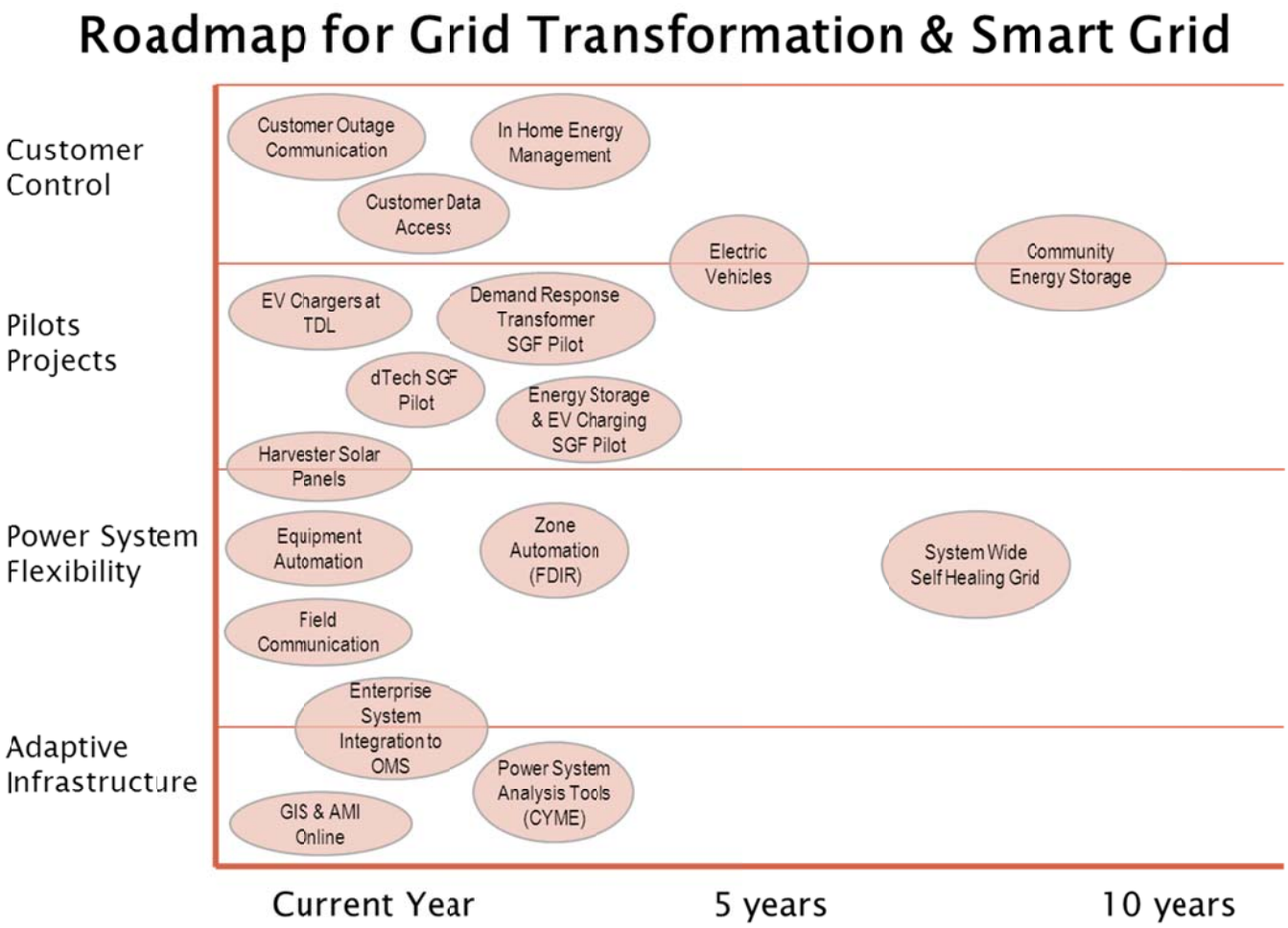
Knowing when and where EV chargers are active is important in understanding their impact on the distribution system. Through participation with Plug'n Drive and Charge My Car, and our own standards and promotions, smart chargers should be recommended that can send an alert when an EV is plugged in. This will enable Oakville Hydro to monitor and possibly control chargers, to the benefit of the distribution system.

v) Integration to Existing Systems

Directional Plans

For network planning purposes it is important to know where EV chargers are installed. Oakville Hydro will utilize the existing GIS system to track the location of customer- owned EVs and established community charging stations. This will be necessary to monitor the locations and study the impact of EVs on the distribution system.
Oakville Hydro's CIS (Customer Information System) should be enabled to track customers that have EVs and charging stations. With smart meter data already available, this would provide not only day-to-day customer information, but excellent planning data and tools – which will be essential if EV adoption is high.

It will also be important to conduct system studies in different areas of the distribution system to evaluate the impact of EVs. For example, in certain areas of the underground system, EVs will likely have little impact on the system, whereas in older overhead areas, the system could be constrained. It will be important to know which areas will have capacity issues, in order to properly plan for capital upgrades, should EVs materialize.


Roadmap for Grid Transformation & Smart Grid
Customer Control
Pilots Projects
Power System Flexibility
Adaptive Infrastructure
Customer Outage Communication
In Home Energy Management
Customer Data Access
Electric Vehicles
Community Energy Storage
EV Chargers at TDL
Demand Response Transformer SGF Pilot
dTech SGF Pilot
Energy Storage & EV Charging SGF Pilot
Harvester Solar Panels
Equipment Automation
Zone Automation (FDIR)
System Wide Self Healing Grid
Field Communication
Enterprise System Integration to OMS
Power System Analysis Tools (CYME)
GIS & AMI Online
Current Year
5 years
10 years

Appendix 6

Information Technology Strategy

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

Information Technology Strategic Plan
2013

Introduction

Information Technology plays an important role in enabling the entire business to operate. The Information Technology (IT) department is responsible for the technology services that facilitate the business to seamlessly organize, analyze and improve the flow of information necessary for the offering of services to its customers. Telecommunications, automated data processing, databases, the Internet, management information systems, and related information, equipment, goods, and services all encompass IT areas of service.

Information Technology will be a key enabler for Oakville Hydro Electricity Distribution Inc. (Oakville Hydro) in meeting its goal of value for ratepayers. In support of effective planning of our future technology investments, Oakville Hydro's Information Technology department uses the overall Oakville Hydro Strategic imperatives as a guide in making operational decisions:

- profit - by reducing costs through productivity improvement and improved business process
- service - by enabling customer self-service and web-based and lower cost interactions, and providing internal customer service to other operational areas of the business
- people - by enhancing collaboration and increasing productivity and to use technology to assist in delivering a safe work environment
- community - by proving a key communications vehicle, the public web site and customer access to important information in the community and facilitating the transfer of information in order to service the community and customers

Over the last 4 years, the demand for more IT services has increased –new projects, applications, system maintenance and rethinking/replacing technologies, placing a heavier reliance on systems as more and more services become driven and dependent on technology. A good example of this change is the significant information technology component associated with Smart Meters. The IT department understands those requirements and is willing and motivated to meet current and future projects along with the everyday running of "normal" business needs.

Without clear direction the network infrastructure can become a conglomerate of pieces added to the systems as the needs arise, adding cost and inefficiencies to the IT systems. This method decreases the level of service to the business. With focus on four main areas of technology shown in figure 1, the infrastructure and consequently the health of the foundation systems can support the demands of the industry and provide the level of service that Oakville Hydro needs to move ahead with the strategies of the organization's overall business plan.

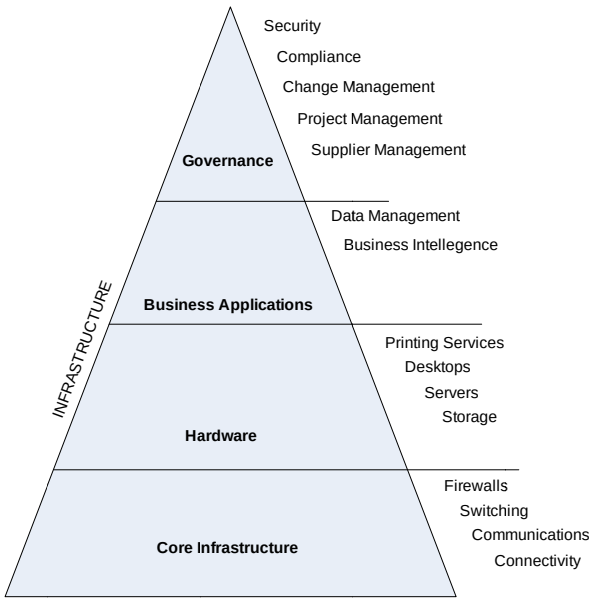


Figure 1

A solid core infrastructure is the key to successful implementation of new technologies, and is included in our asset management plan. Standards in equipment and strong change management procedures support the ongoing maintenance of the systems. Up to date hardware and software provide a strong and secure environment to new and existing projects and programs. Hardware needs to be maintained and configured properly and applications need to be upgraded annually to take advantage of new features and security offered by vendors. A three to five year asset management plan ensures the desktops, servers and security infrastructure is maintained up to date without excessive maintenance costs and with the necessary processing capability to meet the increasing demand by users in order to service the customers, all at a reasonable cost.

Governance is the protection afforded to IT systems and data in order to preserve their availability, integrity, and confidentiality.

Resources in the IT team are fully engaged in the planning process and every member will contribute to the overall success of the organization. External supplier management is in place to review all current and future contracts to ensure the full value of acquired systems and services is available for the Company and will be a template when requesting new services.

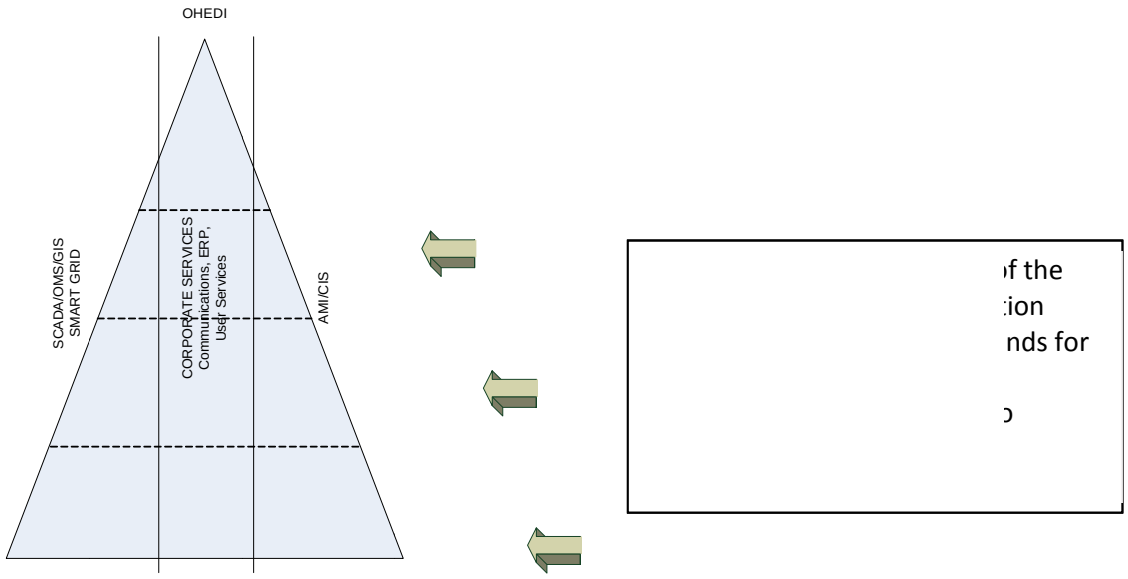


Figure 2

IT Business Objectives

Infrastructure Stabilization

The network, data center and applications are becoming increasingly complex and business-critical. The health of these systems relies on effective monitoring and constant measurement of capacity and performance of the infrastructure within which the hardware operate.

Over the past few years there have been dramatic changes in the electrical industry operation, such as Smart Meters, that necessitate a review of the overall consolidated infrastructure plan. With a focus to stabilize the infrastructure we can deliver high-quality, reliable, information technology and communication services to keep up to date with the changing landscape in the industry.

Performance and system reliability will improve with a stable, adaptive infrastructure that is a high-performance, low-latency, segmented networking environment to address rapidly growing demands of data and analytics. This stabilization is underway in 2013 and will be a foundation of the entire infrastructure going forward.

Mobility and Mobile Device

In a news release on Oct 23, 2012, Gartner Inc. predicted that by 2013 mobile phones will overtake PC's as the most common Web access device and by 2015 over 80% will be smartphones; with only 20% of those in the windows market.

The customer demands for more mobile device applications will drive Oakville Hydro to provide its data to the smartphone clients. This trend will have its own challenges in the secure provisions of data and complex application development for the devices. As customers begin making these demands, application providers will start to move in this market there will need to be adaptability until a customer limit to the design of applications for specific devices comes forth. IT will need to have the capability to adapt to the changes in demands for information in order to deliver it to customers.

Internally we will continue the expansion, upgrade and integration of Wi-Fi, cellular and radio technologies to improve mobile device access and security across the organization. This impacts the infrastructure of the organization in areas of connectivity, hardware, security procedures and practices and their impact on specific business applications. As with all mobile access, privacy is a significant concern and is addressed in our company's privacy policies.

Data Management and Analytics

Our current data management is a "physical" linear approach that demands high server hardware implementation. Increases in data volume with different variety, velocity and complexity will force us to change traditional approaches of server based services to more of a data warehouse of multiple systems with data services and metadata providing a "logical" enterprise data warehouse.

Analytics delivered to the end user will enable more decision flexibility. Business Intelligence will include, at the desk dynamic analytics to better respond to the changing landscape of data.

Integration services are provided with the current set of applications which helps with the integrity of data and improved efficiency. As data integrity expands, we will increase the integration activities between systems to improve the efficiency of analytics. Data warehousing requires a robust infrastructure and specialized hardware for the efficient storage of the data.

Systems Security Goals

Cyber Security demands will increase as more data is made available to the public and there is the growth in the mobility of devices. Controls are in place for escalating threats and new vulnerabilities; however, as technology constantly changes we continue to redefine the framework for achieving our delivery systems Cyber Security. This again highlights the need for adaptability and flexibility as technology changes.

Governance is a critical component overseeing infrastructure, hardware and business applications. Control of access at the desktop, laptop and mobile device level ensures data is stored ensuring data integrity, maintenance of privacy. Change management maintains the systems at its highest level of security and best functionality. Security audits are conducted to provide regular health checks and ensure security procedures as defined are put into practice.

We will expand the current process to include incident and event management. Effective response to security breaches, once identified, will ensure a maturing program of access control. Expanded training and education will increase the network and data protection. IT will work closely with the Regulatory group, specifically with regards to privacy of information.

Collaboration Services

Oakville Hydro has deployed a standards-based enterprise collaboration service, integrating e-mail, calendars, phones and document sharing. Expansion of these services will include instant messaging, archives, mobile access and records management. These new solutions will provide a foundation for new collaboration practices, regulatory compliance and enhanced productivity.

Oakville Hydro has a web site that provides information to the community and our customers. We will continue to expand and provide more visibility and interaction with our community by increasing our services provided on the internet. Incorporating social media collaboration like Twitter, Facebook,

LinkedIn and others, will help meet the demands of our stakeholders to provide information on outage management, account information and service offerings. The integration of systems will be critical in efficiently and effectively communicating outages and system reliability with our customers, while maintaining overall cyber security and privacy.

Oakville Hydro will work with other LDCs and the Town of Oakville to support some of the corporate services that are common to all affiliates. This collaboration of efforts will help to reduce the overall operating costs while providing a strong secure environment for our services.

Learning Services

Our goal is to improve the experience of employee learning. Employee involvement in the IT process involves understanding the technology and how it can help the daily work load. Expanded training will provide a bridge to the opportunities that exist in the area of technology and how we can use this to make more informed business decisions. E-Learning applications will provide ongoing access to learning material after the classroom also giving employees the option of how they want to learn.

Information technology staff must maintain expertise in industry solutions as it is critical to providing reliable services to the community at Oakville Hydro and the Town of Oakville.

Disaster Recovery Planning

Oakville Hydro has a functional Disaster Recovery Plan that outlines the critical services provided by Oakville Hydro to its customers and employees. IT will support and maintain all aspects of the disaster recovery and continue to build the Business Continuity Plan which will be tested and integrated into the OHEDI Emergency Operations Plan. This Business Continuity Plan will integrate with the Town of Oakville's infrastructure and network.

Oakville Hydro has hosted the Disaster Recovery Server for Milton Hydro for a number of years and will explore a reciprocal arrangement. The IT department will look at this and other arrangements to ensure cost efficient delivery of IT services for the business and, if possible, mitigation of costs through cost sharing service agreements.

Risk Management

- Active management of the system
    - Changes in IT management have provided the proper guidance in maintaining the IT strategy

- Contract and supplier management
    - Maintain contracts supplier agreements
    - Agreements with clearly define responsibilities

- Asset management to maintain aging equipment with standard system images.
    - Manage the stability with careful evolutionary improvements rather than revolutionary change with full consideration of the need for adaptability for future unknown changes to systems and system requirements

- Security of the IT infrastructure through governance programs that takes into account SOX and NERC compliance principles

- Data management has multiple application impacts to critical areas such as Asset Management, Smart metering, Outage management, financial planning and regulatory compliance.

- Development and project implementation processes, including developing templates and procedures
    - Project support to help reduce the risk of scope, time, and cost management in projects

At a corporate level there continues to be a strong focus on Cyber Security and Privacy which are being addressed through the use of internal audits of firewall security, change management and ultimately with an external audit performed. Changes in governance of user access, system changes and application access is increasing, thereby reducing the risk. Firewall systems are continuously updated and re-configured to improve protection and privacy remains a priority with considerable effort to liaise with the Regulatory while still moving projects forward.

Information Technology goals are to establish a "continuous improvement" culture to incrementally build on a stable network infrastructure to meet the changing needs of the industry.

Appendix 7

Material Capital Project Templates

Summary 2014 Capital Projects over Materiality Threshold

Project #	Description	System Type
14-64A1	SCADA Enhancements in Loadflow, Contingency Analysis, FDIR	System Service
16-G2	27.6kV Air insulated switchgear upgrades to G&W	System Renewal
16-U1	Gang-Op Switch Replacement Program	System Renewal
05-P2	Power Transformer Replacement Program	System Renewal
05-Q2	Victoria MS Low Voltage Breaker Replacement Program	System Renewal
46-A	Replace Overhead Assets on John Street	System Renewal
46-B	Replace Overhead Assets on Queen Mary, Bond and Chisholm	System Renewal
46-C	Replace Overhead Assets on Robinson St.	System Renewal
45-A	Vault Transformer Replacements	System Renewal
45-D	Poletran Removals and Replace U/G Assets Various Locations	System Renewal
45-Q	Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion	System Renewal
45-X	Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln	System Renewal
42-B	Live front Padmount Transformer Replacements	System Renewal
44-H	27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403	System Access
14-50C	New Development Investment	System Access
14-54	New General Services	System Access
14-61	Distribution Meters	System Access
15-E	North Service Rd Widening, 8th Line to Iroquois Shore Rd	System Access
15-I	Road Widening TBD	System Access
14-62	2014 Fleet	General Plant
14-64D	ERP - GP & Business Intelligence	General Plant
14-64F	IT Infrastructure	General Plant
LSHOLD	HVAC upgrade - 5 year replacement program	General Plant

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	14-64A1
Project Name:	SCADA Enhancements in Loadflow, Contingency Analysis, FDIR
Project Category:	Administration - IT
System Type	System Service
Customer Attachments/Load:	
Project Manager:	Jeff Mocha
Start Date:	January 1, 2014
In Service Date:	October 1, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$300,000	$300,000
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$300,000	$300,000
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$300,000	$0	$0	$0

Risks to Completion and Risk Mitigation:

The current SCADA system has been in service for several years, the proposed enhancements are a functional upgrade to this system. The proposed software enhancements are in service at other utility companies, and are mature products. A detailed project plan will be developed with a defined scope of work. We plan to work closely with the system provider to integrate into our existing SCADA system on time and on budget.

Comparative Information on Equivalent Historical Projects (if any):

Successfully managed development and implementation of Outage Management System functional upgrade with same vendor in 2013

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

The following functional upgrades will be added to the existing SCADA system:
Loadflow will provide the Control Room Operators with an analysis tool to simulate the impact of system loading levels to drive the right solutions.
Contingency Analysis is complimentary to Loadflow, and will provide the Control Room Operators with a report that highlights critical components in the distribution system, allowing the Operator to reconfigure the system as necessary.
Fault Detection Isolation Restoration (FDIR) is also complimentary to Loadflow, and is an element of grid transformation that builds a level of automation into the SCADA system. Existing field sensors and controllable switches are leveraged, and the SCADA system is able to take action without Operator intervention to begin system restoral following an outage.

Project #: 14-64A1

Project Name: SCADA Enhancements in Loadflow, Contingency Analysis, FDIR

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

Process improvements in the Control Room that drive optimized system configuration and improved outage restoral.

Priority and Reasons for Priority:

This project is ranked as a high priority because it will mitigate existing operational risks associated with feeder loading and equipment operation.

Qualitative and Quantitative Analysis of Project and Project Alternatives:

Oakville Hydro's SCADA system is wholly dedicated to the Oakville Hydro distribution system. These enhancements provide system tools that are not available in any other format without removing the entire SCADA system and investing in a full system change out. This alternative would be very costly and disruptive to Control Room Operations.

The addition of these functions would shorten the restoration time following unplanned outages. Also, optimized load flow would provide the Control Room Operators with the information needed to prevent stressing system equipment when the system is operated out of normal configuration.

2. Safety

The Loadflow information provided to Operators will be communicated to field staff to drive proper selection of switching equipment, driving a safety improvement for field staff.

3. Cyber-Security, Privacy

All SCADA traffic is transmitted from our SCADA Masters of which 2 machines are at our head office and the 3rd is offsite. A secure 400MHz radio network is used for remote motorized switches and fault indicators. There is a 1 Gbps dark fiber network interconnecting all our substations.

4. Co-ordination, Interoperability

n/a

5. Economic Development

The SCADA vendor is based out of Mississauga, this investment will support local economic development

6. Environmental Benefits

n/a

Project #: 14-64A1
Project Name: SCADA Enhancements in Loadflow, Contingency Analysis, FDIR
System Type: *System Service*

CATEGORY SPECIFIC REQUIREMENTS

Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable:

The Loadflow and Contingency Analysis functional improvements will prevent equipment stress, maintaining asset health and avoiding premature equipment failure & replacement.

Regional Electricity Infrastructure Requirements which Affected Project , if applicable:

n/a

Description of Incorporation of Advanced Technology, if applicable:

The proposed enhancements will provide additional tools to the Control Room Operators including detailed system load levels, critical equipment impacting system operations, and automatic restoration following an unplanned outage.

Identify any reliability, efficiency, safety or coordination benefits:

Reliability is improved with automated restoration capabilities built into the SCADA system. The Loadflow information provided to Operators will be communicated to field staff to drive proper selection of switching equipment, driving a safety improvement for field staff.

Factors Affecting Timing/Priority:

The proposed enhancements were originally planned for 2013, but development and implementation of the Outage Management System (OMS) lasted into 2014. The first stage of the OMS project required export of GIS network into SCADA, and there were a number of technical challenges that were unforeseen and required resolution. The proposed enhancements require this same network before they can be implemented.

Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (include qualitative factors if applicable):

Without FDIR, remote restoration would continue to be done manually by Control Room Operators. Without Contingency Analysis, the distribution system will continue to be at risk when switched out of normal configuration.

Project #: 14-64A1
Project Name: SCADA Enhancements in Loadflow, Contingency Analysis, FDIR

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	16-G2
Project Name:	27.6kV Air insulated switchgear upgrades to G&W
Project Category:	Alterations and Improvements for Load Transfer and System Security
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	October 1, 2013
In Service Date:	May 15, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$465,000	$379,340
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$465,000	$379,340
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$379,340	$0	$0

Risks to Completion and Risk Mitigation:

This equipment has a very long leadtime, but this will be mitigated by developing the project plan and placing the equipment order in 2013. At the time of installation, there can be unforeseen conditions such as cable length, cable condition, etc.

Comparative Information on Equivalent Historical Projects (if any):

Replacements similar to this proposed replacement have been executed a number of times over the last few years. The proposed replacements use standard materials and field crews have the necessary experience.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

This budget represents the risk, value and cost for the program to complete replacement of 27.6kV air insulated switchgear with new gas insulated switchgear with remote control back to the control room. The existing air insulated switchgear is subject to accelerated aging due to adverse weather conditions, road salt, etc. The gas insulated switchgear have a sealed tank compartment preventing the accelerated aging. This budget represents year two of the program. This project will cover all costs to convert the switchgears and supply new AC service to the locations if required. Proposed for conversion are SC208 on Voyager Dr, south of Dundas St, SC132 on River Glen Blvd at Harman Gate, and SC100 on Heritage Way, west of Goldsmith.

Project #: 16-G2

Project Name: 27.6kV Air insulated switchgear upgrades to G&W

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

The existing assets that are proposed for replacement are reaching end of life and represent a reliability risk to our system.

Priority and Reasons for Priority:

The proposed locations represent a high risk to the distribution system due to the potential to affect large customer groups in the event of failure. Each of these switchgear locations have local circuits directly connected to radially supply customers.

Qualitative and Quantitative Analysis of Project and Project Alternatives: Realize savings of switchgear dry ice cleaning. Air insulated equipment is prone to premature failure and would warrant emergency replacements causing the requirement of additional, non budgeted funds. Crews are needed to be dispatched to mitigate this emergency causing delays in other work. Failed air insulated equipment causes feeder lockout. Crews would have to identify the issue of the failed equipment, and perform switching. Depending on location of failed equipment, some customers could be off up to four hours until the fix was performed.

2. Safety

Switchgear in a degraded, reaching end of life condition can be hazards for electrical flashover due to a build up of contamination on the insulators within the switchgear cubical. New switchgear would contain no contamination, and would make use of Cycloaliphatic Epoxy Resin system which provide maximum resistance to power arcs.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

The control system supplied with the new equipment uses industry standard, substation style, controller products that use communication protocols that are standard in the utility industry. At a later date these can be integrated into an automated restoration scheme.

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 16-G2
Project Name: 27.6kV Air insulated switchgear upgrades to G&W
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

Asset conditions are listed as "Fair" with equipment at end of life. These assets have a poor performance record past their typical useful lives.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

Number of customers affected range between 5,000 to 9,000 customers. Primarily residential customers.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the assets fails. We could expect to see auto-recloses due to flashovers without the entire asset failing. Once the failure curve reaches the breaking point we could expect an approximate 90-240 minute outage to allow for sectionalizing, approximately 450,000-2,160,000 customer minutes. High risk.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention. Medium Risk.

5. Value of Customer Impact (high, medium, low)

Medium to High with the length of outage and number of customers

Factors Affecting Project Timing, if any:

Substantial amount of equipment lead-time.

Consequences for O&M System Costs Including Implications of Not Implementing:

Increase maintenance costs involved due to cleaning required for the existing switchgears, new style switchgear proposed for installation is hermetically sealed and gas filled, so it does not require cleaning.

Reliability and Safety Factors:

Newer switchgear is more reliable due to construction materials, hermetically sealed, and gas filled. Deadfront construction switchgear reduces the potential for injury due to flashovers.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

From a system configuration perspective, this is a like for like replacement, but the proposed equipment is technologically enhanced compared to the existing equipment. The new equipment is hermetically sealed and gas filled to reduce the required maintenance. The new equipment also has two remotely controllable ways compared to the existing equipment which may not even have remote control option.

Project #: 16-G2
Project Name: 27.6kV Air insulated switchgear upgrades to G&W

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	16-U1
Project Name:	Gang-Op Switch Replacement Program
Project Category:	Alterations and Improvements for Load Transfer and System Security
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	March 1, 2013
In Service Date:	May 21, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$361,000	$267,139
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$361,000	$267,139
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$267,139	$0	$0

Risks to Completion and Risk Mitigation:

This equipment has a very long leadtime, but this will be mitigated by developing the project plan and placing the equipment order in 2013. At the time of installation, there can be unforeseen conditions such as pole height.

Comparative Information on Equivalent Historical Projects (if any):

Similar projects since 2006 providing approximate costs for this work.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost for completion of the program to replace 27.6kV Vacuum gang operated switches in the distribution system. This is year one of the program, and will cover the cost to replace five switch locations with new SCADAMate loadbreak switches. The proposed locations are S3111-V at 1400 North Service Road West between Third and Fourth Line; S1015-V on Burloak Rd, two poles south of Rebecca Street; S3074-V on Third Line at the North Service Road (North East corner); S2049-V on Speers Rd, West of Speers MS; S2063-V on Bronte Rd, 3 poles south of South Service Rd; These switches tend to fail without warning, and there is no maintenance that can be performed in order to keep them in working order. In the case they fail, we do not have any spare parts to have them fixed, and they must be replaced with newer style remote operated switches.

Project #: 16-U1

Project Name: Gang-Op Switch Replacement Program

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

Support of Organizational Strategy - Service, by balancing asset management in conjunction with safety, reliability and cost. Reducing the risk to service quality, company image due to degrading service quality, public and employee safety.

Priority and Reasons for Priority:

High Risk, High Probability of failure. Failures can affect multiple TS feeders. In the case these assets fail prematurely, in order to ensure the system is reliable, funds need to be made available to replace the assets regardless of set budgets.

Qualitative and Quantitative Analysis of Project and Project Alternatives:

Vacuum switches are prone to premature failure and would warrant emergency replacements causing the requirement of additional, non budgeted funds. Crews are needed to be dispatched to mitigate this emergency causing delays in other work. Failed vacuum switches can cause multiple feeder lockouts. Crews would have to identify the issue of the failed equipment, and perform switching. Depending on location of failed equipment, some customers could be off up to four hours until the fix was performed.

2. Safety

Vacuum switches in a degraded, near end of life condition can be hazards for electrical flashovers or explosions. There has been recorded history of these switches exploding, and in one case causing a fire.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

N/A

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 16-U1
Project Name: Gang-Op Switch Replacement Program
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

Conditions range from Poor to Very Poor per Health Index. Typical life cycle is 25 years. Assets currently over that life.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

7243 to 13000 customers affected by these assets. Mostly residential customers with some commercial/industrial.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the asset fails. We could expect to see auto-recloses due to flashove

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention. Medium Risk.

5. Value of Customer Impact (high, medium, low)

High

Factors Affecting Project Timing, if any:

Five gang operated switches are proposed to be replaced each year over the forecast period. The vacuum switches are the oldest and most risky gang operated switch in Oakville Hydro's distribution system and will be replaced first, followed by the motor operated load break switches, then load break switches.

Consequences for O&M System Costs Including Implications of Not Implementing:

Expected increase of patrols due to auto-recloses caused by flashovers in these assets causing an increase in O&M system cost. Remote operation failure can cause additional switching times as crews would have to manually access the switching point.

Reliability and Safety Factors:

Newer gang operated switches are more reliable due to construction materials and methods. The switches shall utilize an integrated switch operator having no exposed moving parts between the switch and any other device. The interrupters and the stored-energy operating mechanism shall be maintenance-free. The switch shall have an integral visible-break disconnect device operable by means of a hookstick. Maintenance-free wiping contacts to prevent operational difficulties arising from corrosion or frost. Self-lubricating, maintenance-free bearings.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 16-U1
Project Name: Gang-Op Switch Replacement Program

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	05-P2
Project Name:	Power Transformer Replacement Program
Project Category:	Substations
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Scott Carpenter
Start Date:	
In Service Date:	October 22, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$300,150	$268,190
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$300,150	$268,190
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$118,190	$150,000	$0	$0

Risks to Completion and Risk Mitigation:

This equipment has a very long leadtime, but this will be mitigated by developing the project plan and placing the equipment order in Q4 2013. At the time of installation, there can be site specific restrictions such as existing transformer foundations that need to be accommodated.

Comparative Information on Equivalent Historical Projects (if any):

In the last 5 years we have replaced 3 Municipal Substation power transformers of similar size on schedule and on budget.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost for completion of the yearly program to replace power transformers in the distribution system. It is proposed to replace one power transformer per year in order to manage capital spending levels in the future. If Oakville Hydro does not start replacing these transformers pro-actively, they encounter situations where more than one of these expensive long lead transformers will be required to be replaced within the same year, putting the system at risk and driving capital costs higher than expected. It is proposed to replace the power transformer at Woodhaven Municipal Substation which is the oldest power transformer in our distribution system and has been in service since 1957.

Project #: 05-P2

Project Name: Power Transformer Replacement Program

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

The main driver for this project is to avoid the risks associated with the failure of Municipal Substation power transformers. Our Municipal Substations supply anywhere from 500 to 2000 customers, and in the event of a transformer failure all of these customers would need to be transferred to other substations, which would be challenging to achieve during the summer peak load season and would require extensive manual field operation and coordination.

Priority and Reasons for Priority:

High Risk, High Probability. In the case one of these assets fail we could expect multiple MS feeders to be affected, and it will place our system at risk as the existing feeders will need to be fed from adjacent stations causing strain and inflexibility on the system. In the case this asset fails prematurely, in order to ensure the system is reliable, funds would need to be made available to replace the asset regardless of set budgets.

Qualitative and Quantitative Analysis of Project and Project Alternatives: Without a proactive replacement program for these transformers we could expect to spend over $300,000 to replace a failed unit after an unexpected failure. With no capital budgets set for replacements this would cause a large deferral of a set project. There is potential for large extensive outages until such time as the transformer is replaced, or the load on the feeders can be properly distributed to adjacent feeders. We could also expect longer outages during emergency situations due to the inflexibility of the system with a station out for an extended period of time.

2. Safety

N/A

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

N/A

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 05-P2
Project Name: Power Transformer Replacement Program
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

This asset is 56 years old, and has been noted to have a poor oil quality. Typical lifecycle is 45 years.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

Approximately 715 customers are serviced from this transformer, mostly residential.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the asset fails. We can expect an approximate 120 to 300 minute outage to allow for sectionalizing, approximately 85,800 to 214,500 customer minutes. Medium-High Risk.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention. Medium Risk.

5. Value of Customer Impact (high, medium, low)

High

Factors Affecting Project Timing, if any:

These assets are proposed to be replaced once per year over the forecast period. There are 36 of these assets in the system, at an investment of one per year every unit is proposed to be replaced after TUL has passed. High priority vs. other projects.

Consequences for O&M System Costs Including Implications of Not Implementing:

We would expect to require oil testing on a more frequent basis depending on how quickly the oil condition deteriorates.

Reliability and Safety Factors:

Our Municipal Substations supply anywhere from 500 to 2000 customers, and in the event of a transformer failure all of these customers would need to be transferred to other substations, which would be challenging to achieve during the summer peak load season and would require extensive manual field operation and coordination.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 05-P2
Project Name: Power Transformer Replacement Program

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	05-Q2
Project Name:	Victoria MS Low Voltage Breaker Replacement Program
Project Category:	Substations
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Scott Carpenter
Start Date:	
In Service Date:	October 22, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$635,400	$547,715
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$635,400	$547,715
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$147,715	$400,000	$0	$0

Risks to Completion and Risk Mitigation:

This equipment has a very long lead-time, but this will be mitigated by developing the project plan and placing the equipment order in Q4 2013. At the time of installation, there can be site specific restrictions such as existing footprint requirements for the breakers to accommodate cable entry.

Comparative Information on Equivalent Historical Projects (if any):

In the last 5 years we have replaced 4 sets of breaker equipment in Municipal Substations of similar size on schedule and on budget.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost for completion of the yearly program to replace a lineup of low voltage breakers in the distribution system. It is proposed to replace one breaker lineup per year in order to manage capital spending levels in the future. If Oakville Hydro does not start replacing these breakers pro-actively, they encounter situations where more than one of these expensive long lead lineups will be required to be replaced within the same year, putting the system at risk and driving capital costs higher than expected. It is proposed to replace the breaker lineup at Victoria MS, which is the oldest metal clad breaker lineup in the distribution system and has been in service since 1973.

Project #: 05-Q2
Project Name: Victoria MS Low Voltage Breaker Replacement Program

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for this project is to avoid the risks associated with the failure of Municipal Substation breaker equipment. Our Municipal Substations supply anywhere from 500 to 2000 customers, and in the event of a switchgear failure all of these customers may need to be transferred to other substations, which would be challenging to achieve during the summer peak load season, and would require extensive manual field operation and coordination.

Priority and Reasons for Priority:
High Risk, High Probability. In the case one of these assets fail we could expect multiple MS feeders to be affected, and it will place our system at risk as the existing feeders will need to be fed from adjacent stations causing strain and inflexibility on the system. In the case this asset fails prematurely, in order to ensure the system is reliable, funds would need to be made available to replace the asset regardless of set budgets.

Qualitative and Quantitative Analysis of Project and Project Alternatives: Without a proactive replacement program for these breaker lineups we could expect to spend over $400,000 to replace a failed lineup after an unexpected failure. With no capital budgets set for replacements this would cause a large deferral of a set project. In the case of failure, we could have large extensive outages until such time as the lineup is replaced, or the load on the feeders can be properly distributed to adjacent feeders. We could also expect longer outages during emergency situations due to the inflexibility of the system with a station out for an extended period of time.

2. Safety
The existing equipment is contained within a fabricated metal outdoor enclosure rather than a brick building. The metal enclosure and the switchgear equipment is all past end of life, and will be replaced as one unit. The aging enclosure presents a risk of water entry to the switchgear, which is a safety hazard associated with operation during poor weather conditions. The physical breakers have a number of critical mechanical components that are subject to wear & tear, and present a misoperation risk when they are operated past useful life.

3. Cyber-Security, Privacy
N/A

4. Co-ordination, Interoperability
N/A

5. Economic Development
N/A

6. Environmental Benefits
N/A

Project #: 05-Q2
Project Name: Victoria MS Low Voltage Breaker Replacement Program
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

This asset has exceeded its typical useful life of 25 years.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

826 Customers serviced from this breaker equipment, mostly commercial.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the asset fails. We could expect to see feeder circuit interruptions due to issues with equipment operation without the entire asset failing. Once the failure curve reaches the breaking point we could expect an approximate 120 to 300 minute outage to allow for sectionalizing, approximately 99,120 to 247,800 customer minutes. Medium-High Risk.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention. Medium Risk.

5. Value of Customer Impact (high, medium, low)

High

Factors Affecting Project Timing, if any:

These assets are proposed to be replaced once per year over the forecast period. Currently 19 of these assets in the system, at an investment of one per year every unit is proposed to be replaced after TUL has passed. High priority vs. other projects.

Consequences for O&M System Costs Including Implications of Not Implementing:

N/A

Reliability and Safety Factors:

Our Municipal Substations supply anywhere from 500 to 2000 customers, and in the event of a switchgear failure all of these customers may need to be transferred to other substations, which would be challenging to achieve during the summer peak load season, and would require extensive manual field operation and coordination.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 05-Q2
Project Name: Victoria MS Low Voltage Breaker Replacement Program

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	46-A
Project Name:	Replace Overhead Assets on John Street
Project Category:	Rebuild Overhead Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	May 1, 2013
In Service Date:	June 30, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$310,000	$207,270
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$310,000	$207,270
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$155,453	$51,818	$0	$0

Risks to Completion and Risk Mitigation:

Delays may occur due to unforeseen conditions of existing old duct infrastructure not being useable to replace the existing cable. The existing cable might be too short to be transferred to the new poles or the existing vault structure might be found in poor condition and may require replacement.

Comparative Information on Equivalent Historical Projects (if any):

Over the last five years projects to replace similar equipment have been executed with costs between $50,000 to $300,000.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

This budget represents the risk, value and cost to replace the overhead assets located on John Street between Brock St and Forsythe St. Primary and secondary distribution system assets at this location were found in poor condition during the 2010 overhead patrol reports and should be replaced in order to mitigate the risk of the assets failing along this stretch of road. Also any existing underground dip cables of insufficient length should be replaced. Due to lack of fusing some local feeders are directly connected to the express feeders in this area.

Project #: 46-A

Project Name: Replace Overhead Assets on John Street

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main driver - Balancing asset management in conjunction with safety, reliability and cost. Reducing risk due to degrading service quality by installing new, more reliable assets, as well as following current installation standards and specifications.

Priority and Reasons for Priority: High risk, high probability. Failure can affect many customers due to the existing radial feed system configuration. In case some of the assets fails prematurely, to restore power in this area funds will need to be available to replace assets regardless of set budgets.

Qualitative and Quantitative Analysis of Project and Project Alternatives: These assets are servicing mostly commercial zoned properties and some residential services. We could expect to have multiple customers off at a time. Some parts are directly connected to our express feeders, so problems would affect the whole feeder. If one of these assets fails, we would need to replace it immediately. If the aging assets are not replaced possible failures could cause faults and affect the entire feeder due to direct connections. With no existing fault indication or control to local feeders, customers would be off of power until a call came in and crews could be dispatched to identify the issue and replace. The load on the feeder could be off up to 4 hours until the issue is resolved. Due to the age of the assets we could expect a pole with a transformer to fall over which could cause the insulating oil to spill on a customers property. The top of most of these poles are rotten and if relocation of overhead conductor is required to eliminate a public safety hazard, then clearances are a significant issue. This area is located in a high vegetation level area and current overheads primary conductor insulation is in very poor condition, and there is risk of a fire hazard during periods of high winds and storm conditions. During design all pole loading, related required guying, pole framing, system protection coordination will be re-assessed to conform to current installation standards.

2. Safety

Poor pole conditions, old porcelain insulators, undersized secondary bus, old cable terminations, and aging overhead transformers are a hazard for electrical flashover.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

n/a

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 46-A
Project Name: Replace Overhead Assets on John Street
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

All overhead assets, structure, transformers, overhead wires, UG cable termination and related hardware, during patrol conducted in 2009, have been identified as in "poor" condition, and exceed their useful life.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

The supply to this area impacts 330 customers that are mostly commercial.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend of how and which assets fails. Momentary interruptions are expected due to flashovers without the entire asset to falling. Once a persistent failure reaches the breaking point, we expect approximately 90 minutes of outage time to allow for sectionalizing, approximately 29,700 customer minutes.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints, commercial businesses affected due to the outage require for power restorations

5. Value of Customer Impact (high, medium, low)

medium

Factors Affecting Project Timing, if any:

Availability of resources will impact the project timing, and this is managed as part of the ongoing construction program.

Consequences for O&M System Costs Including Implications of Not Implementing:

There will be an increase of patrols due to momentary interruptions caused by flashovers in these assets causing an increase in O&M system costs.

Reliability and Safety Factors:

New installation will be more reliable, due to new, more technological advanced equipment, due to system upgrade to current installation standard. We expect to reduce or eliminate all possible existing safety hazards due resulting from existing aging equipment.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 46-A
Project Name: Replace Overhead Assets on John Street

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	46-B
Project Name:	Replace Overhead Assets on Queen Mary, Bond and Chisholm
Project Category:	Rebuild Overhead Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	May 1, 2013
In Service Date:	September 1, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$550,000	$358,919
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$550,000	$358,919
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$269,189	$89,730	$0

Risks to Completion and Risk Mitigation:

One major risk to job completion could be unforeseen issues when trying to break into the existing concrete encased duct structure to allow re-routing / replacement or splicing of the radial feed primary cables feeding five apartment buildings; Work must be completed before summer peak time considering the current express feeder configuration at Queen Mary to avoid putting the distribution system at risk when load transfer capacity is not available between Thomas MS and Kerr MS substations.

Comparative Information on Equivalent Historical Projects (if any):

Over the last three years we have successfully completed two similar projects that can be used as comparison: Cross Ave Rebuild, Trafalgar Rd Rebuild

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost to replace the overhead assets located on Queen Mary Dr, south of Riverside Dr, Bond St, and Chisholm St north of Lakeshore Rd W. This area was noted in poor condition during the overhead patrol reports and should be replaced in order to mitigate the risk of the assets failing along these stretches of road. Also any existing underground dip cables of insufficient length will be replaced or extended to the new pole. These roads have express feeders which are directly connected to the Municipal Substations.

Project #: 46-B

Project Name: Replace Overhead Assets on Queen Mary, Bond and Chisholm

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

The main driver for this project is a reduction in risk to the distribution system due to a limited capacity to perform load transfers between major Municipal Substations during summer loading periods.

Priority and Reasons for Priority: The proposed locations represents a high risk and high probability for equipment failure based on the asset age and condition. Failure can affect multiple Municipal Substation feeders or a Transformer Station feeder.

Qualitative and Quantitative Analysis of Project and Project Alternatives: These assets are servicing some commercial, and both low and high density residential properties. We can expect to have multiple customers out of power in the event of a failure. Express feeders are installed on these roads, so an equipment failure would affect the whole feeder. If one of these assets fail, we would need to replace it immediately to new standards. If the aging assets are not replaced then the probability of failure increases, and in the event of a failure the affected customers would be out of power until crews can be dispatched to make repairs. The load on the feeder could be off up to 4 hours until the issue is resolved. Due to the age of all assets in this project we could expect failure of existing insulators, or spacer system, or switches or even pole failure with transformer on it that could cause oil spill and/or cause major safety hazards.

2. Safety

Poor pole conditions, old porcelain insulators, undersized secondary bus, old cable terminations, and aging overhead transformers are a hazard for electrical flashover.

3. Cyber-Security, Privacy

n/a

4. Co-ordination, Interoperability

Majority of the poles included in this project are owned by Bell ; multiple third party attachments are present at these locations; Planning/Design would have to be coordinated with owner of the poles and construction to be coordinated with the third party company having assets installed on these poles.

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 46-B
Project Name: Replace Overhead Assets on Queen Mary, Bond and Chisholm
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

All assets in this project have reached or exceeded their useful life; all assets during patrols have been identified in very poor condition backed up by health index of individual assets.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

1225 customers are affected, a mix of residential and commercial, some high density residential

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions will depend of how and which asset fails. Auto-recloses are expected to be seen due to flashovers whiteout entire asset to fail. Minimum 90 minutes outage is expected to allow sectionalizing; if failure of a specific assets for radial feed sections , such as cable terminations, cable failure, power restoration time will extend to min four hours ; 110,250 to 294,000 possible customer minutes

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local medium attention, due to longer outages required to restore power or "in construction site for a long period of time

5. Value of Customer Impact (high, medium, low)

medium

Factors Affecting Project Timing, if any:

Possible restraints/ delays in acceptance from Pole Owners(Bell) in regard with proposed design, pole height increase, location; this is reason why planning/design need to be completed way in advanced to avoid delays in proposed construction schedule.

Consequences for O&M System Costs Including Implications of Not Implementing:

We can expect an increase of feeder patrols due to auto-recloses due to faults

Reliability and Safety Factors:

Newer assets are more reliable and minimize the risk to failure and/or flashover; switches replacement with gang operating new style switches will improve operations when sectionalized and improve safety

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 46-B
Project Name: Replace Overhead Assets on Queen Mary, Bond and Chisholm

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN
Engineering

GENERAL

Project Number:	46-C
Project Name:	Replace Overhead Assets on Robinson St.
Project Category:	Rebuild Overhead Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	September 15, 2013
In Service Date:	June 30, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$720,000	$458,981
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$720,000	$458,981
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$0	$344,236	$114,745

Risks to Completion and Risk Mitigation:
Delays may occur due to unforeseen conditions of existing old duct infrastructure for existing underground dip primary cables to be re-routed to the new poles. The existing cable might be too short to be transferred to the new poles or the existing vault structure might be found in poor condition and may require replacement.

Comparative Information on Equivalent Historical Projects (if any):
Over the last five years projects to replace similar equipment have been executed with costs between $50,000 to $400,000.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:
This budget represents the risk, value and cost to replace the overhead assets located on Robinson Street between Navy St and Allan St. Primary and secondary distribution system assets at this location were found in poor condition during the 2010 overhead patrol reports and should be replaced in order to mitigate the risk of the assets failing along this stretch of road. Also any existing underground dip cables of insufficient length should be replaced. These roads have express feeders which are directly connected to Municipal substations.

Project #: 46-C
Project Name: Replace Overhead Assets on Robinson St.

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main driver - Balancing asset management in conjunction with safety, reliability and cost. Reducing risk due to degrading service quality by installing new, more reliable assets, as well as following current installation standards and specifications.

Priority and Reasons for Priority: High risk, high probability. Failure can affect many customers due to current looped feed configuration and multiple express feeders interconnection. In case some of the assets fails prematurely, to restore power in this area funds will need to be available to replace assets regardless of set budgets.

Qualitative and Quantitative Analysis of Project and Project Alternatives: These assets are servicing commercial zoned properties and residential services. We could expect to have multiple customers off at a time. Some parts are directly connected to our express feeders, so problems would affect the whole feeder. If one of these assets fails, we would need to replace it immediately. If the aging assets are not replaced possible failures could cause faults and affect the entire feeder due to direct connections. With no existing fault indication or control to local feeders, customers would be off of power until a call came in and crews could be dispatched to identify the issue and replace. The load on the feeder could be off up to 4 hours until the issue is resolved. Due to the age of the assets we could expect a pole with a transformer to fall over which could cause the insulating oil to spill on a customers property. The current hydro poles are concrete pole, majority in very poor condition and due for replacement; if relocation of overhead conductor is required to eliminate a public safety hazard, then clearances are a significant issue. During design all pole loading, related required guying, pole framing, system protection coordination will be re-assessed to conform to current installation standards.

2. Safety

Poor pole conditions, old porcelain insulators, undersized secondary bus, old cable terminations, and aging overhead transformers are a hazard for electrical flashover.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

n/a

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 46-C
Project Name: Replace Overhead Assets on Robinson St.
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

All overhead assets, structure, transformers, overhead wires, UG cable termination and related hardware, during patrol conducted in 2010, have been identified as in "poor" condition, and exceed their useful life.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

The supply to this area impacts approximately 149 customers which are mostly commercial.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions will depend of how and which asset fails. Auto-recloses are expected to be seen due to flashovers whiteout entire asset to fail. Minimum 90 minutes outage is expected to allow sectionalizing; if failure of a specific assets for radial feed sections , such as cable terminations, cable failure, power restoration time will extend to min four hours ; 13,410 to 35,760 possible customer minutes

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints, commercial businesses affected due to the outage require for power restorations

5. Value of Customer Impact (high, medium, low)

medium

Factors Affecting Project Timing, if any:

Availability of resources will impact the project timing, and this is managed as part of the ongoing construction program.

Consequences for O&M System Costs Including Implications of Not Implementing:

There will be an increase of patrols due to momentary interruptions caused by flashovers in these assets causing an increase in O&M system costs.

Reliability and Safety Factors:

New installation will be more reliable, due to new, more technological advanced equipment, due to system upgrade to current installation standard. We expect to reduce or eliminate all possible existing safety hazards due resulting from existing aging equipment.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 46-C
Project Name: Replace Overhead Assets on Robinson St.

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	45-A
Project Name:	Vault Transformer Replacements
Project Category:	Rebuild Underground Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	September 1, 2013
In Service Date:	November 30, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$430,000	$316,241
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$430,000	$316,241
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$0	$316,241	$0

Risks to Completion and Risk Mitigation:

One of the most significant risks to job completion involve the unknown condition of the existing infrastructure such as cables and duct systems. If addition repairs are required once the construction work starts, then the project will take much longer than planned. Alternate solutions such as cable injection will be considered to avoid project delays.

Comparative Information on Equivalent Historical Projects (if any):

This project is part of Oakville Hydro Vault Transformer Replacement Program and similar projects have been built in the last few years. However we will continue to investigate new /improved/ more reliable technologies for use in vault applications.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost of the program to replace all live front vault transformers and NX Fuses from vault rooms. This is a proposed multi-year project to eliminate this type of transformer from our system due to access and operation issues. The average age of these assets is 38 years old. The NX style fuses without tabs cannot be safely operated at this time. Where possible, it is preferable to relocate the transformers outside of the buildings for ease of access using padmount transformers. Where this is not possible, submersible style transformers should be used within the vault rooms to make the installations dead front. This budget represents year two of the program. Location 2303 @ 492 Kerr St, Location 3272 @ 134 Randall St, and 2430 @ 444 Kerr St are proposed within this budget. All locations should be reviewed to determine if conversion to 27.6kV is possible. Project involved replacement of primary cables, transformers, fused switches and grounding system

Project #: 45-A
Project Name: Vault Transformer Replacements

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for this project is a reduction in risk to the distribution system due to aging vault equipment. The vault transformers are the primary driver, but this replacement work will also include related vault switching equipment. Access restrictions to vault equipment result in repair times that are longer than similar equipment outside of a vault.

Priority and Reasons for Priority: High risk , high probability. Failure will affect many customers at the same time. The existing assets (primary cables, transformers, existing NX style fuses) that are proposed for replacement are reaching end of life and represent a reliability risk to our system. All locations in this project are radial feed supply, so failure of any of these assets will require emergency replacement.

Qualitative and Quantitative Analysis of Project and Project Alternatives: These types of assets typically supply large residential buildings or commercial units. We can expect to have multiple customers off at a time. If one of these assets fails, we would need to replace it immediately. If the aging assets are not replaced then a failures would cause the lateral fuses to open. With no existing fault indication or control to local feeders, customers would be out of power until a call came in and crews could be dispatched to identify the issue and replace the fuse(s). The customer supply from the transformers could be off over 12 hours until a replacement solution could be engineered. Due to degrading conditions of the assets in these rooms we can expect to find transformers leaking insulating oil causing a spill within the vault rooms which may leak into the vault drains requiring MOE documentation.

2. Safety

Switching in the vault rooms for existing transformers using the old style air break switches present a high concerns for safety. The new equipment would comply with current safety standards.

3. Cyber-Security, Privacy

n/a

4. Co-ordination, Interoperability

n/a

5. Economic Development

n/a

6. Environmental Benefits

n/a

Project #: 45-A
Project Name: Vault Transformer Replacements
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

Current assets (transformers, switches, connections, grounding system) are over 44 years old and noted in poor condition during patrols. Underground cables are past end of life and would be susceptible to failure if stressed.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

Considering current grid configuration and cable connection, a cable failure will affect many customers connected on the circuit until sectionalizing, where possible is completed; 484 customers, mostly high density residential

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

The assets are aging which will make them more prone to failure. If the aging assets are not replaced possible failures could cause faults causing the upstream protection to open. Without existing fault indication or control to local feeders, customers would be out of power until a call came in and crews are dispatched to identify the issue and replace the fuses(s). The customer supply from transformers could be off over 12 hours until a replacement solution can be engineered.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Frequency of interruption will depend of which and how assets fail. We could expect momentary interruptions to flashovers without the entire asset failing. Once the failure curve reaches the breaking point we could expect an approximate 90 minute to over 720 minute outage to allow for sectionalizing and/or asset replacement, 43,560 to 348,480 customer minutes. Medium risk.

5. Value of Customer Impact (high, medium, low)

medium

Factors Affecting Project Timing, if any:

Oakville Hydro has incorporated proper planning for resources and materials in order to ensure project completion on time.

Consequences for O&M System Costs Including Implications of Not Implementing:

Replacement of current NX style switches with equipment that meets current standards will result in more efficient operations.

Reliability and Safety Factors:

The project will be constructed to current standards and will use new, more reliable equipment; current transformers will be replaced to either padmounted dead front transformers of submersible style, built to current industry standards, which will allow for a system reliability increase as well as improvement for safety factors;

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

From a system configuration perspective the project is like for like, however new equipment will be used which is expected to increase reliability in this area.

Project #: 45-A
Project Name: Vault Transformer Replacements

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	45-D
Project Name:	Poletran Removals and Replace U/G Assets Various Locations
Project Category:	Rebuild Underground Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	June 3, 2013
In Service Date:	June 30, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$370,000	$292,164
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$370,000	$292,164
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$78,963	$213,200	$0	$0

Risks to Completion and Risk Mitigation:

This project involves replacement of system equipment in close proximity to customer property. The risk of public resistance to change is mitigated by communicating project plans with customers impacted to set appropriate expectations.

Comparative Information on Equivalent Historical Projects (if any):

This project is part of Oakville Hydro's asset renewal program, and similar poletran removals and underground rebuild projects have been executed consistently over many years. This is the last project in a multi-year program to remove poletran transformers.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

This budget represents the risk, value and cost for completion of the replacement of underground assets and poletran removals at 150 Water St, 3 Forsythe St, 130 Navy St, 1238 Crawford Court and 428 Donnybrook Rd The underground primary cables in this area are over 40 years old and represent some of the oldest underground cables in Oakville Hydro's distribution territory.

Project #: 45-D

Project Name: Poletran Removals and Replace U/G Assets Various Locations

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system.

Priority and Reasons for Priority:

Within these assets classes the proposed replacement area is composed of distribution assets that have been inspected and have the lowest condition rating.

Qualitative and Quantitative Analysis of Project and Project Alternatives:

The assets are significantly aged which make them prone to failure, requiring emergency replacement. If the aging assets are not replaced possible failures could cause faults causing the lateral fuses to open. With no existing fault indication or control to local feeders, customers would be out of power until a call came in and crews could be dispatched to identify the issue and replace the fuse(s). The outage resulting from equipment failure could last for up to four hours.

2. Safety

The poletrans (a combination steel pole that houses a transformer and supports a streetlight) pose safety concerns to field crews for operations and maintenance. As the existing poletrans continue to age, there is a chance of failure that represents a public safety risk.

3. Cyber-Security, Privacy

n/a

4. Co-ordination, Interoperability

n/a

5. Economic Development

n/a

6. Environmental Benefits

n/a

Project #: 45-D
Project Name: Poletran Removals and Replace U/G Assets Various Locations
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

The overhead assets were determined to be in a "poor" condition based on field inspection. The poletrans and underground cables represent some of the oldest underground assets in our system.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

The proposed projects directly affects 4-10 residential customers, and represents a potential risk to 200-500 upstream customers.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the assets fail. We could expect to see auto-recloses due to flashovers without entire assets failing. Once the failure curve reaches the breaking point for a certain asset, we could expect an approximate 240 minute outage to allow for sectionalizing, approximately 2,400 customer minutes.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention

5. Value of Customer Impact (high, medium, low)

Medium

Factors Affecting Project Timing, if any:

Oakville Hydro has incorporated proper planning for resources and materials in order to ensure project completion on time.

Consequences for O&M System Costs Including Implications of Not Implementing:

Replacement of poletrans in these areas will decrease potential maintenance and repair costs. Possible cable failures will require contractors to dig splice pits, and crew hours to repair cables.

Reliability and Safety Factors:

The area will be rebuilt to new standards, which exceeded the standards of the original construction increasing safety and reliability (I.E. type of materials, installations standards, etc.)

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

From a system configuration perspective the project is like for like, however new equipment will be used which is expected to increase reliability in this area.

Project #: 45-D
Project Name: Poletran Removals and Replace U/G Assets Various Locations

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	45-Q
Project Name:	Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion
Project Category:	Rebuild Underground Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	June 1, 2013
In Service Date:	August 1, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$496,999	$385,205
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$496,999	$385,205
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$154,082	$231,123	$0

Risks to Completion and Risk Mitigation:

This project involves replacement of system equipment in close proximity to customer property. The risk of public resistance to change is mitigated by communicating project plans with customers impacted to set appropriate expectations.

Comparative Information on Equivalent Historical Projects (if any):

This project is part of Oakville Hydro's asset renewal program, and similar overhead and underground rebuild projects have been executed consistently over many years.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

This budget represents the risk, value and cost for completion of the replacement of underground and overhead assets on Colchester, Oakhill, Dolphin and Albion. The underground primary cables in this area are approximately 38 years old and represent one of the oldest underground cables in Oakville Hydro's distribution territory. The overhead assets are of similar age, if not older. The primary cables are 38 years old in this area and are not in ducts.

Project #: 45-Q

Project Name: Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system.

Priority and Reasons for Priority:

Within these assets classes the proposed replacement area is composed of distribution assets that have been inspected and have the lowest condition rating.

Qualitative and Quantitative Analysis of Project and Project Alternatives:

The assets are significantly aged which make them prone to failure, requiring emergency replacement. If the aging assets are not replaced possible failures could cause faults causing the lateral fuses to open. With no existing fault indication or control to local feeders, customers would be out of power until a call came in and crews could be dispatched to identify the issue and replace the fuse(s). The outage resulting from equipment failure could last for up to four hours.

2. Safety

As the existing overhead equipment condition continues to degrade, there is a chance of failure that represents a public safety risk.

3. Cyber-Security, Privacy

n/a

4. Co-ordination, Interoperability

n/a

5. Economic Development

n/a

6. Environmental Benefits

n/a

Project #: 45-Q
Project Name: Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

The overhead assets were determined to be in a "poor" condition based on field inspection. The underground cables represent some of the oldest cables in our system.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

The proposed project area directly affects 43 residential customers, and represents a potential risk to 507 upstream customers.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the assets fail. We could expect to see auto-recloses due to flashovers without entire assets failing. Once the failure curve reaches the breaking point for a certain asset, we could expect an approximate 240 minute outage to allow for sectionalizing, approximately 10,320 customer minutes.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention

5. Value of Customer Impact (high, medium, low)

Medium

Factors Affecting Project Timing, if any:

Oakville Hydro has incorporated proper planning for resources and materials in order to ensure project completion on time.

Consequences for O&M System Costs Including Implications of Not Implementing:

Replacement of wood poles in this area will decrease the required testing and treatment costs for the next 15 years. Possible cable failures will require contractors to dig splice pits, and crew hours to repair cables.

Reliability and Safety Factors:

The area will be rebuilt to new standards, which exceeded the standards of the original construction increasing safety and reliability (I.E. type of materials, spacing standards, etc.)

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

From a system configuration perspective the project is like for like, however new equipment will be used which is expected to increase reliability in this area.

Project #: 45-Q
Project Name: Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	45-X
Project Name:	Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln
Project Category:	Rebuild Underground Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	June 1, 2013
In Service Date:	July 1, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$260,000	$184,665
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$260,000	$184,665
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$0	$92,332	$92,332

Risks to Completion and Risk Mitigation:

This project involves replacement of system equipment in close proximity to customer property. The risk of public resistance to change is mitigated by communicating project plans with customers impacted to set appropriate expectations.

Comparative Information on Equivalent Historical Projects (if any):

This project is part of Oakville Hydro's asset renewal program, and similar overhead and underground rebuild projects have been executed consistently over many years.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost for completion of the replacement of underground and overhead assets on Willowbrook Dr & Wendy Ln. The underground primary cables in this area are approximately 36 years old and represent one of the oldest underground cables in Oakville Hydro's distribution territory. The overhead assets are of similar age, if not older. The cables are 36 years old in this area and not in ducts.

Project #: 45-X

Project Name: Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system.

Priority and Reasons for Priority:
Within these assets classes the proposed replacement area is composed of distribution assets that have been inspected and have the lowest condition rating.

Qualitative and Quantitative Analysis of Project and Project Alternatives: The assets are aging which would make them more prone to failure requiring emergency replacement. If the aging assets are not replaced possible failures could cause faults causing the lateral fuses to open. With no existing fault indication or control to local feeders, customers would be off of power until a call came in and crews could be dispatched to identify the issue and replace the fuse(s). The load from the transformers could be off up to four hours until a new transformer could be installed or switching to isolate cable. Aging transformers could fail and allow insulating oil to escape onto sewer connections.

2. Safety

As the existing overhead equipment condition continues to degrade, there is a chance of failure that represents a public safety risk.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

N/A

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 45-X
Project Name: Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

Overhead wires, switches, and poles noted to be in poor to very poor condition. Underground wires are not installed in ducts, and are not TR-XLPE.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

The proposed project area directly affects 35 residential customers, and represents a potential risk to 233 upstream customers.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the asset fails. We could expect to see momentary interruptions due to flashovers without the entire asset failing. Once the failure curve reaches the breaking point we could expect an approximate 90 to 240 minute outage to allow for sectionalizing, approximately 3,150 to 55,920 customer minutes. Medium Risk.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to the company. Medium-Low risk.

5. Value of Customer Impact (high, medium, low)

Medium

Factors Affecting Project Timing, if any:

Oakville Hydro has incorporated proper planning for resources and materials in order to ensure project completion on time.

Consequences for O&M System Costs Including Implications of Not Implementing:

Replacement of wood poles in this area will decrease the required testing and treatment costs for the next 15 years. Possible cable failures will require contractors to dig splice pits, and crew hours to repair cables.

Reliability and Safety Factors:

The area will be rebuilt to new standards, which exceeded the standards of the original construction increasing safety and reliability (I.E. type of materials, spacing standards, etc.)

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

From a system configuration perspective the project is like for like, however new equipment will be used which is expected to increase reliability in this area.

Project #: 45-X
Project Name: Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	42-B
Project Name:	Live front Padmount Transformer Replacements
Project Category:	Transformer Replacements and Voltage Conversion
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	June 1, 2013
In Service Date:	May 30 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$350,000	$275,730
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$350,000	$275,730
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$82,719	$193,011	$0	$0

Risks to Completion and Risk Mitigation:

This project involves replacement of system equipment in close proximity to commercial customer property. The risk of public resistance to change is mitigated by communicating project plans with customers impacted to set appropriate expectations.

Comparative Information on Equivalent Historical Projects (if any):

Similar three phase transformer installations have been completed for all industrial/commercial services which can provide comparative information regarding costs and requirements.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost for completion of the program to replace all of the remaining Live front Padmount Transformers in Oakville Hydro's distribution territory. Oakville Hydro has phased these transformers out over time and only a handful remain in the field with no straight replacement stock available. On average these units are 40 years old. This budget represents year one of the program. Location 4371 at 215 Rebecca St is proposed for replacement, and is a candidate for voltage conversion from 4kV to 27.6kV. Location 4267 and 4588 at 1005 and 1027 Speers Rd are proposed for replacement. These three transformers are candidates for voltage conversion from 4kV to 27.6kV, and should be placed on a loop feed. This budget should cover the cost of all cable replacements and pole upgrades required to perform the work.

Project #: 42-B

Project Name: Live front Padmount Transformer Replacements

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system.

Priority and Reasons for Priority:

Within these assets classes the proposed replacement area is composed of distribution assets that have been inspected and have the lowest condition rating.

Qualitative and Quantitative Analysis of Project and Project Alternatives: The assets are older which would make them more prone to failure requiring replacement without a capital budget. Typically installed to old standards and without proper transformer vaults, it would require replacement onto a new pad. If the aging assets are not replaced possible failures could cause faults causing the lateral fuses to open. With no existing fault indication or control to local feeders, customers would be off of power until a call came in and crews could be dispatched to identify the issue and replace the fuse(s). The load from the transformers could be off over 12 hours until a replacement solution could be engineered. Aging transformers could rust enough to allow insulating oil to escape onto private property.

2. Safety

Due to the transformer having live contacts it is possible for an employee to fall into the energized primary while doing inspections every three years. New transformer standards require a dead-front style to be used, which limits the danger to crews.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

N/A

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 42-B
Project Name: Live front Padmount Transformer Replacements
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

Condition listed between "Fair" and "Poor" per Health Index. Typical life cycle 35 years.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

Four to Ten commercial customers serviced from these locations

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the asset fails. We could expect to see auto-recloses due to flashovers without the entire asset failing. Once the failure curve reaches the breaking point we could expect an approximate 720 minute outage to allow for sectionalizing, approximately 2880 to 7200 customer minutes. High Risk.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to regulator, with possible regional media attention. Medium-High Risk.

5. Value of Customer Impact (high, medium, low)

High

Factors Affecting Project Timing, if any:

Three of these assets are proposed to be replaced per year over the forecast period. Currently 41 of these assets in the system, at an investment of three per year every unit is proposed to be replaced after TUL has passed. High priority vs. other projects.

Consequences for O&M System Costs Including Implications of Not Implementing:

Expected increase of patrols due to auto-recloses caused by flashovers in these assets causing an increase in O&M system costs.

Reliability and Safety Factors:

Newer padmount transformers are deadfront construction, where the primary cables are insulated from the crews working on the equipment. Newer installations have vaults underneath the transformers to allow for extra cable to be stored in the case failure occurs and extra slack is required without replacing the entire cable.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 42-B
Project Name: Live front Padmount Transformer Replacements

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	44H
Project Name:	27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403
Project Category:	27.6kV Additions
System Type	System Access
Customer Attachments/Load:	
Project Manager:	Jon Foreshew
Start Date:	
In Service Date:	June 20, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$500,000	$420,973
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$500,000	$420,973
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$420,973	$0	$0

Risks to Completion and Risk Mitigation:

There is minimal risk to completion, this project is to support load growth in the area.

Comparative Information on Equivalent Historical Projects (if any):

Oakville Hydro has completed many similar projects in the past to extend or construct new circuits for system access activities.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

This budget represents the risk, value and cost for completion of work required to add an additional 27.6kV feeder on Upper Middle Road E, from Ninth Line to Highway #403, to support load growth in the Winston Business Park. This will also support future load growth in the next phase of new development in the area (Winston Park West). This project includes one additional fully rated 27.6kV circuit to interconnect with the existing network.

Project #: 44H

Project Name: 27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver: Support load growth and increased supply reliability to Winston Business Park. Support load growth for next phase of development, Winston Park West.

Priority and Reasons for Priority: Regulatory requirement and non-discretionary project, driven by development.

Qualitative and Quantitative Analysis of Project and Project Alternatives: The addition of this circuit will support load growth in the area, improve reliability and provide supply for new developments. The design and construction will be done in accordance with the most recent design and safety standards, and in the most cost effective manner.

2. Safety

n/a

3. Cyber-Security, Privacy

n/a

4. Co-ordination, Interoperability

n/a

5. Economic Development

This project supports economic development by providing supply facilities for new development and jobs.

6. Environmental Benefits

n/a

Project #: 44H
Project Name: 27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:

Customer drives the timing of the service requirement and Oakville Hydro prioritizes projects within its project planning schedule by meeting their in-service dates.

Factors Relating to Customer Preferences or Input:

n/a - the scope of this project is within the municipal road allowance and does not have direct impact on private property.

Factors Affecting the Final Cost of the Project:

Final cost is based upon actual cost of the construction, factors that can affect actual costs include: unexpected changes to scope, number of customer requests (anticipated vs. actual), customer initiated changes, weather and/or field conditions.

How Controllable Costs have been Minimized:

Prudent cost estimates are based on standardized materials, unit rate construction contracts, and appropriate equipment sizing.

Identify if Other Planning Objectives are Met by the Project, if so which ones:

The addition of this circuit will not only supply load growth and new developments but improve the supply reliability in the area.

Options Considered and Summary of Analysis:

n/a

Results of Final Economic Valuation, if applicable:

n/a

System Impacts (Nature, Magnitude and Costs):

n/a

Project #: 44H
Project Name: 27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	14-50C
Project Name:	New Development Investment
Project Category:	New Development / Services
System Type	System Access
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	
In Service Date:	December 31, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$2,691,000	$2,280,508
Contributed Capital:	$2,191,000	$1,856,780
OHEDI Capital Cost:	$500,000	$423,729
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$105,932	$169,492	$148,305

Risks to Completion and Risk Mitigation:

n/a

Comparative Information on Equivalent Historical Projects (if any):

Oakville Hydro continues to have new customer connections on an annual basis. The value and number of connections vary year to year based on market and new construction demands. These projects are commonly included in Oakville Hydro's project plans.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

New residential subdivisions require an economic evaluation to determine Oakville Hydro's capital contribution requirements.

Project #: 14-50C
Project Name: New Development Investment

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
This is a regulatory requirement based on the prescribed economic evaluation methodology.

Priority and Reasons for Priority:
n/a

Qualitative and Quantitative Analysis of Project and Project Alternatives:
Represents capital contributed for investment in new developments.

2. Safety

n/a

3. Cyber-Security, Privacy

n/a

4. Co-ordination, Interoperability

n/a

5. Economic Development

n/a

6. Environmental Benefits

n/a

Project #: 14-50C
Project Name: New Development Investment
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:
Oakville Hydro assesses the connection of new customers on an annual basis.

Factors Relating to Customer Preferences or Input:
n/a

Factors Affecting the Final Cost of the Project:
The number of customer connections vary from year to year.

How Controllable Costs have been Minimized:
n/a

Identify if Other Planning Objectives are Met by the Project, if so which ones:
n/a

Options Considered and Summary of Analysis:
n/a

Results of Final Economic Valuation, if applicable:
Final economic evaluations are done on a site by site basis.

System Impacts (Nature, Magnitude and Costs):
n/a

Project #: 14-50C
Project Name: New Development Investment

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	14-54
Project Name:	New General Services
Project Category:	New Development / Services
System Type	System Access
Customer Attachments/Load:	
Project Manager:	Jon Foreshew
Start Date:	January 1, 2014
In Service Date:	December 31, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$787,000	$598,945
Contributed Capital:	$325,000	$247,341
OHEDI Capital Cost:	$462,000	$351,604
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$87,901	$87,901	$87,901	$87,901

Risks to Completion and Risk Mitigation:

General service and large industrial customer requirements drive project timing. Oakville Hydro maintains a close relationship with these customers to ensure that service dates are met.

Comparative Information on Equivalent Historical Projects (if any):

General service requirements are an annual requirement based on the needs and demands of our customers. Services vary depending on size and complexity.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

This budget represents the risk, value and cost for any new general services in Oakville's distribution territory. Per Oakville Hydro conditions of service, Oakville Hydro funds transformation up to 2500kVA.
The Electricity Act states:
A distributor shall connect a building to its distribution system if, a) the building lies along any of the lines of the distributor's distribution system; and b) the owner, occupant or other person in charge of the building requests the connection in writing.

Project #: 14-54
Project Name: New General Services

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
The general service customer requires service for their proposed facilities.

Priority and Reasons for Priority:
Regulatory requirement and non-discretionary project, initiated by customers.

Qualitative and Quantitative Analysis of Project and Project Alternatives:
Ensure compliance with Section 28 of the Electricity Act and customer satisfaction. The costs associated with this project are partially funded by the customer based upon calculated estimates.

2. Safety
New services are designed and constructed to ESA regulations.

3. Cyber-Security, Privacy
N/A

4. Co-ordination, Interoperability
N/A

5. Economic Development
Installation of distribution equipment allows for local economic development and jobs.

6. Environmental Benefits
N/A

Project #: 14-54
Project Name: New General Services
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:

Customer drives the timing of the service requirement and Oakville Hydro prioritizes projects within its project planning schedule by meeting their in-service dates.

Factors Relating to Customer Preferences or Input:

Oakville Hydro works with potential customers to ensure that their needs are met. Projects are designed according to their input, within the guidelines of the conditions of service.

Factors Affecting the Final Cost of the Project:

Final cost is based upon actual cost of the construction, factors that can affect actual costs include: unexpected changes to scope, number of customer requests (anticipated vs. actual), customer initiated changes, weather and/or field conditions.

How Controllable Costs have been Minimized:

Prudent cost estimates are based on standardized materials, unit rate construction contracts, and appropriate equipment sizing. For these project, the customer contributes to all costs except for the transformer.

Identify if Other Planning Objectives are Met by the Project, if so which ones:

n/a

Options Considered and Summary of Analysis:

These projects are initiated by the customer, and Oakville Hydro can provide the customer with some options to align with the needs of the customer provided that the project satisfies all technical and safety requirements.

Results of Final Economic Valuation, if applicable:

n/a

System Impacts (Nature, Magnitude and Costs):

Any new services that would impact our system from a loading perspective are captured under a specific project. The services included in this project do not generally impact the existing system.

Project #: 14-54
Project Name: New General Services

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	14-61
Project Name:	Distribution Meters
Project Category:	Distribution Meters / Wholesale Meter Upgrades
System Type	System Access
Customer Attachments/Load:	
Project Manager:	Bob Myers
Start Date:	January 1, 2014
In Service Date:	December 31, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$605,625	$481,706
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$605,625	$481,706
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$101,850	$128,700	$102,600	$272,475

Risks to Completion and Risk Mitigation:

Comparative Information on Equivalent Historical Projects (if any):

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

Project Summary:

This budget is for the required distribution meters in Oakville's distribution territory. The Distribution System Code states: 5.1.1 A distributor shall provide, install and maintain a meter installation for retail settlement and billing purposes for each customer connected to the distributor's distribution system. This project includes new residential meters equipped with zigbee to facilitate "real-time" data access and "behind the meter" services, new multi-residential meters, new commercial meters, commercial meter communication conversion from dial up to flex net, and a new Tower Gateway Base ("TGB") station to support smart meter data collection.

Project #: 14-61
Project Name: Distribution Meters

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
This project supplies metering infrastructure to measure consumption as required for new services. A new TGB is required to address new residential and small commercial growth in Oakville. Each TGB will reach its saturation point for number of meters it can read and a new TGB must be installed to communicate with new smart meters. New development currently under-way north of Hwy 5 in Oakville will result in the requirement for a 6th TGB since existing TGB's are at capacity and will not be capable of communicating with the new meters.

Priority and Reasons for Priority:
Meter replacement is a mandatory requirement as per the Distribution System Code. The TGB is required to meet requirements as a result of new growth.

Qualitative and Quantitative Analysis of Project and Project Alternatives:
Ensure compliance with Section 5 of the Distribution Code

2. Safety

n/a

3. Cyber-Security, Privacy

Oakville Hydro operates an encrypted smart meter communication network.

4. Co-ordination, Interoperability

n/a

5. Economic Development

n/a

6. Environmental Benefits

n/a

Project #: 14-61
Project Name: Distribution Meters
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:
New development activity and new customers drive the timing for this project.

Factors Relating to Customer Preferences or Input:
Zigbee meter communications facilitate future "real-time" data access and "behind the meter" services.

Factors Affecting the Final Cost of the Project:
New development activity and new customers drive the cost for this project.

How Controllable Costs have been Minimized:
Crew site visits are optimized by managing expectations and collaborating with site contractors.

Identify if Other Planning Objectives are Met by the Project, if so which ones:
Commercial meters will be upgraded from simple dial-up to smart meters connected to the existing flex net communication network.

Options Considered and Summary of Analysis:
Older meter technologies will continue to generate connectivity issues if they continue to be used.

Results of Final Economic Valuation, if applicable:

n/a

System Impacts (Nature, Magnitude and Costs):

n/a

Project #: 14-61
Project Name: Distribution Meters

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	15-E
Project Name:	North Service Rd Widening, 8th Line to Iroquois Shore Rd
Project Category:	Road Widening (Dependent on Road Work - No Hydro Control)
System Type	System Access
Customer Attachments/Load:	
Project Manager:	Jon Foreshew
Start Date:	February 1, 2014
In Service Date:	September 5, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$358,135	$244,991
Contributed Capital:	$134,000	$91,191
OHEDI Capital Cost:	$224,135	$153,800
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$76,900	$76,900	$0

Risks to Completion and Risk Mitigation:

Before design work can begin, Oakville Hydro requires final road design from the Town of Oakville. If these road design plans are delayed, then this project will be delayed. Also, upon completion of the road design, any land acquisition delays from the Town of Oakville will impact the timing for construction. Regular communication and ongoing meetings are maintained with the Town of Oakville to provide clear line of sight on project timing.

Comparative Information on Equivalent Historical Projects (if any):

Road widening projects are completed annually with the Town of Oakville, Region of Halton, and Ministry of Transportation. The value and timing of past projects have varied depending on the road authorities' construction program.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

The North Service Rd will be widened from the existing 2 lanes into 4 lanes from 8th Line to Iroquois Shore Rd. This represents 1 km of roadway and at least 20 new poles. This project will require relocation of poles and associated distribution equipment to make room for the new lanes. As this equipment is relocated there will be associated planned customer outages.

Project #: 15-E

Project Name: North Service Rd Widening, 8th Line to Iroquois Shore Rd

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

The main driver for this project is a third party road design change as a result of an infrastructural need identified by the Town of Oakville.

Priority and Reasons for Priority:

This is a regulatory requirement to comply with distribution plan relocation when requested by road authorities.

Qualitative and Quantitative Analysis of Project and Project Alternatives:

Subject to section 5 of the Government of Ontario's Public Service Works on Highway Act, R.S.O. 1990, Chapter P.49, Oakville Hydro is required to take up, remove or change the location of appliances or works, or make due compensation to the road authority for such loss or expense. Under the OEB enforcement the Board may impose an administrative penalty of $20,000 per day for each day or part day on which the contravention occurred or continues.

2. Safety

New distribution equipment will be designed and constructed according to new safety standards.

3. Cyber-Security, Privacy

n/a

4. Co-ordination, Interoperability

n/a

5. Economic Development

n/a

6. Environmental Benefits

n/a

Project #: 15-E
Project Name: North Service Rd Widening, 8th Line to Iroquois Shore Rd
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:
Before design work can begin, Oakville Hydro requires final road design from the Town of Oakville. If these road design plans are delayed, then this project will be delayed. Also, upon completion of the road design, any land acquisition delays from the Town of Oakville will impact the timing for construction.

Factors Relating to Customer Preferences or Input:
Customers that will be impacted by a scheduled outage will be contacted in advance.
The placement of new poles will be reviewed with the Town of Oakville for their approval.

Factors Affecting the Final Cost of the Project:
Design changes from the Town of Oakville, field conditions, scheduling delays, and restricted working hours will impact the final cost of the project.

How Controllable Costs have been Minimized:
Material costs will be controlled using standardized design and material selection. Crews deployment will be optimized based on allowable working hours. Typically half of the labour and vehicle costs are recovered from the Town of Oakville.

Identify if Other Planning Objectives are Met by the Project, if so which ones:
Asset replacement objectives are also being met in this project. The new distribution equipment is installed in place of the existing ageing equipment.

Options Considered and Summary of Analysis:
The designated project area is set by the Town of Oakville, however, the specific placement of Oakville Hydro's distribution equipment and system functionality is assessed and optimized.

Results of Final Economic Valuation, if applicable:
n/a

System Impacts (Nature, Magnitude and Costs):
n/a

Project #: 15-E
Project Name: North Service Rd Widening, 8th Line to Iroquois Shore Rd

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	15-I
Project Name:	Road Widening TBD
Project Category:	Road Widening (Dependent on Road Work - No Hydro Control)
System Type	System Access
Customer Attachments/Load:	
Project Manager:	Jon Foreshew
Start Date:	
In Service Date:	March 19, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$474,000	$309,752
Contributed Capital:	$163,000	$106,518
OHEDI Capital Cost:	$311,000	$203,234
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$0	$101,617	$101,617

Risks to Completion and Risk Mitigation:

Before design work can begin, Oakville Hydro requires final road design from the road authority. If these road design plans are delayed, then this project will be delayed. Also, upon completion of the road design, any land acquisition delays from the road authority will impact the timing for construction. Regular communication and ongoing meetings are maintained with the road authority to provide clear line of sight on project timing.

Comparative Information on Equivalent Historical Projects (if any):

Road widening projects are completed annually with the Town of Oakville, Region of Halton, and Ministry of Transportation. The value and timing of past projects have varied depending on the road authorities' construction program.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

Historically, Oakville Hydro has been engaged in annual road widening requirements, and this project represents road widening work that has not been specifically identified by the road authorities.

Project #: 15-I
Project Name: Road Widening TBD

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for this project is a third party road design change as a result of an infrastructural need identified by the road authority.

Priority and Reasons for Priority:
This is a regulatory requirement to comply with distribution plan relocation when requested by road authorities.

Qualitative and Quantitative Analysis of Project and Project Alternatives:
Subject to section 5 of the Government of Ontario's Public Service Works on Highway Act, R.S.O. 1990, Chapter P.49, Oakville Hydro is required to take up, remove or change the location of appliances or works, or make due compensation to the road authority for such loss or expense. Under the OEB enforcement the Board may impose an administrative penalty of $20,000 per day for each day or part day on which the contravention occurred or continues.

2. Safety
New distribution equipment will be designed and constructed according to new safety standards.

3. Cyber-Security, Privacy
n/a

4. Co-ordination, Interoperability
n/a

5. Economic Development
n/a

6. Environmental Benefits
n/a

Project #: 15-I
Project Name: Road Widening TBD
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:
Before design work can begin, Oakville Hydro requires final road design from the road authority. If these road design plans are delayed, then this project will be delayed. Also, upon completion of the road design, any land acquisition delays from the road authority will impact the timing for construction.

Factors Relating to Customer Preferences or Input:
Customers that will be impacted by a scheduled outage will be contacted in advance.
The placement of new poles will be reviewed with the road authority for their approval.

Factors Affecting the Final Cost of the Project:
Design changes from the road authority, field conditions, scheduling delays, and restricted working hours will impact the final cost of the project.

How Controllable Costs have been Minimized:
Material costs will be controlled using standardized design and material selection. Crews deployment will be optimized based on allowable working hours. Typically half of the labour and vehicle costs are recovered from the road authority.

Identify if Other Planning Objectives are Met by the Project, if so which ones:
Asset replacement objectives are also being met in this project. The new distribution equipment is installed in place of the existing ageing equipment.

Options Considered and Summary of Analysis:
The designated project area is set by the road authority, however, the specific placement of Oakville Hydro's distribution equipment and system functionality is assessed and optimized.

Results of Final Economic Valuation, if applicable:
n/a

System Impacts (Nature, Magnitude and Costs):
n/a

Project #: 15-I
Project Name: Road Widening TBD

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	14-62
Project Name:	2014 Fleet
Project Category:	Vehicles
System Type	General Plant
Customer Attachments/Load:	
Project Manager:	Chris Cudmore
Start Date:	January 1, 2014
In Service Date:	November 1, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$404,000	$384,762
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$404,000	$384,762
OM&A Costs:		

Expenditure Timing:	Q1	Q2	Q3	Q4

Risks to Completion and Risk Mitigation:

Changes to type of vehicle e.g. HYBRID vs. regular

Comparative Information on Equivalent Historical Projects (if any):

Annual projects for fleet replacement, projects vary depending on fleet age and vehicle type.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost for replacing existing fleet to be purchased in 2014. This budget represents the risk, value and cost for vehicles to be purchased in 2014. Four existing pickup trucks are proposed to be replaced with new 2014 hybrid pickup type vehicles having an active fuel management system, the following trucks are proposed for replacement #69, 75, 80, and 65 ranging between 8-11 years old. One existing car #68, which is ten years old, is proposed to be replaced with a new 2014 hybrid car type vehicle having an active fuel management system. One existing van #77, which is nine years old, is proposed to be replaced with new 2014 hybrid van type vehicles having an active fuel management system. One existing blocker truck chassis #20, which is 24 years old, is proposed to be replaced with a large used truck chassis. One existing warehouse forklift #406, which is 23 years old, is proposed for replacement.

Project #: 14-62
Project Name: 2014 Fleet

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
Replacement of aging fleet assets.

Priority and Reasons for Priority:
Fleet asset replacement program. Replacements due to age and reliability of fleet assets.

Qualitative and Quantitative Analysis of Project and Project Alternatives: Hybrid vehicles will result in reduced fuel consumption. The proposed fleet vehicles for replacement have reached the end of useful life. Reduced operating and maintenance expenses are expected.

2. Safety

The replaced vehicles will be matched to the work requirements and will reduce the risk of improper work methods. The timing for fleet replacement ensures that vehicles are replaced before they deteriorate to a degree that represents an operational safety hazard.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

N/A

5. Economic Development

Proposed fleet asset replacements will be tendered to local dealerships.

6. Environmental Benefits

New fleet vehicles have better fuel efficiency and lower emissions.

Project #: 14-62
Project Name: 2014 Fleet
System Type: *General Plant*

CATEGORY SPECIFIC REQUIREMENTS

Impact of Deferral/"Do Nothing" Option

Potential for increased maintenance and fuel costs; reduced reliability.

Net Benefits of Project in Monetary Terms (where practicable)

Reduced maintenance and fuel costs.

Project #: 14-62
Project Name: 2014 Fleet

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

IT

GENERAL

Project Number:	14-64D
Project Name:	Business Systems Applications
Project Category:	Administration - IT
System Type	General Plant
Customer Attachments/Load:	
Project Manager:	Business Systems Analyst
Start Date:	
In Service Date:	

	Old CGAAP	New CGAAP
Total Capital Cost:	$203,000	$203,000
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$203,000	$203,000
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$203,000	$0	$0

Risks to Completion and Risk Mitigation:

Microsoft Dynamics GP 2013 statement of direction is clear and was implemented Q4 - 2012. We will upgrade our system in 2014 once all investigating has been complete in 2013. There are no risks to completion.

Comparative Information on Equivalent Historical Projects (if any):

Microsoft Dynamics GP has been maintained since the initial cutover from JD Edwards in 2008. Average annual costs for new additions to the software have been necessary to increase functionality as the business requirements change. This upgrade will provide the functionality to help reduce the need for new additional software. The GP strategy is to use the current investment as much as possible and purchase new software only where necessary.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

Initiatives include:

Harris Collection Project - $25K to automate our current collection methodology and create an efficient and effective process

Northstar modifications - implementation of Automation Platform including custom Cognos and SQL rule development to enhance Oakville Hydro billing processes due to introduction of added complexities in billing.

Workforce Management (WFM) improvements - Oakville Hydro will be automating the service orders currently used with the Halton Region along with improving Oakville Hydro's existing WFM used for electric service orders. This includes implementation of electronic service orders for the Region, testing of service orders and its affect on billing processes, and introducing WFM to new Oakville Hydro business processes

GP ERP system Upgrade - This is a substantial upgrade from GP 2010 to GP 2013. Activities around the upgrade features will require a full re-implementation and integration of existing software to the new GP2013 system. This upgrade required to allow us to take advantage of new features that not only assist in daily activities but also for analysis and reconciliations. There should be no additional software required for the ERP system in 2014 while we are implementing the new version.

Business Intelligence - Good business intelligence tools will need further development to provide good analysis to the business.

Project #: 14-64D
Project Name: Business Systems Applications

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

It is important for software to be maintained at the Vendors current versions to take advantage of new features in functionality and security. Oakville Hydro does not want to leave the upgrade for too long as GP and all related software are developing at the same rate and we are not able to take advantage of any of the new features from any of the existing related software. Deferral will result in a complete re-install rather than an upgrade if the existing system becomes too dated.

Priority and Reasons for Priority:

GP - High - This is the core ERP/finance/Job related software. Support on the existing GP 2010 will end Oct 2015. To have this system completed by 2014 will ensure there is no risks of increased costs from vendors to support the system after Microsoft has completed it's support. GP2013 has features that may assist in the development of asset management strategies. GP2013 is required to be in place and operating in order to develop these strategies.

Harris Collection Project - High - automation of collection process to increase efficiency, timeliness and reduce bad debt - We are currently receiving complaints from some customers in regards to the current process. We would like to make a change to implement an enhanced version of credit scoring so that letters, notices and disconnections are not directed to customers with good payment history.

Northstar Modification - the introduction of efficiencies in the Meter to Cash process through automation of service orders and CIS processes will help reduce Oakville Hydro's dependence on manual processes. This will help reduce billing errors, delayed bills, and improve utilization of resources, which will serve to benefit Oakville customers.

Qualitative and Quantitative Analysis of Project and Project Alternatives:

Harris Collection Project - goal of project is to reduce bad debts and to minimize customer complaints.

2. Safety

N/A

3. Cyber-Security, Privacy

Microsoft Dynamics GP 2013 is an internal system that resides in the existing infrastructure

4. Co-ordination, Interoperability

The CIS based Automation Platform will enable the development of automated meter to cash business processes.

5. Economic Development

6. Environmental Benefits

N/A

Project #: 14-64D
Project Name: Business Systems Applications
System Type: *General Plant*

CATEGORY SPECIFIC REQUIREMENTS

Impact of Deferral/"Do Nothing" Option

GP - The business is requesting access to new features that are available in the GP2013 environment. If the upgrade is not completed, new software will need to be sourced to cover the deficiencies of the existing GP 2010 version.

Harris Collection Project - service would continue as status quo with the possible increase of bad debts due to the manual process. Reduction of complaints would not be minimized.

Northstar Modification and Workforce Management Improvements - without improving the automation within Oakville's CIS and WFM, the meter to cash processes will continue to be manual process where human errors are more prevalent, resulting in billing errors. Due to the requirement to operate in 'real time' since the introduction of smart meters, automation is critical in the meter to cash process.

Net Benefits of Project in Monetary Terms (where practicable)

Mandatory upgrade for applications

Project #: 14-64D
Project Name: Business Systems Applications

OTHER INFORMATION

Microsoft Dynamics GP 2013 is scheduled to be released in Calendar Q4 of 2012. The release marks another milestone for the Microsoft Dynamics GP product by:
-Delivering a Web Client option
-deployment options and capabilities
-Enhancing the core functionality
-Making Rapid Start Services for Microsoft Dynamics GP available

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

IT

GENERAL

Project Number:	14-64F
Project Name:	IT Infrastructure
Project Category:	Administration - IT
System Type	General Plant
Customer Attachments/Load:	
Project Manager:	Infrastructure Specialist
Start Date:	January 2, 2014
In Service Date:	Various dates throughout the year

	Old CGAAP	New CGAAP
Total Capital Cost:	$420,000	$420,000
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$420,000	$420,000
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$105,000	$105,000	$105,000	$105,000

Risks to Completion and Risk Mitigation:
N/A

Comparative Information on Equivalent Historical Projects (if any):
The ongoing maintenance of our infrastructure is core to maintaining the systems the business requires. Asset plans in the IT Strategy define a good basis for a plan that makes sense from a system and cost point of view. In 2011 and 2012 there was increased focus on operational IT projects rather than IT infrastructure projects. 2014 continues the 2013 infrastructure improvements with a focus on critical systems to support the distribution system (e.g. SCADA) and general operations. Key areas include security and business continuity.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:
N/A

Project Summary:
This is a combined project taking into account all infrastructure changes to support the organization in the initiatives.

Project #: 14-64F
Project Name: IT Infrastructure

1. Efficiency, Customer Value, Reliability

Main Driver:

Infrastructure Stability to support the organization

Priority and Reasons for Priority:

Medium - Regular replacement of existing system for system security and business continuity

Qualitative and Quantitative Analysis of Project and Project Alternatives:

This project is new technologies, sustaining replacements and increased capacity to keep up with the demands of the business.

2. Safety

N/A

3. Cyber-Security, Privacy

IT currently supports three infrastructures.
-Operations (SCADA, OMS, GIS)
-Corporate (ERP,
-AMI/CIS (Metering, Customer services, Billing)
All changes to the infrastructure follow change management process that takes into account the Cyber Security, Privacy

4. Co-ordination, Interoperability

This project is new technologies, sustaining replacements and increased capacity to keep up with the demands of the business.
The implementation of all IT resources follows NERC , CIP001-CIP009 compliance and ISO27000 standards

5. Economic Development

6. Environmental Benefits

Newer technologies provide a greener footprint.

Project #: 14-64F
Project Name: IT Infrastructure
System Type: *General Plant*

CATEGORY SPECIFIC REQUIREMENTS

Impact of Deferral/"Do Nothing" Option

Out of date equipment and demand for higher resources will result in deficiencies in the organization's other projects and ongoing operating activities.

Net Benefits of Project in Monetary Terms (where practicable)

Project #: 14-64F
Project Name: IT Infrastructure

OTHER INFORMATION

The 2014 Infrastructure project includes some of the following as a means to secure the right resources to support the initiatives of the organization.
-Further virtualization for the server farm, and new licenses for servers/virtualization from Microsoft as part of our ongoing project to consolidate and maintain the IT infrastructure. Licenses are purchased through the current EA agreement with Microsoft.
-Further desktop replacements for 5 year asset management plan
-Further storage needs for increase in storage from last year
-Switches, routers, network connections that were previously installed will need replacement and redundancy
-Foundry switches were installed in 2010 at all substations. These switches will require investigation and redundancy in 2014
-Increased Mobile Security for all mobile devices. -IPSec VPN Tunnel using 4G Mobile cellular VPN connectivity.
-Central administration tool to manage (diagnose, support) all mobile devices include E-Mobile devices

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Buildings

GENERAL

Project Number:
Project Name: HVAC upgrade - 5 year replacement program
Project Category: Administration - Buildings
System Type General Plant
Customer Attachments/Load:
Project Manager: Ron Vandermolen

Start Date:
In Service Date: ongoing

	Old CGAAP	New CGAAP
Total Capital Cost:	$230,000	$230,000
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$230,000	$230,000
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:		$115,000	$115,000	$0

Risks to Completion and Risk Mitigation:

Comparative Information on Equivalent Historical Projects (if any):

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

Project Summary:

Replacement of HVAC and mechanical equipment (approx. 85 units) over a five year period. Three units have been replaced since 2011, and several units have had compressor replacements and/or major repairs to date.

Project #: n/a

Project Name: HVAC upgrade - 5 year replacement program

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

Priority and Reasons for Priority:

Qualitative and Quantitative Analysis of Project and Project Alternatives: This is a proactive plan to replace units that have reached end of life cycle, as they are original equipment (1994). We are experiencing more frequent breakdowns of units requiring replacement, particularly with units that are rooftop and exposed to the elements. Lead time for replacement units on an emergency basis varies from 4-10 weeks depending on make and model type/size. Repair costs on these aging units continue to increase. Newer technology will result in more energy efficient products, improved operations, improved reliability and decreased maintenance costs - as well as ensure smooth operation of the facility.

2. Safety

3. Cyber-Security, Privacy

4. Co-ordination, Interoperability

5. Economic Development

6. Environmental Benefits

Project #: n/a
Project Name: HVAC upgrade - 5 year replacement program
System Type: *General Plant*

CATEGORY SPECIFIC REQUIREMENTS

Impact of Deferral/"Do Nothing" Option

Deferring this project, or replacing units on an as required basis only will result in increased risk of failure as the units age. Since these units are all of the same vintage, the risk is quite high that we will begin to experience multiple failures. The cost of emergency services for repairs and individual replacements will decrease reliability, and increase our maintenance costs. A replacement program will allow us to negotiate better pricing for both supply and installation, and allow us to much better analyse in advance, the best overall solution in terms of unit requirements.

Net Benefits of Project in Monetary Terms (where practicable)

Project #: n/a
Project Name: HVAC upgrade - 5 year replacement program

OTHER INFORMATION

Appendix 3

Capital Expenditure Plan

2013/14

Oakville Hydro Electricity Distribution Inc.

Capital Expenditure Plan

16/10/2013

Version 1C

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1 Capital Expenditure Plan Purpose and Objective

Noted in the "Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements" issued on March 28, 2013 by the OEB this document elicits key information about a distributor's capital expenditure plan including, by category, significant projects and activities to be undertaken and their respective key drivers; the relationship between investments in each category and a distributor's objectives and targets; and the primary factors affecting the timing of investment in each category (or of projects within each category, if significant)

2 System Access

Noted in the "Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements" issued on March 28, 2013 by the OEB these investments are modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to the electricity services via the distribution system.

Projects/Activities in this category are driven by statutory, regulatory or other obligations on the part of the distributor to provide customers with access to their distribution system. Most frequently, investments relate to request by customers for connections or connection modifications, but also include requests from municipal authorities for a distributor to relocate system assets in order to accommodate infrastructure development or modifications. Consequently, investment budgets for this category can vary from one DS Plan to the next depending on business conditions.

In the event that the project involves replacing a distributor's system assets, there may also be asset life-cycle related considerations to the extent that infrastructure is taken out of service prior to the end of its service life and new infrastructure is commissioned.

Investments in this category are considered mandatory; therefore allocation of capital budget to investments within is also mandatory.

2.1 2013 Investment Plan

Table 1

Description	Hydro Share	Contributed Capital	Total
Distribution System Inspection/Energization		500,000	500,000
New Services		400,000	400,000
New Development Investment	500,000		500,000
Residential Underground Services	100,000	250,000	350,000
New General Services	300,000	300,000	600,000
Distribution Meters	400,000		400,000
Neyagawa Rd Widening – Dundas to Burnhamthorpe Rd	793,130	456,250	1,249,380
Hospital Feeder Construction – Dundas & Neyagawa	1,250,000		1,250,000
New Feeders to Milton Hydro	551,840		551,840
Total	**3,965,470**	**1,951,850**	**5,917,320**

Only projects which meet OHEDI's materiality level are displayed. OHEDI's materiality level is $190,000 based on 0.05% of distribution revenue requirement. The total line includes projects that do not meet the materiality level.

2.1.1 Customer Enhancement

Six annual customer enhancement projects have been identified, consisting of Distribution System Inspection & Energization, New Services, New Development Investment, Residential Underground Services, New General Services, and Distribution Meters. The following values are at risk:

- Financial – Due to the requirement to spend capital for customer enhancements when none is set aside to do so.
- Image – Due to customer complaints resulting from ignorance of regulations
- Legal - Due to lawsuits resulting from ignorance of regulations
- Regulatory – Due to contravention resulting from ignorance of regulations

The estimated cost to complete this work, not including capital contribution, is $1,328,410

2.1.2 Road Widening/Intersection Improvements

2.1.2.1 Widening of Neyagawa Boulevard

The Region of Halton has identified the widening of Neyagawa Boulevard between Dundas Street and Burnhamthorpe Road. The following values are at risk:

- Financial – Due to compensation to the road authority for loss or expense
- Image – Due to Regional government complaints resulting from ignorance of regulations
- Legal - Due to lawsuits resulting from ignorance of regulations
- Regulatory – Due to contravention resulting from ignorance of regulations

The estimated cost to complete this work is $1,249,380, which includes capital contributions, within the area shown in the below figure:



Figure 1 – Neyagawa Blvd Widening

2.1.3 27.6kV Additions

2.1.3.1 Hospital Feeder Construction

Construction of a new feeder to service the new Oakville Hospital has been identified. The following values are at risk:

- Financial – Due to the requirement to spend capital for customer enhancements when none is set aside to do so.
- Image – Due to customer complaints resulting from ignorance of regulations
- Legal - Due to lawsuits resulting from ignorance of regulations
- Regulatory – Due to contravention resulting from ignorance of regulations

The estimated cost to complete this work is $1,250,000, within the area shown in the below figure:

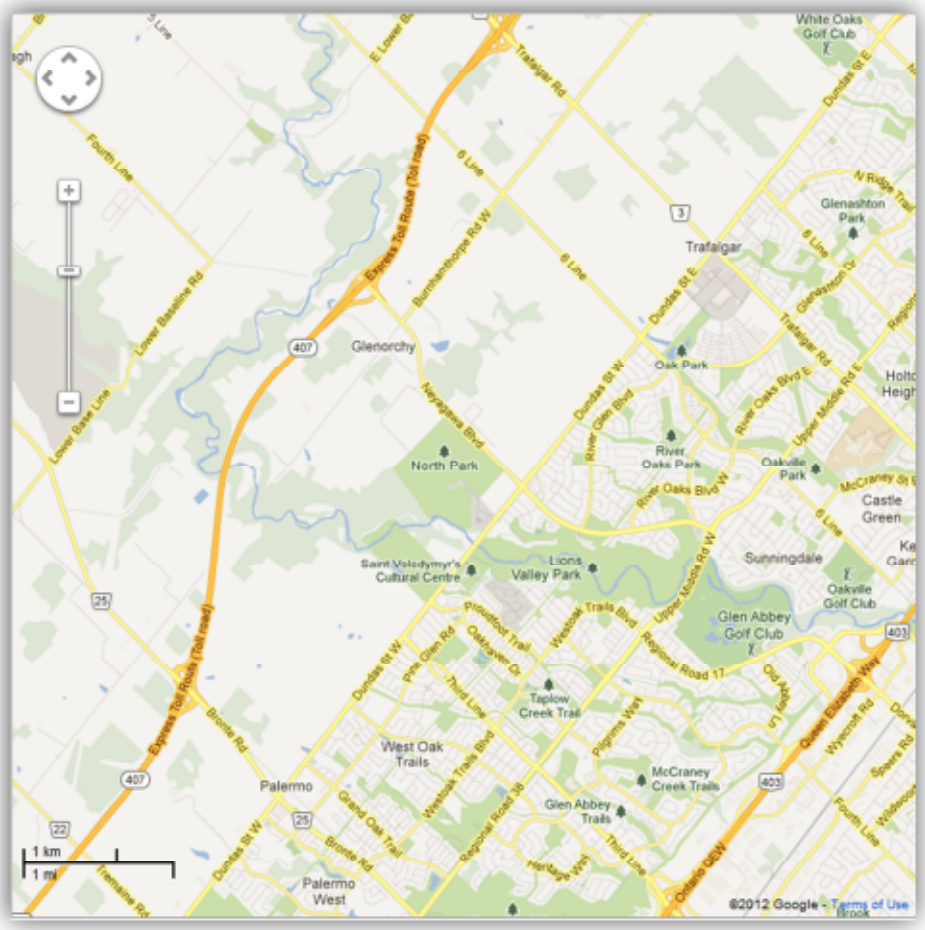


Figure 2 – Hospital Feeder Construction

2.1.3.2 Milton Feeders

Construction of new feeders to service Milton Hydro from the Glenorchy MTS has been identified. The following values are at risk:

- Financial – Due to the requirement to spend capital for customer enhancements when none is set aside to do so.
- Image – Due to customer complaints resulting from ignorance of regulations
- Legal - Due to lawsuits resulting from ignorance of regulations
- Regulatory – Due to contravention resulting from ignorance of regulations

The estimated cost to complete this work is $551,840, within the area shown in the below figure:

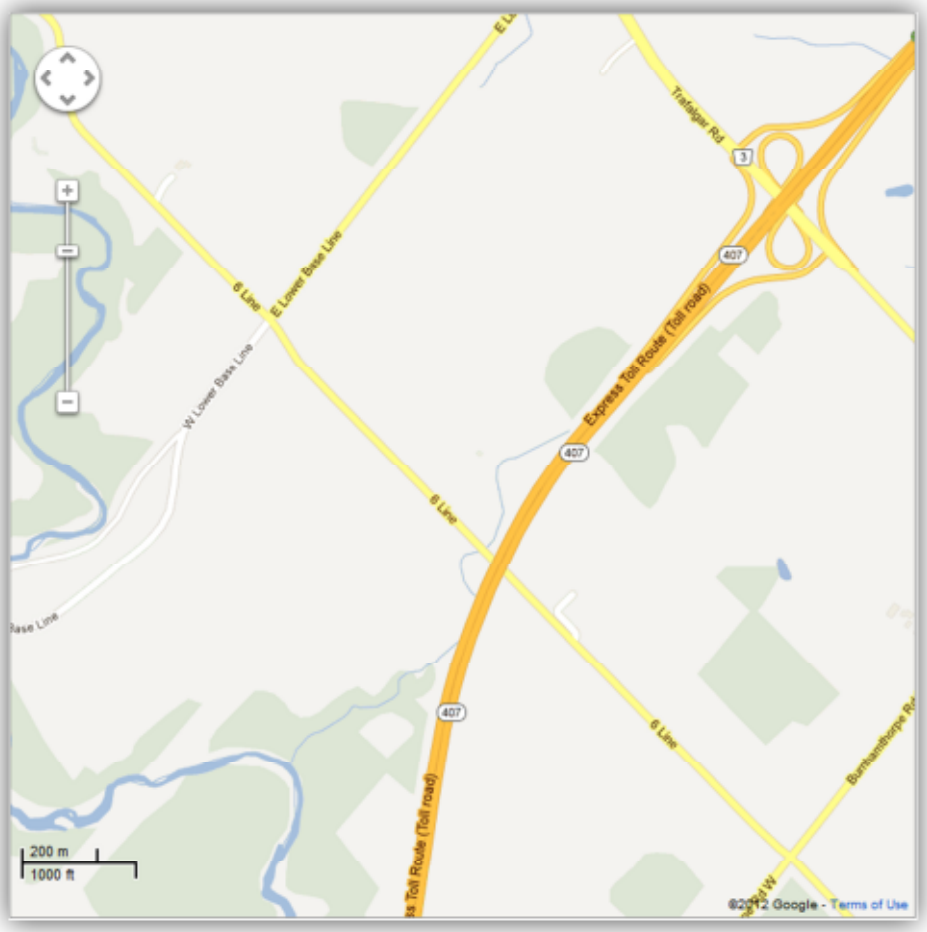


Figure 3 – Milton Hydro Feeders

2.2 2014 Investment Plan

Table 2

Description	Hydro Share	Contributed Capital	Old CGAAP Total
Distribution System Inspection/Energization		600,000	600,000
New Services		500,000	500,000
New Development Investment	500,000	2,191,000	2,691,000
Residential Underground Services	100,000	250,000	350,000
New General Services	462,000	325,000	787,000
Distribution Meters	605,625		605,625
North Service Road East Widening	224,135	134,000	358,135
Misc Road Widening	311,000	163,000	474,000
27.6kV Circuit, Upper Middle Rd, Ninth Line to HW 403	500,000		500,000
Total	**2,702,760**	**4,163,000**	**6,865,760**

Only projects which meet OHEDI's materiality level are displayed. OHEDI's materiality level is $190,000 based on 0.05% of distribution revenue requirement. The total line includes projects that do not meet the materiality level.

See Appendix A for detailed project summaries.

2.2.1 Customer Enhancement

Six annual customer enhancement projects have been identified, consisting of Distribution System Inspection & Energization, New Services, New Development Investment, Residential Underground Services, New General Services, and Distribution Meters. The following values are at risk:

- Financial – Due to the requirement to spend capital for customer enhancements when none is set aside to do so.
- Image – Due to customer complaints resulting from ignorance of regulations
- Legal - Due to lawsuits resulting from ignorance of regulations
- Regulatory – Due to contravention resulting from ignorance of regulations

The estimated cost to complete this work, not including capital contribution, is $1,667,625

2.2.2 Road Widening/Intersection Improvements

2.2.2.1 Widening of North Service Road

The Town of Oakville has identified the widening of North Service Road between 8th Line and Iroquois Shore Road. The following values are at risk:

- Financial – Due to compensation to the road authority for loss or expense
- Image – Due to Regional government complaints resulting from ignorance of regulations
- Legal - Due to lawsuits resulting from ignorance of regulations
- Regulatory – Due to contravention resulting from ignorance of regulations

The estimated cost to complete this work is $360,000, which includes capital contribution, within the area shown in the below figure:

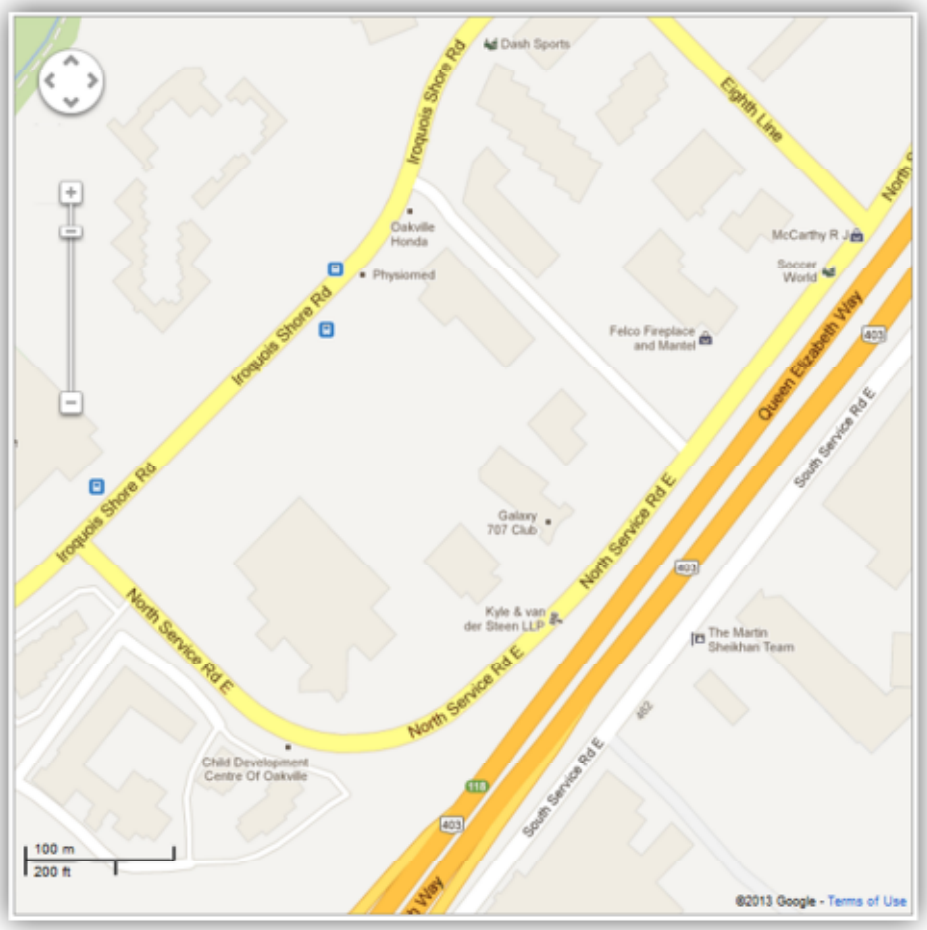


Figure 4 – North Service Road Widening

2.2.3 27.6kV Circuit, Upper Middle Rd, Ninth Line to HW 403

An additional circuit of 27.6kV is to be added between Ninth Line to Highway 403 on Upper Middle Road East to support load growth in the Winston Business Park. The following values will be at risk:

- Financial – Due to the requirement to spend capital for customer enhancements when none is set aside to do so.
- Image – Due to customer complaints resulting from ignorance of regulations
- Legal - Due to lawsuits resulting from ignorance of regulations
- Regulatory – Due to contravention resulting from ignorance of regulations

The estimated cost reserved to complete this work is $500,000

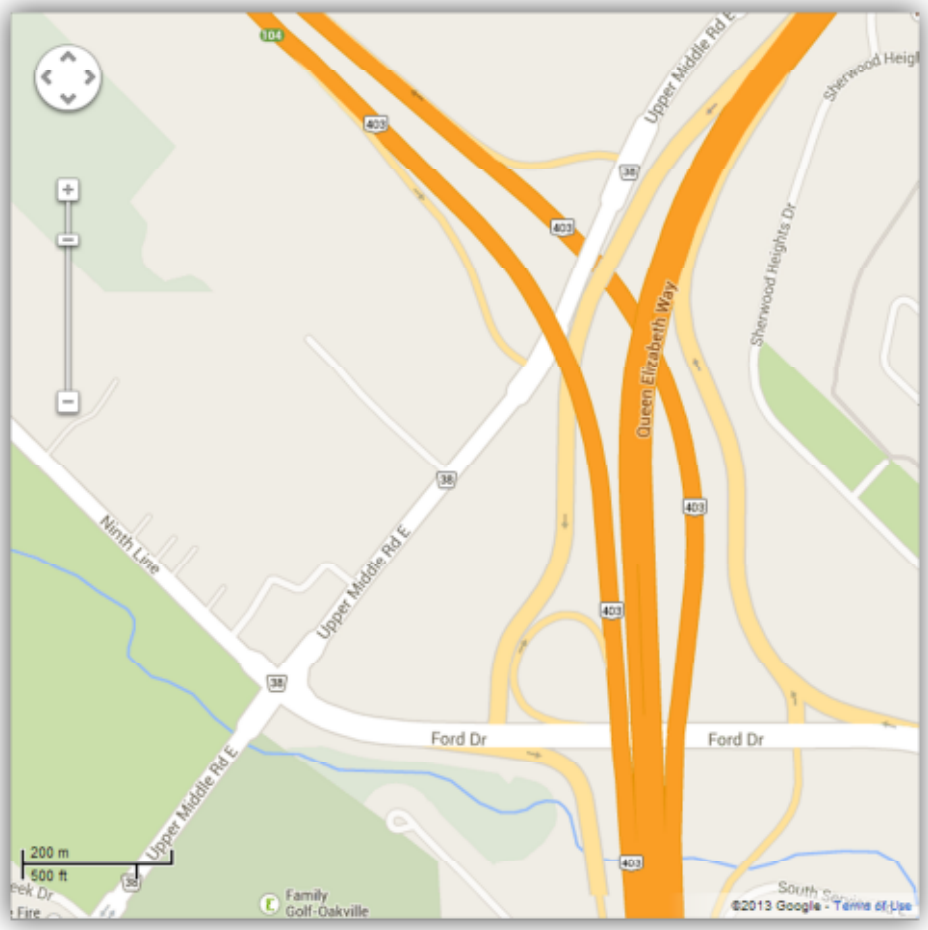


Figure 5 – 27.6kV Circuit, Upper Middle Rd, Ninth Line to HW 403

2.3 2015 Through 2018 Investment Plan

Table 3

Description	2015	2016	2017	2018
New Development Investment	1,419,459	1,717,679	1,769,915	1,904,604
Distribution Meters	499,500	583,300	608,200	655,100
Road Widening/Intersection Improvements	475,000	451,250	428,688	407,253
27.6kV Additions	520,200	541,216	563,081	585,830
Total	**2,914,159**	**3,293,445**	**3,369,884**	**3,552,787**

Only projects which meet OHEDI's materiality level are displayed. OHEDI's materiality level is $190,000 based on 0.05% of distribution revenue requirement. The total line includes projects that do not meet the materiality level.

The above values only represent OHEDI's capital share and do not include capital contribution.

2.4 2019 Through 2033 Investment Plan

New Development Investment is expected to increase until approximately 2021, after which time there should be some stability or decrease in this requirement.

Distribution Meter Investment is expected to follow New Development Investment and increase until approximately 2021, after which time there should be some stability or decrease in this requirement.

Road Widening/Intersection Improvement Investment is expected to steadily decrease over this timeframe.

27.6kV Addition Investment is expected to increase until approximately 2021, after which time there should be some stability or decrease in this requirement.

3 System Renewal

Noted in the "Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements" issued on March 28, 2013 by the OEB these investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.

Projects/Activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure"). Generally, the lower of the former and/or higher the latter, the more important it becomes to replace or refurbish the asset(s) sooner rather than later.

Hence, a distributor's discretion over the timing and priority of projects in this category may lessen over time, such as where assets with high consequence of failure are consistently operating outside applicable operating limits. On the other hand, a distributor may have considerable discretion over timing and priority where deteriorating asset condition has little or no impact on performance and the consequences in terms of the number of customers and criticality of service potentially affected by an asset failure are relatively low.

Investments in this category are considered non-mandatory; therefore allocation of capital to investments within is required to be optimized based upon risk and value. Investments are optimized against others within this category and in the System Service category. Investments are assessed by the probability and consequence the risk and value have on the OHEDI Capital Investment Objectives, as noted in the Asset Management Objectives document.

3.1 2013 Investment Plan

Table 4

Description	Cost
27.6kV air insulated switchgear upgrades	395,000
Voltage conversion 4kV on First Street South	215,000
PoleTran transformer replacements	287,000
Replace O/H and U/G assets in Holton Heights	808,000
Replace underground assets on Copeland Ct	210,000
Replace Underground Assets on Speers Rd, Kerr St to Cross Ave	260,000
Replace transformer bushing and elbows	205,000
Replace overhead assets on Oxford	240,000
Replace rear lot assets in zone 3 north	1,765,000
Power transformer replacement program	288,000
MS low voltage breaker replacement	335,000
Total	6,161,869

Only projects which meet OHEDI's materiality level are displayed. OHEDI's materiality level is $190,000 based on 0.05% of distribution revenue requirement. The total line includes projects that do not meet the materiality level.

3.1.1 27.6kV Air Insulated Switchgear Upgrade Program

The 27.6kV air insulated style padmount switchgear has been a risk due to contamination and flashovers. The insulators inside of these switchgears are susceptible to salt spray contamination during the winter. When located in a high traffic area, the contamination builds up and can cause flashovers. In these cases typically the switchgear needs to be removed and either refurbished or scrapped depending on the level of damage. If replaced with deadfront switchgear, the salt spray does not affect the unit, mitigating the risk of the flashovers. The existing switchgear is subject to accelerated aging due to adverse weather conditions and road salt. The new switchgears are easier to operate and have an electronic trip and will not require re-fusing. The other benefit of conversion is the mitigation of dry ice cleaning required every six years. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Safety – Employee – Due to injuries caused from equipment failures while operating the equipment.

The estimated cost to complete this work is $395,000.



Figure 6 – Padmount Switchgear

3.1.2 Voltage Conversion 4kV on First Street South

First Street South has been patrolled and the assets have been identified in poor and degrading condition. The existing 4kV system can be upgraded to 27.6kV in this area. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Legal - Due to customer claims from equipment failures
- Safety – Public – Due to customer injuries from equipment failures
- Environmental – Due to spills from equipment failures

The estimated cost to complete this work is $455,000. The following images show the areas of Town as noted above:



Figure 7 – First St.

3.1.3 PoleTran Transformer Replacements

These transformers are typically over 44 years old and are difficult to operate due to insufficient access, and difficult to maintain due to limited availability of parts. In the case that one of these transformers fails, it is difficult to have a suitable replacement installed, causing a long outage. There are five remaining units in the distribution system, single units on Water St, Forsythe St, Navy St, Crawford Ct, and Donnybrook Rd. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Legal – Due to customer claims from equipment failures
- Safety – Employee – Due to employee injuries caused by lack of working space within the equipment
- Safety – Public – Due to customer injuries caused by equipment failures
- Environmental – Due to spills from equipment failures

The estimated cost to complete this work is $287,000.



Figure 8 – Poletran Transformer

3.1.4 Replace Overhead and Underground Assets in Holton Heights

A number of areas with aging underground distribution have been identified for replacement including the Holten Heights area. Typically in these older areas the cables are direct buried, causing an issue with replacement. If one of these cables were to fail, the fault will have to be located, and excavated. Once the fault is isolated, a splice can be added in order to use the cable again. Rebuilding of these areas with ducts will provide a means to remove the cables when they are failing to allow for the installation of new cables. These areas typically have non-vented inserts and elbows which can allow flashovers to occur when switching takes place. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Legal – Due to customer claims from equipment failures
- Safety – Public – Due to customer injuries caused by equipment failures
- Environmental – Due to spills from equipment failures

The estimated cost to complete this work is $808,000 within the areas shown in the below figure:



Figure 9 – Holton Heights Area

3.1.5 Replace Underground Assets on Copeland Court

A number of areas with aging underground distribution have been identified for replacement including on Copeland Court. Typically in these older areas the cables are direct buried, causing an issue with replacement. If one of these cables were to fail, the fault will have to be located, and excavated. Once the fault is isolated, a splice can be added in order to use the cable again. Rebuilding of these areas with ducts will provide a means to remove the cables when they are failing to allow for the installation of new cables. These areas typically have non-vented inserts and elbows which can allow flashovers to occur when switching takes place. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Legal – Due to customer claims from equipment failures
- Safety – Public – Due to customer injuries caused by equipment failures
- Environmental – Due to spills from equipment failures

The estimated cost to complete this work is $210,000 within the areas shown in the below figure:



Figure 10 – Copeland Court

3.1.6 Replace Underground Assets on Speers Road, between Kerr Street and Cross Avenue

The vault transformers in this area service residential apartment buildings. There are NX style fuses installed which are difficult to operate and replace. This location is difficult to access and poses safety issues due to open air live parts within the rooms. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Legal – Due to customer claims from equipment failures
- Safety – Public – Due to customer injuries caused by equipment failures
- Environmental – Due to spills from equipment failures

The estimated cost to complete this work is $260,000.

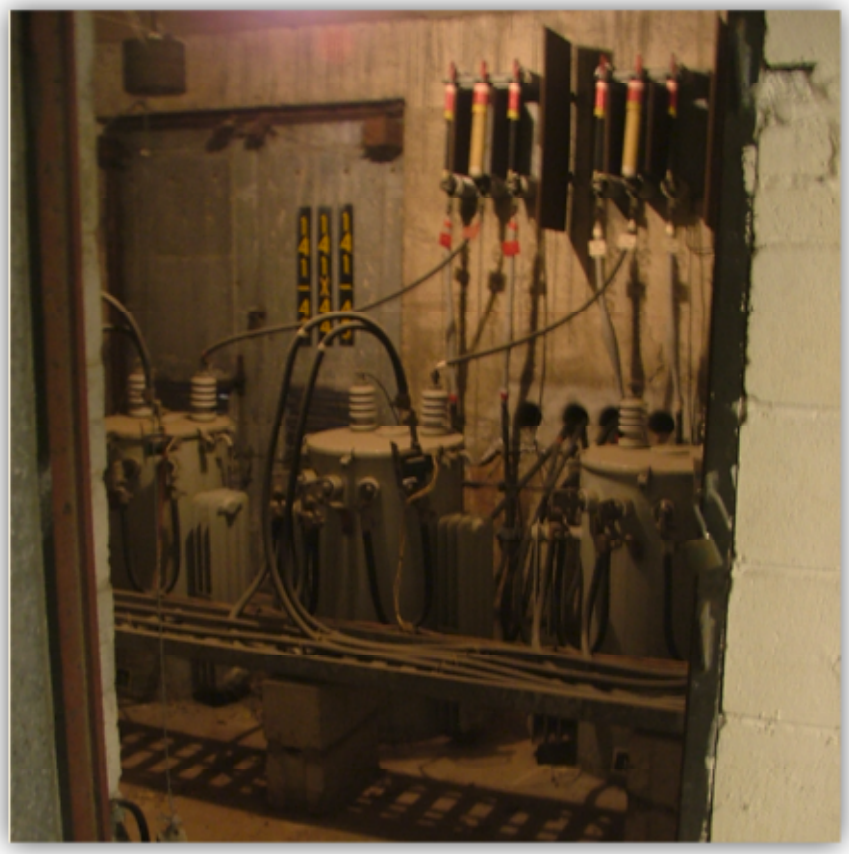


Figure 11 – Vault Room Transformers

3.1.7 Replace Transformer Bushing and Elbow Program

In older areas of OHEDI's system non-vented bushing inserts and elbows are used, which are unsafe for operation under load. There is no venting available to extinguish the electrical arc created when removing the elbow from the insert under load. Due to this operational issue, it is difficult to sectionalize certain areas of the system, causing longer than expected outage times to more customers. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Legal – Due to customer claims from equipment failures
- Safety – Public – Due to customer injuries caused by equipment failures
- Environmental – Due to spills from equipment failures

The estimated cost to complete this work is $205,000, within the area shown in the below figure:



Figure 12 – Zone 3C (South) Bushing and Elbow Replacement

3.1.8 Replace Overhead Assets on Oxford Avenue

Oxford Avenue has been patrolled and the assets have been identified in poor and degrading condition. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Legal - Due to customer claims from equipment failures
- Safety – Public – Due to customer injuries from equipment failures
- Environmental – Due to spills from equipment failures

The estimated cost to complete this work is $240,000, within the area shown in the below figure:



Figure 13 – Oxford Ave.

3.1.9 Replace Rear Lot Assets in Zone 3 North

The removal of overhead primary cables from the backyard pole lines in Oakville has been an ongoing project for a number of years. Overhead primary lines, located in the backyards, are susceptible to falling limbs from trees. Access to replace or repair equipment in the backyards is difficult, and any patrols following an outage are lengthy & cumbersome. OHEDI intends to remove remaining rear lot primary lines in order to mitigate these risks. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Legal – Due to customer claims from equipment failures
- Safety – Employee – Due to employee injuries caused during maintenance due to difficult equipment access
- Safety – Public – Due to customer injuries caused by equipment failures
- Environmental – Due to spills from equipment failures

The estimated cost to complete this work is $1,765,000, within the area shown in the below figure:



Figure 14 – Zone 3 North

3.1.10 Power Transformer Replacement Program

It is proposed to replace Power Transformer Loc-A at Albion MS, which is the oldest power transformer in OHEDI's distribution system, unless another is found with a lower health index. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures

The estimated cost to complete this work is $288,000.



Figure 15 – Power Transformer

3.1.11 Municipal Substation Low Voltage Breaker Replacement Program

It is proposed to replace the Low Voltage Breaker lineup at Sunset MS, which is the oldest Low Voltage Breaker lineup in OHEDI's distribution system, unless another is found with a lower health index. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures

The estimated cost to complete this work is $335,000.



Figure 16 – Low Voltage Breakers

3.2 2014 Investment Plan

Table 5

Description	Old CGAAP	New CGAAP
27.6kV Air Insulated Switchgear Upgrade Program	465,000	379,340
Gang-Operated Switch Replacement Program	361,000	267,139
Livefront Transformer Replacement Program	350,000	275,730
Vault Transformer Replacement Program	430,000	316,241
Replace U/G & O/H Assets on Colchester, Oakhill, etc.	496,999	385,205
Replace U/G & O/H Assets on Willowbrook and Wendy	260,000	184,665
Replace O/H Assets on John Street	310,000	207,270
Replace O/H Assets on Queen Mary, Bond, etc.	550,000	358,919
Replace O/H Assets on Robinson St.	720,000	458,981
Power transformer replacement Program	300,150	268,190
MS low voltage breaker replacement Program	635,400	547,715
Total	**6,483,669**	**5,979,745**

Only projects which meet OHEDI's materiality level are displayed. OHEDI's materiality level is $190,000 based on 0.05% of distribution revenue requirement. The total line includes projects that do not meet the materiality level.

See Appendix A for detailed project summaries.

3.2.1 27.6kV Air Insulated Switchgear Upgrade Program

The 27.6kV air insulated style padmount switchgear has been a risk due to contamination and flashovers. The insulators inside of these switchgears are susceptible to salt spray contamination during the winter. When located in a high traffic area, the contamination builds up and can cause flashovers. In these cases typically the switchgear needs to be removed and either refurbished or scrapped depending on the level of damage. If replaced with deadfront switchgear, the salt spray does not affect the unit, mitigating the risk of the flashovers. The existing switchgear is subject to accelerated aging due to adverse weather conditions and road salt. The new switchgears are easier to operate and have an electronic trip and will not require re-fusing. The other benefit of conversion is the mitigation of dry ice cleaning required every six years. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Safety – Employee – Due to injuries caused from equipment failures while operating the equipment.

The estimated cost to complete this work is $465,000.



Figure 17 – Padmount Switchgear

3.2.2 Gang-Operated Switch Replacement Program

Vacuum gang-operated switches tend to fail without warning, and there is little to no maintenance that can be performed in order to keep them in working order. In the case they fail, we do not have any spare parts to have them fixed, and they must be replaced with newer style remote operated switches. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Legal - Due to customer claims from equipment failures
- Safety – Public – Due to customer injuries from equipment failures
- Safety – Employee – Due to employee injuries from equipment failures
- Environmental – Due to fires caused from equipment failures

The estimated cost to complete this work is $361,000.



Figure 18 – Vacuum Gang Operated Switch

3.2.3 Livefront Transformer Replacement Program

OHEDI has phased these transformers out over time and only a handful remain in the field with no straight replacement stock available. The units are typically placed without foundations causing issue during replacement with newer units that require foundations. On average these units are 40 years old. Location 4371 at 215 Rebecca St is proposed for replacement, and is a candidate for voltage conversion from 4kV to 27.6kV. Location 4267 and 4588 at 1005 and 1027 Speers Rd are proposed for replacement. These two transformers are candidates for voltage conversion from 4kV to 27.6kV, and should be placed on a loop feed. This budget should cover the cost of all cable replacements and pole upgrades required to perform the work. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Legal – Due to customer claims from equipment failures
- Safety – Employee – Due to employee injuries caused by obsolete, livefront equipment
- Environmental – Due to spills from equipment failures

The estimated cost to complete this work is $350,000.

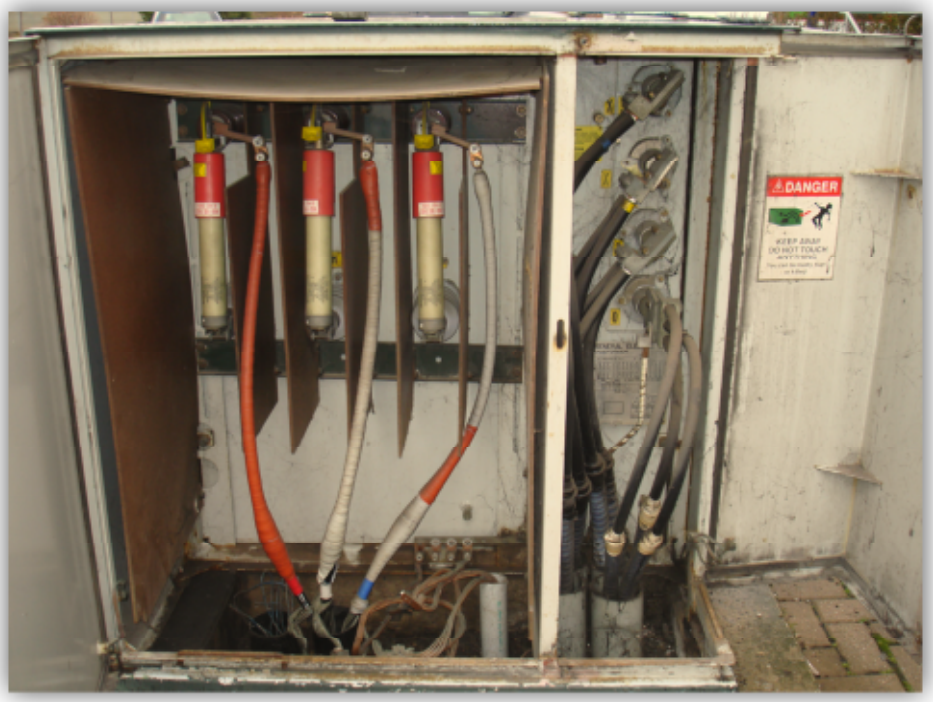


Figure 19 – Livefront Transformer

3.2.4 Vault Transformer Replacement Program

These transformers typically service residential apartment buildings or commercial plazas. There are a lot of instances where NX style fuses are installed that are difficult to operate and replace. Many of these locations are difficult to access and pose safety issues due to open air live parts. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Legal – Due to customer claims from equipment failures
- Safety – Public – Due to customer injuries caused by equipment failures
- Environmental – Due to spills from equipment failures

The estimated cost to complete this work is $430,000.

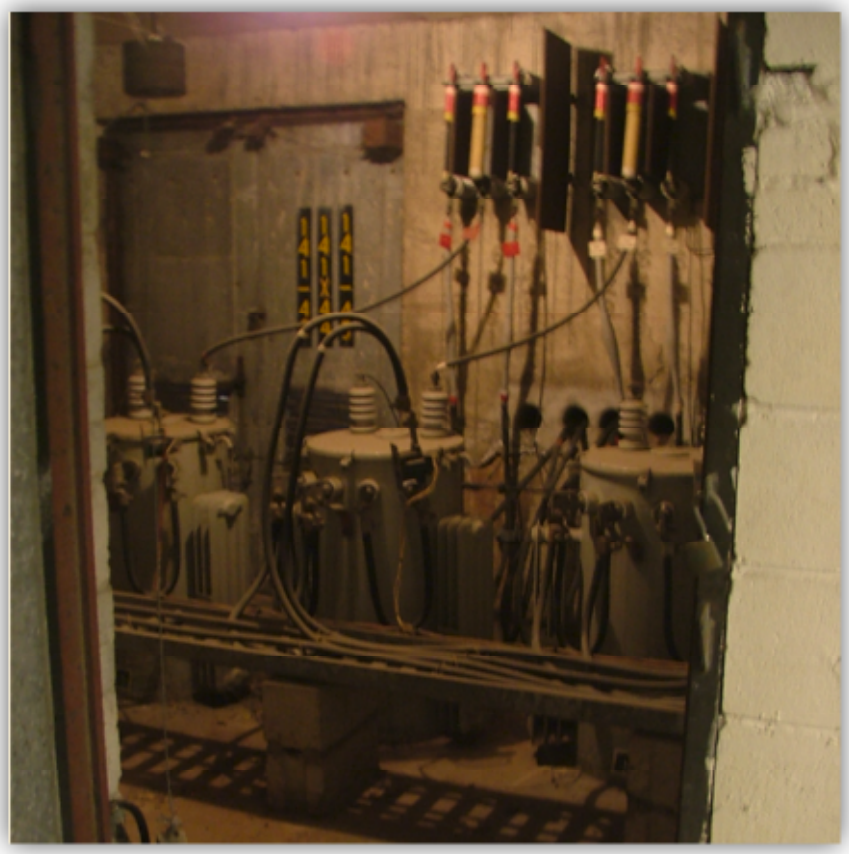


Figure 20 – Vault Room Transformers

3.2.5 Replace Underground and Overhead Assets in Colchester Area

A number of areas with aging underground distribution have been identified for replacement including the Colchester area. Typically in these older areas the cables are direct buried, causing an issue with replacement. If one of these cables were to fail, the fault will have to be located, and excavated. Once the fault is isolated, a splice can be added in order to use the cable again. Rebuilding of these areas with ducts will provide a means to remove the cables when they are failing to allow for the installation of new cables. These areas typically have non-vented inserts and elbows which can allow flashovers to occur when switching takes place. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Legal – Due to customer claims from equipment failures
- Safety – Public – Due to customer injuries caused by equipment failures
- Environmental – Due to spills from equipment failures

The estimated cost to complete this work is $497,000 within the areas shown in the below figure:

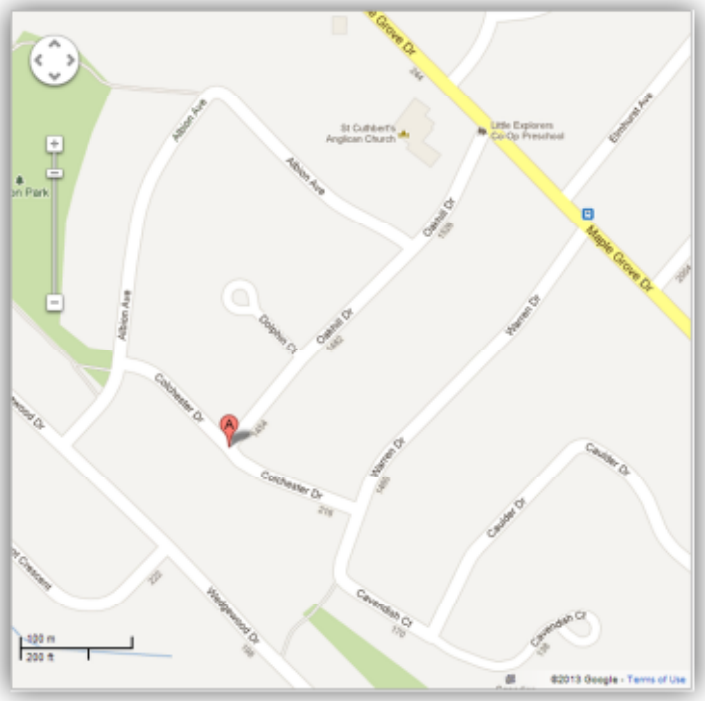


Figure 21 – Colchester Area

3.2.6 Replace Underground and Overhead Assets in Willlowbrook Area

A number of areas with aging underground distribution have been identified for replacement including the Willowbrook area. Typically in these older areas the cables are direct buried, causing an issue with replacement. If one of these cables were to fail, the fault will have to be located, and excavated. Once the fault is isolated, a splice can be added in order to use the cable again. Rebuilding of these areas with ducts will provide a means to remove the cables when they are failing to allow for the installation of new cables. These areas typically have non-vented inserts and elbows which can allow flashovers to occur when switching takes place. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Legal – Due to customer claims from equipment failures
- Safety – Public – Due to customer injuries caused by equipment failures
- Environmental – Due to spills from equipment failures

The estimated cost to complete this work is $260,000 within the areas shown in the below figure:



Figure 22 – Willowbrook Area

3.2.7 Replace Overhead Assets on John Street

John Street has been patrolled and the assets have been identified in poor and degrading condition. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Legal - Due to customer claims from equipment failures
- Safety – Public – Due to customer injuries from equipment failures
- Environmental – Due to spills from equipment failures

The estimated cost to complete this work is $310,000, within the area shown in the below figure:



Figure 23 – 2014 John St.

3.2.8 Replace Overhead Assets in Queen Mary Area

Queen Mary area has been patrolled and the assets have been identified in poor and degrading condition. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Legal - Due to customer claims from equipment failures
- Safety – Public – Due to customer injuries from equipment failures
- Environmental – Due to spills from equipment failures

The estimated cost to complete this work is $550,000, within the area shown in the below figure:



Figure 24 – 2014 Queen Mary Dr., Bond St, and Chisholm St.

3.2.9 Replace Overhead Assets on Robinson St.

Robinson Street has been patrolled and the assets have been identified in poor and degrading condition. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Legal - Due to customer claims from equipment failures
- Safety – Public – Due to customer injuries from equipment failures
- Environmental – Due to spills from equipment failures

The estimated cost to complete this work is $720,000, within the area shown in the below figure:

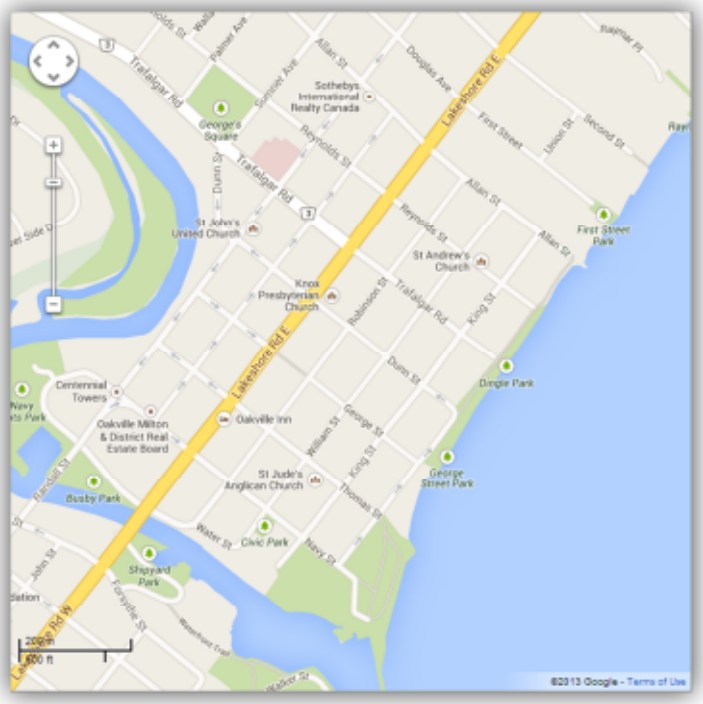


Figure 25 – 2014 Robinson St.

3.2.10 Power Transformer Replacement Program

It is proposed to replace Power Transformer Loc-B at Woodhaven MS, which is the oldest power transformer in OHEDI's distribution system, unless another is found with a lower health index. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures

The estimated cost to complete this work is $300,150.



Figure 26 – Power Transformer

3.2.11 Municipal Substation Low Voltage Breaker Replacement Program

It is proposed to replace the Low Voltage Breaker lineup at Victoria MS, which is the oldest Low Voltage Breaker lineup in OHEDI's distribution system, unless another is found with a lower health index. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIFI – Due to more frequent outages from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures

The estimated cost to complete this work is $635,400.



Figure 27 – Low Voltage Breakers

3.3 2015 Through 2018 Investment Plan

Table 6

Description	2015	2016	2017	2018
Power Transformer Replacement Program	313,000	320,000	327,000	334,000
M.S. Low Voltage Breaker Replacement Program	1,090,800	373,000	381,000	389,000
Overhead Distribution Transformer Replacements	260,357	265,564	270,875	276,293
Padmount Distribution Transformer Replacements	2,520,000	2,580,000	2,640,000	800,000
Vault Room Distribution Transformer Replacements	441,000	450,000	459,000	477,000
Padmount Switchgear Replacements	460,000	472,000	484,000	496,000
O/H Gang-op Switch Replacements	370,000	380,000	390,000	400,000
O/H Primary Wire Replacements	1,404,540	1,432,631	1,461,283	1,490,509
U/G Primary Cable Replacements	2,951,467	3,010,497	3,070,707	3,132,121
Pole Replacements	571,180	582,603	594,255	606,140
Overhead Secondary Wire Replacements	856,145	873,268	890,733	908,548
Underground Secondary Cable Replacements	2,267,864	2,313,221	2,359,486	2,406,675
Total	**13,154,586**	**13,580,193**	**13,924,324**	**12,633,083**

Only projects which meet OHEDI's materiality level are displayed. OHEDI's materiality level is $190,000 based on 0.05% of distribution revenue requirement. The total line includes projects that do not meet the materiality level.

3.4 2019 Through 2033 Investment Plan

OHEDI expects the overall System Renewal category to increase in cost due to failures, failure risk, substandard performance, high risk performance and functional obsolescence.

OHEDI predicts the following:

- Power Transformer Replacement Program – Low increase until 2024 when it doubles to accommodate two replacements per year.
- Low Voltage Breaker Replacement Program – Low increase until 2027 when it is no longer required as all assets will have been replaced.
- High Voltage Station Switch Replacement Program – Up and down spending throughout this timeframe, none expecting to meet the materiality level.
- Overhead Distribution Transformer Replacement Program – Low increase through this timeframe.
- Padmount Distribution Transformer Replacement Program – High increase until 2030 and then changes to Low.
- Submersible Distribution Transformer Replacement Program – Low increase until 2029 and then changes to High, only meeting the materiality level at that time.

- Vault-Room Distribution Transformer Replacement Program – Low increase throughout this timeframe.
- Padmount Switchgear Replacement Program – Low increase until 2025 and then changes to Moderate.
- Vault-Style Switchgear Replacement Program – Low increase until 2020 and then up and down spending throughout the remainder of the timeframe, none expecting to meet the materiality level.
- Overhead Gang-op Switch Replacement Program – Low increase throughout this timeframe.
- Overhead Primary Wire Replacement Program – Low increase throughout this timeframe.
- Underground Primary Cable Replacement Program – Moderate increase throughout this timeframe.
- Pole Replacement Program – Low increase throughout this timeframe.
- Overhead Secondary Wire Replacement Program – Low increase throughout this timeframe.
- Underground Secondary Cable Replacement Program – Moderate increase throughout this timeframe.
- Primary Metering Replacement Program – Low increase throughout this timeframe, none expecting to meet the materiality level.
- Residential Meter Replacement Program – Moderate increase until 2023 and then changes to Low, only meeting the materiality level by 2020.
- Commercial Meter Replacement Program – Low increase throughout this timeframe, none expecting to meet the materiality level.

4 System Service

Noted in the "Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements" issued on March 28, 2013 by the OEB these investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements.

Projects/Activities in this category are driven by the distributor's expectations that evolving customer use of the system may occasion the creation of system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor's service delivery standards or objectives. Distributor discretion in relation to investments in this category can be relatively high in terms of both initiating a project and determining the priority and timing of project-related expenditures.

Investments in this category are considered non-mandatory; therefore allocation of capital to investments within is required to be optimized based upon risk and value. Investments are optimized against others within this category and in the System Renewal category. Investments are assessed by the probability and consequence the risk and value have on the OHEDI Capital Investment Objectives, as noted in the Asset Management Objectives document.

4.1 2013 Investment Plan

Table 7

Description	Cost
N/A	N/A
Total	**100,000**

Only projects which meet OHEDI's materiality level are displayed. OHEDI's materiality level is $190,000 based on 0.05% of distribution revenue requirement. The total line includes projects that do not meet the materiality level.

No projects in this category meet the materiality level so they will not be described within.

4.2 2014 Investment Plan

Table 8

Description	Old CGAAP	New CGAAP
Spare Transformer for Glenorchy MTS	5,142,000	5,000,000
SCADA Enhancements in Loadflow, Contingency Analysis, FDIR	300,000	300,000
Total	**5,744,000**	**5,588,899**

Only projects which meet OHEDI's materiality level are displayed. OHEDI's materiality level is $190,000 based on 0.05% of distribution revenue requirement. The total line includes projects that do not meet the materiality level.

See Appendix A for detailed project summaries.

4.2.1 Spare Transformer for Glenorchy MTS

In July of 2011, this transformer station realized a peak load level of 44MW supplied to the north-central area of Oakville. The transformer station's capacity will be utilized more for the new Hospital expected to be open in late 2015 and for Milton Hydro who are using load for the south end of Milton.

This transformer station however does not have an on-site standby transformer for use in event of a failure. Therefore, Oakville Hydro believes it is imperative and critical to the customers it serves to have this capability on hand. The following values are at risk:

- Financial – Due to lost revenue and unexpected capital costs from equipment failures
- SAIDI – Due to longer outages from equipment failures
- Image – Due to received customer calls from equipment failures
- Legal - Due to customer claims from equipment failures

The estimated cost to complete this work is $5,142,000

4.2.2 SCADA Enhancements in Loadflow, Contingency Analysis, FDIR

The following functional upgrades will be added to the existing SCADA system:

- Loadflow will provide the Control Room Operators with an analysis tool to simulate the impact of system loading levels to drive the right solutions.
- Contingency Analysis is complimentary to Loadflow, and will provide the Control Room Operators with a report that highlights critical components in the distribution system, allowing the Operator to reconfigure the system as necessary.
- Fault Detection Isolation Restoration (FDIR) is also complimentary to Loadflow, and is an element of grid transformation that builds a level of automation into the SCADA system. Existing field sensors and controllable switches are leveraged, and the SCADA system is able to take action without Operator intervention to begin system restoral following an outage.

The estimated cost to complete this work is $300,000

4.3 2015 Through 2018 Investment Plan

Table 9

Description	2015	2016	2017	2018
N/A	N/A	N/A	N/A	N/A
Total	**51,000**	**53,000**	**55,000**	**57,000**

Only projects which meet OHEDI's materiality level are displayed. OHEDI's materiality level is $190,000 based on 0.05% of distribution revenue requirement. The total line includes projects that do not meet the materiality level.

4.4 2019 Through 2033 Investment Plan

OHEDI expects a slight increase in costs in the System Service category over this time period, with no further identified investments.

5 General Plant

Noted in the "Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements" issued on March 28, 2013 by the OEB these investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities.

Projects/Activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities. Distributor discretion in relation to investments in this category can be relatively high in terms of both initiating a project and determining the priority and timing of project-related expenditures.

Investments in this category are considered non-mandatory; therefore allocation of capital to investments within is required to be optimized based upon risk and value.

5.1 2013 Investment Plan

Table 10

Description	Cost
Fleet	402,000
Building - Leasehold	238,000
Total	**2,656,921**

Only projects which meet OHEDI's materiality level are displayed. OHEDI's materiality level is $190,000 based on 0.05% of distribution revenue requirement. The total line includes projects that do not meet the materiality level.

5.1.1 Fleet

Two vehicles are proposed for 2013. The first is the replacement of engineering pickup #70, a 2004 4x4 inspector's vehicle. It is to be replaced with a new 2013 HYBRID 4x4 SUV type vehicle having an active fuel management system. The second is the addition of a 2013 46' HYBRID material handler. The following values are at risk:

- Financial – Due to higher fuel consumption by use of non-HYBRID vehicles, use of large vehicles where a smaller vehicle can complete the task required, and stranded and unproductive employees due to breakdowns
- SAIDI – Due to longer outages from insufficient response to equipment failures
- Image – Due to vehicle breakdowns and insufficient response to equipment failures
- Legal – Due to customer claims from insufficient response to equipment failures
- Safety – Employee – Due to improperly matched vehicles to work requirements
- Safety – Public – Due to public exposure of electrical danger from insufficient response times
- Environmental – Due to higher emissions from use of non-HYBRID vehicles.

The estimated cost to complete this work is $402,000.



Figure 28 – Truck #70



Figure 29 – Material Handler

5.1.2 Building - Leasehold

Full asphalt replacement of upper parking lot at the Admin Building which will include directional and parking re-lining, approximately 15,500 square feet of asphalt. Deterioration has continued, this replacement has been deferred for 3 years, with repairs taking place each year. Unevenness, water pooling, heaving and spongy areas due to spidering are evident.

Replacement of HVAC and mechanical equipment (approx.. 85 units) over a five year period. This is a proactive plan to replace units that have reached or are reaching end of life cycle, as they are original equipment. OHEDI is experiencing more frequent breakdowns, requiring replacement, in particular with units that are rooftop and exposed to the elements.

Replacement of all exterior building neon signage/lighting to LED's from NEON technology. Will allow for reduced operating costs as well as extremely low maintenance costs.

The estimated cost to complete this work is $238,000.

5.2 2014 Investment Plan

Table 11

Description	Old CGAAP	New CGAAP
Fleet	404,000	384,762
Building - Leasehold	230,000	230,000
Business Systems Applications	203,000	203,000
IT Infrastructure	420,000	420,000
Total	**2,736,158**	**2,716,920**

Only projects which meet OHEDI's materiality level are displayed. OHEDI's materiality level is $190,000 based on 0.05% of distribution revenue requirement. The total line includes projects that do not meet the materiality level.

See Appendix A for detailed project summaries.

5.2.1 Fleet

Eight vehicles are proposed for 2014. Four existing pickup trucks are proposed to be replaced with new 2014 HYBRID Pickup type vehicles having an active fuel management system, the following trucks are proposed for replacement #69, 75, 80, and 65. One existing car #68 is proposed to be replaced with a new 2014 HYBRID car type vehicle having an active fuel management system. One existing van #77 is proposed to be replaced with new 2014 HYBRID van type vehicles having an active fuel management system. One existing blocker truck chasis #20 is proposed to be replaced with a large used truck chasis. One existing warehouse forklift #406 is proposed for replacement. The following values are at risk:

- Financial – Due to higher fuel consumption by use of non-HYBRID vehicles, use of large vehicles where a smaller vehicle can complete the task required, and stranded and unproductive employees due to breakdowns
- SAIDI – Due to longer outages from insufficient response to equipment failures
- Image – Due to vehicle breakdowns and insufficient response to equipment failures
- Legal – Due to customer claims from insufficient response to equipment failures
- Safety – Employee – Due to improperly matched vehicles to work requirements
- Safety – Public – Due to public exposure of electrical danger from insufficient response times
- Environmental – Due to higher emissions from use of non-HYBRID vehicles.

The estimated cost to complete this work is $404,000.



Figure 30 – Truck #69



Figure 31 - Truck #75



Figure 32 - Truck #80



Figure 33 - Truck #65



Figure 34 - Car #68



Figure 35 - Van #77



Figure 36 - Truck #20



Figure 37 - Forklift #406

5.2.2 Building - Leasehold

Replacement of HVAC and mechanical equipment (approx.. 85 units) over a five year period. This is a proactive plan to replace units that have reached or are reaching end of life cycle, as they are original equipment. OHEDI is experiencing more frequent breakdowns, requiring replacement, in particular with units that are rooftop and exposed to the elements.

The estimated cost to complete this work is $230,000.

5.2.3 Business Systems Applications

Project initiatives include:

- Harris Collection project, to automate our current collection methodology and create an efficient and effective process
- Northstar modifications, to implement an Automation Platform including custom Cognos and SQL rule development to enhance Oakville Hydro's billing processes due to introduction of added complexities in billing
- Workforce Management (WFM) improvements, to automate service orders currently used with the Halton Region along with improving Oakville Hydro's existing WFM used for electric service orders. This includes implementation of electronic service orders for the Region, testing of service orders and its effect on billing processes, and introducing WFM to new Oakville Hydro business processes
- GP ERP system upgrade, requires a full re-implementation and integration of existing software to the new GP2013 system. This upgrade requires to allow us to take advantage of new features that not oly assist in daily activities but also for analysis and crecociliations. There should be no additional software required for the ERP system in 2014 while we are implementing the new version.
- Business intelligence, where good business intelligence tools will need further development to provide good analysis to the business.

The estimated cost to complete this work is $203,000.

5.2.4 IT Infrastructure

This is a combined project taking into account all infrastructure changes to support the organization in the initiatives.

The estimated cost to complete this work is $420,000

5.3 2015 Through 2018 Investment Plan

Table 12

Description	2015	2016	2017	2018
Fleet	420,000	453,000	592,000	715,000
Buildings and Leaseholds	300,000	250,000	200,000	200,000
Plant and equipment	400,000	700,000	400,000	400,000
Computer Equipment	900,000	750,000	750,000	750,000
Total	**2,195,000**	**2,330,000**	**2,122,000**	**2,248,000**

Only projects which meet OHEDI's materiality level are displayed. OHEDI's materiality level is $190,000 based on 0.05% of distribution revenue requirement. The total line includes projects that do not meet the materiality level.

5.4 2019 Through 2033 Investment Plan

Fleet costs are expected to continue to increase greatly through 2020, then level until 2027 at which time it should greatly increase again.

Tool costs are expected to slowly increase over this period through inflation of prices only. Large purchases are not expected at this time.

Buildings and Leaseholds are expected to remain constant throughout this timeframe.

Plant and equipment is expected to remain relatively constant throughout this timeframe.

Investment in Operational IT systems, focused on systems integration, distribution system performance and service reliability will continue (GIS, OMS, SCADA) and remain relatively constant through this timeframe.

6 Summary

This document provides sufficient information regarding the Capital Expenditure Plan which outlines the detailed plans to achieve the outcomes of the Asset Management Objectives. It will be communicated to all relevant stakeholders, and will be reviewed regularly to ensure currency, consistency and effectiveness.

7 Appendix A

Summary 2014 Capital Projects over Materiality Threshold

Project #	Description	System Type
14-64A1	SCADA Enhancements in Loadflow, Contingency Analysis, FDIR	System Service
16-G2	27.6kV Air insulated switchgear upgrades to G&W	System Renewal
16-U1	Gang-Op Switch Replacement Program	System Renewal
05-P2	Power Transformer Replacement Program	System Renewal
05-Q2	Victoria MS Low Voltage Breaker Replacement Program	System Renewal
46-A	Replace Overhead Assets on John Street	System Renewal
46-B	Replace Overhead Assets on Queen Mary, Bond and Chisholm	System Renewal
46-C	Replace Overhead Assets on Robinson St.	System Renewal
45-A	Vault Transformer Replacements	System Renewal
45-D	Poletran Removals and Replace U/G Assets Various Locations	System Renewal
45-Q	Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion	System Renewal
45-X	Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln	System Renewal
42-B	Live front Padmount Transformer Replacements	System Renewal
44-H	27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403	System Access
14-50C	New Development Investment	System Access
14-54	New General Services	System Access
14-61	Distribution Meters	System Access
15-E	North Service Rd Widening, 8th Line to Iroquois Shore Rd	System Access
15-I	Road Widening TBD	System Access
14-62	2014 Fleet	General Plant
14-64D	ERP - GP & Business Intelligence	General Plant
14-64F	IT Infrastructure	General Plant
LSHOLD	HVAC upgrade - 5 year replacement program	General Plant

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	14-64A1
Project Name:	SCADA Enhancements in Loadflow, Contingency Analysis, FDIR
Project Category:	Administration - IT
System Type	System Service
Customer Attachments/Load:	
Project Manager:	Jeff Mocha
Start Date:	January 1, 2014
In Service Date:	October 1, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$300,000	$300,000
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$300,000	$300,000
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$300,000	$0	$0	$0

Risks to Completion and Risk Mitigation:

The current SCADA system has been in service for several years, the proposed enhancements are a functional upgrade to this system. The proposed software enhancements are in service at other utility companies, and are mature products. A detailed project plan will be developed with a defined scope of work. We plan to work closely with the system provider to integrate into our existing SCADA system on time and on budget.

Comparative Information on Equivalent Historical Projects (if any):

Successfully managed development and implementation of Outage Management System functional upgrade with same vendor in 2013

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

The following functional upgrades will be added to the existing SCADA system:
Loadflow will provide the Control Room Operators with an analysis tool to simulate the impact of system loading levels to drive the right solutions.
Contingency Analysis is complimentary to Loadflow, and will provide the Control Room Operators with a report that highlights critical components in the distribution system, allowing the Operator to reconfigure the system as necessary.
Fault Detection Isolation Restoration (FDIR) is also complimentary to Loadflow, and is an element of grid transformation that builds a level of automation into the SCADA system. Existing field sensors and controllable switches are leveraged, and the SCADA system is able to take action without Operator intervention to begin system restoral following an outage.

Project #: 14-64A1

Project Name: SCADA Enhancements in Loadflow, Contingency Analysis, FDIR

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

Process improvements in the Control Room that drive optimized system configuration and improved outage restoral.

Priority and Reasons for Priority:

This project is ranked as a high priority because it will mitigate existing operational risks associated with feeder loading and equipment operation.

Qualitative and Quantitative Analysis of Project and Project Alternatives:

Oakville Hydro's SCADA system is wholly dedicated to the Oakville Hydro distribution system. These enhancements provide system tools that are not available in any other format without removing the entire SCADA system and investing in a full system change out. This alternative would be very costly and disruptive to Control Room Operations.

The addition of these functions would shorten the restoration time following unplanned outages. Also, optimized load flow would provide the Control Room Operators with the information needed to prevent stressing system equipment when the system is operated out of normal configuration.

2. Safety

The Loadflow information provided to Operators will be communicated to field staff to drive proper selection of switching equipment, driving a safety improvement for field staff.

3. Cyber-Security, Privacy

All SCADA traffic is transmitted from our SCADA Masters of which 2 machines are at our head office and the 3rd is offsite. A secure 400MHz radio network is used for remote motorized switches and fault indicators. There is a 1 Gbps dark fiber network interconnecting all our substations.

4. Co-ordination, Interoperability

n/a

5. Economic Development

The SCADA vendor is based out of Mississauga, this investment will support local economic development

6. Environmental Benefits

n/a

Project #: 14-64A1
Project Name: SCADA Enhancements in Loadflow, Contingency Analysis, FDIR
System Type: *System Service*

CATEGORY SPECIFIC REQUIREMENTS

Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable:

The Loadflow and Contingency Analysis functional improvements will prevent equipment stress, maintaining asset health and avoiding premature equipment failure & replacement.

Regional Electricity Infrastructure Requirements which Affected Project , if applicable:

n/a

Description of Incorporation of Advanced Technology, if applicable:

The proposed enhancements will provide additional tools to the Control Room Operators including detailed system load levels, critical equipment impacting system operations, and automatic restoration following an unplanned outage.

Identify any reliability, efficiency, safety or coordination benefits:

Reliability is improved with automated restoration capabilities built into the SCADA system. The Loadflow information provided to Operators will be communicated to field staff to drive proper selection of switching equipment, driving a safety improvement for field staff.

Factors Affecting Timing/Priority:

The proposed enhancements were originally planned for 2013, but development and implementation of the Outage Management System (OMS) lasted into 2014. The first stage of the OMS project required export of GIS network into SCADA, and there were a number of technical challenges that were unforeseen and required resolution. The proposed enhancements require this same network before they can be implemented.

Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (include qualitative factors if applicable):

Without FDIR, remote restoration would continue to be done manually by Control Room Operators. Without Contingency Analysis, the distribution system will continue to be at risk when switched out of normal configuration.

Project #: 14-64A1
Project Name: SCADA Enhancements in Loadflow, Contingency Analysis, FDIR

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	16-G2
Project Name:	27.6kV Air insulated switchgear upgrades to G&W
Project Category:	Alterations and Improvements for Load Transfer and System Security
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	October 1, 2013
In Service Date:	May 15, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$465,000	$379,340
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$465,000	$379,340
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$379,340	$0	$0

Risks to Completion and Risk Mitigation:

This equipment has a very long leadtime, but this will be mitigated by developing the project plan and placing the equipment order in 2013. At the time of installation, there can be unforeseen conditions such as cable length, cable condition, etc.

Comparative Information on Equivalent Historical Projects (if any):

Replacements similar to this proposed replacement have been executed a number of times over the last few years. The proposed replacements use standard materials and field crews have the necessary experience.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

This budget represents the risk, value and cost for the program to complete replacement of 27.6kV air insulated switchgear with new gas insulated switchgear with remote control back to the control room. The existing air insulated switchgear is subject to accelerated aging due to adverse weather conditions, road salt, etc. The gas insulated switchgear have a sealed tank compartment preventing the accelerated aging. This budget represents year two of the program. This project will cover all costs to convert the switchgears and supply new AC service to the locations if required. Proposed for conversion are SC208 on Voyager Dr, south of Dundas St, SC132 on River Glen Blvd at Harman Gate, and SC100 on Heritage Way, west of Goldsmith.

Project #: 16-G2

Project Name: 27.6kV Air insulated switchgear upgrades to G&W

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

The existing assets that are proposed for replacement are reaching end of life and represent a reliability risk to our system.

Priority and Reasons for Priority:

The proposed locations represent a high risk to the distribution system due to the potential to affect large customer groups in the event of failure. Each of these switchgear locations have local circuits directly connected to radially supply customers.

Qualitative and Quantitative Analysis of Project and Project Alternatives: Realize savings of switchgear dry ice cleaning. Air insulated equipment is prone to premature failure and would warrant emergency replacements causing the requirement of additional, non budgeted funds. Crews are needed to be dispatched to mitigate this emergency causing delays in other work. Failed air insulated equipment causes feeder lockout. Crews would have to identify the issue of the failed equipment, and perform switching. Depending on location of failed equipment, some customers could be off up to four hours until the fix was performed.

2. Safety

Switchgear in a degraded, reaching end of life condition can be hazards for electrical flashover due to a build up of contamination on the insulators within the switchgear cubical. New switchgear would contain no contamination, and would make use of Cycloaliphatic Epoxy Resin system which provide maximum resistance to power arcs.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

The control system supplied with the new equipment uses industry standard, substation style, controller products that use communication protocols that are standard in the utility industry. At a later date these can be integrated into an automated restoration scheme.

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 16-G2
Project Name: 27.6kV Air insulated switchgear upgrades to G&W
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

Asset conditions are listed as "Fair" with equipment at end of life. These assets have a poor performance record past their typical useful lives.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

Number of customers affected range between 5,000 to 9,000 customers. Primarily residential customers.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the assets fails. We could expect to see auto-recloses due to flashovers without the entire asset failing. Once the failure curve reaches the breaking point we could expect an approximate 90-240 minute outage to allow for sectionalizing, approximately 450,000-2,160,000 customer minutes. High risk.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention. Medium Risk.

5. Value of Customer Impact (high, medium, low)

Medium to High with the length of outage and number of customers

Factors Affecting Project Timing, if any:

Substantial amount of equipment lead-time.

Consequences for O&M System Costs Including Implications of Not Implementing:

Increase maintenance costs involved due to cleaning required for the existing switchgears, new style switchgear proposed for installation is hermetically sealed and gas filled, so it does not require cleaning.

Reliability and Safety Factors:

Newer switchgear is more reliable due to construction materials, hermetically sealed, and gas filled. Deadfront construction switchgear reduces the potential for injury due to flashovers.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

From a system configuration perspective, this is a like for like replacement, but the proposed equipment is technologically enhanced compared to the existing equipment. The new equipment is hermetically sealed and gas filled to reduce the required maintenance. The new equipment also has two remotely controllable ways compared to the existing equipment which may not even have remote control option.

Project #: 16-G2
Project Name: 27.6kV Air insulated switchgear upgrades to G&W

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	16-U1
Project Name:	Gang-Op Switch Replacement Program
Project Category:	Alterations and Improvements for Load Transfer and System Security
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	March 1, 2013
In Service Date:	May 21, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$361,000	$267,139
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$361,000	$267,139
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$267,139	$0	$0

Risks to Completion and Risk Mitigation:

This equipment has a very long leadtime, but this will be mitigated by developing the project plan and placing the equipment order in 2013. At the time of installation, there can be unforeseen conditions such as pole height.

Comparative Information on Equivalent Historical Projects (if any):

Similar projects since 2006 providing approximate costs for this work.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost for completion of the program to replace 27.6kV Vacuum gang operated switches in the distribution system. This is year one of the program, and will cover the cost to replace five switch locations with new SCADAMate loadbreak switches. The proposed locations are S3111-V at 1400 North Service Road West between Third and Fourth Line; S1015-V on Burloak Rd, two poles south of Rebecca Street; S3074-V on Third Line at the North Service Road (North East corner); S2049-V on Speers Rd, West of Speers MS; S2063-V on Bronte Rd, 3 poles south of South Service Rd; These switches tend to fail without warning, and there is no maintenance that can be performed in order to keep them in working order. In the case they fail, we do not have any spare parts to have them fixed, and they must be replaced with newer style remote operated switches.

Project #: 16-U1

Project Name: Gang-Op Switch Replacement Program

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

Support of Organizational Strategy - Service, by balancing asset management in conjunction with safety, reliability and cost. Reducing the risk to service quality, company image due to degrading service quality, public and employee safety.

Priority and Reasons for Priority:

High Risk, High Probability of failure. Failures can affect multiple TS feeders. In the case these assets fail prematurely, in order to ensure the system is reliable, funds need to be made available to replace the assets regardless of set budgets.

Qualitative and Quantitative Analysis of Project and Project Alternatives:

Vacuum switches are prone to premature failure and would warrant emergency replacements causing the requirement of additional, non budgeted funds. Crews are needed to be dispatched to mitigate this emergency causing delays in other work. Failed vacuum switches can cause multiple feeder lockouts. Crews would have to identify the issue of the failed equipment, and perform switching. Depending on location of failed equipment, some customers could be off up to four hours until the fix was performed.

2. Safety

Vacuum switches in a degraded, near end of life condition can be hazards for electrical flashovers or explosions. There has been recorded history of these switches exploding, and in one case causing a fire.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

N/A

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 16-U1
Project Name: Gang-Op Switch Replacement Program
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

Conditions range from Poor to Very Poor per Health Index. Typical life cycle is 25 years. Assets currently over that life.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

7243 to 13000 customers affected by these assets. Mostly residential customers with some commercial/industrial.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the asset fails. We could expect to see auto-recloses due to flashove

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention. Medium Risk.

5. Value of Customer Impact (high, medium, low)

High

Factors Affecting Project Timing, if any:

Five gang operated switches are proposed to be replaced each year over the forecast period. The vacuum switches are the oldest and most risky gang operated switch in Oakville Hydro's distribution system and will be replaced first, followed by the motor operated load break switches, then load break switches.

Consequences for O&M System Costs Including Implications of Not Implementing:

Expected increase of patrols due to auto-recloses caused by flashovers in these assets causing an increase in O&M system cost. Remote operation failure can cause additional switching times as crews would have to manually access the switching point.

Reliability and Safety Factors:

Newer gang operated switches are more reliable due to construction materials and methods. The switches shall utilize an integrated switch operator having no exposed moving parts between the switch and any other device. The interrupters and the stored-energy operating mechanism shall be maintenance-free. The switch shall have an integral visible-break disconnect device operable by means of a hookstick. Maintenance-free wiping contacts to prevent operational difficulties arising from corrosion or frost. Self-lubricating, maintenance-free bearings.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 16-U1
Project Name: Gang-Op Switch Replacement Program

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	05-P2
Project Name:	Power Transformer Replacement Program
Project Category:	Substations
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Scott Carpenter
Start Date:	
In Service Date:	October 22, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$300,150	$268,190
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$300,150	$268,190
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$118,190	$150,000	$0	$0

Risks to Completion and Risk Mitigation:

This equipment has a very long leadtime, but this will be mitigated by developing the project plan and placing the equipment order in Q4 2013. At the time of installation, there can be site specific restrictions such as existing transformer foundations that need to be accommodated.

Comparative Information on Equivalent Historical Projects (if any):

In the last 5 years we have replaced 3 Municipal Substation power transformers of similar size on schedule and on budget.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost for completion of the yearly program to replace power transformers in the distribution system. It is proposed to replace one power transformer per year in order to manage capital spending levels in the future. If Oakville Hydro does not start replacing these transformers pro-actively, they encounter situations where more than one of these expensive long lead transformers will be required to be replaced within the same year, putting the system at risk and driving capital costs higher than expected. It is proposed to replace the power transformer at Woodhaven Municipal Substation which is the oldest power transformer in our distribution system and has been in service since 1957.

Project #: 05-P2

Project Name: Power Transformer Replacement Program

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

The main driver for this project is to avoid the risks associated with the failure of Municipal Substation power transformers. Our Municipal Substations supply anywhere from 500 to 2000 customers, and in the event of a transformer failure all of these customers would need to be transferred to other substations, which would be challenging to achieve during the summer peak load season and would require extensive manual field operation and coordination.

Priority and Reasons for Priority:

High Risk, High Probability. In the case one of these assets fail we could expect multiple MS feeders to be affected, and it will place our system at risk as the existing feeders will need to be fed from adjacent stations causing strain and inflexibility on the system. In the case this asset fails prematurely, in order to ensure the system is reliable, funds would need to be made available to replace the asset regardless of set budgets.

Qualitative and Quantitative Analysis of Project and Project Alternatives: Without a proactive replacement program for these transformers we could expect to spend over $300,000 to replace a failed unit after an unexpected failure. With no capital budgets set for replacements this would cause a large deferral of a set project. There is potential for large extensive outages until such time as the transformer is replaced, or the load on the feeders can be properly distributed to adjacent feeders. We could also expect longer outages during emergency situations due to the inflexibility of the system with a station out for an extended period of time.

2. Safety

N/A

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

N/A

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 05-P2
Project Name: Power Transformer Replacement Program
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

This asset is 56 years old, and has been noted to have a poor oil quality. Typical lifecycle is 45 years.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

Approximately 715 customers are serviced from this transformer, mostly residential.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the asset fails. We can expect an approximate 120 to 300 minute outage to allow for sectionalizing, approximately 85,800 to 214,500 customer minutes. Medium-High Risk.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention. Medium Risk.

5. Value of Customer Impact (high, medium, low)

High

Factors Affecting Project Timing, if any:

These assets are proposed to be replaced once per year over the forecast period. There are 36 of these assets in the system, at an investment of one per year every unit is proposed to be replaced after TUL has passed. High priority vs. other projects.

Consequences for O&M System Costs Including Implications of Not Implementing:

We would expect to require oil testing on a more frequent basis depending on how quickly the oil condition deteriorates.

Reliability and Safety Factors:

Our Municipal Substations supply anywhere from 500 to 2000 customers, and in the event of a transformer failure all of these customers would need to be transferred to other substations, which would be challenging to achieve during the summer peak load season and would require extensive manual field operation and coordination.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 05-P2
Project Name: Power Transformer Replacement Program

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	05-Q2
Project Name:	Victoria MS Low Voltage Breaker Replacement Program
Project Category:	Substations
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Scott Carpenter
Start Date:	
In Service Date:	October 22, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$635,400	$547,715
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$635,400	$547,715
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$147,715	$400,000	$0	$0

Risks to Completion and Risk Mitigation:

This equipment has a very long lead-time, but this will be mitigated by developing the project plan and placing the equipment order in Q4 2013. At the time of installation, there can be site specific restrictions such as existing footprint requirements for the breakers to accommodate cable entry.

Comparative Information on Equivalent Historical Projects (if any):

In the last 5 years we have replaced 4 sets of breaker equipment in Municipal Substations of similar size on schedule and on budget.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost for completion of the yearly program to replace a lineup of low voltage breakers in the distribution system. It is proposed to replace one breaker lineup per year in order to manage capital spending levels in the future. If Oakville Hydro does not start replacing these breakers pro-actively, they encounter situations where more than one of these expensive long lead lineups will be required to be replaced within the same year, putting the system at risk and driving capital costs higher than expected. It is proposed to replace the breaker lineup at Victoria MS, which is the oldest metal clad breaker lineup in the distribution system and has been in service since 1973.

Project #: 05-Q2
Project Name: Victoria MS Low Voltage Breaker Replacement Program

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for this project is to avoid the risks associated with the failure of Municipal Substation breaker equipment. Our Municipal Substations supply anywhere from 500 to 2000 customers, and in the event of a switchgear failure all of these customers may need to be transferred to other substations, which would be challenging to achieve during the summer peak load season, and would require extensive manual field operation and coordination.

Priority and Reasons for Priority:
High Risk, High Probability. In the case one of these assets fail we could expect multiple MS feeders to be affected, and it will place our system at risk as the existing feeders will need to be fed from adjacent stations causing strain and inflexibility on the system. In the case this asset fails prematurely, in order to ensure the system is reliable, funds would need to be made available to replace the asset regardless of set budgets.

Qualitative and Quantitative Analysis of Project and Project Alternatives: Without a proactive replacement program for these breaker lineups we could expect to spend over $400,000 to replace a failed lineup after an unexpected failure. With no capital budgets set for replacements this would cause a large deferral of a set project. In the case of failure, we could have large extensive outages until such time as the lineup is replaced, or the load on the feeders can be properly distributed to adjacent feeders. We could also expect longer outages during emergency situations due to the inflexibility of the system with a station out for an extended period of time.

2. Safety
The existing equipment is contained within a fabricated metal outdoor enclosure rather than a brick building. The metal enclosure and the switchgear equipment is all past end of life, and will be replaced as one unit. The aging enclosure presents a risk of water entry to the switchgear, which is a safety hazard associated with operation during poor weather conditions. The physical breakers have a number of critical mechanical components that are subject to wear & tear, and present a misoperation risk when they are operated past useful life.

3. Cyber-Security, Privacy
N/A

4. Co-ordination, Interoperability
N/A

5. Economic Development
N/A

6. Environmental Benefits
N/A

Project #: 05-Q2
Project Name: Victoria MS Low Voltage Breaker Replacement Program
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

This asset has exceeded its typical useful life of 25 years.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

826 Customers serviced from this breaker equipment, mostly commercial.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the asset fails. We could expect to see feeder circuit interruptions due to issues with equipment operation without the entire asset failing. Once the failure curve reaches the breaking point we could expect an approximate 120 to 300 minute outage to allow for sectionalizing, approximately 99,120 to 247,800 customer minutes. Medium-High Risk.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention. Medium Risk.

5. Value of Customer Impact (high, medium, low)

High

Factors Affecting Project Timing, if any:

These assets are proposed to be replaced once per year over the forecast period. Currently 19 of these assets in the system, at an investment of one per year every unit is proposed to be replaced after TUL has passed. High priority vs. other projects.

Consequences for O&M System Costs Including Implications of Not Implementing:

N/A

Reliability and Safety Factors:

Our Municipal Substations supply anywhere from 500 to 2000 customers, and in the event of a switchgear failure all of these customers may need to be transferred to other substations, which would be challenging to achieve during the summer peak load season, and would require extensive manual field operation and coordination.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 05-Q2
Project Name: Victoria MS Low Voltage Breaker Replacement Program

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	46-A
Project Name:	Replace Overhead Assets on John Street
Project Category:	Rebuild Overhead Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	May 1, 2013
In Service Date:	June 30, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$310,000	$207,270
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$310,000	$207,270
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$155,453	$51,818	$0	$0

Risks to Completion and Risk Mitigation:

Delays may occur due to unforeseen conditions of existing old duct infrastructure not being useable to replace the existing cable. The existing cable might be too short to be transferred to the new poles or the existing vault structure might be found in poor condition and may require replacement.

Comparative Information on Equivalent Historical Projects (if any):

Over the last five years projects to replace similar equipment have been executed with costs between $50,000 to $300,000.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

This budget represents the risk, value and cost to replace the overhead assets located on John Street between Brock St and Forsythe St. Primary and secondary distribution system assets at this location were found in poor condition during the 2010 overhead patrol reports and should be replaced in order to mitigate the risk of the assets failing along this stretch of road. Also any existing underground dip cables of insufficient length should be replaced. Due to lack of fusing some local feeders are directly connected to the express feeders in this area.

Project #: 46-A

Project Name: Replace Overhead Assets on John Street

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main driver - Balancing asset management in conjunction with safety, reliability and cost. Reducing risk due to degrading service quality by installing new, more reliable assets, as well as following current installation standards and specifications.

Priority and Reasons for Priority: High risk, high probability. Failure can affect many customers due to the existing radial feed system configuration. In case some of the assets fails prematurely, to restore power in this area funds will need to be available to replace assets regardless of set budgets.

Qualitative and Quantitative Analysis of Project and Project Alternatives: These assets are servicing mostly commercial zoned properties and some residential services. We could expect to have multiple customers off at a time. Some parts are directly connected to our express feeders, so problems would affect the whole feeder. If one of these assets fails, we would need to replace it immediately. If the aging assets are not replaced possible failures could cause faults and affect the entire feeder due to direct connections. With no existing fault indication or control to local feeders, customers would be off of power until a call came in and crews could be dispatched to identify the issue and replace. The load on the feeder could be off up to 4 hours until the issue is resolved. Due to the age of the assets we could expect a pole with a transformer to fall over which could cause the insulating oil to spill on a customers property. The top of most of these poles are rotten and if relocation of overhead conductor is required to eliminate a public safety hazard, then clearances are a significant issue. This area is located in a high vegetation level area and current overheads primary conductor insulation is in very poor condition, and there is risk of a fire hazard during periods of high winds and storm conditions. During design all pole loading, related required guying, pole framing, system protection coordination will be re-assessed to conform to current installation standards.

2. Safety

Poor pole conditions, old porcelain insulators, undersized secondary bus, old cable terminations, and aging overhead transformers are a hazard for electrical flashover.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

n/a

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 46-A
Project Name: Replace Overhead Assets on John Street
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

All overhead assets, structure, transformers, overhead wires, UG cable termination and related hardware, during patrol conducted in 2009, have been identified as in "poor" condition, and exceed their useful life.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

The supply to this area impacts 330 customers that are mostly commercial.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend of how and which assets fails. Momentary interruptions are expected due to flashovers without the entire asset to falling. Once a persistent failure reaches the breaking point, we expect approximately 90 minutes of outage time to allow for sectionalizing, approximately 29,700 customer minutes.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints, commercial businesses affected due to the outage require for power restorations

5. Value of Customer Impact (high, medium, low)

medium

Factors Affecting Project Timing, if any:

Availability of resources will impact the project timing, and this is managed as part of the ongoing construction program.

Consequences for O&M System Costs Including Implications of Not Implementing:

There will be an increase of patrols due to momentary interruptions caused by flashovers in these assets causing an increase in O&M system costs.

Reliability and Safety Factors:

New installation will be more reliable, due to new, more technological advanced equipment, due to system upgrade to current installation standard. We expect to reduce or eliminate all possible existing safety hazards due resulting from existing aging equipment.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 46-A
Project Name: Replace Overhead Assets on John Street

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	46-B
Project Name:	Replace Overhead Assets on Queen Mary, Bond and Chisholm
Project Category:	Rebuild Overhead Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	May 1, 2013
In Service Date:	September 1, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$550,000	$358,919
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$550,000	$358,919
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$269,189	$89,730	$0

Risks to Completion and Risk Mitigation:

One major risk to job completion could be unforeseen issues when trying to break into the existing concrete encased duct structure to allow re-routing / replacement or splicing of the radial feed primary cables feeding five apartment buildings; Work must be completed before summer peak time considering the current express feeder configuration at Queen Mary to avoid putting the distribution system at risk when load transfer capacity is not available between Thomas MS and Kerr MS substations.

Comparative Information on Equivalent Historical Projects (if any):

Over the last three years we have successfully completed two similar projects that can be used as comparison: Cross Ave Rebuild, Trafalgar Rd Rebuild

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost to replace the overhead assets located on Queen Mary Dr, south of Riverside Dr, Bond St, and Chisholm St north of Lakeshore Rd W. This area was noted in poor condition during the overhead patrol reports and should be replaced in order to mitigate the risk of the assets failing along these stretches of road. Also any existing underground dip cables of insufficient length will be replaced or extended to the new pole. These roads have express feeders which are directly connected to the Municipal Substations.

Project #: 46-B

Project Name: Replace Overhead Assets on Queen Mary, Bond and Chisholm

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

The main driver for this project is a reduction in risk to the distribution system due to a limited capacity to perform load transfers between major Municipal Substations during summer loading periods.

Priority and Reasons for Priority: The proposed locations represents a high risk and high probability for equipment failure based on the asset age and condition. Failure can affect multiple Municipal Substation feeders or a Transformer Station feeder.

Qualitative and Quantitative Analysis of Project and Project Alternatives: These assets are servicing some commercial, and both low and high density residential properties. We can expect to have multiple customers out of power in the event of a failure. Express feeders are installed on these roads, so an equipment failure would affect the whole feeder. If one of these assets fail, we would need to replace it immediately to new standards. If the aging assets are not replaced then the probability of failure increases, and in the event of a failure the affected customers would be out of power until crews can be dispatched to make repairs. The load on the feeder could be off up to 4 hours until the issue is resolved. Due to the age of all assets in this project we could expect failure of existing insulators, or spacer system, or switches or even pole failure with transformer on it that could cause oil spill and/or cause major safety hazards.

2. Safety

Poor pole conditions, old porcelain insulators, undersized secondary bus, old cable terminations, and aging overhead transformers are a hazard for electrical flashover.

3. Cyber-Security, Privacy

n/a

4. Co-ordination, Interoperability

Majority of the poles included in this project are owned by Bell ; multiple third party attachments are present at these locations; Planning/Design would have to be coordinated with owner of the poles and construction to be coordinated with the third party company having assets installed on these poles.

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 46-B
Project Name: Replace Overhead Assets on Queen Mary, Bond and Chisholm
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

All assets in this project have reached or exceeded their useful life; all assets during patrols have been identified in very poor condition backed up by health index of individual assets.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

1225 customers are affected, a mix of residential and commercial, some high density residential

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions will depend of how and which asset fails. Auto-recloses are expected to be seen due to flashovers whiteout entire asset to fail. Minimum 90 minutes outage is expected to allow sectionalizing; if failure of a specific assets for radial feed sections , such as cable terminations, cable failure, power restoration time will extend to min four hours ; 110,250 to 294,000 possible customer minutes

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local medium attention, due to longer outages required to restore power or "in construction site for a long period of time

5. Value of Customer Impact (high, medium, low)

medium

Factors Affecting Project Timing, if any:

Possible restraints/ delays in acceptance from Pole Owners(Bell) in regard with proposed design, pole height increase, location; this is reason why planning/design need to be completed way in advanced to avoid delays in proposed construction schedule.

Consequences for O&M System Costs Including Implications of Not Implementing:

We can expect an increase of feeder patrols due to auto-recloses due to faults

Reliability and Safety Factors:

Newer assets are more reliable and minimize the risk to failure and/or flashover; switches replacement with gang operating new style switches will improve operations when sectionalized and improve safety

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 46-B
Project Name: Replace Overhead Assets on Queen Mary, Bond and Chisholm

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN
Engineering

GENERAL

Project Number:	46-C
Project Name:	Replace Overhead Assets on Robinson St.
Project Category:	Rebuild Overhead Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	September 15, 2013
In Service Date:	June 30, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$720,000	$458,981
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$720,000	$458,981
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$0	$344,236	$114,745

Risks to Completion and Risk Mitigation:
Delays may occur due to unforeseen conditions of existing old duct infrastructure for existing underground dip primary cables to be re-routed to the new poles. The existing cable might be too short to be transferred to the new poles or the existing vault structure might be found in poor condition and may require replacement.

Comparative Information on Equivalent Historical Projects (if any):
Over the last five years projects to replace similar equipment have been executed with costs between $50,000 to $400,000.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:
This budget represents the risk, value and cost to replace the overhead assets located on Robinson Street between Navy St and Allan St. Primary and secondary distribution system assets at this location were found in poor condition during the 2010 overhead patrol reports and should be replaced in order to mitigate the risk of the assets failing along this stretch of road. Also any existing underground dip cables of insufficient length should be replaced. These roads have express feeders which are directly connected to Municipal substations.

Project #: 46-C
Project Name: Replace Overhead Assets on Robinson St.

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main driver - Balancing asset management in conjunction with safety, reliability and cost. Reducing risk due to degrading service quality by installing new, more reliable assets, as well as following current installation standards and specifications.

Priority and Reasons for Priority: High risk, high probability. Failure can affect many customers due to current looped feed configuration and multiple express feeders interconnection. In case some of the assets fails prematurely, to restore power in this area funds will need to be available to replace assets regardless of set budgets.

Qualitative and Quantitative Analysis of Project and Project Alternatives: These assets are servicing commercial zoned properties and residential services. We could expect to have multiple customers off at a time. Some parts are directly connected to our express feeders, so problems would affect the whole feeder. If one of these assets fails, we would need to replace it immediately. If the aging assets are not replaced possible failures could cause faults and affect the entire feeder due to direct connections. With no existing fault indication or control to local feeders, customers would be off of power until a call came in and crews could be dispatched to identify the issue and replace. The load on the feeder could be off up to 4 hours until the issue is resolved. Due to the age of the assets we could expect a pole with a transformer to fall over which could cause the insulating oil to spill on a customers property. The current hydro poles are concrete pole, majority in very poor condition and due for replacement; if relocation of overhead conductor is required to eliminate a public safety hazard, then clearances are a significant issue. During design all pole loading, related required guying, pole framing, system protection coordination will be re-assessed to conform to current installation standards.

2. Safety

Poor pole conditions, old porcelain insulators, undersized secondary bus, old cable terminations, and aging overhead transformers are a hazard for electrical flashover.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

n/a

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 46-C
Project Name: Replace Overhead Assets on Robinson St.
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

All overhead assets, structure, transformers, overhead wires, UG cable termination and related hardware, during patrol conducted in 2010, have been identified as in "poor" condition, and exceed their useful life.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

The supply to this area impacts approximately 149 customers which are mostly commercial.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions will depend of how and which asset fails. Auto-recloses are expected to be seen due to flashovers whiteout entire asset to fail. Minimum 90 minutes outage is expected to allow sectionalizing; if failure of a specific assets for radial feed sections , such as cable terminations, cable failure, power restoration time will extend to min four hours ; 13,410 to 35,760 possible customer minutes

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints, commercial businesses affected due to the outage require for power restorations

5. Value of Customer Impact (high, medium, low)

medium

Factors Affecting Project Timing, if any:

Availability of resources will impact the project timing, and this is managed as part of the ongoing construction program.

Consequences for O&M System Costs Including Implications of Not Implementing:

There will be an increase of patrols due to momentary interruptions caused by flashovers in these assets causing an increase in O&M system costs.

Reliability and Safety Factors:

New installation will be more reliable, due to new, more technological advanced equipment, due to system upgrade to current installation standard. We expect to reduce or eliminate all possible existing safety hazards due resulting from existing aging equipment.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 46-C
Project Name: Replace Overhead Assets on Robinson St.

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	45-A
Project Name:	Vault Transformer Replacements
Project Category:	Rebuild Underground Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	September 1, 2013
In Service Date:	November 30, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$430,000	$316,241
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$430,000	$316,241
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$0	$316,241	$0

Risks to Completion and Risk Mitigation:

One of the most significant risks to job completion involve the unknown condition of the existing infrastructure such as cables and duct systems. If addition repairs are required once the construction work starts, then the project will take much longer than planned. Alternate solutions such as cable injection will be considered to avoid project delays.

Comparative Information on Equivalent Historical Projects (if any):

This project is part of Oakville Hydro Vault Transformer Replacement Program and similar projects have been built in the last few years. However we will continue to investigate new /improved/ more reliable technologies for use in vault applications.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost of the program to replace all live front vault transformers and NX Fuses from vault rooms. This is a proposed multi-year project to eliminate this type of transformer from our system due to access and operation issues. The average age of these assets is 38 years old. The NX style fuses without tabs cannot be safely operated at this time. Where possible, it is preferable to relocate the transformers outside of the buildings for ease of access using padmount transformers. Where this is not possible, submersible style transformers should be used within the vault rooms to make the installations dead front. This budget represents year two of the program. Location 2303 @ 492 Kerr St, Location 3272 @ 134 Randall St, and 2430 @ 444 Kerr St are proposed within this budget. All locations should be reviewed to determine if conversion to 27.6kV is possible. Project involved replacement of primary cables, transformers, fused switches and grounding system

Project #: 45-A
Project Name: Vault Transformer Replacements

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for this project is a reduction in risk to the distribution system due to aging vault equipment. The vault transformers are the primary driver, but this replacement work will also include related vault switching equipment. Access restrictions to vault equipment result in repair times that are longer than similar equipment outside of a vault.

Priority and Reasons for Priority: High risk , high probability. Failure will affect many customers at the same time. The existing assets (primary cables, transformers, existing NX style fuses) that are proposed for replacement are reaching end of life and represent a reliability risk to our system. All locations in this project are radial feed supply, so failure of any of these assets will require emergency replacement.

Qualitative and Quantitative Analysis of Project and Project Alternatives: These types of assets typically supply large residential buildings or commercial units. We can expect to have multiple customers off at a time. If one of these assets fails, we would need to replace it immediately. If the aging assets are not replaced then a failures would cause the lateral fuses to open. With no existing fault indication or control to local feeders, customers would be out of power until a call came in and crews could be dispatched to identify the issue and replace the fuse(s). The customer supply from the transformers could be off over 12 hours until a replacement solution could be engineered. Due to degrading conditions of the assets in these rooms we can expect to find transformers leaking insulating oil causing a spill within the vault rooms which may leak into the vault drains requiring MOE documentation.

2. Safety

Switching in the vault rooms for existing transformers using the old style air break switches present a high concerns for safety. The new equipment would comply with current safety standards.

3. Cyber-Security, Privacy

n/a

4. Co-ordination, Interoperability

n/a

5. Economic Development

n/a

6. Environmental Benefits

n/a

Project #: 45-A
Project Name: Vault Transformer Replacements
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

Current assets (transformers, switches, connections, grounding system) are over 44 years old and noted in poor condition during patrols. Underground cables are past end of life and would be susceptible to failure if stressed.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

Considering current grid configuration and cable connection, a cable failure will affect many customers connected on the circuit until sectionalizing, where possible is completed; 484 customers, mostly high density residential

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

The assets are aging which will make them more prone to failure. If the aging assets are not replaced possible failures could cause faults causing the upstream protection to open. Without existing fault indication or control to local feeders, customers would be out of power until a call came in and crews are dispatched to identify the issue and replace the fuses(s). The customer supply from transformers could be off over 12 hours until a replacement solution can be engineered.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Frequency of interruption will depend of which and how assets fail. We could expect momentary interruptions to flashovers without the entire asset failing. Once the failure curve reaches the breaking point we could expect an approximate 90 minute to over 720 minute outage to allow for sectionalizing and/or asset replacement, 43,560 to 348,480 customer minutes. Medium risk.

5. Value of Customer Impact (high, medium, low)

medium

Factors Affecting Project Timing, if any:

Oakville Hydro has incorporated proper planning for resources and materials in order to ensure project completion on time.

Consequences for O&M System Costs Including Implications of Not Implementing:

Replacement of current NX style switches with equipment that meets current standards will result in more efficient operations.

Reliability and Safety Factors:

The project will be constructed to current standards and will use new, more reliable equipment; current transformers will be replaced to either padmounted dead front transformers of submersible style, built to current industry standards, which will allow for a system reliability increase as well as improvement for safety factors;

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

From a system configuration perspective the project is like for like, however new equipment will be used which is expected to increase reliability in this area.

Project #: 45-A
Project Name: Vault Transformer Replacements

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	45-D
Project Name:	Poletran Removals and Replace U/G Assets Various Locations
Project Category:	Rebuild Underground Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	June 3, 2013
In Service Date:	June 30, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$370,000	$292,164
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$370,000	$292,164
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$78,963	$213,200	$0	$0

Risks to Completion and Risk Mitigation:

This project involves replacement of system equipment in close proximity to customer property. The risk of public resistance to change is mitigated by communicating project plans with customers impacted to set appropriate expectations.

Comparative Information on Equivalent Historical Projects (if any):

This project is part of Oakville Hydro's asset renewal program, and similar poletran removals and underground rebuild projects have been executed consistently over many years. This is the last project in a multi-year program to remove poletran transformers.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

This budget represents the risk, value and cost for completion of the replacement of underground assets and poletran removals at 150 Water St, 3 Forsythe St, 130 Navy St, 1238 Crawford Court and 428 Donnybrook Rd The underground primary cables in this area are over 40 years old and represent some of the oldest underground cables in Oakville Hydro's distribution territory.

Project #: 45-D

Project Name: Poletran Removals and Replace U/G Assets Various Locations

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system.

Priority and Reasons for Priority:

Within these assets classes the proposed replacement area is composed of distribution assets that have been inspected and have the lowest condition rating.

Qualitative and Quantitative Analysis of Project and Project Alternatives:

The assets are significantly aged which make them prone to failure, requiring emergency replacement. If the aging assets are not replaced possible failures could cause faults causing the lateral fuses to open. With no existing fault indication or control to local feeders, customers would be out of power until a call came in and crews could be dispatched to identify the issue and replace the fuse(s). The outage resulting from equipment failure could last for up to four hours.

2. Safety

The poletrans (a combination steel pole that houses a transformer and supports a streetlight) pose safety concerns to field crews for operations and maintenance. As the existing poletrans continue to age, there is a chance of failure that represents a public safety risk.

3. Cyber-Security, Privacy

n/a

4. Co-ordination, Interoperability

n/a

5. Economic Development

n/a

6. Environmental Benefits

n/a

Project #: 45-D
Project Name: Poletran Removals and Replace U/G Assets Various Locations
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

The overhead assets were determined to be in a "poor" condition based on field inspection. The poletrans and underground cables represent some of the oldest underground assets in our system.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

The proposed projects directly affects 4-10 residential customers, and represents a potential risk to 200-500 upstream customers.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the assets fail. We could expect to see auto-recloses due to flashovers without entire assets failing. Once the failure curve reaches the breaking point for a certain asset, we could expect an approximate 240 minute outage to allow for sectionalizing, approximately 2,400 customer minutes.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention

5. Value of Customer Impact (high, medium, low)

Medium

Factors Affecting Project Timing, if any:

Oakville Hydro has incorporated proper planning for resources and materials in order to ensure project completion on time.

Consequences for O&M System Costs Including Implications of Not Implementing:

Replacement of poletrans in these areas will decrease potential maintenance and repair costs. Possible cable failures will require contractors to dig splice pits, and crew hours to repair cables.

Reliability and Safety Factors:

The area will be rebuilt to new standards, which exceeded the standards of the original construction increasing safety and reliability (I.E. type of materials, installations standards, etc.)

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

From a system configuration perspective the project is like for like, however new equipment will be used which is expected to increase reliability in this area.

Project #: 45-D
Project Name: Poletran Removals and Replace U/G Assets Various Locations

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	45-Q
Project Name:	Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion
Project Category:	Rebuild Underground Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	June 1, 2013
In Service Date:	August 1, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$496,999	$385,205
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$496,999	$385,205
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$154,082	$231,123	$0

Risks to Completion and Risk Mitigation:

This project involves replacement of system equipment in close proximity to customer property. The risk of public resistance to change is mitigated by communicating project plans with customers impacted to set appropriate expectations.

Comparative Information on Equivalent Historical Projects (if any):

This project is part of Oakville Hydro's asset renewal program, and similar overhead and underground rebuild projects have been executed consistently over many years.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

This budget represents the risk, value and cost for completion of the replacement of underground and overhead assets on Colchester, Oakhill, Dolphin and Albion. The underground primary cables in this area are approximately 38 years old and represent one of the oldest underground cables in Oakville Hydro's distribution territory. The overhead assets are of similar age, if not older. The primary cables are 38 years old in this area and are not in ducts.

Project #: 45-Q

Project Name: Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system.

Priority and Reasons for Priority:

Within these assets classes the proposed replacement area is composed of distribution assets that have been inspected and have the lowest condition rating.

Qualitative and Quantitative Analysis of Project and Project Alternatives:

The assets are significantly aged which make them prone to failure, requiring emergency replacement. If the aging assets are not replaced possible failures could cause faults causing the lateral fuses to open. With no existing fault indication or control to local feeders, customers would be out of power until a call came in and crews could be dispatched to identify the issue and replace the fuse(s). The outage resulting from equipment failure could last for up to four hours.

2. Safety

As the existing overhead equipment condition continues to degrade, there is a chance of failure that represents a public safety risk.

3. Cyber-Security, Privacy

n/a

4. Co-ordination, Interoperability

n/a

5. Economic Development

n/a

6. Environmental Benefits

n/a

Project #: 45-Q
Project Name: Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

The overhead assets were determined to be in a "poor" condition based on field inspection. The underground cables represent some of the oldest cables in our system.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

The proposed project area directly affects 43 residential customers, and represents a potential risk to 507 upstream customers.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the assets fail. We could expect to see auto-recloses due to flashovers without entire assets failing. Once the failure curve reaches the breaking point for a certain asset, we could expect an approximate 240 minute outage to allow for sectionalizing, approximately 10,320 customer minutes.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention

5. Value of Customer Impact (high, medium, low)

Medium

Factors Affecting Project Timing, if any:

Oakville Hydro has incorporated proper planning for resources and materials in order to ensure project completion on time.

Consequences for O&M System Costs Including Implications of Not Implementing:

Replacement of wood poles in this area will decrease the required testing and treatment costs for the next 15 years. Possible cable failures will require contractors to dig splice pits, and crew hours to repair cables.

Reliability and Safety Factors:

The area will be rebuilt to new standards, which exceeded the standards of the original construction increasing safety and reliability (I.E. type of materials, spacing standards, etc.)

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

From a system configuration perspective the project is like for like, however new equipment will be used which is expected to increase reliability in this area.

Project #: 45-Q
Project Name: Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	45-X
Project Name:	Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln
Project Category:	Rebuild Underground Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	June 1, 2013
In Service Date:	July 1, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$260,000	$184,665
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$260,000	$184,665
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$0	$92,332	$92,332

Risks to Completion and Risk Mitigation:

This project involves replacement of system equipment in close proximity to customer property. The risk of public resistance to change is mitigated by communicating project plans with customers impacted to set appropriate expectations.

Comparative Information on Equivalent Historical Projects (if any):

This project is part of Oakville Hydro's asset renewal program, and similar overhead and underground rebuild projects have been executed consistently over many years.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost for completion of the replacement of underground and overhead assets on Willowbrook Dr & Wendy Ln. The underground primary cables in this area are approximately 36 years old and represent one of the oldest underground cables in Oakville Hydro's distribution territory. The overhead assets are of similar age, if not older. The cables are 36 years old in this area and not in ducts.

Project #: 45-X

Project Name: Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system.

Priority and Reasons for Priority:
Within these assets classes the proposed replacement area is composed of distribution assets that have been inspected and have the lowest condition rating.

Qualitative and Quantitative Analysis of Project and Project Alternatives: The assets are aging which would make them more prone to failure requiring emergency replacement. If the aging assets are not replaced possible failures could cause faults causing the lateral fuses to open. With no existing fault indication or control to local feeders, customers would be off of power until a call came in and crews could be dispatched to identify the issue and replace the fuse(s). The load from the transformers could be off up to four hours until a new transformer could be installed or switching to isolate cable. Aging transformers could fail and allow insulating oil to escape onto sewer connections.

2. Safety

As the existing overhead equipment condition continues to degrade, there is a chance of failure that represents a public safety risk.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

N/A

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 45-X
Project Name: Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

Overhead wires, switches, and poles noted to be in poor to very poor condition. Underground wires are not installed in ducts, and are not TR-XLPE.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

The proposed project area directly affects 35 residential customers, and represents a potential risk to 233 upstream customers.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the asset fails. We could expect to see momentary interruptions due to flashovers without the entire asset failing. Once the failure curve reaches the breaking point we could expect an approximate 90 to 240 minute outage to allow for sectionalizing, approximately 3,150 to 55,920 customer minutes. Medium Risk.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to the company. Medium-Low risk.

5. Value of Customer Impact (high, medium, low)

Medium

Factors Affecting Project Timing, if any:

Oakville Hydro has incorporated proper planning for resources and materials in order to ensure project completion on time.

Consequences for O&M System Costs Including Implications of Not Implementing:

Replacement of wood poles in this area will decrease the required testing and treatment costs for the next 15 years. Possible cable failures will require contractors to dig splice pits, and crew hours to repair cables.

Reliability and Safety Factors:

The area will be rebuilt to new standards, which exceeded the standards of the original construction increasing safety and reliability (I.E. type of materials, spacing standards, etc.)

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

From a system configuration perspective the project is like for like, however new equipment will be used which is expected to increase reliability in this area.

Project #: 45-X
Project Name: Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	42-B
Project Name:	Live front Padmount Transformer Replacements
Project Category:	Transformer Replacements and Voltage Conversion
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	June 1, 2013
In Service Date:	May 30 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$350,000	$275,730
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$350,000	$275,730
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$82,719	$193,011	$0	$0

Risks to Completion and Risk Mitigation:

This project involves replacement of system equipment in close proximity to commercial customer property. The risk of public resistance to change is mitigated by communicating project plans with customers impacted to set appropriate expectations.

Comparative Information on Equivalent Historical Projects (if any):

Similar three phase transformer installations have been completed for all industrial/commercial services which can provide comparative information regarding costs and requirements.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost for completion of the program to replace all of the remaining Live front Padmount Transformers in Oakville Hydro's distribution territory. Oakville Hydro has phased these transformers out over time and only a handful remain in the field with no straight replacement stock available. On average these units are 40 years old. This budget represents year one of the program. Location 4371 at 215 Rebecca St is proposed for replacement, and is a candidate for voltage conversion from 4kV to 27.6kV. Location 4267 and 4588 at 1005 and 1027 Speers Rd are proposed for replacement. These three transformers are candidates for voltage conversion from 4kV to 27.6kV, and should be placed on a loop feed. This budget should cover the cost of all cable replacements and pole upgrades required to perform the work.

Project #: 42-B

Project Name: Live front Padmount Transformer Replacements

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system.

Priority and Reasons for Priority:

Within these assets classes the proposed replacement area is composed of distribution assets that have been inspected and have the lowest condition rating.

Qualitative and Quantitative Analysis of Project and Project Alternatives: The assets are older which would make them more prone to failure requiring replacement without a capital budget. Typically installed to old standards and without proper transformer vaults, it would require replacement onto a new pad. If the aging assets are not replaced possible failures could cause faults causing the lateral fuses to open. With no existing fault indication or control to local feeders, customers would be off of power until a call came in and crews could be dispatched to identify the issue and replace the fuse(s). The load from the transformers could be off over 12 hours until a replacement solution could be engineered. Aging transformers could rust enough to allow insulating oil to escape onto private property.

2. Safety

Due to the transformer having live contacts it is possible for an employee to fall into the energized primary while doing inspections every three years. New transformer standards require a dead-front style to be used, which limits the danger to crews.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

N/A

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 42-B
Project Name: Live front Padmount Transformer Replacements
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

Condition listed between "Fair" and "Poor" per Health Index. Typical life cycle 35 years.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

Four to Ten commercial customers serviced from these locations

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the asset fails. We could expect to see auto-recloses due to flashovers without the entire asset failing. Once the failure curve reaches the breaking point we could expect an approximate 720 minute outage to allow for sectionalizing, approximately 2880 to 7200 customer minutes. High Risk.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to regulator, with possible regional media attention. Medium-High Risk.

5. Value of Customer Impact (high, medium, low)

High

Factors Affecting Project Timing, if any:

Three of these assets are proposed to be replaced per year over the forecast period. Currently 41 of these assets in the system, at an investment of three per year every unit is proposed to be replaced after TUL has passed. High priority vs. other projects.

Consequences for O&M System Costs Including Implications of Not Implementing:

Expected increase of patrols due to auto-recloses caused by flashovers in these assets causing an increase in O&M system costs.

Reliability and Safety Factors:

Newer padmount transformers are deadfront construction, where the primary cables are insulated from the crews working on the equipment. Newer installations have vaults underneath the transformers to allow for extra cable to be stored in the case failure occurs and extra slack is required without replacing the entire cable.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 42-B
Project Name: Live front Padmount Transformer Replacements

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	44H
Project Name:	27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403
Project Category:	27.6kV Additions
System Type	System Access
Customer Attachments/Load:	
Project Manager:	Jon Foreshew
Start Date:	
In Service Date:	June 20, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$500,000	$420,973
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$500,000	$420,973
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$420,973	$0	$0

Risks to Completion and Risk Mitigation:

There is minimal risk to completion, this project is to support load growth in the area.

Comparative Information on Equivalent Historical Projects (if any):

Oakville Hydro has completed many similar projects in the past to extend or construct new circuits for system access activities.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

This budget represents the risk, value and cost for completion of work required to add an additional 27.6kV feeder on Upper Middle Road E, from Ninth Line to Highway #403, to support load growth in the Winston Business Park. This will also support future load growth in the next phase of new development in the area (Winston Park West). This project includes one additional fully rated 27.6kV circuit to interconnect with the existing network.

Project #: 44H

Project Name: 27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver: Support load growth and increased supply reliability to Winston Business Park. Support load growth for next phase of development, Winston Park West.

Priority and Reasons for Priority: Regulatory requirement and non-discretionary project, driven by development.

Qualitative and Quantitative Analysis of Project and Project Alternatives: The addition of this circuit will support load growth in the area, improve reliability and provide supply for new developments. The design and construction will be done in accordance with the most recent design and safety standards, and in the most cost effective manner.

2. Safety

n/a

3. Cyber-Security, Privacy

n/a

4. Co-ordination, Interoperability

n/a

5. Economic Development

This project supports economic development by providing supply facilities for new development and jobs.

6. Environmental Benefits

n/a

Project #: 44H
Project Name: 27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:

Customer drives the timing of the service requirement and Oakville Hydro prioritizes projects within its project planning schedule by meeting their in-service dates.

Factors Relating to Customer Preferences or Input:

n/a - the scope of this project is within the municipal road allowance and does not have direct impact on private property.

Factors Affecting the Final Cost of the Project:

Final cost is based upon actual cost of the construction, factors that can affect actual costs include: unexpected changes to scope, number of customer requests (anticipated vs. actual), customer initiated changes, weather and/or field conditions.

How Controllable Costs have been Minimized:

Prudent cost estimates are based on standardized materials, unit rate construction contracts, and appropriate equipment sizing.

Identify if Other Planning Objectives are Met by the Project, if so which ones:

The addition of this circuit will not only supply load growth and new developments but improve the supply reliability in the area.

Options Considered and Summary of Analysis:

n/a

Results of Final Economic Valuation, if applicable:

n/a

System Impacts (Nature, Magnitude and Costs):

n/a

Project #: 44H
Project Name: 27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	14-50C
Project Name:	New Development Investment
Project Category:	New Development / Services
System Type	System Access
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	
In Service Date:	December 31, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$2,691,000	$2,280,508
Contributed Capital:	$2,191,000	$1,856,780
OHEDI Capital Cost:	$500,000	$423,729
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$105,932	$169,492	$148,305

Risks to Completion and Risk Mitigation:

n/a

Comparative Information on Equivalent Historical Projects (if any):

Oakville Hydro continues to have new customer connections on an annual basis. The value and number of connections vary year to year based on market and new construction demands. These projects are commonly included in Oakville Hydro's project plans.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

New residential subdivisions require an economic evaluation to determine Oakville Hydro's capital contribution requirements.

Project #: 14-50C
Project Name: New Development Investment

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
This is a regulatory requirement based on the prescribed economic evaluation methodology.

Priority and Reasons for Priority:
n/a

Qualitative and Quantitative Analysis of Project and Project Alternatives:
Represents capital contributed for investment in new developments.

2. Safety

n/a

3. Cyber-Security, Privacy

n/a

4. Co-ordination, Interoperability

n/a

5. Economic Development

n/a

6. Environmental Benefits

n/a

Project #: 14-50C
Project Name: New Development Investment
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:
Oakville Hydro assesses the connection of new customers on an annual basis.

Factors Relating to Customer Preferences or Input:
n/a

Factors Affecting the Final Cost of the Project:
The number of customer connections vary from year to year.

How Controllable Costs have been Minimized:
n/a

Identify if Other Planning Objectives are Met by the Project, if so which ones:
n/a

Options Considered and Summary of Analysis:
n/a

Results of Final Economic Valuation, if applicable:
Final economic evaluations are done on a site by site basis.

System Impacts (Nature, Magnitude and Costs):
n/a

Project #: 14-50C
Project Name: New Development Investment

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	14-54
Project Name:	New General Services
Project Category:	New Development / Services
System Type	System Access
Customer Attachments/Load:	
Project Manager:	Jon Foreshew
Start Date:	January 1, 2014
In Service Date:	December 31, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$787,000	$598,945
Contributed Capital:	$325,000	$247,341
OHEDI Capital Cost:	$462,000	$351,604
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$87,901	$87,901	$87,901	$87,901

Risks to Completion and Risk Mitigation:

General service and large industrial customer requirements drive project timing. Oakville Hydro maintains a close relationship with these customers to ensure that service dates are met.

Comparative Information on Equivalent Historical Projects (if any):

General service requirements are an annual requirement based on the needs and demands of our customers. Services vary depending on size and complexity.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

This budget represents the risk, value and cost for any new general services in Oakville's distribution territory. Per Oakville Hydro conditions of service, Oakville Hydro funds transformation up to 2500kVA.
The Electricity Act states:
A distributor shall connect a building to its distribution system if, a) the building lies along any of the lines of the distributor's distribution system; and b) the owner, occupant or other person in charge of the building requests the connection in writing.

Project #: 14-54
Project Name: New General Services

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
The general service customer requires service for their proposed facilities.

Priority and Reasons for Priority:
Regulatory requirement and non-discretionary project, initiated by customers.

Qualitative and Quantitative Analysis of Project and Project Alternatives:
Ensure compliance with Section 28 of the Electricity Act and customer satisfaction. The costs associated with this project are partially funded by the customer based upon calculated estimates.

2. Safety
New services are designed and constructed to ESA regulations.

3. Cyber-Security, Privacy
N/A

4. Co-ordination, Interoperability
N/A

5. Economic Development
Installation of distribution equipment allows for local economic development and jobs.

6. Environmental Benefits
N/A

Project #: 14-54
Project Name: New General Services
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:

Customer drives the timing of the service requirement and Oakville Hydro prioritizes projects within its project planning schedule by meeting their in-service dates.

Factors Relating to Customer Preferences or Input:

Oakville Hydro works with potential customers to ensure that their needs are met. Projects are designed according to their input, within the guidelines of the conditions of service.

Factors Affecting the Final Cost of the Project:

Final cost is based upon actual cost of the construction, factors that can affect actual costs include: unexpected changes to scope, number of customer requests (anticipated vs. actual), customer initiated changes, weather and/or field conditions.

How Controllable Costs have been Minimized:

Prudent cost estimates are based on standardized materials, unit rate construction contracts, and appropriate equipment sizing. For these project, the customer contributes to all costs except for the transformer.

Identify if Other Planning Objectives are Met by the Project, if so which ones:

n/a

Options Considered and Summary of Analysis:

These projects are initiated by the customer, and Oakville Hydro can provide the customer with some options to align with the needs of the customer provided that the project satisfies all technical and safety requirements.

Results of Final Economic Valuation, if applicable:

n/a

System Impacts (Nature, Magnitude and Costs):

Any new services that would impact our system from a loading perspective are captured under a specific project. The services included in this project do not generally impact the existing system.

Project #: 14-54
Project Name: New General Services

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	14-61
Project Name:	Distribution Meters
Project Category:	Distribution Meters / Wholesale Meter Upgrades
System Type	System Access
Customer Attachments/Load:	
Project Manager:	Bob Myers
Start Date:	January 1, 2014
In Service Date:	December 31, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$605,625	$481,706
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$605,625	$481,706
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$101,850	$128,700	$102,600	$272,475

Risks to Completion and Risk Mitigation:

Comparative Information on Equivalent Historical Projects (if any):

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

Project Summary:

This budget is for the required distribution meters in Oakville's distribution territory. The Distribution System Code states: 5.1.1 A distributor shall provide, install and maintain a meter installation for retail settlement and billing purposes for each customer connected to the distributor's distribution system. This project includes new residential meters equipped with zigbee to facilitate "real-time" data access and "behind the meter" services, new multi-residential meters, new commercial meters, commercial meter communication conversion from dial up to flex net, and a new Tower Gateway Base ("TGB") station to support smart meter data collection.

Project #: 14-61
Project Name: Distribution Meters

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
This project supplies metering infrastructure to measure consumption as required for new services. A new TGB is required to address new residential and small commercial growth in Oakville. Each TGB will reach its saturation point for number of meters it can read and a new TGB must be installed to communicate with new smart meters. New development currently under-way north of Hwy 5 in Oakville will result in the requirement for a 6th TGB since existing TGB's are at capacity and will not be capable of communicating with the new meters.

Priority and Reasons for Priority:
Meter replacement is a mandatory requirement as per the Distribution System Code. The TGB is required to meet requirements as a result of new growth.

Qualitative and Quantitative Analysis of Project and Project Alternatives:
Ensure compliance with Section 5 of the Distribution Code

2. Safety

n/a

3. Cyber-Security, Privacy

Oakville Hydro operates an encrypted smart meter communication network.

4. Co-ordination, Interoperability

n/a

5. Economic Development

n/a

6. Environmental Benefits

n/a

Project #: 14-61
Project Name: Distribution Meters
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:
New development activity and new customers drive the timing for this project.

Factors Relating to Customer Preferences or Input:
Zigbee meter communications facilitate future "real-time" data access and "behind the meter" services.

Factors Affecting the Final Cost of the Project:
New development activity and new customers drive the cost for this project.

How Controllable Costs have been Minimized:
Crew site visits are optimized by managing expectations and collaborating with site contractors.

Identify if Other Planning Objectives are Met by the Project, if so which ones:
Commercial meters will be upgraded from simple dial-up to smart meters connected to the existing flex net communication network.

Options Considered and Summary of Analysis:
Older meter technologies will continue to generate connectivity issues if they continue to be used.

Results of Final Economic Valuation, if applicable:

n/a

System Impacts (Nature, Magnitude and Costs):

n/a

Project #: 14-61
Project Name: Distribution Meters

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	15-E
Project Name:	North Service Rd Widening, 8th Line to Iroquois Shore Rd
Project Category:	Road Widening (Dependent on Road Work - No Hydro Control)
System Type	System Access
Customer Attachments/Load:	
Project Manager:	Jon Foreshew
Start Date:	February 1, 2014
In Service Date:	September 5, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$358,135	$244,991
Contributed Capital:	$134,000	$91,191
OHEDI Capital Cost:	$224,135	$153,800
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$76,900	$76,900	$0

Risks to Completion and Risk Mitigation:

Before design work can begin, Oakville Hydro requires final road design from the Town of Oakville. If these road design plans are delayed, then this project will be delayed. Also, upon completion of the road design, any land acquisition delays from the Town of Oakville will impact the timing for construction. Regular communication and ongoing meetings are maintained with the Town of Oakville to provide clear line of sight on project timing.

Comparative Information on Equivalent Historical Projects (if any):

Road widening projects are completed annually with the Town of Oakville, Region of Halton, and Ministry of Transportation. The value and timing of past projects have varied depending on the road authorities' construction program.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

The North Service Rd will be widened from the existing 2 lanes into 4 lanes from 8th Line to Iroquois Shore Rd. This represents 1 km of roadway and at least 20 new poles. This project will require relocation of poles and associated distribution equipment to make room for the new lanes. As this equipment is relocated there will be associated planned customer outages.

Project #: 15-E

Project Name: North Service Rd Widening, 8th Line to Iroquois Shore Rd

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

The main driver for this project is a third party road design change as a result of an infrastructural need identified by the Town of Oakville.

Priority and Reasons for Priority:

This is a regulatory requirement to comply with distribution plan relocation when requested by road authorities.

Qualitative and Quantitative Analysis of Project and Project Alternatives:

Subject to section 5 of the Government of Ontario's Public Service Works on Highway Act, R.S.O. 1990, Chapter P.49, Oakville Hydro is required to take up, remove or change the location of appliances or works, or make due compensation to the road authority for such loss or expense. Under the OEB enforcement the Board may impose an administrative penalty of $20,000 per day for each day or part day on which the contravention occurred or continues.

2. Safety

New distribution equipment will be designed and constructed according to new safety standards.

3. Cyber-Security, Privacy

n/a

4. Co-ordination, Interoperability

n/a

5. Economic Development

n/a

6. Environmental Benefits

n/a

Project #: 15-E
Project Name: North Service Rd Widening, 8th Line to Iroquois Shore Rd
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:
Before design work can begin, Oakville Hydro requires final road design from the Town of Oakville. If these road design plans are delayed, then this project will be delayed. Also, upon completion of the road design, any land acquisition delays from the Town of Oakville will impact the timing for construction.

Factors Relating to Customer Preferences or Input:
Customers that will be impacted by a scheduled outage will be contacted in advance.
The placement of new poles will be reviewed with the Town of Oakville for their approval.

Factors Affecting the Final Cost of the Project:
Design changes from the Town of Oakville, field conditions, scheduling delays, and restricted working hours will impact the final cost of the project.

How Controllable Costs have been Minimized:
Material costs will be controlled using standardized design and material selection. Crews deployment will be optimized based on allowable working hours. Typically half of the labour and vehicle costs are recovered from the Town of Oakville.

Identify if Other Planning Objectives are Met by the Project, if so which ones:
Asset replacement objectives are also being met in this project. The new distribution equipment is installed in place of the existing ageing equipment.

Options Considered and Summary of Analysis:
The designated project area is set by the Town of Oakville, however, the specific placement of Oakville Hydro's distribution equipment and system functionality is assessed and optimized.

Results of Final Economic Valuation, if applicable:
n/a

System Impacts (Nature, Magnitude and Costs):
n/a

Project #: 15-E
Project Name: North Service Rd Widening, 8th Line to Iroquois Shore Rd

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	15-I
Project Name:	Road Widening TBD
Project Category:	Road Widening (Dependent on Road Work - No Hydro Control)
System Type	System Access
Customer Attachments/Load:	
Project Manager:	Jon Foreshew
Start Date:	
In Service Date:	March 19, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$474,000	$309,752
Contributed Capital:	$163,000	$106,518
OHEDI Capital Cost:	$311,000	$203,234
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$0	$101,617	$101,617

Risks to Completion and Risk Mitigation:

Before design work can begin, Oakville Hydro requires final road design from the road authority. If these road design plans are delayed, then this project will be delayed. Also, upon completion of the road design, any land acquisition delays from the road authority will impact the timing for construction. Regular communication and ongoing meetings are maintained with the road authority to provide clear line of sight on project timing.

Comparative Information on Equivalent Historical Projects (if any):

Road widening projects are completed annually with the Town of Oakville, Region of Halton, and Ministry of Transportation. The value and timing of past projects have varied depending on the road authorities' construction program.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

Historically, Oakville Hydro has been engaged in annual road widening requirements, and this project represents road widening work that has not been specifically identified by the road authorities.

Project #: 15-I
Project Name: Road Widening TBD

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for this project is a third party road design change as a result of an infrastructural need identified by the road authority.

Priority and Reasons for Priority:
This is a regulatory requirement to comply with distribution plan relocation when requested by road authorities.

Qualitative and Quantitative Analysis of Project and Project Alternatives:
Subject to section 5 of the Government of Ontario's Public Service Works on Highway Act, R.S.O. 1990, Chapter P.49, Oakville Hydro is required to take up, remove or change the location of appliances or works, or make due compensation to the road authority for such loss or expense. Under the OEB enforcement the Board may impose an administrative penalty of $20,000 per day for each day or part day on which the contravention occurred or continues.

2. Safety
New distribution equipment will be designed and constructed according to new safety standards.

3. Cyber-Security, Privacy
n/a

4. Co-ordination, Interoperability
n/a

5. Economic Development
n/a

6. Environmental Benefits
n/a

Project #: 15-I
Project Name: Road Widening TBD
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:
Before design work can begin, Oakville Hydro requires final road design from the road authority. If these road design plans are delayed, then this project will be delayed. Also, upon completion of the road design, any land acquisition delays from the road authority will impact the timing for construction.

Factors Relating to Customer Preferences or Input:
Customers that will be impacted by a scheduled outage will be contacted in advance.
The placement of new poles will be reviewed with the road authority for their approval.

Factors Affecting the Final Cost of the Project:
Design changes from the road authority, field conditions, scheduling delays, and restricted working hours will impact the final cost of the project.

How Controllable Costs have been Minimized:
Material costs will be controlled using standardized design and material selection. Crews deployment will be optimized based on allowable working hours. Typically half of the labour and vehicle costs are recovered from the road authority.

Identify if Other Planning Objectives are Met by the Project, if so which ones:
Asset replacement objectives are also being met in this project. The new distribution equipment is installed in place of the existing ageing equipment.

Options Considered and Summary of Analysis:
The designated project area is set by the road authority, however, the specific placement of Oakville Hydro's distribution equipment and system functionality is assessed and optimized.

Results of Final Economic Valuation, if applicable:
n/a

System Impacts (Nature, Magnitude and Costs):
n/a

Project #: 15-I
Project Name: Road Widening TBD

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	14-62
Project Name:	2014 Fleet
Project Category:	Vehicles
System Type	General Plant
Customer Attachments/Load:	
Project Manager:	Chris Cudmore
Start Date:	January 1, 2014
In Service Date:	November 1, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$404,000	$384,762
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$404,000	$384,762
OM&A Costs:		

Expenditure Timing:	Q1	Q2	Q3	Q4

Risks to Completion and Risk Mitigation:

Changes to type of vehicle e.g. HYBRID vs. regular

Comparative Information on Equivalent Historical Projects (if any):

Annual projects for fleet replacement, projects vary depending on fleet age and vehicle type.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost for replacing existing fleet to be purchased in 2014. This budget represents the risk, value and cost for vehicles to be purchased in 2014. Four existing pickup trucks are proposed to be replaced with new 2014 hybrid pickup type vehicles having an active fuel management system, the following trucks are proposed for replacement #69, 75, 80, and 65 ranging between 8-11 years old. One existing car #68, which is ten years old, is proposed to be replaced with a new 2014 hybrid car type vehicle having an active fuel management system. One existing van #77, which is nine years old, is proposed to be replaced with new 2014 hybrid van type vehicles having an active fuel management system. One existing blocker truck chassis #20, which is 24 years old, is proposed to be replaced with a large used truck chassis. One existing warehouse forklift #406, which is 23 years old, is proposed for replacement.

Project #: 14-62
Project Name: 2014 Fleet

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
Replacement of aging fleet assets.

Priority and Reasons for Priority:
Fleet asset replacement program. Replacements due to age and reliability of fleet assets.

Qualitative and Quantitative Analysis of Project and Project Alternatives: Hybrid vehicles will result in reduced fuel consumption. The proposed fleet vehicles for replacement have reached the end of useful life. Reduced operating and maintenance expenses are expected.

2. Safety

The replaced vehicles will be matched to the work requirements and will reduce the risk of improper work methods. The timing for fleet replacement ensures that vehicles are replaced before they deteriorate to a degree that represents an operational safety hazard.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

N/A

5. Economic Development

Proposed fleet asset replacements will be tendered to local dealerships.

6. Environmental Benefits

New fleet vehicles have better fuel efficiency and lower emissions.

Project #: 14-62
Project Name: 2014 Fleet
System Type: *General Plant*

CATEGORY SPECIFIC REQUIREMENTS

Impact of Deferral/"Do Nothing" Option

Potential for increased maintenance and fuel costs; reduced reliability.

Net Benefits of Project in Monetary Terms (where practicable)

Reduced maintenance and fuel costs.

Project #: 14-62
Project Name: 2014 Fleet

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

IT

GENERAL

Project Number:	14-64D
Project Name:	Business Systems Applications
Project Category:	Administration - IT
System Type	General Plant
Customer Attachments/Load:	
Project Manager:	Business Systems Analyst
Start Date:	
In Service Date:	

	Old CGAAP	New CGAAP
Total Capital Cost:	$203,000	$203,000
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$203,000	$203,000
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$203,000	$0	$0

Risks to Completion and Risk Mitigation:

Microsoft Dynamics GP 2013 statement of direction is clear and was implemented Q4 - 2012. We will upgrade our system in 2014 once all investigating has been complete in 2013. There are no risks to completion.

Comparative Information on Equivalent Historical Projects (if any):

Microsoft Dynamics GP has been maintained since the initial cutover from JD Edwards in 2008. Average annual costs for new additions to the software have been necessary to increase functionality as the business requirements change. This upgrade will provide the functionality to help reduce the need for new additional software. The GP strategy is to use the current investment as much as possible and purchase new software only where necessary.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

Initiatives include:

Harris Collection Project - $25K to automate our current collection methodology and create an efficient and effective process

Northstar modifications - implementation of Automation Platform including custom Cognos and SQL rule development to enhance Oakville Hydro billing processes due to introduction of added complexities in billing.

Workforce Management (WFM) improvements - Oakville Hydro will be automating the service orders currently used with the Halton Region along with improving Oakville Hydro's existing WFM used for electric service orders. This includes implementation of electronic service orders for the Region, testing of service orders and its affect on billing processes, and introducing WFM to new Oakville Hydro business processes

GP ERP system Upgrade - This is a substantial upgrade from GP 2010 to GP 2013. Activities around the upgrade features will require a full re-implementation and integration of existing software to the new GP2013 system. This upgrade required to allow us to take advantage of new features that not only assist in daily activities but also for analysis and reconciliations. There should be no additional software required for the ERP system in 2014 while we are implementing the new version.

Business Intelligence - Good business intelligence tools will need further development to provide good analysis to the business.

Project #: 14-64D
Project Name: Business Systems Applications

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

It is important for software to be maintained at the Vendors current versions to take advantage of new features in functionality and security. Oakville Hydro does not want to leave the upgrade for too long as GP and all related software are developing at the same rate and we are not able to take advantage of any of the new features from any of the existing related software. Deferral will result in a complete re-install rather than an upgrade if the existing system becomes too dated.

Priority and Reasons for Priority:

GP - High - This is the core ERP/finance/Job related software. Support on the existing GP 2010 will end Oct 2015. To have this system completed by 2014 will ensure there is no risks of increased costs from vendors to support the system after Microsoft has completed it's support. GP2013 has features that may assist in the development of asset management strategies. GP2013 is required to be in place and operating in order to develop these strategies.

Harris Collection Project - High - automation of collection process to increase efficiency, timeliness and reduce bad debt - We are currently receiving complaints from some customers in regards to the current process. We would like to make a change to implement an enhanced version of credit scoring so that letters, notices and disconnections are not directed to customers with good payment history.

Northstar Modification - the introduction of efficiencies in the Meter to Cash process through automation of service orders and CIS processes will help reduce Oakville Hydro's dependence on manual processes. This will help reduce billing errors, delayed bills, and improve utilization of resources, which will serve to benefit Oakville customers.

Qualitative and Quantitative Analysis of Project and Project Alternatives:

Harris Collection Project - goal of project is to reduce bad debts and to minimize customer complaints.

2. Safety

N/A

3. Cyber-Security, Privacy

Microsoft Dynamics GP 2013 is an internal system that resides in the existing infrastructure

4. Co-ordination, Interoperability

The CIS based Automation Platform will enable the development of automated meter to cash business processes.

5. Economic Development

6. Environmental Benefits

N/A

Project #: 14-64D
Project Name: Business Systems Applications
System Type: *General Plant*

CATEGORY SPECIFIC REQUIREMENTS

Impact of Deferral/"Do Nothing" Option

GP - The business is requesting access to new features that are available in the GP2013 environment. If the upgrade is not completed, new software will need to be sourced to cover the deficiencies of the existing GP 2010 version.

Harris Collection Project - service would continue as status quo with the possible increase of bad debts due to the manual process. Reduction of complaints would not be minimized.

Northstar Modification and Workforce Management Improvements - without improving the automation within Oakville's CIS and WFM, the meter to cash processes will continue to be manual process where human errors are more prevalent, resulting in billing errors. Due to the requirement to operate in 'real time' since the introduction of smart meters, automation is critical in the meter to cash process.

Net Benefits of Project in Monetary Terms (where practicable)

Mandatory upgrade for applications

Project #: 14-64D
Project Name: Business Systems Applications

OTHER INFORMATION

Microsoft Dynamics GP 2013 is scheduled to be released in Calendar Q4 of 2012. The release marks another milestone for the Microsoft Dynamics GP product by:
-Delivering a Web Client option
-deployment options and capabilities
-Enhancing the core functionality
-Making Rapid Start Services for Microsoft Dynamics GP available

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

IT

GENERAL

Project Number:	14-64F
Project Name:	IT Infrastructure
Project Category:	Administration - IT
System Type	General Plant
Customer Attachments/Load:	
Project Manager:	Infrastructure Specialist
Start Date:	January 2, 2014
In Service Date:	Various dates throughout the year

	Old CGAAP	New CGAAP
Total Capital Cost:	$420,000	$420,000
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$420,000	$420,000
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$105,000	$105,000	$105,000	$105,000

Risks to Completion and Risk Mitigation:
N/A

Comparative Information on Equivalent Historical Projects (if any):
The ongoing maintenance of our infrastructure is core to maintaining the systems the business requires. Asset plans in the IT Strategy define a good basis for a plan that makes sense from a system and cost point of view. In 2011 and 2012 there was increased focus on operational IT projects rather than IT infrastructure projects. 2014 continues the 2013 infrastructure improvements with a focus on critical systems to support the distribution system (e.g. SCADA) and general operations. Key areas include security and business continuity.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:
N/A

Project Summary:
This is a combined project taking into account all infrastructure changes to support the organization in the initiatives.

Project #: 14-64F
Project Name: IT Infrastructure

1. Efficiency, Customer Value, Reliability

Main Driver:

Infrastructure Stability to support the organization

Priority and Reasons for Priority:

Medium - Regular replacement of existing system for system security and business continuity

Qualitative and Quantitative Analysis of Project and Project Alternatives:

This project is new technologies, sustaining replacements and increased capacity to keep up with the demands of the business.

2. Safety

N/A

3. Cyber-Security, Privacy

IT currently supports three infrastructures.
-Operations (SCADA, OMS, GIS)
-Corporate (ERP,
-AMI/CIS (Metering, Customer services, Billing)
All changes to the infrastructure follow change management process that takes into account the Cyber Security, Privacy

4. Co-ordination, Interoperability

This project is new technologies, sustaining replacements and increased capacity to keep up with the demands of the business.
The implementation of all IT resources follows NERC , CIP001-CIP009 compliance and ISO27000 standards

5. Economic Development

6. Environmental Benefits

Newer technologies provide a greener footprint.

Project #: 14-64F
Project Name: IT Infrastructure
System Type: *General Plant*

CATEGORY SPECIFIC REQUIREMENTS

Impact of Deferral/"Do Nothing" Option

Out of date equipment and demand for higher resources will result in deficiencies in the organization's other projects and ongoing operating activities.

Net Benefits of Project in Monetary Terms (where practicable)

Project #: 14-64F
Project Name: IT Infrastructure

OTHER INFORMATION

The 2014 Infrastructure project includes some of the following as a means to secure the right resources to support the initiatives of the organization.
-Further virtualization for the server farm, and new licenses for servers/virtualization from Microsoft as part of our ongoing project to consolidate and maintain the IT infrastructure. Licenses are purchased through the current EA agreement with Microsoft.
-Further desktop replacements for 5 year asset management plan
-Further storage needs for increase in storage from last year
-Switches, routers, network connections that were previously installed will need replacement and redundancy
-Foundry switches were installed in 2010 at all substations. These switches will require investigation and redundancy in 2014
-Increased Mobile Security for all mobile devices. -IPSec VPN Tunnel using 4G Mobile cellular VPN connectivity.
-Central administration tool to manage (diagnose, support) all mobile devices include E-Mobile devices

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Buildings

GENERAL

Project Number:
Project Name: HVAC upgrade - 5 year replacement program
Project Category: Administration - Buildings
System Type General Plant
Customer Attachments/Load:
Project Manager: Ron Vandermolen

Start Date:
In Service Date: ongoing

	Old CGAAP	New CGAAP
Total Capital Cost:	$230,000	$230,000
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$230,000	$230,000
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:		$115,000	$115,000	$0

Risks to Completion and Risk Mitigation:

Comparative Information on Equivalent Historical Projects (if any):

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

Project Summary:

Replacement of HVAC and mechanical equipment (approx. 85 units) over a five year period. Three units have been replaced since 2011, and several units have had compressor replacements and/or major repairs to date.

Project #: n/a

Project Name: HVAC upgrade - 5 year replacement program

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

Priority and Reasons for Priority:

Qualitative and Quantitative Analysis of Project and Project Alternatives: This is a proactive plan to replace units that have reached end of life cycle, as they are original equipment (1994). We are experiencing more frequent breakdowns of units requiring replacement, particularly with units that are rooftop and exposed to the elements. Lead time for replacement units on an emergency basis varies from 4-10 weeks depending on make and model type/size. Repair costs on these aging units continue to increase. Newer technology will result in more energy efficient products, improved operations, improved reliability and decreased maintenance costs - as well as ensure smooth operation of the facility.

2. Safety

3. Cyber-Security, Privacy

4. Co-ordination, Interoperability

5. Economic Development

6. Environmental Benefits

Project #: n/a
Project Name: HVAC upgrade - 5 year replacement program
System Type: *General Plant*

CATEGORY SPECIFIC REQUIREMENTS

Impact of Deferral/"Do Nothing" Option

Deferring this project, or replacing units on an as required basis only will result in increased risk of failure as the units age. Since these units are all of the same vintage, the risk is quite high that we will begin to experience multiple failures. The cost of emergency services for repairs and individual replacements will decrease reliability, and increase our maintenance costs. A replacement program will allow us to negotiate better pricing for both supply and installation, and allow us to much better analyse in advance, the best overall solution in terms of unit requirements.

Net Benefits of Project in Monetary Terms (where practicable)

Project #: n/a
Project Name: HVAC upgrade - 5 year replacement program

OTHER INFORMATION

Exhibit 4

Business Cases

OAKVILLE HYDRO

BRONTE TS – FEEDER REPLACEMENT, RELOCATION AND WHOLESALE FEEDER METERING REPLACEMENT

Investment Category	System Access
Project Forecast Capital Investment	$1,700,000
Project Construction Schedule	Original Schedule: Apr 30, 2019 to Oct 30, 2019 Dec 5, 2019 Update: Feeder cutover now scheduled for Dec 11, 2019 to Jan 21, 2020
Project Duration	9 months
Expected In-service Date	All feeders ready for service as of Dec 5, 2019. Feeder cutover schedule: Dec 11, 2019 - FDR 13M1, 13M3; Dec 12, 2019 - FDR 13M2; Jan 13, 2020 – FDR 13M4 & 13M6; Jan 14, 2020 – FDR 13M8; Jan, 15 2020 – FDR 13M7; Jan 21, 2020 – FDR 13M5

PROJECT DESCRIPTION

The Bronte TS Replacement and relocation projects is due to Hydro One's Project for a new Bronte TS transformer station. This will replace the existing transformer station where currently Oakville Hydro has eight 27.6kV distribution feeders connected (feeder reference 13M1 to 13M8).



The project involves replacement, relocation and connection of eight 27.6kV distribution feeders to the new transformer station. Hydro One's station design required that the connection to new Bronte TS had to be underground infrastructure, and connection to existing overhead egress feeders as overhead infrastructure. In addition, the project

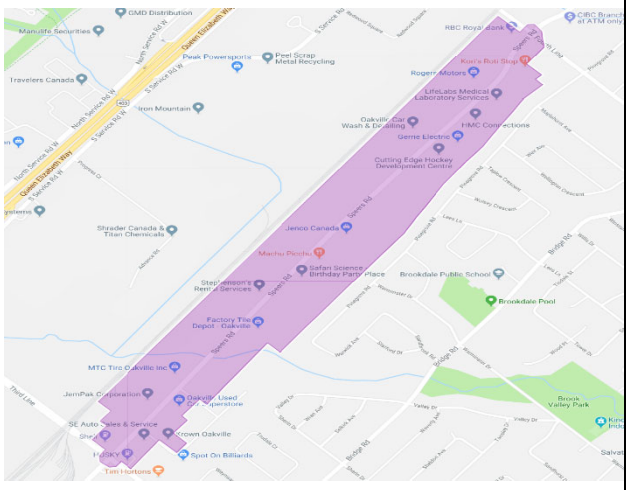
OAKVILLE HYDRO

TOWN OF OAKVILLE ROAD WIDENING - SPEERS ROAD	
Investment Category	System Access
Project Forecast Capital Investment	$2,000,000
Project Construction Schedule	February to July 2019
Project Duration	6 months
Expected In-service Date	July 2019

PROJECT DESCRIPTION

The Town of Oakville is widening and reconstructing Speers Road to five lanes (four through lanes and a centre turning lane) with separated on-road bike lanes.

To facilitate this project, Oakville Hydro must relocate the 27.6 kV and 4.16 kV overhead pole-lines on Speers Road from Third Line to Fourth Line to accommodate the road-work being completed by the Town of Oakville (the "Town"). Oakville Hydro's total estimated cost for this project is $3,100,000.



Oakville Hydro has estimated that it will recover $1,100,000 in capital contributions from the Town in accordance with the Public Service Works on Highways Act ("PSWHA") which provides for the recovery of 50% of the labour costs for these projects.

Evaluation Criteria

Project Drivers

The main driver for this project is the municpal road work being undertaken by the Town. Oakville Hydro is mandated to relocate its assets under the PSWHA. The work needs to be completed safely and in a timely manner that meets the scheduling needs of the municipality and complies with Ontario Regulation 22/04.

Priority

The priority of this project is high as Oakville Hydro has mandated obligation to relocate its distribution assets under the PSWHA. As such, the project cannot be deferred or neglected. If Oakville Hydro does not proceed with this project, the Town road-work would be delayed and Oakville Hydro could be subject to penalties under the PSWHA.

Cost Effectiveness

This project involves the relocation of hydro assets including: hydro poles, pole support, primary overhead wires, and other distribution assets. When designing this project, Oakville Hydro will identify opportunities to upgrade and/or modify the existing distribution assets to improve reliability and interoperability where doing so provides value to Oakville Hydro's customers. This proactive approach to system renewal will extend the life of the distribution assets, reducing the requirement for future sytem renewal and asset maintenance investments.

When doing these projects, Oakville Hydro works closely with the requesting road authority to optimize the roadway design to minimize the relocation requirements while meeting the needs of the community. Since the costs are shared with the road authority, cost reductions benefit both parties.

Customer Benefits

Oakville Hydro's customers will benefit from new distribution assets which will improve Oakville Hydro's ability to deliver safe and reliable electricity to the homes and businesses across Oakville.

Reliability

While the primary purpose of this project is to accommodate the Town's request for the relocation of Oakville Hydro's distribution assets, Oakville Hydro's customers will benefit from the investment in distribution assets through improved reliabilty.

Safety

Relocation projects ensure that Oakville Hydro's distribution assets are safely positioned and away from vehicles, pedestrians and cyclists. This ensures that the public is protected from hazardous contact with Oakville Hydro's distribution lines and other equipment.

required replacement of existing wholesale primary metering units currently installed within Old Bronte TS, with new wholesale primary metering units installed within egress area, on Oakville Hydro poles. In accordance with installation standards and safety policies, additional work for grading and driveway access installation was also completed as part of this project.

EVALUATION CRITERIA

PROJECT DRIVERS

The main driver for this project is the Hydro One Project to design/build a new Bronte TS Transformer Station.

PRIORITY

The priority of this project is high as Oakville Hydro has a mandated obligation to complete replacement and relocations of eight distribution feeders to connect to the new Transformer Station within the project timeline outline by Hydro One project schedule.

COST EFFECTIVENESS

This project involves the installation of new overhead infrastructure, including wood poles, pole framing, pole support, primary overhead wires, primary metering units and overhead secondary wires. The project also includes underground infrastructure (underground concrete encased reinforced structure, primary undergorund cables and neutral cable, c/w cable terminations, support) to allow interconnection to existing overhead poleline infrastructure and connection to the new transformer station. The proposed replacement and relocation design solution selected is the optimal solution to avoid any reconstruction of existing infrastrucutre, except mandatory assets removals (wood poles, pole supports, primary and neutral wires, overhead in-line switches). The design solution also ensures that system reliability and continuity of Oakville Hydro services, supplied from these feeders, is maintained at all times.

REGIONAL PLANNING

Hydro One's Transmission System Plan ("TSP"), filed on May 31, 2016 (EB-2016-0160) included plans to the replace obsolete, non-standard assets at the Bronte TS that were directly affecting the operability and reliability of the transmission system. In their TSP, Hydro One concluded that failing to proceed with this investment would result in a significant risk of further equipment deterioration and declining reliability to the customers in the area.

The plan to replace assets at the Bronte TS was also addressed in Section 7.12 of the joint Burlington to Nanticoke Regional Infrastructure Plan ("RIP") dated February 7, 2017.

In its TSP, Hydro One considered three options:

1. Continue to maintain the assets (status quo);
2. In-Situ replacement of the assets; or
3. Relocated replacement of the assets.

Alternative one was considered and rejected as it did not address the risk of failure due to asset condition and would result in increased maintenance expenses. Both alternatives two and three were considered further. Option three was the preferred and recommended option, as option two would impose staging risks associated with maintaining supply to the local distribution company. In addition, option two was not feasible due to space limitations posed by the station property.

CUSTOMER BENEFITS

Oakville Hydro's customers will benefit from main feeder connection to a new transformer station, which will improve Oakville Hydro's ability to deliver safe and reliable electricity to the homes and businesses across Oakville.

RELIABILITY

While the primary purpose of this project is to accommodate the Hydro One new transformer station project, Oakville Hydro's customers will benefit from the investment in distribution assets through improved reliabilty.

SAFETY

Relocation projects ensure that Oakville Hydro's distribution assets are safely positioned away from vehicles, pedestrians and cyclists. This ensures that the public is protected from hazardous contact with Oakville Hydro's distribution lines and other equipment.

OAKVILLE HYDRO

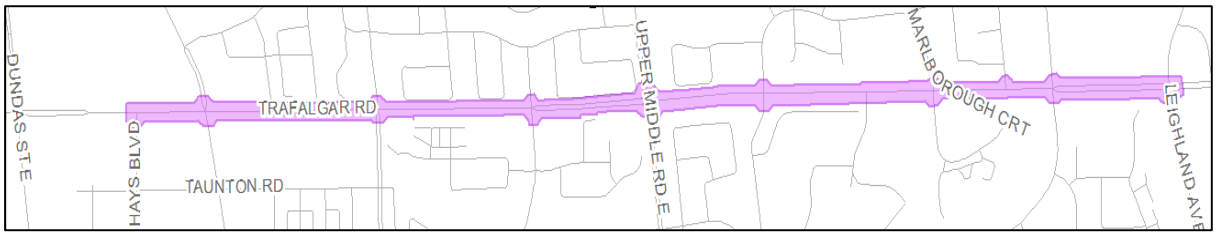
HALTON REGION ROAD WIDENING – TRAFALGAR ROAD	
Investment Category	System Access
Project Forecast Capital Investment	$2,200,000
Project Construction Schedule	March to December 2019
Project Duration	9 months
Expected In-service Date	December 2019

PROJECT DESCRIPTION

Halton Region is making improvements to Trafalgar Road between Leighland Avenue and north of Hays Boulevard in the Region of Oakville. This project will address future traffic demands and provide safe travel options for motorists, pedestrians and cyclists.

To facilitate this project, Oakville Hydro is required to relocate the 27.6 kV and 13.8 kV overhead pole-lines on Trafalgar Road between Leighland Avenue and Hays Boulevard to accommodate the road-work being completed by the Region of Halton (the "Region"). Oakville Hydro will also extend the 27.6kV overhead circuit south of Upper Middle Road to improve system reliability in South Oakville. Oakville Hydro's total estimated cost of this project is $2,900,000.

Oakville Hydro has estimated that it will recover $700,000 in capital contributions from the Region in accordance with the Public Service Works on Highways Act ("PSWHA") which provides for the recovery of 50% of the labour costs for these projects.



Evaluation Criteria

Project Drivers

The main driver for this project is the municpal road work being undertaken by the Region. Oakville Hydro is mandated to relocate its assets under the PSWHA. The work needs to be completed safely and in a timely manner that meets the scheduling needs of the municipality and complies with Ontario Regulation 22/04.

Priority

The priority of this project is high as Oakville Hydro has a mandated obligation to relocate its distribution assets under the PSWHA. As such, the project cannot be deferred or neglected. If Oakville Hydro does not proceed with this project, the Region road-work would be delayed and Oakville Hydro could be subject to penalties under the PSWHA.

Cost Effectiveness

This project involves the relocation of hydro assets including: hydro poles, pole support, primary overhead wires, and other distribution assets. When designing this project, Oakville Hydro will also identify opportunities to upgrade and/or modify the existing distribution assets to improve reliability and interoperability where doing so provides value to Oakville Hydro's customers. This proactive approach to system renewal will extend the life of the distribution assets, reducing the requirement for future sytem renewal and asset maintenance investments.

When doing these projects, Oakville Hydro works closely with the requesting road authority to optimize the roadway design to minimize the relocation requirements while meeting the needs of the community. Since the costs are shared with the road authority, cost reductions benefit both parties.

Customer Benefits

Oakville Hydro's customers will benefit from new distribution assets which will improve Oakville Hydro's ability to deliver safe and reliable electricity to the homes and businesses across Oakville.

Reliability

While the primary purpose of this project is to accommodate the Region's request for the relocation of Oakville Hydro's distribution assets, Oakville Hydro's customers will benefit from the investment in distribution assets through improved reliabilty.

Safety

Relocation projects ensure that Oakville Hydro's distribution assets are safely positioned and away from vehicles, pedestrians and cyclists. This ensures that the public is protected from hazardous contact with Oakville Hydro's distribution lines and other equipment.

OAKVILLE HYDRO

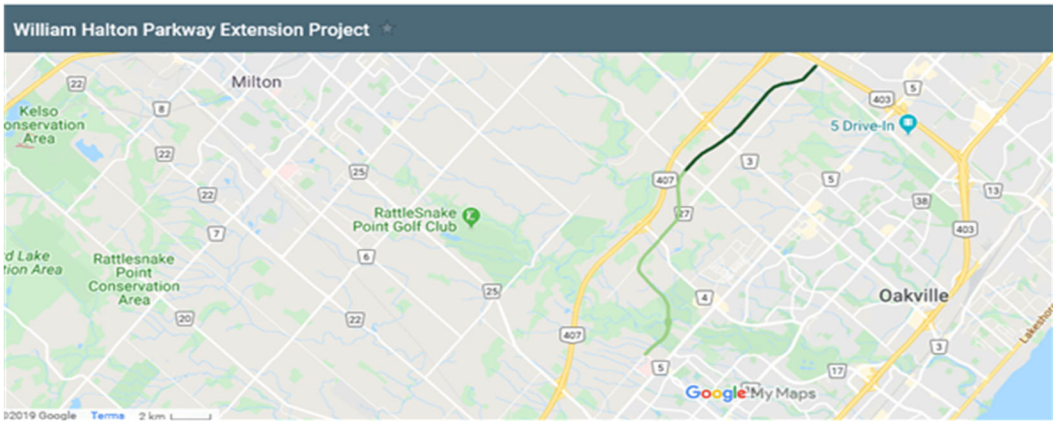
HALTON REGION ROAD WIDENING – WILLIAM HALTON PARKWAY	
Investment Category	System Access
Project Forecast Capital Investment	$1,200,000
Project Construction Schedule	February to December 2019
Project Duration	9 months
Expected In-service Date	December 2019

PROJECT DESCRIPTION

The Region is extending the William Halton Parkway from Bronte Road to Ninth Line to accommodate growth, traffic demands and provide new travel options. The project is divided into two phases, Ninth Line to Trafalgar Road and Trafalgar Road to Neyagawa Boulevard.

To facilitate this project, Oakville Hydro is required to relocate the 27.6 kV and 13.8 kV overhead pole-lines on Trafalgar Road and the new William Halton Parkway to accommodate the extension of the William Halton Parkway by the Region of Halton (the "Region"). Oakville Hydro will also remove an old 8kV pole-line to 27.6kV and provide for future pole line extensions for future system expansions. Oakville Hydro's total estimated cost of this project is $1,857,000.

Oakville Hydro has estimated that it will recover $657,000 in capital contributions from the Region in accordance with the Public Service Works on Highways Act ("PSWHA") which provides for the recovery of 50% of the labour costs for these projects.



Evaluation Criteria

Project Drivers

The main driver for this project is the municpal road work being undertaken by the Region. Oakville Hydro is mandated to relocate its assets under the PSWHA. The work needs to be completed safely and in a timely manner that meets the scheduling needs of the municipality and complies with Ontario Regulation 22/04.

Priority

The priority of this project is high as Oakville Hydro has a mandated obligation to relocate its distribution assets under the PSWHA. As such, the project cannot be deferred or neglected. If Oakville Hydro does not proceed with this project, the Region road-work would be delayed and Oakville Hydro could be subject to penalties under the PSWHA.

Cost Effectiveness

This project involves the relocation of hydro assets including: hydro poles, pole support, primary overhead wires, and other distribution assets. Oakville Hydro will also remove an old 8kV pole-line to 27.6kV and provide for future pole line extensions for future system expansions.

When designing this project, Oakville Hydro will also identify opportunities to upgrade and/or modify the existing distribution assets to improve reliability and interoperability where doing so provides value to Oakville Hydro's customers. This proactive approach to system renewal will extend the life of the distribution assets, reducing the requirement for future sytem renewal and asset maintenance investments.

When doing these projects, Oakville Hydro works closely with the requesting road authority to optimize the roadway design to minimize the relocation requirements while meeting the needs of the community. Since the costs are shared with the road authority, cost reductions benefit both parties.

Customer Benefits

Oakville Hydro's customers will benefit from new distribution assets which will improve Oakville Hydro's ability to deliver safe and reliable electricity to the homes and businesses across Oakville.

Reliability

While the primary purpose of this project is to accommodate the Region's request for the relocation of Oakville Hydro's distribution assets, Oakville Hydro's customers will benefit from the investment in distribution assets through improved reliabilty.

Safety

Relocation projects ensure that Oakville Hydro's distribution assets are safely positioned and away from vehicles, pedestrians and cyclists. This ensures that the public is protected from hazardous contact with Oakville Hydro's distribution lines and other equipment.

Exhibit 5

Correspondence

Energy Probe Question Two

Correspondence

Regarding the

Speers Road Project

From: Kasia Piskorz [mailto:kasia.piskorz@oakville.ca]
Sent: October 22, 2015 3:17 PM
To: Daniela Motoc <dmotoc@oakvillehydro.com>
Subject: Speers Rd Widening (West of Third Line to Fourth Line)

Hi Daniela,
The Town has retained a design consultant for the widening of Speers Road from west of Third Line to Fourth Line.
It is most likely that the design will require the relocation of the hydro poles along the south side of the Road and I would like to arrange a meeting to discuss this.

Can you suggest some dates and times that you are available for the week of Nov 2, Nov 9 and Nov 16 and I will set up a meeting along with our consultant.

Thanks,
Kasia

Kasia Piskorz
Project Leader - Capital Projects
Engineering and Construction
Town of Oakville | 905-845-6601, ext.3533 | f: 905-338-4159 | www.oakville.ca Complete our Community Development customer service survey

From: Wong, Felix KY [mailto:felix.wong@amecfw.com]
Sent: November 26, 2015 2:56 PM
To: Gill, Chris (6011790) <chris.gill@bell.ca>; samantha.gillespie@cogeco.com; Gadbois, Dave <DGadbois@uniongas.com>; Daniela Motoc <dmotoc@oakvillehydro.com>; Steve.Andrews@rci.rogers.com; Zone2Scheduling@HydroOne.com
Cc: Kasia Piskorz <kasia.piskorz@oakville.ca>; Sinke, David <david.sinke@amecfw.com>; Hellman, Jeremy D <jeremy.hellman@amecfw.com>
Subject: Speers Road, Town of Oakville - Utility Markups

Hello all,

Our firm has been retained by Town of Oakville to complete the Detailed Design for **Speers Road from West of Third Line to Fourth Line.**

Attached is a PDF copy of base plan drawings showing the existing road layout and existing utility information that was previously gathered by the Town. Please review and confirm plants that are shown on the plans, provide us with mark-ups of any additional existing plant (including type, size, depths, clearances, and offsets from roadway or property line) in the vicinity and any

further plans for the area. Also, please identify if any facility is shared with others. Any copies of design or as-built drawings that you could provide to us would be greatly appreciated if available. If you require hard copies of the attached plan drawing, please advise me and we will have that couriered to your office.

This information will assist in determine the utility conflicts once our road design is completed.

Please provide your mark-ups to us by ***Friday December 18h, 2015***.

If this project falls under the jurisdiction of another representative of your office, please forward this email to them, and advise us at your earliest convenience.

Included in this email are the following utilities. If you know of any others that we may have missed for this area, we would really appreciate it if you could please advise us.

- Bell Canada
- Cogeco Cable
- Union Gas
- Oakville Hydro
- Hydro One
- Rogers

If you have any questions or concerns, please do not hesitate to contact me.

Thank you,

Felix

Correspondence

Regarding the

Trafalgar Road Project

R.V. Anderson Associates Limited
engineering · environment · infrastructure

2001 Sheppard Avenue East Suite 400
Toronto Ontario M2J 4Z8 Canada
Tel 416 497 8600 Fax 416 497 0342
www.rvanderson.com

MEETING NOTES

THE REGIONAL MUNICIPALITY OF HALTON

TRAFALGAR ROAD (REGIONAL ROAD 3) FROM LEIGHLAND AVENUE TO HIGHWAY 407
Region File PR-2079 B/C/D

Oakville Hydro Meeting

DATE: August 26, 2016 at 9:00 a.m.

PLACE: 1075 North Service Road West, Oakville, Ontario, Oak Room

PROJECT NO.: 163269

PRESENT:

Chris Ewen	- Region of Halton (Region)
Rama Garigipati	- Region of Halton
Daniel Steele	- Oakville Hydro (OH)
Daniela Motoc	- Oakville Hydro
Lauren Sebastian	- UTS Consultants
John Does	- R.V. Anderson Associates Limited (RVA)
Peter Cho	- R.V. Anderson Associates Limited

The purpose of the meeting was to meet with Oakville Hydro to start the relocation design process.

DISCUSSION:	**ACTION BY:**
1. Project Schedule	
Phase 1 – Leighland to Hays – Spring 2017	INFO
Phase 2 – Hays to William Halton Parkway – summer 2018	INFO
2. Project Details	
6 lane configuration with sidewalk and multi-use path.	INFO
Hydro informed us that there's a lot of third parties on the Trafalgar Road pole line.	INFO
Currently there should be Bell, Rogers and Cogeco on existing hydro pole.	INFO
Hydro will try to include the third-party design with their work.	INFO
Upper Middle Road East is a heavy pole line, if possible, avoid relocating at the intersection.	RVA
Oakville Hydro spacing limit is 60m, 47m is the general limit.	INFO

DISCUSSION:	ACTION BY:
At mid-block locations where we have bus pad, due to property constraints, would an underground hydro line be a feasible option.	OH
OH to contact the telecom companies about this relocation.	OH
OH recommended the Region contact all other telecom companies to discuss the timeline of the project and try to get commitments on allocating their resources. OH expressed their concerns with the short timeframe to complete their relocation, but they have no control over the resources of their third party companies.	REGION/RVA
Street lighting is to be joint-use on the east side whereever possible.	INFO
RVA to forward Hydro's contact to Moon Matz (RVA's lighting sub-consultant)	RVA
Ideal location for Hydro is to be between back of curb and SW.	OH
3.0m clearance minimum safety clearance.	INFO
7.0m clearance for neutral wires, Moon Matz to confirm with OH, probably will be higher for Trafalgar.	RVA
5.0m clear zone from edge of travel lane. For Trafalgar Road, we won't be able to achieve this for phase 1 due to property constraints. There are opportunities to achieve the 5.0m clear zone in Phase 2.	RVA
Wherever possible, provide minimum 1.5 m from back of curb to face of pole in Phase 1.	RVA
0.5m from edge of sidewalk to face of pole to avoid snow plows.	RVA
3.5m minimum require for pole off-set to property line. If heavy circuit pole 5m.	OH/RVA
RVA to discuss with Multi-view and see when we can finalize Sue-B.	RVA
UTS will require a couple of weeks to get all the information on the existing poles, and a couple of weeks to do the preliminary design and discuss with other utilities. Mid October will probably have our preliminary design.	OH
RVA to finalize our plan locations for sidewalk and curb by September.	RVA
Target for OH is to target final design in December and the cost estimate in January.	OH

Notes prepared by: P. Cho, P.Eng.

Distribution: All present/absent

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PLEASE ADVISE THE WRITER OF ANY ERRORS OR OMISSIONS WITHIN 1 WEEK OF RECEIPT OF THESE NOTES

Correspondence

Regarding the

William Halton Parkway Project

Meeting Notes

Utility Coordination Meeting No. 1

New North Oakville Transportation Corridor, Trafalgar Road to Ninth Line, Town of Oakville

Halton Region File PR-2538A

Stantec

Date/Time:	December 6, 2013 / 1:30 – 4:30 PM
Place:	Halton Region Offices, 1151 Bronte Road, Oakville
Attendees:	Steve Andrews (Rogers, System Planner) Jeremy Getson (Union Gas, Utility Service Manager) Octavian Ghiricociu (Union Gas, Construction Project Manager) Rick Schatz (HONI, Senior Real Estate Coordinator) Angela Fedorenko (Cogeco, Planner) Jon Foreshaw (Oakville Hydro, Distribution Engineer) Adam Sheldon (TransCanada, Regional Land Representative) Bob Wicklund, Halton Region (Halton Region, Project Manager) Bill Hopkins (Halton Region, Water) Gord Murray (Stantec, Project Manager) Jerry Zhu (Stantec Project Engineer)
Distribution:	Attendees, Joseph Choi (Halton Region), Faye Wang (Union Gas), Ann Newman (Enbridge), Amanda Mcquay (Bell Canada)

Item:	Action:
1. INTRODUCTION	
Meeting started with a brief introduction of all attendees.	
2. REVIEW THE STATUS OF THE PROJECT	
Gord Murray provided a general overview of NNOTC project and the purpose for the meeting, and indicated that construction is planned to start in summer 2014.	
3. UTILITY RELOCAITON PLANS	
<u>Rogers</u> Rogers cable is currently on the hydro poles on east side of Ninth Line south of Burnhamthorpe Road. It was agreed to relocate the Rogers aerial cable following the relocated hydro poles. Rogers and Oakville Hydro to coordinate.	

<u>Oakville Hydro</u> Jon indicated that they require a minimum 3.5 metre offset from the property line to place hydro poles. Stantec suggested that new hydro poles on NNOTC will be placed on the boulevard between the curb line and multiuse pathway (or sidewalk). Installation at bottom of ditch or on the grading slope is not desirable. The pole spacing is generally 45-60 metres. Region would like to sell a part of existing Burnhamthorpe ROW. It was suggested that the Hydro line could be moved on to the new Connecting Link right-of-way to clear the abandoned section of ROW for sale. Region will determine how to illuminate NNOTC using either the new pre-installed hydro poles, or provide power to new street lights, if pre-installing hydro poles is not feasible. Stantec will provide Oakville Hydro with revisions to the suggested relocation plan, and the relevant cross-sections on NNOTC, Ninth Line and Trafalgar Road, for design of the relocations and new aerial pole line on NNOTC.	 Region Stantec
<u>Union Gas</u> Relocation of a 12" line is required due to the conflict with the new roundabout intersection at Ninth Line and Burnhamthorpe. The exact location and depth will be determined once Union Gas provides approximate location of their lines. Generally, the relocated line should be 1 metre from the property line. Jeremy indicated that the 2" plastic live gas line is on the south side of Burnhamthorpe Road. Further verification is required to determine if there are conflicts with design. Union Gas has plans to install a 20" diameter gas main along Trafalgar Road. Installation is scheduled for 2015 – 2016. Union Gas will provide additional details as they are available. Stantec will provide relevant cross-sections for Ninth Line, NNOTC, Burnhamthorpe and Trafalgar Road to Union Gas.	 Union Gas Stantec Union Gas Stantec Union Gas Stantec

<u>Hydro One Networks Inc. (HONI)</u> Rick indicated that HONI will ultimately install a double line of hydro towers within the corridor crossing NNOTC (west of Ninth Line) in the future. The tower locations may conflict with NNOTC corridor. To avoid this conflict, additional property may be required from adjacent owners, or additional towers installed to "turn the corner" across NNOTC.	
In term of landscape, trees are not allowed to plant on hydro One property within the hydro corridor.	Stantec
Rick will provide some guidance on the future tower locations so that they can be installed without conflict in the future.	HONI
A 6.0 metre wide access is required from NNOTC for future construction and/or maintenance on the corridor (both sides of NNOTC).	Stantec
HONI requires the drawings showing all pole heights within the hydro corridor for their review of separation from future hydro transmission lines.	Stantec
<u>TransCanada Pipelines and Enbridge Gas</u> The existing TCPL oil pipe line has been shown on the drawings based on best estimates. A 24" Enbridge Gas line in an 18.3m wide easement also runs within the corridor. While the proposed construction will place substantial earth fill over the pipe, there are no permanent structures (such as concrete culvert, storm sewer pipe, etc.) proposed above the pipe line.	
Stantec/Region will contact TransCanada's land service representative and apply for a crossing approval.	Stantec
<u>Region Watermain</u> An existing 1200mm feedermain is installed outside of the existing east gravel shoulder on Trafalgar Road. Relocation of the feedermain is not anticipated for Trafalgar Road reconstruction and widening. One of the chambers will need to be adjusted upward, and the air release vent pipe will need to be relocated to the boulevard.	Stantec

Cogeco Cogeco has no cables on existing Burnhamthorpe Road, Ninth Line or Trafalgar Road. Cogeco intends to place new aerial/cable along the new corridor (likely joint use with Bell Canada and Oakville Hydro).	
Bell Canada (A Bell representative was not present at the meeting.) It was suggested that the existing buried cable/conduit on Ninth Line and Burnhamthorpe Road be relocated aerially with the relocated Oakville Hydro poles. There are two buried lines on the west side of Trafalgar Road. The innermost line must be relocated, either buried further west in the new ROW, or joint use aerially, with hydro poles on the east side of Trafalgar Road. An updated suggested utility relocation plan and cross-sections will be provided to Enbridge Gas, Oakville Hydro, Union Gas, Rogers and Bell Canada for review and a request to commence with relocation designs as soon as possible to meet the summer 2014 construction start.	Stantec

The meeting adjourned at 4:00 PM.

The foregoing is considered to be a true and accurate record of all items discussed. If any discrepancies or inconsistencies are noted, please contact the writer immediately.

STANTEC CONSULTING LTD.

Jerry Zhu, P.Eng.
Senior Project Engineer
jerry.zhu@stantec.com

Stantec

Meeting Minutes

Utility Coordination Meeting #3

William Halton Parkway(WHP1) (Ninth Line to Trafalgar Road) (PR2538A) / 160210544

William Halton Parkway(WHP2) (Trafalgar Road to Neyagawa Boulevard) (PR2263D) / 165010557

Date/Time:	September 30, 2015 / 1:30 PM	
Place:	Oakville Hydro – Engineering Boardroom	
Next Meeting:	TBD	
Attendees:	Daniela Motoc, Manager Planning & Design	Oakville Hydro
	Daniel Steele, Director, Engineering & Construction	Oakville Hydro
	Jimmy P. Roxas Jr., Engineering Manager	NBM
	Kelsi McGinty, Design Technician	NBM
	Andrew Gorman, Project Manager	Halton Region
	Jerry Zhu, Project Engineer	Stantec Consulting
Absentees:	**Gord Murray (Stantec)**	
Distribution:	Attendees and Absentees	

Item:	Action:
1. Introduction and Review the Status of the Project Daniela Motoc initialized the meeting. Jerry Zhu went over the minutes for the last utility coordination meeting (meeting #2). Region proposes to construct these two sections of William Halton Parkway (WHP) stating in Spring 2016, and requests the tender documents be ready in February 2016. The 60% detailed design has been completed for both WHP sections. The design files in ACAD have been provided to Oakville Hydro to update their utility relocation design. Stantec requested that the revised hydro pole relocation design be complete by the end of October 2015.	
2. Utility Relocation Design for WHP1 and WHP2 The easements for some relocated hydro poles are not included in the current property plan. It may be necessary to revise the property plan and R-plan after the hydro pole design is complete.	Region Stantec
The streetlighting design will not be finalized until the hydro pole relocation plan is complete. <u>Utility Relocation along Roundabouts (at Sixth Line, and at Ninth Line)</u> NBM outlined the new options for hydro pole relocation in the vicinity of the roundabout at Sixth Line and WHP, based on the 60% design plan. It was discussed that guying and anchor towards the roadway is not desirable. OH and NBM are reviewing these locations and will attempt to	NBM Oakville Hydro

redesign the guy anchor locations as much as possible.	
It was agreed that NBM would optimize the design (between the curb line and the proposed property line) without consideration of the current multi-use pathway (MUP) design. The design of multi-use pathway will be modified to accommodate the final pole locations.	NBM Stantec
The design for the hydro pole relocation must avoid conflict with the pedestrian crossing.	NBM
Oakville Hydro advised that they do not want street lights on the Sixth Line hydro poles. Stantec commented that they are concerned this will create conflicts between street lights and hydro poles along the roadway and intersection. This will need to be reviewed once the electrical design is initiated and after the hydro pole locations are finalized.	NBM Oakville Hydro Stantec
<u>Utility Relocation on existing Burnhamthorpe Road - from Ninth Line westerly 700m in WHP1; and - from Neyagawa Blvd easterly 1 km in WHP2</u>	
It was agreed that hydro poles be placed between the curb line and sidewalk (or MUP). Oakville Hydro indicated that they have planned their hydro lines to be on the south side of the WHP corridor, for current and future lines.	NBM Oakville Hydro
Region indicated that the property bounded by existing Burnhamthorpe Road, WHP and the western Connecting Link, east of Neyagawa Boulevard, will be eventually sold, and, as such, the Region would prefer to move all utilities off the surplus property to clear any/all encumberances for a future sale.	NBM Oakville Hydro
To maintain the hydro poles which have been recently installed / relocated along Burnhamthorpe Road in the Neyagawa project, the proposed sidewalk and MUP have been designed around these poles. Therefore, it is preferred to leave sidewalk and MUP as-is. Oakville Hydro and NBM will re-visit the design to determine any adjustments required for these poles.	NBM Oakville Hydro
Oakville Hydro shall coordinate with the Neyagawa Road project (Andrew Gorman as project manager) for utility relocation design along the existing Burnhamthorpe Road.	Oakville Hydro
Hydro pole relocations shall avoid impacting the existing water main under Burnhamthorpe Road in WHP2.	NBM Oakville Hydro
<u>Utility Relocation on William Halton Parkway (1,2)</u>	
OH commented that that 0.5m space behind the sidewalk (or MUP) to the property line is too tight to accommodate the guying and	Stantec

anchoring, and requested 0.75m is more desirable. Where hand rail (or steel beam guide rail) is to be installed, 1.0m space shall be provided. Stantec will adjust the plan to fit these requirements. Stantec to provide Oakville Hydro the future intersections along WHP. <u>Utility Relocations at Trafalgar Road (in WHP1)</u> The design for Trafalgar Road across the GO parking lot frontage has been revised. The proposed construction is roadway widening on both sides of Trafalgar Road (no longer full depth reconstruction). The rural section will be maintained. Oakville Hydro / NBM will undertake the relocation design for this section.	Stantec NBM Oakville Hydro
3. Next Step Daniela Motoc is the contact person for Oakville Hydro for the relocation design of both WHP sections and NBM is the design consultant. Stantec will update the plan and send to Oakville hydro / NBM by October 7, 2015. NBM / Oakville Hydro will prepare the final relocation design and submit the revised design to Region and Stantec for review by October, 31st, 2015.	Stantec NBM Oakville Hydro

The meeting adjourned at 3:00 PM
The foregoing is considered to be a true and accurate record of all items discussed. If any discrepancies or inconsistencies are noted, please contact the writer immediately.

STANTEC CONSULTING LTD.

Jerry Zhu

Jerry Zhu, P.Eng.
Project Engineer
Phone: 905-944-6861
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Appendix 6

Financial Statements

Financial Statements of

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

December 31, 2014

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

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Oakville Hydro Electricity Distribution Inc.

We have audited the accompanying financial statements of Oakville Hydro Electricity Distribution Inc. ("the Entity"), which comprise the balance sheet as at December 31, 2014, and the statements of operations and retained earnings and cash flows for the year 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 Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform an audit to obtain reasonable assurance about whether the 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 is sufficient and appropriate to provide a basis for our audit opinion.

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KPMG Confidential

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Oakville Hydro Electricity Distribution Inc. as at December 31, 2014, and its results of operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Hamilton, Canada
March 31, 2015

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
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December 31, 2014

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OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
Balance Sheet
December 31, 2014
(in thousands of dollars)

	2014	2013
ASSETS		
CURRENT		
Cash and cash equivalents	**$ 22,471**	$ 16,248
Accounts receivable	**38,257**	34,859
Inventories (Note 3)	**3,001**	3,327
Prepaid expenses	**737**	940
	64,466	55,374
OTHER		
Future income taxes (Note 5)	**15,667**	17,754
	15,667	17,754
CAPITAL ASSETS (Note 6)	**162,653**	156,927
	$ 242,786	$ 230,055
LIABILITIES		
CURRENT		
Accounts payable and accrued charges	**$ 32,255**	$ 24,592
Consumer deposits	**7,584**	5,766
Current portion-long term debt (Note 10)	**422**	406
Capital lease obligation (Note 9)	**386**	355
	40,647	31,119
OTHER		
Due to related parties (Note 13)	**305**	-
Regulatory liabilities (Note 4)	**11,990**	14,994
Post employment benefits (Note 7)	**8,022**	7,741
Capital lease obligation (Note 9)	**10,920**	11,306
Long-term debt (Note 10)	**88,664**	89,087
	119,901	123,128
	160,548	154,247
SHAREHOLDER'S EQUITY		
SHARE CAPITAL		
Authorized and issued - 1,407 common shares	**76,108**	76,108
RETAINED EARNINGS (DEFICIT)	**6,130**	(300)
	82,238	75,808
	$ 242,786	$ 230,055

See accompanying notes to the financial statements

APPROVED BY THE BOARD

…….. Director

…….. Director

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
Statement of Operations and Retained Earnings
Year ended December 31, 2014
(in thousands of dollars)

	2014	2013
REVENUE		
Energy and distribution revenue	**$ 214,009**	$ 199,537
Cost of power	**(176,670)**	(164,079)
Net distribution revenue	**37,339**	35,458
Other revenues	**2,749**	2,435
Intercompany revenue	**1,469**	1,412
	41,557	39,305
EXPENSES		
Personnel costs	**13,310**	13,119
Contract services	**2,456**	2,811
Property and occupancy costs	**1,214**	1,193
Material costs	**218**	419
Other costs	**5,457**	4,986
Intercompany costs	**137**	37
Costs allocated to capital	**(2,154)**	(2,504)
	20,638	20,061
EARNINGS BEFORE AMORTIZATION, INTEREST AND INCOME TAXES	**20,919**	19,244
AMORTIZATION	**(8,261)**	(8,832)
INTEREST (Notes 10 and 13)	**(5,991)**	(5,968)
INCOME BEFORE INCOME TAXES	**6,667**	4,444
PROVISION FOR INCOME TAXES (RECOVERY)(Note 5)	**237**	(264)
NET INCOME	**6,430**	4,708
DEFICIT, BEGINNING OF YEAR	**(300)**	(5,008)
RETAINED EARNINGS (DEFICIT), END OF YEAR	**$ 6,130**	$ (300)

See accompanying notes to the financial statements

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
Statement of Cash Flows
Year ended December 31, 2014
(in thousands of dollars)

		2014		2013
NET INFLOW (OUTFLOW) OF CASH RELATED TO THE FOLLOWING ACTIVITIES				
OPERATING				
Net income	**$**	**6,430**	$	4,708
Items not affecting cash				
Amortization		**8,261**		8,832
Future income taxes		**461**		273
Gain on disposal of fixed asset		**-**		(26)
Post employment benefits		**281**		100
		15,433		13,887
Changes in non-cash working capital items				
Accounts receivable		**(3,398)**		(1,497)
Accounts payable and accrued charges		**7,663**		664
Other		**529**		(581)
Net cash provided by operating activities		**20,227**		12,473
FINANCING				
Consumer deposits		**1,818**		1,127
Amount due from related parties		**305**		-
Contributions in aid of construction		**2,687**		2,771
Long term debt		**(407)**		(389)
Capital lease obligation		**(355)**		(325)
Net cash provided by financing activities		**4,048**		3,184
INVESTING				
Proceeds on disposition of capital assets		**-**		28
Additions to capital assets		**(16,764)**		(14,428)
Regulatory liabilities		**(1,288)**		(778)
Net cash used in investing activities		**(18,052)**		(15,178)
INCREASE IN CASH AND CASH EQUIVALENTS		**6,223**		479
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR		**16,248**		15,769
CASH AND CASH EQUIVALENTS, END OF YEAR	**$**	**22,471**	$	16,248

See accompanying notes to the financial statements

SUPPLEMENTARY INFORMATION				
Interest paid	**$**	**5,991**	$	5,968
Income tax recovered	**$**	**(820)**	$	(384)
Acquisition of capital assets through non-cash capital contributions	**$**	**1,069**	$	1,120
Decrease in regulatory liabilities related to decrease in future tax assets	**$**	**(1,626)**	$	(1,864)

1. NATURE OF OPERATIONS

Oakville Hydro Electricity Distribution Inc. (the "Corporation"), is a wholly-owned subsidiary of Oakville Hydro Corporation and was incorporated January 28, 2000 under the laws of the Province of Ontario.

The principal activity of the Corporation is to distribute electricity to the residents and businesses in the Town of Oakville, under a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated by the OEB and adjustments to the Corporation's distribution and power rates require OEB approval.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles and policies set forth in the Accounting Procedures Handbook issued by the OEB under the authority of the Ontario Energy Board Act, 1998:

(a) Measurement uncertainty

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

Accounts receivable, regulatory assets and liabilities are stated after evaluation of amounts expected to be collected and an appropriate allowance for recoverability. Inventories are recorded net of provisions for obsolescence. Amounts recorded for amortization of capital assets are based on estimates of useful service life. Post-employment benefits are based on certain assumptions, including interest (discount) rates, salary escalation, the average retirement age of employees, employee turnover and expected health and dental costs.

(b) Cash and cash equivalents

Cash and cash equivalents include demand deposits held and may include short-term investments that are readily convertible to cash without significant loss in value with a term of less than 3 months.

(c) Inventories

Inventories are stated at the lower of cost and net realizable value and consist of maintenance materials and supplies. Cost is determined on a weighted average basis. Major spare parts and standby equipment are presented as capital assets as they are used during more than one period.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(d) Capital assets

Capital assets are recorded at cost, and are amortized over their estimated service lives using the straight-line method of amortization. In the year of addition or completion, a half a year of amortization is taken on the asset. Construction in progress assets are not amortized until the project is complete and in service. The Corporation has not capitalized interest to the cost of assets constructed.

The estimated service lives, revised January 1, 2013 as required by the OEB, of the various assets used in calculating amortization are as follows:

Asset	Rate
Buildings and leasehold improvements	10 – 60 years
Transmission and distribution system	15 – 60 years
Building under capital lease	20 years
Office equipment	10 years
Computer equipment and software	3 – 5 years
Plant and equipment	5 – 20 years

Contributions in aid of construction consist of third party contributions toward the cost of constructing distribution assets and may be refunded by the Corporation based on future economic evaluations, in accordance with the OEB Distribution System Code. They are accounted for as reductions to the cost of related capital assets and are amortized at rates corresponding with the useful lives of the related capital assets, until such time as they are repayable to the third party contributor.

(e) Post-employment benefits other than pension

The Corporation provides its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans. The cost of these benefits is expensed as earned by employees through employment service. The excess of the net accumulated actuarial gains or losses over 10% of the accrued benefit obligation is amortized over the average remaining service period of active employees. The expected average remaining service life of the current active group is 11 years.

(f) Regulatory environment

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Regulatory environment (continued)

distinct businesses, conservation and demand management targets and filing and process requirements for rate setting purposes.

Rate Setting

The electricity distribution rates and other regulated charges of the Corporation are determined in a manner that provides shareholders with a regulated Maximum Allowable Return on Equity ("MARE") on the amount of shareholder's equity supporting the business of electricity distribution, which is also determined by regulation.

Rate Applications

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

IRM adjustments to the Corporation's distribution rates are principally formulaic in nature and based on a 2-factor "input price index"(IPI) consisting of a 70% weighting of the annual change of non- labour sub-index comprised of the Canada GDP-IPI (FDD) and 30% weighting of the annual change in the labour sub-index comprised of the average weekly earnings for workers in Ontario, net of a "Stretch Factor" determined by the relative efficiency of an electricity distributor.

The rate adjustment resulting from a cost of service application is normally based on forecast test year data, including the amount of operating and capital expenditures, payments in lieu of taxes (PILs), deemed debt, and shareholder's equity required to support an electricity distributor's business. The aggregate amount of debt and equity upon which an electricity distributor may recover interest charges and MARE is equal to the "rate base" of an electricity distributor, which is determined as the aggregate of its capital assets in support of regulated electricity distribution activities and a working capital allowance.

Rates have historically, and typically, been effective from May 1st to April 30th. Accordingly, for the first four months of 2014, distribution revenue was based on rates approved for 2013. For years subsequent to 2014, rates are effective from January 1st through December 31st.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Regulatory environment (continued)

On April 30, 2014, the OEB approved the 2014 Cost of Service Application ("Application") with rates effective May 1, 2014. The Application allows a rate of return on debt and equity of 4.51% and 9.36% respectively, based on the Corporation's deemed debt (60%) and equity (40%) capital structure. The noted returns on debt is a blended rate derived from deemed 4% short term debt and 56% long term debt. The Application also resulted in the following:

- disposition of the cumulative regulatory liabilities as at December 31, 2012 in the amount of $2,720, over a one year period.
- recovery of the stranded meter balance of $3,422, over a five year period
- disposition of the impact of the 2013 accounting changes of $475, over a one year period
- recovery of the true-up of incremental capital rate rider for the Glenorchy Transformer station over a one year period and,
- the recovery of Lost revenue adjustment mechanism (LRAM) for 2011 and 2012 of $105 over a one year period.

On December 4, 2014, the OEB approved the 2015 IRM application for distribution rates effective January 1, 2015. In addition, the application included z-factor component for recovery of the incremental "2013 Ice storm costs". The Corporation was granted recovery of $ 338 for the 2013 ice storm costs over a one year period.

Select Energy Policies and Regulation Affecting the Corporation

Electricity distributor License Requirements - Conservation and Demand Management Targets

On November 12, 2010, the OEB amended electricity distributor licenses to include requirements for achieving certain CDM targets over a four year period commencing January 1, 2011. The Corporation's CDM targets include a demand reduction target of 20.70 megawatts ("MW") and a consumption reduction target of 74.06 gigawatt-hours ("GWh"). On December 17, 2014 the Ontario Energy Board issued a letter stating that it "has determined that it will take no compliance action for distributors that reach at least 80% of their targets". The Corporation has achieved the threshold and therefore no compliance action is necessary. On December 18, 2014, the OEB amended electricity distributor's licenses to include requirements for achieving certain CDM targets over a six year period commencing January 1, 2015. The Corporation's CDM targets include a consumption reduction target of 92.4 GWh.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Regulatory environment (continued)

Other Matters

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

Regulatory Accounting

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

Regulatory Liabilities

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

(g) Revenue recognition and cost of power

Energy revenue is recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power consumed. Revenues from other activities are recorded when goods are delivered or services are provided.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(h) Payments in lieu of income taxes ("PILs")

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

The Corporation accounts for PILs using the liability method. Under the liability method, future income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

PILs are henceforth referred to as income taxes.

(i) Impairment of long-lived assets

Generally accepted accounting principles require that an impairment loss be recognized when events or circumstances indicate that the carrying amount of the long-lived asset exceeds its fair value. Any resulting impairment loss is recorded in the period in which the impairment occurs. The Corporation has determined that there was no impairment of long-lived assets as at December 31, 2014.

(j) Financial assets and liabilities

All financial instruments are classified into one of the following categories – held-for-trading, available for sale, held-to-maturity, other liabilities or loans and receivables. All financial instruments are carried on the balance sheet at fair value, except for loans and receivables, held-to-maturity investments and other liabilities, which are measured at amortized cost.

The company has classified its financial instruments as follows:

Cash and cash equivalents	Held for trading
Accounts receivable	Loans and receivables
Accounts payable	Other liabilities
Consumer deposits	Other liabilities
Long-term debt	Other liabilities

Derivatives and hedge accounting

The Corporation does not have derivatives and does not engage in derivative trading or speculative activities. Hedge accounting has not been used in the preparation of these financial statements.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(j) Financial assets and liabilities (continued)

Financial instruments

The Corporation has adopted CPA Canada Handbook Sections 3862 Financial Instruments Disclosures and 3863 Financial Instruments Presentation. The adoption of these standards requires the disclosure of qualitative and quantitative information about the Corporation's risks associated with recognized and unrecognized financial instruments (see Note 12).

3. INVENTORIES

The amount of inventories consumed by the Corporation and recognized as an expense during 2014 was $184 (2013 - $191).

4. REGULATORY LIABILITIES

		2014		2013
Settlement of variances	$	989	$	(1,675)
Regulatory variances disposition account		(1,007)		326
Other regulatory assets		838		511
Stranded meter recovery		3,052		3,332
Customer liability for future taxes		(15,862)		(17,488)
Balance, end of year	$	(11,990)	$	(14,994)

5. INCOME TAXES

		2014		2013
Accounting income before tax	$	6,677	$	4,444
Increase (decrease) in taxable income resulting from:				
Non-deductible and non-taxable items		53		38
Timing differences		(7,324)		(6,965)
Taxable loss	$	(594)	$	(2,483)
Tax rate		26.50%		26.50%

5. INCOME TAXES (continued)

The income taxes provision consists of:

	2014	2013
Current	$ (158)	$ (658)
Future income tax expense relating to current year change in temporary differences	1,655	1,644
Regulatory liability relating to future tax expense	(1,195)	(1,370)
Other miscellaneous adjustments	(65)	120
Income tax provision (recovery)	$ 237	$ (264)

Significant components of the Corporation's future tax balance as at December 31 are as follows:

	2014	2013
Post-employment benefits other than pensions	$ 2,126	$ 2,051
Plant and equipment	9,934	11,506
Regulatory liabilities	3,177	3,973
Non capital losses carried forward	255	110
Tax reserves	175	114
Future income tax asset	$ 15,667	$ 17,754

Future income tax rates are calculated using a 26.5% rate (2013 - 26.5%).

6. CAPITAL ASSETS

	2014			2013
	Cost	Accumulated amortization	Net book value	Net book value
Land	$ 1,722	$ -	$ 1,722	$ 1,722
Land and building under capital lease	11,689	(8,067)	3,622	3,863
Buildings and leasehold improvements	9,222	(2,362)	6,860	7,304
Plant and equipment	6,401	(4,237)	2,164	2,261
Transmission and distribution system	285,774	(106,310)	179,464	171,241
Office equipment	920	(805)	115	136
Computer equipment and software	14,897	(12,294)	2,603	2,816
Construction in progress	3,033	-	3,033	1,722
	333,658	(134,075)	199,583	191,065
Contributions in aid of construction	(48,605)	11,675	(36,930)	(34,138)
Balance, end of year	$ 285,053	$ 122,400	$ 162,653	$ 156,927

7. POST EMPLOYMENT BENEFITS

The Corporation provides certain unfunded health, dental and life insurance benefits on behalf of its retired employees. The Corporation recognizes these post-employment costs in the period in which the employees earn the benefits, through their services. The accrued benefit liability and the expense for the year ended December 31, 2014 were based on results and assumptions determined by actuarial valuation as at January 1, 2014.

		2014		2013
Accrued benefit obligation, beginning of year	$	6,835	$	6,650
Estimated benefit expense for year		177		176
Interest expense		362		302
Actuarial loss for year		2,087		-
Benefits paid during the year		(283)		(293)
Accrued benefit obligation, end of year		9,178		6,835
Unamortized actuarial (loss) gain		(1,156)		906
Accrued benefit liability, end of year	$	8,022	$	7,741

In 2014, the amortization of the actuarial loss (gain) was $26 (2013 - ($85)).

The significant assumptions used are as follows (weighted average):

	2014	2013
Accrued benefit obligation as at December 31:		
Discount rate	4.10%	4.50%
Rate of compensation increase	3.00%	3.00%
Benefit cost of years ended December 31:		
Discount rate	4.50%	5.50%
Rate of compensation increase	3.00%	3.00%
Assumed health care cost trend rates at December 31:		
Initial health care cost trend rate	8.33%	8.33%
Cost trend rate declines to	4.00%	4.00%
Year that rate reaches the rate it is assumed to remain at	2025	2025

8. PENSIONS

The Corporation provides a pension plan for some of its employees through the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund"), and provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. However, because it is a multi-employer plan it is accounted for as a defined contribution plan.

Contributions by the Corporation were at a rate of 9% for employee earnings below the year's maximum pensionable earnings and 14.6% thereafter. In 2014, the Corporation made employer contributions of $1,300 to OMERS (2013 - $1,210).

9. CAPITAL LEASE OBLIGATION

The Corporation has a capital lease arrangement with the Town of Oakville for the head office at 861 Redwood Square. The assets under capital lease are included in Capital Assets (see Note 6). The property under capital lease is amortized on a straight-line basis over the term of the lease agreement of 20 years.

Future minimum payments under the capital lease arrangement are as follows for the year-ends:

2015	$ 1,345
2016	1,345
2017	1,345
2018	1,345
2019	1,345
2020-2029	13,450
	20,175
Less amount representing interest inputed at 8.6%	(8,869)
Less current portion	(386)
Long-term portion of lease obligation	$ 10,920

10. LONG-TERM DEBT

The Corporation had promissory notes outstanding in the amount of $67,946 (2013 - $67,946), issued effective February 1, 2000, held by the Town of Oakville, with principal repayment due on February 1, 2020. Future interest rates to be determined annually throughout the balance of the terms of the notes. At December 31, 2014 interest rates in effect were 6% (2013 - 5.87%)

The Corporation has a $21,140 debenture with Infrastructure Ontario for a 30 year term and a fixed interest rate of 4% throughout the term of the loan. The Infrastructure Ontario debt is secured by a General Security Agreement with a second charge over all assets of the Corporation. Proceeds were used to replace working capital used in the 2010-2011 construction of a transmission station in Oakville. Repayment is through monthly installments of $105 including principal and interest.

Repayment of the Long term debt for the years ended December 31:

2015	$ 422
2016	440
2017	457
2018	476
2019	496
Thereafter	86,795
Total long-term debt	89,086
Less current portion	(422)
Long-term portion of lease obligation	$ 88,664

11. GENERAL LIABILITY INSURANCE

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the electrical utilities in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members on a pro-rata basis based 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, 2014, no assessments have been made.

12. FINANCIAL INSTRUMENTS

The Corporation's fair value measurements are as follows:

Level 1

The carrying values of cash and cash equivalents, accounts receivable, consumer deposits and accounts payable approximate fair value because of the short maturity of these instruments.

Level 2

Compared with the carrying value of the infrastructure Ontario debenture $21,140, the fair value is calculated as $23,482 using a discount rate of 3.1%. This discount rate is determined using indicative quoted rates for instruments with the approximately the same terms and credit risk.

12. FINANCIAL INSTRUMENTS (continued)

Level 3

It is not practicable to determine the fair value of the long-term borrowings from the Town of Oakville as there is no defined term to the loans. Due to the lack of comparable market information fair value cannot readily be determined. The fair value of the Infrastructure Ontario debenture is equal to its carrying value.

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

i) Credit risk

Cash and cash equivalents are held in a Canadian Chartered Bank. Financial assets carry credit risk that a counter party 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 Oakville. No single customer would account for revenue in excess of 10% of total revenue.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the statement of operations. Subsequent recoveries of receivables previously provisioned are credited to the statement of operations. The amount of the allowance for doubtful accounts at December 31, 2014 is $725 (2013 - $398).

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2014, approximately $356 (2013 - $237) is considered 60 days past due. The Corporation has approximately 67,244 customers, the majority of which are residential. Credit risk is managed through collection of security deposits from commercial customers in accordance with OEB requirements. At December 31, 2014, the Corporation holds security deposits in the amount of $7,584 (2013 - $5,766).

The amount of the security deposit is reviewed annually to determine if the amount should be adjusted to comply with the OEB's requirements. Deposits are returned to commercial customers who have demonstrated an acceptable level of credit risk as determined by the requirements set out by the OEB. Customer deposits are also returned to the customer upon closure of the customer's account, subject to OHEDI's right to use the deposit to offset electricity charges owed by the customer. Interest expense of $23 was incurred on these consumer deposits in 2014 (2013 - $22).

12. FINANCIAL INSTRUMENTS (continued)

Level 3 (continued)

ii) Market risk

Market risks primarily refer to the risk of loss which results from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the 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 which is set every 5 years, the last one being 2014.

iii) Liquidity risk

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity exists to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $ 20,000 line of credit and monitors cash balances to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

The majority of accounts payable, as reported on the balance sheet, are due within 30 days.

13. RELATED PARTY TRANSACTIONS

The following summarizes the Corporation's related party transactions, recorded at the exchange amounts and balances with the Town of Oakville for the year ended December 31:

	2014	2013
Transactions:		
Revenue		
Energy sales	$ 6,281	$ 6,357
Rent	147	147
Expenses		
Interest on long –term debt	4,077	3,988
Interest on capital leases	1,038	1,046
Garage services	497	480
Property taxes	355	348
Tree trimming services	315	250
IT services	77	-
Internal audit	23	30
Cashier services	7	8
Other	7	-
Balances:		
Amounts due to:		
Capital leases	11,306	11,661
Long-term debt	67,946	67,946

Included in accounts receivable reported in the balance sheet is $622 owing from the Town of Oakville (2013 - $640) relating to Energy sales and $248 (2013 - $142) relating to other receivables. Included in accounts payable reported in the balance sheet is $130 owing to the Town of Oakville (2013 - $155). These balances are non-interest bearing.

13. RELATED PARTY TRANSACTIONS (continued)

The following summarizes the Corporation's related party transactions, recorded at the exchange amounts and balances with the parent, Oakville Hydro Corporation, and its subsidiaries, for the year ended December 31:

	2014	2013
Transactions:		
Revenue		
Billing administration fee	$ 720	$ 713
Management fees	617	538
Other charges	132	161
Expenses		
Meter repair and related services	115	14
Corporate governance charge	7	8
Locating/construction services from affiliates	850	1,213
Other Charges	13	37
Balances:		
Amounts due from/due to:		
Payable to related parties	305	-

Included in accounts payable reported on the balance sheet is $2,054 owing to related parties (2013 - $1,429). Included in accounts receivable reported on the balance sheet is $nil owing from related parties (2013 - $32). These balances are non-interest bearing.

14. SHORT-TERM CREDIT FACILITIES

The Corporation participates in the pooling of deposits and banking facilities with its parent company OHC and certain OHC wholly owned subsidiaries. These balances can then be used in support of these subsidiaries. Under this arrangement, the Corporation has an uncommitted line of $20 million credit facility available with a Canadian chartered bank. As at December 31, 2014, no amount was drawn on this facility. The Corporation has a letter of credit facility available of $16 million with a Canadian chartered bank, of which $10.5 million has been assigned to secure its primary source of electricity as required by the Independent Electricity System Operator's Settlement Manual ("IESO").

15. CAPITAL DISCLOSURE

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

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2014, shareholder's equity amounts to $82,238 (2013 - $75,808) and long-term debt amounts to $88,664 (2013 - $89,087).

16. EMERGING ACCOUNTING ISSUES

a) Transition to International Financial Reporting Standards

The Canadian Accounting Standards Board ("AcSB") adopted a strategic plan that would have Canadian GAAP converge with IFRS, effective January 1, 2011 which would have required entities to restate, for comparative purposes, their interim and annual financial statements and their opening financial position.

In October 2010, the AcSB approved a deferral of adoption of IFRS for qualifying entities with activities subject to rate regulation. Part 1 of the CPA Canada Handbook specifies that first-time adoption is mandatory for interim and annual financial statements relating to annual periods beginning on or after January 1, 2015.

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

The Corporation has decided to implement IFRS commencing on January 1, 2015.

b) Accounting for rate regulated activities under IFRS

In January 2014, The International Accounting Standards Board ("IASB") released IFRS14 *Regulatory Deferral Accounts*. This standard provides specific guidance on accounting for the effects of rate regulation and permits first-time adopters of IFRS to continue using previous GAAP to account for regulatory deferral account balances while the IASB completes its comprehensive project in this area. Adoption of this standard is optional for entities eligible to use it. Deferral account balances and movement in the balances will be required to be presented as separate line items on the financial statements distinguished from assets, liabilities, income and expenses recognized in accordance with IFRS. Extensive disclosures will be required to enable users of the financial statements to understand the features and nature of risks associated with rate regulation and the effects of rate regulation on the Corporation's financial position, performance and cash flows.

Financial Statements of

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

Year ended December 31, 2015
(Expressed in thousands of dollars)

KPMG LLP
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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Oakville Hydro Electricity Distribution Inc.

We have audited the accompanying financial statements of Oakville Hydro Electricity Distribution Inc. ("the Entity"), which comprise the statements of financial position as at December 31, 2015, December 31, 2014 and January 1, 2014, the statement of profit or loss and other comprehensive income, changes in equity and cash flows for the years ended December 31, 2015, and December 31, 2014, 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.

We believe that the audit evidence we have obtained in our audit 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 KPMG network independent member firms affiliated with KPMG International Cooperative ("KPMG International") a Swiss entity. KPMG Canada provides services to KPMG LLP.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Oakville Hydro Electricity Distribution Inc. as at December 31, 2015, December 31, 2014 and January 1, 2014, and its financial performance and its cash flows for the years ended December 31, 2015, and December 31, 2014 in accordance with International Financial Reporting Standards**.**

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

April 7, 2016
Hamilton, Canada

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

Statements of Financial Position
(in thousands of dollars)

	Note	December 31, 2015	December 31, 2014	January 1, 2014
Assets				
Current assets				
Cash and cash equivalents	5	$ 24,841	$ 22,471	$ 16,248
Accounts receivable	6	39,283	38,257	34,827
Materials and supplies	7	3,311	3,001	3,327
Prepaid expenses		600	737	940
Total current assets		68,035	64,466	55,342
Non-current assets				
Property, plant and equipment	8	206,334	198,397	189,961
Intangible assets	9	883	1,167	1,105
Deferred tax assets	10	10,733	12,579	13,763
Total non-current assets		217,950	212,143	204,829
Total assets		285,985	276,609	260,171
Regulatory balances	11	12,323	14,342	12,260
Total assets and regulatory balances		$ 298,308	$ 290,951	$ 272,431

	Note	December 31, 2015	December 31, 2014	January 1, 2014
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities	12	$ 34,074	$ 29,676	$ 22,268
Due to related parties	22	2,343	2,359	1,397
Long-term debt due within one year	13	440	422	406
Capital lease obligation		421	386	355
Customer deposits		9,202	7,584	5,766
Total current liabilities		46,480	40,427	30,192
Non-current liabilities				
Long-term debt	13	88,224	88,664	89,087
Capital lease obligation	14	10,499	10,920	11,306
Post-employment benefits	15	9,392	9,178	6,835
Deferred revenue		40,770	36,931	34,139
Total non-current liabilities		148,885	145,693	141,367
Total liabilities		195,365	186,120	171,559
Equity				
Share capital	16	76,108	76,108	76,108
Retained earnings		7,607	5,912	(300)
Accumulated other comprehensive income (loss)		(958)	(958)	906
Total equity		82,757	81,062	76,714
Total liabilities and equity		278,122	267,182	248,273
Regulatory balances	11	20,186	23,769	24,158
Total liabilities, equity and regulatory balances		$ 298,308	$ 290,951	$ 272,431

See accompanying notes to the financial statements.

On behalf of the Board:

_____ Director _____ Director

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

Statements of Comprehensive Income
Year ended December 31, 2015, with comparative information for 2014
(in thousands of dollars)

	Note	2015	2014
Revenue			
Sale of energy		$ 194,533	$ 178,105
Distribution revenue		38,257	37,489
Other	17	6,238	5,271
		239,028	220,865
Operating expenses			
Cost of power purchased		195,293	179,505
Employee salaries and benefits	18	14,090	13,541
Operating expenses	19	7,474	7,195
Depreciation and amortization		9,591	9,315
		226,448	209,556
Income from operating activities		12,580	11,309
Finance income	20	414	339
Finance costs	20	(6,353)	(6,353)
Income before income taxes		6,641	5,295
Income tax expense	10	1,810	1,510
Net income for the year		4,831	3,785
Net movement in regulatory balances, net of tax	11	1,564	2,427
Net income for the year and net movement in regulatory balances		6,395	6,212
Other comprehensive income			
Items that will not be reclassified to profit or loss:			
Re-measurements of post-employment benefits	15	---	(2,088)
Tax on re-measurements	10	---	224
Other comprehensive income for the year		---	(1,864)
Total comprehensive income for the year		$ 6,395	$ 4,348

See accompanying notes to the financial statements.

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

Statements of Changes in Equity
Year ended December 31, 2015, with comparative information for 2014
(in thousands of dollars)

	Share capital	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance at January 1, 2014	$ 76,108	$ (300)	$ 906	$ 76,714
Net Income and net movement in regulatory balances	---	6,212	---	6,212
Other comprehensive income	---	---	(1,864)	(1,864)
Dividends	---	---	---	---
Balance at December 31, 2014	$ 76,108	$ 5,912	$ (958)	$ 81,062
Balance at January 1, 2015	$ 76,108	$ 5,912	$ (958)	$ 81,062
Net income and net movement in regulatory balances	---	6,395	---	6,395
Other comprehensive income	---	---	---	---
Dividends	---	(4,700)	---	(4,700)
Balance at December 31, 2015	$ 76,108	$ 7,607	$ (958)	$ 82,757

See accompanying notes to the financial statements.

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

Statements of Cash Flows
Year ended December 31, 2015, with comparative information for 2014
(in thousands of dollars)

	2015	2014
Operating activities		
Net Income and net movement in regulatory balances	$ 6,395	$ 6,212
Adjustments for:		
Depreciation and amortization	9,591	9,315
Amortization of deferred revenue	(1,046)	(964)
Post-employment benefits	214	255
(Gain)/loss on disposal of property, plant and equipment	(45)	20
Net finance costs	5,939	6,014
Income tax expense	1,810	1,510
	22,858	22,362
Change in non-cash operating working capital:		
Accounts receivable	(1,365)	(3,987)
Due to/from related parties	(16)	962
Materials and supplies	(310)	326
Prepaid expenses	137	203
Accounts payable and accrued liabilities	4,398	7,407
Customer deposits	1,618	1,818
	4,462	6,729
Regulatory balances	(1,762)	(2,797)
Income tax received	375	780
Interest paid	(6,353)	(6,353)
Interest received	414	339
Net cash from operating activities	19,994	21,060
Investing activities		
Purchase of property, plant and equipment	(14,265)	(16,340)
Proceeds on disposal of property, plant and equipment	107	---
Purchase of intangible assets	(446)	(422)
Contributions received from customers	2,488	2,687
Net cash used by investing activities	(12,116)	(14,075)
Financing activities		
Dividends paid	(4,700)	---
Repayment of long-term debt	(422)	(407)
Repayment of capital lease	(386)	(355)
Net cash from financing activities	(5,508)	(762)
Change in cash and cash equivalents	2,370	6,223
Cash and cash equivalents, beginning of year	22,471	16,248
Cash and cash equivalents, end of year	$ 24,841	$ 22,471

See accompanying notes to the financial statements.

1. Reporting entity

Oakville Hydro Electricity Distribution Inc. (the "Corporation") is a wholly owned subsidiary of Oakville Enterprises Corporation (formerly Oakville Hydro Corporation) and was incorporated on January 28, 2000 under the *Business Corporations Act* (Ontario), in accordance with the *Electricity Act.* The address of the Corporation's registered office is 861 Redwood Square, Oakville, Ontario L6K 0C7.

The principle activity of the Corporation is to distribute electricity to the residents and businesses in the Town of Oakville, under a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated by the OEB and adjustments to the Corporation's distribution and power rates require OEB approval.

The financial statements are for the Corporation as at and for the year ended December 31, 2015.

2. Basis of presentation

(a) Statement of compliance

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

(b) Adoption of IFRS

These are the Corporation's first financial statements prepared in accordance with IFRS and IFRS 1 *First-time Adoption of International Financial Reporting Standards* has been applied.

An explanation of how the transition to IFRS has affected the reported financial position, financial performance and cash flows of the Corporation is provided in note 24.

The financial statements were approved by the Board of Directors on April 7, 2016.

(c) Basis of measurement

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(d) 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.

2. Basis of presentation (continued)

(e) 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.

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 15 – measurement of defined benefit obligations: key actuarial assumptions
(v) Note 21 – recognition and measurement of provisions and contingencies

(ii) Judgements

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 13 – leases: whether an arrangement contains a lease

(f) 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.

2. Basis of presentation (continued)

(f) Rate regulation (continued)

Rate setting

(i) Distribution Rates

The Corporation files a "Cost of Service" ("COS") rate application every five years under which the OEB establishes the revenues required to recover the forecasted operating costs, including amortization and income taxes, of providing the regulated electricity distribution service and providing a fair return on the Corporation's rate base. 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 any registered interveners. Rates are approved based upon the review of evidence and information, including any revisions resulting from that review.

In the intervening years, an Incentive Regulation Mechanism application ("IRM") is filed. An IRM application results 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 set by the OEB and a "stretch factor" determined by the relative efficiency of an electricity distributor.

On October 1, 2013, the Corporation submitted a COS rate application to the OEB to change distribution rates effective May 1, 2014. The application was approved by the OEB on May 1, 2014.

On August 13, 2014, the Corporation submitted an IRM Application to the OEB requesting approval to change distribution rates effective January 1, 2015. The IRM Application, which provided a mechanistic and formulaic adjustment to distribution rates and charges, was approved by the OEB on December 5, 2014. The GDP IPI-FDD for 2015 is 1.6%, the Corporation's stretch factor is 0.45% and the productivity factor determined by the OEB is 0%, resulting in a net adjustment of 1.15% to the previous year's rates.

(ii) Electricity Rates

The OEB sets Ontario electricity prices for low-volume consumers twice each year (May and November) 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 by the Independent Electricity System Operator and passes this cost on to the customer at cost without a mark-up.

2. Basis of presentation (continued)

(f) Rate regulation (continued)

(iii) Retail Transmission Rates

These are the costs of delivering electricity from generating stations across the Province to local distribution networks. These charges include the costs to build and maintain the transmission lines, towers and poles and operate provincial transmission systems. Retail transmission rates are passed through to the operators of transmission networks and facilities.

(iv) Wholesale Market Service Rates

These are the costs of administering the wholesale electricity system and maintaining the reliability of the provincial grid and include the costs associated with funding Ministry of Energy conservation and renewable energy programs. Wholesale charges are passed through to the Independent Electricity System Operator.

3. Significant accounting policies

The accounting policies set out below have been applied consistently in all years presented in these financial statements and in preparing the opening IFRS statement of financial position at January 1, 2014 for the purpose of the transition to IFRS.

(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 may 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 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.

3. Significant accounting policies (continued)

(b) Revenue recognition (continued)

For customer billing related to electricity generated by third parties, along with the associated costs of providing electricity 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.

Customer billings for debt retirement charges and the Ontario Electricity Support Program are recorded on a net basis as the Corporation is acting as an agent for these billing streams.

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered.

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 is consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on an 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.

(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 (see note 24(a)), 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.

3. Significant accounting policies (continued)

(d) Property, plant and equipment (continued)

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, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

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 six 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:

	Years
Buildings and leasehold improvements	10 - 60
Distribution system equipment	15 - 60
Other PP&E	3 - 20

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 (see note 24(a)), 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.

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

	Years
Computer software	4 - 5

(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.

(ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than 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.

3. Significant accounting policies (continued)

(f) Impairment (continued)

(ii) Non-financial assets (continued)

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.

The goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to CGUs that are expected to benefit from the synergies of the combination.

(ii) Non-financial assets (continued)

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. They are allocated first to reduce the carrying amount of any goodwill allocated to the CGU, and then to reduce the carrying amounts of the other assets in the CGU on a prorate basis, if applicable.

An impairment loss in respect of goodwill is not reversed. 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 and deposits. Interest is paid on customer deposits. Deposits are also received for planned chargeable work. No interest is paid on these 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

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of recognizing regulatory balances in accordance with its previous GAAP when it adopts IFRS. An entity is permitted to apply the requirements of this standard in its first IFRS financial statements if it conducts rate-regulated activities and recognized amounts that qualify as regulatory deferral account balances in its financial statements in accordance with its previous GAAP. IFRS 14 is effective from periods beginning on or after January 1, 2016, however, early application is permitted. The Corporation has elected to apply this Standard in its first IFRS financial statements.

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account 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. 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.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. When the amounts are returned to the customer at rates approved by the OEB the amounts are recognized as a reduction of revenue.

The probability of recovery of the regulatory deferral account 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.

(j) Post-employment benefits

(i) Pension plan

The Corporation provides a pension plan for some of its full-time employees through Ontario Municipal Employees Retirement System (“OMERS”). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund (“the Fund”), and provides pensions for employees of Ontario municipalities, local boards and public utilities. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. To the extent that the Fund finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

3. Significant accounting policies (continued)

(j) Post-employment benefits (continued)

(i) Pension plan (continued)

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

(ii) Post-employment benefits, other than pension

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Re-measurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

(k) 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)

(l) 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 and dividend income.

Finance costs comprise interest expense on borrowings, finance lease obligations and unwinding of the discount on provisions, net interest expense on post-employment benefits. Finance costs are recognized in profit or loss unless they are capitalized as part of the cost of qualifying assets.

(m) 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 and some if its' subsidiaries are 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. Payments in lieu of taxes and payments under the Tax Acts are collectively 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 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. The replacement of IAS 39 is a multi-phase project with the objective of improving and simplifying the reporting for financial instruments. The issuance of IFRS 9 is part of the first phase of this project. 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.

Property, Plant and Equipment and Intangible Assets

In May 2014, the IASB issued amendments to IAS 16, Property, Plant and Equipment and IAS 38 Intangible Assets, which are effective for years beginning on or after January 1, 2016. The amendments clarify when revenue-based depreciation methods are permitted. The Corporation does not expect this to have an impact.

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

	December 31, 2015	December 31, 2014	January 1, 2014
Bank balances	$ 24,841	$ 22,471	$ 16,248
Cash and cash equivalents in the statements of cash flows	$ 24,841	$ 22,471	$ 16,248

The Corporation has a mirror accounting agreement with certain related companies whereby the bank has the right of setoff between overdrafts in these related companies and the Corporation's bank account. As at December 31, 2015 the net overdraft totaled ($28,124) (2014 – ($14,834)).

6. Accounts receivable

	December 31, 2015	December 31, 2014	January 1, 2014
Trade receivables	$ 15,406	$ 14,916	$ 11,711
Income tax receivable	244	582	1,138
Unbilled revenue	23,633	22,759	21,978
	$ 39,283	$ 38,257	$ 34,827

7. Materials and supplies

Amount written down (recovered) due to obsolescence in 2015 was $8 (2014 – ($12)). The amount of materials and supplies consumed by the Corporation and recognized as an expense during 2015 was $127 (2014 - $181).

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, 2015	$ 12,899	$ 186,329	$ 5,088	$ 3,033	$ 207,349
Additions	669	14,086	576	1,529	16,860
Disposals/retirements	---	(61)	(7)	---	(68)
Balance at December 31, 2015	$ 13,568	$ 200,354	$ 5,657	$ 4,562	$ 224,141
Balance at January 1, 2014	$ 12,890	$ 171,241	$ 4,108	$ 1,722	$ 189,961
Additions	9	15,109	980	1,311	17,409
Disposals/retirements	---	(21)	---	---	(21)
Balance at December 31, 2014	$ 12,899	$ 186,329	$ 5,088	$ 3,033	$ 207,349
Accumulated depreciation					
Balance at January 1, 2015	$ 695	$ 6,883	$ 1,374	$ ---	$ 8,952
Depreciation	713	7,119	1,029	---	8,861
Disposals/retirements	---	(1)	(5)	---	(6)
Balance at December 31, 2015	$ 1,408	$ 14,001	$ 2,398	$ ---	$ 17,807
Balance at January 1, 2014	$ ---	$ ---	$ ---	$ ---	$ ---
Depreciation	695	6,884	1,374	---	8,953
Disposals/retirements	---	(1)	---	---	(1)
Balance at December 31, 2014	$ 695	$ 6,883	$ 1,374	$ ---	$ 8,952
Carrying amounts					
At December 31, 2015	$ 12,160	$ 186,353	$ 3,259	$ 4,562	$ 206,334
At December 31, 2014	12,204	179,446	3,714	3,033	198,397
At January 1, 2014	12,890	171,241	4,108	1,722	189,961

The Corporation has a capital lease agreement with the Town of Oakville for the head office at 861 Redwood Square. The leased building secures lease obligations (see note 14). At December 31, 2015 the net carrying amount of leased building was $3,381 (2014 - $3,622)

At December 31, 2015 Property plant and equipment with a carrying amount of $206,334 (2014 - $198,397) are subject to a general security agreement.

There were no borrowing costs capitalized as part of the cost of property, plant and equipment in 2014 and 2015.

9. Intangible assets

	Computer software	Total
Cost or deemed cost		
Balance at January 1, 2015	$ 1,527	$ 1,527
Additions	446	446
Balance at December 31, 2015	$ 1,973	$ 1,973
Balance at January 1, 2014	$ 1,105	$ 1,105
Additions	422	422
Balance at December 31, 2014	$ 1,527	$ 1,527
Accumulated amortization		
Balance at January 1, 2015	$ 360	$ 360
Amortization	730	730
Balance at December 31, 2015	$ 1,090	$ 1,090
Balance at January 1, 2014	$ ---	$ ---
Amortization	360	360
Balance at December 31, 2014	$ 360	$ 360
Carrying amounts		
At December 31, 2015	$ 883	$ 883
At December 31, 2014	1,167	1,167
At January 1, 2014	1,105	1,105

10. Income tax expense

Current tax expense

	2015	2014
Current year	$ ---	$ ---
Adjustment for prior years	(36)	(224)
	$ (36)	$ (224)

Deferred tax expense

	2015	2014
Origination and reversal of temporary differences	$ 1,846	$ 1,730
	$ 1,846	$ 1,730

Reconciliation of effective tax rate

	2015	2014
Income before taxes	$ 6,641	$ 5,295
Canada and Ontario statutory Income tax rates	26.5%	26.5%
Expected tax provision on income at statutory rates	1,760	1,403
Increase (decrease) in income taxes resulting from:		
Permanent differences	19	(223)
Prior year adjustment	(36)	14
Other	67	316
Income tax expense	$ 1,810	$ 1,510

Significant components of the Corporation's deferred tax balances

	2015	2014	January 1, 2014
Deferred tax assets (liabilities):			
Property, plant, equipment and intangibles	$ 5,569	$ 6,938	$ 8,415
Capital Lease obligation	2,894	2,996	3,090
Post-employment benefits	2,489	2,432	1,811
Non-capital loss carried forward	24	255	110
Other tax reserves	(243)	(42)	337
	$ 10,733	$ 12,579	$ 13,763

11. Regulatory balances

The Corporation has determined that certain debit and credit balances arising from rate-regulated activities qualify for regulatory accounting treatment in accordance with IFRS 14 and the OEB's prescribed accounting procedures for electricity distributors. The regulatory balances are comprised of regulatory debit variances of $12,323 and regulatory credit balances for $20,186 for a net regulatory liability of $7,863.

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 2015, the rate was 1.47% for the period January 2015 to March 2015 and 1.1% for the period April 2015 to December 2015.

The regulatory balances for the Corporation consist of the following:

(a) Settlement Variance

This account includes the variances between amounts charged by the Corporation, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by the Corporation such as commodity charges, retail transmission rates and wholesale market services charges. The Corporation has deferred the variances and related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. This account also includes variances between the amounts approved for disposition by the OEB and the amounts collected or paid through OEB approved rate riders.

Settlement variances are reviewed annually as part of a COS or IRM application submitted to the OEB and a request for disposition is made if the aggregate of the settlement accounts exceeds the OEB's prescribed materiality level.

In its 2014 cost of service application, the Corporation received approval from the OEB for the disposition of the 2012 audited balances of the settlement variance accounts over a period of one year beginning on May 1, 2014 and ending on April 30, 2015.

In its 2015 IRM application, submitted in August 2014, the Corporation did not request the disposition of the 2013 audited balances of the settlement variance accounts as they were below the OEB's predetermined materiality threshold.

(b) Stranded Meters

The stranded meter account relates to the provincial government's directive to install smart meters for all Ontario customers by December 2010. In its 2014 cost of service application, the Corporation received approval from the OEB for the recovery of the stranded meter costs associated with the Province's smart meter initiative over a five-year period beginning on May 1, 2014 and ending on April 30, 2019.

11. Regulatory balances (continued)

(c) Customer Liability for Future Taxes

The customer liability for future taxes variance account relates to the expected future taxes arising from timing differences in the recognition of deferred income tax assets.

(d) Other

This deferral account includes the allowable costs associated with the transition to IFRS and other miscellaneous regulatory accounts.

Reconciliation of the carrying amount for each class of regulatory balances

Regulatory deferral account debit balances	January 1, 2015	Additions/ transfers	Recovery/ reversal	December 31, 2015	Remaining recovery/ reversal years
Settlement variances	$ 6,617	$ (588)	$ (154)	$ 5,875	Note 1
Stranded meters	3,052	---	(705)	2,347	Note 2
Other regulatory accounts	1,168	257	(495)	930	Note 3
Income tax	3,505	---	(334)	3,171	---
	$ 14,342	$ (331)	$ (1,688)	$ 12,323	

Regulatory deferral account debit balances	January 1, 2014	Additions/ transfers	Recovery/ reversal	December 31, 2014	Remaining years
Settlement variances	$ 4,453	$ 3,637	$ (1,473)	$ 6,617	Note 1
Stranded meters	3,332	---	(280)	3,052	Note 2
Other regulatory accounts	810	170	188	1,168	Note 3
Income tax	3,665	---	(160)	3,505	---
	$ 12,260	$ 3,807	$ (1,725)	$ 14,342	---

Regulatory deferral account credit balances	January 1, 2015	Additions/ transfers	Recovery/ reversal	December 31, 2015	Remaining years
Settlement variances	$ (6,531)	$ 200	$ 1,320	$ (5,011)	Note 1
Other regulatory liabilities	(959)	(287)	385	(861)	Note 4
Customer liability for deferred taxes	(16,279)		1,965	(14,314)	---
	$ (23,769)	$ (87)	$ 3,670	$ (20,186)	

Regulatory deferral account credit balances	January 1, 2014	Additions/ transfers	Recovery/ reversal	December 31, 2014	Remaining years
Settlement variances	$ (5,672)	$ (999)	$ 140	$ (6,531)	Note 1
Other regulatory liabilities	(1,324)	188	177	(959)	Note 4
Customer liability for deferred taxes	(17,162)		883	(16,279)	---
	$ (24,158)	$ (811)	$ 1,200	$ (23,769)	

11. Regulatory balances (continued)

(d) Other (continued)

1. The Corporation did not seek recovery of settlement variances as the net balance is below the OEB determined threshold for materiality.
2. The OEB approved the stranded meter costs over a five-year period beginning May 1, 2014 and ending April 30, 2019.
3. The Corporation will apply for the disposition of the other regulatory assets in its next COS application.
4. The Corporation will apply for the disposition of the other regulatory assets in its next COS application.

The "Additions" column consists of new additions to regulatory balances (for both debits and credits). The "Recovery/Reversal" column consists of amounts collected or paid through rate riders or transactions reversing an existing regulatory balance. Recoveries and reversals occur as a result of the approval of an application. There were no reversals of regulatory balances for the years ended December 31, 2014 and December 31, 2015.

12. Accounts payable and accrued liabilities

	2015	2014	January 1, 2014
Accounts payable – energy purchases	$ 5,582	$ 5,340	$ 5,492
Debt retirement charge payable to OEFC	761	734	690
Payroll payable	1,935	1,645	1,858
Interest payable	4,146	70	72
Trade payables	21,650	21,887	14,156
	$ 34,074	$ 29,676	$ 22,268

13. Long-term debt

	2015	2014	January 1, 2014
Notes payable	$ 67,946	$ 67,946	$ 67,946
Ontario Infrastructure loans	20,718	21,140	21,547
Capital lease liabilities	10,920	11,307	11,661
	$ 99,584	$ 100,393	$ 101,154

13. Long-term debt (continued)

The Corporation had unsecured promissory notes $67,946 (2014 - $67,946) which are held by The Corporation of the Town of Oakville and were issued effective February 1, 2000 for a 20 year term. The notes bear interest at a rate of 6% (2014 – 6%), payable annually no later than 30 days after the end of the fiscal year. Interest rates are reviewed annually. The Corporation of the Town of Oakville has the option to change the terms of the promissory notes with one year notice. The Corporation of the Town of Oakville and the Corporation have set the interest rates for 2016 at 6%.

The Corporation has a $20,718 debenture with Infrastructure Ontario due October 2042 with a fixed interest rate of 4% for the entire term of the debenture. Interest is payable monthly in arrears along with principal of $105. The debenture was issued on October 1, 2012. The Infrastructure Ontario debt is secured by a General Security Agreement with a second charge over all the assets of the Corporation. Proceeds were used to replace working capital used in the 2010 - 2011 construction of a transmission station in Oakville.

Repayment of the long term debt for the years ended December 31:

2016	$	861
2017		916
2018		976
2019		1,040
2020		1,109
thereafter		94,682
		99,584
Current portion		861
Long-term portion	$	98,723

14. Capital lease

The Corporation has a capital lease arrangement with the Town of Oakville for the head office at 861 Redwood Square. The assets under capital lease are included in Capital Assets (see Note 8). The property under capital lease is amortized on a straight-line basis over the term of the lease agreement of 20 years.

Future minimum payments under the capital lease arrangements are as follows for the years ended December 31:

	Less than one year	Between one and five years	More than five years	Total
Future min lease payments				
2015	$ 1,345	$ 5,380	$ 12,105	$ 18,830
2014	1,345	5,380	13,450	20,175
January 1, 2014	1,345	5,380	14,795	21,520
Interest				
2015	924	3,284	3,702	7,910
2014	959	3,456	4,454	8,869
January 1, 2014	990	3,615	5,254	9,859
Present value of min lease Payments				
2015	421	2,096	8,403	10,920
2014	386	1,924	8,996	11,306
January 1, 2014	355	1,765	9,541	11,661

15. Post-employment benefits

(a) OMERS pension plan

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2015, the Corporation made employer contributions of $1,275 to OMERS (2014 - $1,300) which has been recognized in profit or loss. The Corporation estimates that a contribution of $1,247 to OMERS will be made during the next fiscal year.

(b) Post-employment benefits other than pension

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expense and remeasurements recognized for post-employment benefit plans.

Reconciliation of the obligation		2015		2014
Defined benefit obligation, beginning of year	$	9,178	$	6,835
Included in profit or loss				
Current service cost		200		177
Interest cost		384		361
		9,762		7,373
Included in OCI				
Actuarial (gains) losses arising from:				
changes in demographic assumptions		---		574
changes in financial assumptions		---		1,514
		---		2088
Benefits paid		(370)		(283)
Defined benefit obligation, end of year	$	9,392	$	9,178

Actuarial assumptions	2015	2014
Discount (interest) rate	4.10%	4.10%
Salary levels	3.00%	3.00%
Medical Costs	8.33%	8.33%
Dental Costs	4.00%	4.00%

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by 15.6%. A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by 15.6%.

16. Share capital

	2015	2014
Authorized:		
Unlimited number of common shares		
Issued:		
1,407 common shares	$ 76,108	$ 76,108

Dividends

The holders of the common shares are entitled to receive dividends from time to time.

The Corporation paid aggregate dividends in the year on common shares of $3.34 per share which amount to total dividends paid in the year of $4,700.

17. Other revenue

	2015	2014
Services revenue	$ 4,981	$ 4,300
Contributions received from customers	1,046	964
Performance incentive payments under CDM programs	211	7
	$ 6,238	$ 5,271

18. Employee salaries and benefits

	2015	2014
Salaries, wages and benefits	$ 12,169	$ 11,703
CPP and EI remittances	446	431
Contributions to OMERS	1,275	1,230
Post-employment benefit plans	200	177
	$ 14,090	$ 13,541

19. Operating expenses

	2015	2014
Contract/consulting	$ 4,958	$ 2,946
Materials and supplies	157	230
Vehicles	615	575
Write down of material and supplies	8	(12)
Losses on disposal of property, plant and equipment	---	20
Other	1,736	3,436
	$ 7,474	$ 7,195

20. Finance income and costs

		2015		2014
Finance income				
Interest income on bank deposits	$	414	$	339
Finance costs				
Interest expense on long-term debt		5,948		5,968
Interest expense on customer deposits		21		23
Net interest expense on post-employment benefits		384		362
		6,353		6,353
Net finance costs recognized in profit or loss	$	5,939	$	6,014

21. Commitments and contingencies

Contractual Obligations

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.

General Liability Insurance

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2015, no assessments have been made.

22. Related party transactions

(a) Parent and ultimate controlling party

The sole shareholder of the Corporation is Oakville Enterprises Corporation (formerly Oakville Hydro Corporation) which is wholly owned by The Corporation of the Town of Oakville. The Town of Oakville produces consolidated financial statements that are available for public use.

The following summarizes the Corporation's related party transactions recorded at the exchange amounts and balances with the Town of Oakville for the year ended December 31:

	2015	2014	January 1, 2014
Amounts due to:			
Promissory note	$ 67,946	$ 67,946	$ 67,946
Capital Lease	10,920	11,306	11,661
Interest on promissory note	4,077	---	---
Accounts payable	45	130	155
Amounts due from:			
Energy receivable	327	622	640
Accounts receivable	12	248	142
Transactions:			
Revenue:			
Energy Sales	6,258	6,281	---
Rent	147	147	---
Other	95	---	---
Expenses:			
Interest on promissory notes	4,077	4,077	---
Interest on capital lease	1,034	1,038	---
Garage services	517	49	---
Property taxes	364	355	---
Tree trimming	301	315	---
Other	114	78	---

The Corporation delivers electricity to the Town of Oakville 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.

22. Related party transactions (continued)

1. Transactions with other related parties

The following summarizes the Corporation's related party transactions recorded at the exchange amounts and balances with the parent, Oakville Enterprises Corporation, and its subsidiaries, for the year ended December 31:

	2015	2014	January 1, 2014
Amounts due to:			
Accounts payable	$ 2,570	$ 2,359	$ 1,429
Amounts due from:			
Accounts receivable	227	---	32
Transactions:			
Revenue:			
Billing administration fee	725	720	---
Management fees	728	617	---
Other	184	132	---
Expenses:			
Locating/construction services	1,303	850	---
Fleet and administration	168	---	---
Meter services	15	115	---
Corporate governance charge	10	7	---
Other	24	13	---

(c) 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:

	2015	2014
Directors' fees	$ 83	$ 83
Salaries, bonuses and other short-term benefits	1,834	1,738
	$ 1,917	$ 1,821

23. 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 the customer deposits approximates fair value because the amounts are payable on demand.

Compared with the carrying value of the Infrastructure Ontario debenture $20,718, the fair value is calculated as $21,740 using a discount rate of 3.57%. This discount rate is determined using indicative quoted rates for instruments with approximately the same terms and credit risk.

It is not practicable to determine the fair value of the long-term borrowings from the Town of Oakville as there is no defined term to the loans. Due to the lack of comparable market information fair value cannot readily be determined.

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 throughout the Province of Ontario. No single customer accounts for a balance in excess of 10% 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, 2015 is $715 (2014 - $725). An impairment loss of $235 (2014 - $145) was recognized during the year.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2015, approximately $469 (2014 - $356) is considered 60 days past due. The Corporation has over 68 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, 2015 the Corporation holds security deposits in the amount of $9,202 (2014 - $7,584).

23. Financial instruments and risk management (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 $20,000 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, 2015, $3,300 (2014 - $nil) had been drawn under the Corporation's $20,000 credit facility.

The Corporation also has a bilateral facility for $16,000 (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which $10,400 has been drawn and posted with the IESO (2014 - $10,400).

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, 2015, shareholder's equity amounts to $82,757 (2014 - $81,062) and long-term debt amounts to $99,584 (2014 - $100,392).

24. Explanation of transition to IFRS

As stated in note 2(b), these are the Corporation's first financial statements prepared in accordance with IFRS.

The accounting policies set out in note 3 have been applied in preparing the financial statements for the year ended December 31, 2015, the comparative information presented in these financial statements for the year ended December 31, 2014, and in the preparation of the opening IFRS Statement of Financial Position as at January 1, 2014 (the Corporation's date of transition).

In preparing its opening IFRS Statement of Financial Position, the Corporation has adjusted the amounts reported previously in the financial statements prepared in accordance with Canadian general accepted accounting principles (CGAAP). An explanation of how the transition from CGAAP to IFRS has affected the Corporation's financial position, financial performance and cash flows is set out in the following tables and the notes accompanying the tables.

Regulatory accounts

IFRS 14: *Regulatory Deferral Accounts*, permits an entity to continue to account for regulatory deferral account balances in its financial statements in accordance with its previous GAAP when it adopts IFRS. An entity is permitted to apply the requirements of this standard in its first IFRS financial statements if and only if it conducts rate-regulated activities and recognized amounts that qualify as regulatory deferral account balances in its financial statements in accordance with its previous GAAP. This standard exempts an entity from applying paragraph 11 of IAS 8: *Accounting policies, changes in accounting estimates and errors*, to its accounting policies for the recognition, measurement, impairment and derecognition of regulatory deferral account balances.

IFRS 14 is effective from periods beginning on or after January 1, 2016, however, early application is permitted. The Corporation has elected to apply this Standard in its first IFRS financial statements.

IFRS 1 Exemptions

IFRS 1 *First-time adoption of International Financial Reporting Standards* sets out the procedures that the Corporation must follow when it adopts IFRS for the first time as the basis for preparing its financial statements. The Corporation is required to establish its IFRS accounting policies as at December 31, 2015 and, in general, apply these retrospectively to determine the IFRS opening statement of financial position as its date of transition, January 1, 2014. This standard provides a number of mandatory and optional exemptions to this general principle. These are set out below, together with a description in each case of the exemption adopted by the Corporation.

24. Explanation of transition to IFRS (continued)

(a) Transfer of assets from customers

The corporation has elected to apply the transitional provisions in IFRIC 18 *Transfers of Assets from Customers.* This provision states that the effective date of this standard should be July 1, 2019 or the date of transition to IFRS whichever is the later.

(b) Deemed cost

IFRS 1 provides an optional exemption for a first-time adopter with rate-regulated activities to use the carrying amount of PP&E and intangible assets as deemed cost on transition date when the carrying amount includes costs that do not quality for capitalization in accordance with IFRS. The Corporation elected this exemption and used the carrying amount of the PP&E and intangible assets under CGAPP as deemed cost on transition date. The carrying amount used as deemed cost is $189,961 for PP&E and $1,105 for intangible assets.

If an entity applies this exemption, at the date of transition to IFRS, it shall test for impairment each item for which this exemption is used. The assets were tested for impairment at the date of transition and it was determined that the assets were not impaired.

24. Explanation of transition to IFRS (continued)

Reconciliation of statement of financial position and statement of changes in equity

January 1, 2014	Note	CGAAP	Presentation differences	Measurement & recognition differences	IFRS
Cash and cash equivalents	-	$ 16,248	$ ---	$ ---	$ 16,248
Accounts receivable	5	34,859	(32)	---	34,827
Materials and supplies	-	3,327	---	---	3,327
Prepaid expenses	-	940	---	---	940
Property, plant and equipment	3	156,927	33,034	---	189,961
Intangible assets	3	---	1,105	---	1,105
Deferred tax assets	-	17,754	(3,665)	(326)	13,763
Total assets	-	230,055	30,442	(326)	260,171
Regulatory balances	6	-	12,260	---	12,260
Total assets and regulatory balances		$ 230,055	$ 42,702	$ (326)	$ 272,431
Accounts payable and accrued liabilities	5/6	$ 24,592	$ (2,324)	$ ---	$ 22,268
Due to related parties	5	---	1,397	---	1,397
Long-term debt due within a year	-	406	---	---	406
Capital lease obligation		355	---	---	355
Customer deposits	-	5,766	---	---	5,766
Deferred revenue	-	---	---	---	---
Long-term debt	-	89,087	---	---	89,087
Capital lease obligation		11,306	---	--	11,306
Post-employment benefits	4	7,741	---	(906)	6,835
Deferred revenue	3	---	34,139	---	34,139
Total liabilities	-	139,253	33,212	(906)	171,559
Share capital	-	76,108	---	---	76,108
Retained earnings	-	(300)	---	---	(300)
Accumulated OCI	4	---	---	906	906
Total liabilities and equity	-	215,061	33,212	---	248,273
Regulatory balances	-	14,994	9,490	(326)	24,158
Total liabilities, equity and regulatory balances		$ 230,055	$ 42,702	$ (326)	$ 272,431

24. Explanation of transition to IFRS (continued):

Reconciliation of statement of financial position and statement of changes in equity

December 31, 2014	Note	CGAAP	Presentation differences	Measurement & recognition differences	IFRS
Cash and cash equivalents	-	$ 22,471	$ ---	$ ---	$ 22,471
Accounts receivable	-	38,257	---	---	38,257
Material and supplies	-	3,001	---	---	3,001
Prepaid expenses		737	---	---	737
Property, plant and equipment	3	162,653	35,764	(20)	198,397
Intangible assets	3	---	1,167	---	1,167
Deferred tax assets	4	15,667	(3,505)	417	12,579
Total assets	-	242,786	33,426	397	276,609
Regulatory balances	6	---	14,342	---	14,342
Total assets and regulatory balances		$ 242,786	$ 47,768	$ 397	$ 290,951
Accounts payable and accrued liabilities	5/6	$ 32,255	$ (2,579)	$ ---	$ 29,676
Due to related parties	5	305	2,054	---	2,359
Long-term debt due within one year	-	422	--	---	422
Capital lease obligation		386	---	---	386
Customer deposits	-	7,584	---	---	7,584
Long-term debt	-	88,664	---	---	88,664
Capital lease obligation		10,920	---	---	10,920
Post-employment benefits	4	8,022	---	1,156	9,178
Deferred revenue	3	---	36,931	---	36,931
Total liabilities	-	148,558	36,406	1,156	186,120
Share capital	-	76,108	---	-	76,108
Retained earnings	-	6,130	---	(218)	5,912
Accumulated OCI	4	---	---	(958)	(958)
Total liabilities and equity	-	230,796	36,406	(20)	267,182
Regulatory balances	6	11,990	11,362	417	23,769
Total liabilities, equity and regulatory balances		$ 242,786	$ 47,768	$ 397	$ 290,951

24. Explanation of transition to IFRS (continued)

Reconciliation of net income for 2014

	Note	CGAAP	Presentation differences	Measurement & recognition differences	IFRS
Revenue					
Sale of energy	6	$ 176,670	$ 1,435	$ ---	$ 178,105
Distribution revenue	6	37,339	150	---	37,489
Other	6	4,218	1,053	---	5,271
		218,227	2,638	---	220,865
Operating expenses-					
Cost of power purchased	6	176,670	2,835	---	179,505
Employee salaries and benefits	6	13,878	(337)	---	13,541
Operating expenses	3/4	6,760	441	(6)	7,195
Depreciation and amortization	6	8,261	1,054	---	9,315
Finance income	6	---	(339)	---	(339)
Finance costs	6	5,991	362	---	6,353
Income tax expense	6	237	1,049	224	1,510
Net income for the year		6,430	(2,427)	(218)	3,785
Net movement in regulatory balances, net of tax	6	---	2,427	---	2,427
Net income and net movement in regulatory balances		6,430	---	(218)	6,212
Other comprehensive income					
Remeasurement of post-employment benefits	4	---	---	(2,088)	(2,088)
Tax on re-measurements	4	---	---		
Net movement in regulatory balances, net of tax	-	---	---	224	224
Total comprehensive income for the year		$ 6,430	$ ---	$(2,082)	$ 4,348

24. Explanation of transition to IFRS (continued)

Notes to the reconciliations

1. The Corporation has elected under IFRS 1 to use the carrying value of items of PP&E and intangible assets as the deemed cost at the date of transition. Therefore, there has been no change to the net PP&E and intangible assets at January 1, 2014. The effect of this transitional adjustment is a decrease to the original cost and accumulated depreciation of the affected PP&E and intangible assets by $120,534 and $4,227 respectively, the CGAAP accumulated depreciation amount, on January 1, 2014.

2. IFRS requires that borrowing costs related to the construction of the qualifying assets be capitalized. The Corporation has applied IAS 23 to all qualifying assets that were in progress or commenced since January 1, 2014. No qualifying assets were identified and therefore no borrowing costs were capitalized for the year ended December 31, 2014.

3. Under CGAAP, customer contributions were netted against the cost of PP&E and amortized to profit or loss as an offset to depreciation expense, on the same basis as the related assets. Under IFRS, customer contributions are recognized as deferred revenue, not netted against PP&E, and amortized into profit or loss over the life of the related asset.

   The effect of the above is to increase deferred revenue by $34,139 at January 1, 2014 and by $36,930 at December 31, 2014; to increase PP&E by $36,930 at December 31, 2014 and to increase other revenue and depreciation expense by $964 for the year ended December 31, 2014.

   Under CGAAP for rate regulated entities, the Corporation removed assets from the accounts at the end of their estimated useful lives. IFRS requires assets to be removed from the accounts when they have been removed from service. The effect is to decrease PP&E by $20 at December 31, 2014 and to increase loss on retirement of PP&E by $20 for the year ended December 31, 2014.

   Software was re-classed to intangible assets.

4. The Corporation adopted the revised Employee Benefits standard effective January 1, 2014. This revised standard requires recognition of actuarial gains and losses through other comprehensive income. This decreased post-employment benefits and increased retained earnings by $906 at January 1, 2014 and decreased operating expenses by $26 and increased post-employment benefits by $1,156 at December 31, 2014.

5. Intercompany trade accounts receivable and payable were re-classed to due to related parties.

6. Regulatory transactions were removed from the statement of financial position.

Explanation of material adjustments to the statement of cash flows for 2014

There are no material differences between the statement of cash flows presented under IFRS and the statement of cash flows presented under CGAAP.

Financial Statements of

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

Year ended December 31, 2016
(Expressed in thousands of dollars)

KPMG LLP
Commerce Place
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Canada
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Fax (905) 523-2222

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Oakville Hydro Electricity Distribution Inc.

We have audited the accompanying financial statements of Oakville Hydro Electricity Distribution Inc. ("the Entity"), which comprise the statements of financial position as at December 31, 2016, the statements of comprehensive income, changes in equity and cash flows for the year 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 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 Oakville Hydro Electricity Distribution Inc. 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

March 30, 2017
Hamilton, Canada

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

Statement of Financial Position
December 31, 2016
(in thousands of dollars)

	Note	2016	2015
Assets			
Current assets			
Cash and cash equivalents	5	$ 13,699	$ 24,841
Accounts receivable	6	51,221	39,283
Materials and supplies	7	3,507	3,311
Prepaid expenses		732	600
Total current assets		69,159	68,035
Non-current assets			
Property, plant and equipment	8	184,452	173,601
Intangible assets	9	1,318	1,324
Deferred tax assets	10	10,487	10,733
Total non-current assets		196,257	185,658
Total assets		265,416	253,693
Regulatory balances	11	14,895	12,323
Total assets and regulatory balances		$ 280,311	$ 266,016

See accompanying notes to the financial statements.

	Note	2016	2015
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	12	$ 36,319	$ 34,074
Due to related parties	22	1,523	2,343
Long-term debt due within one year	13	458	440
Capital lease obligation	14	459	421
Customer deposits		8,575	9,202
Total current liabilities		47,334	46,480
Non-current liabilities			
Long-term debt	13	87,767	88,224
Capital lease obligation	14	10,041	10,499
Post-employment benefits	15	11,221	9,392
Deferred revenue		18,080	8,478
Total non-current liabilities		127,109	116,593
Total liabilities		174,443	163,073
Equity			
Share capital	16	76,108	76,108
Retained earnings		10,664	7,607
Accumulated other comprehensive loss		(2,002)	(958)
Total equity		84,770	82,757
Total liabilities and equity		259,213	245,830
Regulatory balances	11	21,098	20,186
Total liabilities, equity and regulatory balances		$ 280,311	$ 266,016

See accompanying notes to the financial statements.

On behalf of the Board:

_____ Director _____ Director

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

Statement of Comprehensive Income
Year ended December 31, 2016, with comparative information for 2015
(in thousands of dollars)

	Note	2016	2015
Revenue			
Sale of energy		$ 223,433	$ 194,533
Distribution revenue		41,580	38,257
Other	17	6,217	5,318
		271,230	238,108
Operating expenses			
Cost of power purchased		224,530	195,293
Employee salaries and benefits	18	13,577	14,090
Operating expenses	19	8,777	7,474
Depreciation and amortization		8,985	8,671
		255,869	225,528
Income from operating activities		15,361	12,580
Finance income	20	427	414
Finance costs	20	(6,401)	(6,353)
Income before income taxes		9,387	6,641
Income tax expense	10	2,695	1,810
Net income for the year		6,692	4,831
Net movement in regulatory balances	11	498	(67)
Tax on net movement		667	1631
		1,165	1,564
Net income for the year and net movement in regulatory balances		7,857	6,395
Other comprehensive income			
Items that will not be reclassified to profit or loss:			
Re-measurements of post-employment benefits	15	(1,528)	-
Tax on re-measurements	10	484	-
Other comprehensive income for the year		(1,044)	-
Total comprehensive income for the year		$ 6,813	$ -

See accompanying notes to the financial statements.

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

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, 2015	$ 76,108	$ 5,912	$ (958)	$ 81,062
Net income and net movement in regulatory balances	-	6,395	-	6,395
Other comprehensive income	-	-	-	-
Dividends	-	(4,700)	-	(4,700)
Balance at December 31, 2015	$ 76,108	$ 7,607	$ (958)	$ 82,757
Balance at January 1, 2016	$ 76,108	$ 7,607	$ (958)	$ 82,757
Net income and net movement in regulatory balances	-	7,857	-	7,857
Other comprehensive income	-	-	(1,044)	(1,044)
Dividends	-	(4,800)	-	(4,800)
Balance at December 31, 2016	$ 76,108	$ 10,664	$ (2,002)	$ 84,770

See accompanying notes to the financial statements.

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

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	$	7,857	$	6,395
Adjustments for:				
Depreciation and amortization		8,985		8,671
Amortization of deferred revenue		(281)		(126)
Post-employment benefits		301		214
Gain on disposal of property, plant and equipment		(101)		(45)
Net finance costs		5,974		5,939
Income tax expense		2,695		1,810
		25,430		22,858
Change in non-cash operating working capital:				
Accounts receivable		(11,938)		(1,365)
Due to/from related parties		(820)		(16)
Materials and supplies		(196)		(310)
Prepaid expenses		(132)		137
Accounts payable and accrued liabilities		791		4,398
Customer deposits		(627)		1,618
		(12,922)		4,462
Regulatory balances		(1,464)		(1,762)
Contributions received from customers		5,165		2,488
Income tax received		244		375
Income tax paid		(753)		-
Interest paid		(6,401)		(6,353)
Interest received		427		414
Net cash from operating activities		9,725		22,482
Investing activities				
Purchase of property, plant and equipment		(15,044)		(14,265)
Proceeds on disposal of property, plant and equipment		399		107
Purchase of intangible assets		(564)		(446)
Net cash used by investing activities		(15,209)		(14,604)
Financing activities				
Dividends paid		(4,800)		(4,700)
Repayment of long-term debt		(439)		(422)
Repayment of capital lease		(420)		(386)
Net cash from financing activities		(5,659)		(5,508)
Change in cash and cash equivalents		(11,142)		2,370
Cash and cash equivalents, beginning of year		24,841		22,471
Cash and cash equivalents, end of year	$	13,699	$	24,841
Non-cash additions to property, plant and equipment	$	(4,518)	$	(2,153)
Non-cash contributions from customers		4,518		2,153

See accompanying notes to the financial statements.

1. Reporting entity

Oakville Hydro Electricity Distribution Inc. (the "Corporation") is a wholly owned subsidiary of Oakville Enterprises Corporation (formerly Oakville Hydro Corporation) and was incorporated on January 28, 2000 under the *Business Corporations Act* (Ontario), in accordance with the *Electricity Act.* The address of the Corporation's registered office is 861 Redwood Square, Oakville, Ontario L6K 0C7.

The principal activity of the Corporation is to distribute electricity to the residents and businesses in the Town of Oakville, under a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated by the OEB and adjustments to the Corporation's distribution and power rates require OEB approval.

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 March 30, 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 15 – measurement of defined benefit obligations: key actuarial assumptions
(v) Note 21 – 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 13 – 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.

Rate setting

(i) Distribution Rates

The Corporation files a "Cost of Service" ("COS") rate application every five years under which the OEB establishes the revenues required to recover the forecasted operating costs, including amortization and income taxes, of providing the regulated electricity distribution service and providing a fair return on the Corporation's rate base. 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 any registered interveners. Rates are approved based upon the review of evidence and information, including any revisions resulting from that review.

2. Basis of presentation (continued)

(e) Rate regulation (continued)

(i) Distribution Rates (continued)

In the intervening years, an Incentive Regulation Mechanism application ("IRM") is filed. An IRM application results 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 set by the OEB and a "stretch factor" determined by the relative efficiency of an electricity distributor.

On October 1, 2013, the Corporation submitted a COS rate application to the OEB to change distribution rates effective May 1, 2014. The application was approved by the OEB on May 1, 2014.

On August 17, 2015, the Corporation submitted an IRM Application to the OEB requesting approval to change distribution rates effective January 1, 2016. The IRM Application, which provided a mechanistic and formulaic adjustment to distribution rates and charges, was approved by the OEB on January 22, 2016. The GDP IPI-FDD for 2016 is 2.1%, the Corporation's stretch factor is 0.45% and the productivity factor determined by the OEB is 0%, resulting in a net adjustment of 1.65% to the previous year's rates.

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 the distribution charge will be collected through a fully fixed monthly charge instead of the current fixed and variable rate charge.

The OEB has announced that, by the end of 2016, all electricity distributors in Ontario will be required to bill their customers on a monthly basis rather than the current bi-monthly basis. This policy change incorporates an expectation that distributors will issue bills based on actual meter reads rather than estimates, at least 98% of the time.

(ii) Electricity Rates

The OEB sets Ontario electricity prices for low-volume consumers twice each year (May and November) 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 by the Independent Electricity System Operator and passes this cost on to the customer at cost without a mark-up.

2. Basis of presentation (continued)

(e) Rate regulation (continued)

(iii) Retail Transmission Rates

These are the costs of delivering electricity from generating stations across the Province to local distribution networks. These charges include the costs to build and maintain the transmission lines, towers and poles and operate provincial transmission systems. Retail transmission rates are passed through to the operators of transmission networks and facilities.

(iv) Wholesale Market Service Rates

These are the costs of administering the wholesale electricity system and maintaining the reliability of the provincial grid and include the costs associated with funding Ministry of Energy conservation and renewable energy programs. Wholesale charges are passed through to the Independent Electricity System Operator.

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 may 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 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 billing related to electricity generated by third parties, along with the associated costs of providing electricity 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)

Customer billings for debt retirement charges and the Ontario Electricity Support Program are recorded on a net basis as the Corporation is acting as an agent for these billing streams.

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered.

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 is consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on an 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.

(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 date of transition to IFRS, 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, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

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 six months to construct.

3. Significant accounting policies (continued)

(d) Property, plant and equipment (continued)

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:

	Years
Buildings	10 - 60
Distribution equipment	15 - 60
PP&E	3 - 20

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 date of transition to IFRS, 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.

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

	Years
Computer software	4 - 5

(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.

(ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than 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.

3. Significant accounting policies (continued)

(f) Impairment (continued)

(ii) Non-financial assets (continued)

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.

The goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to CGUs that are expected to benefit from the synergies of the combination.

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. They are allocated first to reduce the carrying amount of any goodwill allocated to the CGU, and then to reduce the carrying amounts of the other assets in the CGU on a prorated basis, if applicable.

An impairment loss in respect of goodwill is not reversed. 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 and deposits. Interest is paid on customer deposits. Deposits are also received for planned chargeable work. No interest is paid on these 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

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of recognizing regulatory balances in accordance with its previous GAAP when it adopts IFRS. An entity is permitted to apply the requirements of this standard in its first IFRS financial statements if it conducts rate-regulated activities and recognized amounts that qualify as regulatory deferral account balances in its financial statements in accordance with its previous GAAP. IFRS 14 is effective for periods beginning on or after January 1, 2016, however, early application was permitted. The Corporation elected to apply this Standard in its first IFRS financial statements as at December 31, 2015.

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account 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. 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.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. When the amounts are returned to the customer at rates approved by the OEB the amounts are recognized as a reduction of revenue.

The probability of recovery of the regulatory deferral account 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.

3. Significant accounting policies (continued)

(j) Post-employment benefits

(i) Pension plan

The Corporation provides a pension plan for some of its full-time employees through Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan that provides pensions for employees of Ontario municipalities, local boards and public utilities. OMERS is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by investment earnings. To the extent that the plan finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

(ii) Post-employment benefits, other than pension

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Re-measurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

(k) 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)

(l) 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 and dividend income.

Finance costs comprise interest expense on borrowings, finance lease obligations and unwinding of the discount on provisions, net interest expense on post-employment benefits. Finance costs are recognized in profit or loss unless they are capitalized as part of the cost of qualifying assets.

(m) 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 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. Payments in lieu of taxes and payments under the Tax Acts are collectively 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 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	$	13,699	$	24,841
Cash and cash equivalents in the statements of cash flows	$	13,699	$	24,841

The Corporation has a mirror accounting agreement with certain related companies whereby the bank has the right of setoff between overdrafts in these related companies and the Corporation's bank account. As at December 31, 2016 the net overdraft totaled ($2) (2015 – ($28,124)).

6. Accounts receivable

	2016	2015
Trade receivables	$ 18,719	$ 15,406
Income tax receivable	-	244
Unbilled revenue	32,502	23,633
	$ 51,221	$ 39,283

7. Materials and supplies

Amount written down due to obsolescence in 2016 was $nil (2015 – $8). The amount of materials and supplies consumed by the Corporation and recognized as an expense during 2016 was $290 (2015 - $169).

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	$ 13,568	$ 166,216	$ 5,216	$ 4,562	$ 189,562
Additions	1,232	17,705	800	(173)	19,564
Transfers	-	-	-	-	-
Disposals/retirements	-	(35)	(440)	-	(475)
Balance at December 31, 2016	$ 14,800	$ 183,886	$ 5,576	$ 4,389	$ 208,651
Balance at January 1, 2015	$ 12,899	$ 152,191	$ 5,088	$ 3,033	$ 173,211
Additions	669	14,086	135	1,529	16,419
Disposals/retirements	-	(61)	(7)	-	(68)
Balance at December 31, 2015	$ 13,568	$ 166,216	$ 5,216	$ 4,562	$ 189,562
Accumulated depreciation					
Balance at January 1, 2016	$ 1,408	$ 12,155	$ 2,398	$ -	$ 15,961
Depreciation	822	6,558	1,035	-	8,415
Disposals/retirements	-	(3)	(174)	-	(177)
Balance at December 31, 2016	$ 2,230	$ 18,710	$ 3,259	$ -	$ 24,199
Balance at January 1, 2015	$ 695	$ 5,957	$ 1,374	$ -	$ 8,026
Depreciation	713	6,199	1,029	-	7,941
Disposals/retirements	-	(1)	(5)	-	(6)
Balance at December 31, 2015	$ 1,408	$ 12,155	$ 2,398	$ -	$ 15,961
Carrying amounts					
At December 31, 2016	$ 12,570	$ 165,176	$ 2,317	$ 4,389	$ 184,452
At December 31, 2015	12,160	154,061	2,818	4,562	173,601

The Corporation has a finance lease agreement with the Town of Oakville for the head office at 861 Redwood Square. The leased building secures lease obligations (see note 14). At December 31, 2016 the net carrying amount of leased building was $3,139 (2015 - $3,381).

At December 31, 2016 Property plant and equipment with a carrying amount of $184,452 (2015 - $173,601) are subject to a general security agreement.

There were no borrowing costs capitalized as part of the cost of property, plant and equipment in 2015 and 2016.

9. Intangible assets

	Computer software	Total
Cost or deemed cost		
Balance at January 1, 2016	$ 2,414	$ 2,414
Additions	564	564
Balance at December 31, 2016	2,978	2,978
Balance at January 1, 2015	$ 1,968	$ 1,968
Additions	446	446
Balance at December 31, 2015	2,414	2,414
Accumulated amortization		
Balance at January 1, 2016	$ 1,090	$ 1,090
Amortization	570	570
Balance at December 31, 2016	1,660	1,660
Balance at January 1, 2015	$ 360	$ 360
Amortization	730	730
Balance at December 31, 2015	1,090	1,090
Carrying amounts		
At December 31, 2016	$ 1,318	$ 1,318
At December 31, 2015	1,324	1,324

10. Income tax expense

Current tax expense

	2016	2015
Current year	$ 1,212	$ -
Adjustment for prior years	752	(36)
	$ 1,964	$ (36)

Deferred tax expense

	2016	2015
Origination and reversal of temporary differences	$ 731	$ 1,846
	$ 731	$ 1,846

Reconciliation of effective tax rate

	2016	2015
Income before taxes	$ 9,387	$ 6,641
Canada and Ontario statutory Income tax rates	26.5%	26.5%
Expected tax provision on income at statutory rates	2,488	1,760
Increase (decrease) in income taxes resulting from:		
Permanent differences	14	19
Prior year adjustment	752	(36)
Other	(559)	67
Income tax expense	$ 2,695	$ 1,810

Significant components of the Corporation's deferred tax balances

	2016	2015
Deferred tax assets (liabilities):		
Property, plant, equipment and intangibles	$ 3,813	$ 5,569
Capital Lease obligation	2,782	2,894
Post-employment benefits	2,974	2,489
Non-capital loss carried forward	-	24
Other tax reserves	918	(243)
	$ 10,487	$ 10,733

11. Regulatory balances

The Corporation has determined that certain debit and credit balances arising from rate-regulated activities qualify for regulatory accounting treatment in accordance with IFRS 14 and the OEB's prescribed accounting procedures for electricity distributors. The regulatory balances are comprised of regulatory debit variances of $14,895 and regulatory credit balances for $21,098 for a net regulatory liability of $6,203.

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers' Acceptances three-month rate plus a spread of 25 basis points, with the exception of the tax balances. In 2016, the rate was 1.1% for the period January 2016 to December 2016.

The regulatory balances for the Corporation consist of the following:

(a) Settlement Variance

This account includes the variances between amounts charged by the Corporation, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by the Corporation such as commodity charges, retail transmission rates and wholesale market services charges. The Corporation has deferred the variances and related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. This account also includes variances between the amounts approved for disposition by the OEB and the amounts collected or paid through OEB approved rate riders.

Settlement variances are reviewed annually as part of a COS or IRM application submitted to the OEB and a request for disposition is made if the aggregate of the settlement accounts exceeds the OEB's prescribed materiality level.

In its 2016 IRM application, submitted in August 2015, the Corporation did not request the disposition of the 2014 audited balances of the settlement variance accounts as they were below the OEB's predetermined materiality threshold.

(b) Stranded Meters

The stranded meter account relates to the provincial government's directive to install smart meters for all Ontario customers by December 2010. In its 2014 cost of service application, the Corporation received approval from the OEB for the recovery of the stranded meter costs associated with the Province's smart meter initiative over a five-year period beginning on May 1, 2014 and ending on April 30, 2019.

(c) Customer Liability for Deferred Taxes

The customer liability for deferred taxes variance account relates to the expected regulatory liability relating to deferred taxes arising from timing differences in the determination of income taxes.

(d) Other

This deferral account includes the allowable costs associated with the transition to IFRS, the installation of interval meters for General Service greater than 50 kilowatts, as directed by the OEB, and other miscellaneous regulatory accounts.

11. Regulatory balances (continued)

(d) Other (continued)

Reconciliation of the carrying amount for each class of regulatory balances

Regulatory deferral account debit balances	January 1, 2016	Additions/ transfers	Recovery/ reversal	December 31, 2016	Remaining years
Settlement variances	$ 5,875	$ 3,277	$ -	$ 9,152	2
Stranded meters	2,347	-	(740)	1,607	3
Other regulatory accounts	930	500	(44)	1,386	3
Income tax	3,171	(421)	-	2,750	Note 1
	$ 12,323	$ 3,356	$ (784)	$ 14,895	

Regulatory deferral account debit balances	January 1, 2015	Additions/ transfers	Recovery/ reversal	December 31, 2015	Remaining recovery/ reversal years
Settlement variances	$ 6,617	$ (588)	$ (154)	$ 5,875	3
Stranded meters	3,052	-	(705)	2,347	4
Other regulatory accounts	1,168	257	(495)	930	4
Income tax	3,505	-	(334)	3,171	Note 1
	$ 14,342	$ (331)	$ (1,688)	$ 12,323	

Regulatory deferral account credit balances	January 1, 2016	Additions/ transfers	Recovery/ reversal	December 31, 2016	Remaining years
Settlement variances	$ (5,011)	$ (2,075)	$ -	$ (7,086)	2
Other regulatory liabilities	(861)	76	-	(785)	3
Customer liability for deferred taxes	(14,314)	1,087	-	(13,227)	Note 1
	$ (20,186)	$ (912)	$ -	$ (21,098)	

Regulatory deferral account credit balances	January 1, 2015	Additions/ transfers	Recovery/ reversal	December 31, 2015	Remaining years
Settlement variances	$ (6,531)	$ 200	$ 1,320	$ (5,011)	3
Other regulatory liabilities	(959)	(287)	385	(861)	4
Customer liability for deferred taxes	(16,279)	-	1,965	(14,314)	Note 1
	$ (23,769)	$ (87)	$ 3,670	$ (20,186)	

1. These balances will be recovered over the life of the related capital assets.

The “Additions/Transfers” column consists of new additions to regulatory balances (for both debits and credits). The “Recovery/Reversal” column consists of amounts collected or paid through rate riders or transactions reversing an existing regulatory balance to recover. Recoveries and reversals occur as a result of the approval of an application. There were no reversals of regulatory balances for the year ended December 31, 2016.

12. Accounts payable and accrued liabilities

	2016	2015
Accounts payable – energy purchases	$ 10,889	$ 5,582
Debt retirement charge payable to OEFC	432	761
Payroll payable	2,161	1,935
Interest payable	4,144	4,146
Trade payables	18,693	21,650
	$ 36,319	$ 34,074

13. Long-term debt

	2016	2015
Notes Payable	$ 67,946	$ 67,946
Ontario Infrastructure loans	20,279	20,718
Capital lease liabilities	10,500	10,920
	$ 98,725	$ 99,584

The Corporation has unsecured promissory notes $67,946 (2015 - $67,946) which are held by The Corporation of the Town of Oakville and were issued effective February 1, 2000 for a 20 year term. The notes bear interest at a rate of 6% (2015 – 6%), payable annually no later than 30 days after the end of the fiscal year. Interest rates are reviewed annually. The Corporation of the Town of Oakville has the option to change the terms of the promissory notes with one year notice. The Corporation of the Town of Oakville and the Corporation have set the interest rates for 2017 at 6%.

The Corporation has a $20,279 debenture with Infrastructure Ontario due October 2042 with a fixed interest rate of 4% for the entire term of the debenture. Interest is payable in monthly principal and interest installments of $105. The debenture was issued on October 1, 2012. Security is in the form of a pari passu first charge, dated August 31, 2016 on the assets of the Corporation, which replaced the original second charge agreement dated October 1, 2012.

Proceeds were used to replace working capital used in the 2010-2011 construction of a transmission station in Oakville.

Repayment of the long term debt for the years ended December 31:

2017	$ 917
2018	976
2019	1,040
2020	1,109
2021	1,183
Thereafter	93,500
	98,725
Current portion	917
Long-term portion	$ 97,808

14. Finance lease

The Corporation has a finance lease arrangement with the Town of Oakville for the head office at 861 Redwood Square. The assets under finance lease are included in property, plant and equipment (see Note 8). The property under finance lease is amortized on a straight-line basis over the term of the lease agreement of 20 years.

Future minimum payments under the finance lease arrangements are as follows for the years ended December 31:

2016	Less than one year	Between one and five years	More than five years	Total
Future minimum lease payments payments	$ 1,345	$ 5,380	$ 10,760	$ 17,485
Less: interest	886	3,096	3,003	6,985
Present value of minimum lease payments	$ 459	$ 2,284	$ 7,757	$ 10,500

2015	Less than one year	Between one and five years	More than five years	Total
Future minimum lease payments	$ 1,345	$ 5,380	$ 12,105	$ 18,830
Less: interest	924	3,284	3,702	7,910
Present value of minimum lease payments	$ 421	$ 2,096	$ 8,403	$ 10,920

15. Post-employment benefits

(a) OMERS pension plan

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2016, the Corporation made employer contributions of $1,226 to OMERS (2015 - $1,275) which has been recognized in profit or loss. The Corporation estimates that a contribution of $1,290 to OMERS will be made during the next fiscal year.

15. Post-employment benefits (continued)

(b) Post-employment benefits other than pension

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expense and remeasurements recognized for post-employment benefit plans.

Reconciliation of the obligation		2016		2015
Defined benefit obligation, beginning of year	$	9,392	$	9,178
Included in profit or loss				
Current service cost		205		200
Interest cost		430		384
		10,027		9,762
Included in OCI				
Actuarial losses arising from:				
changes in financial assumptions		1,528		-
		1,528		-
Benefits paid		(334)		(370)
Defined benefit obligation, end of year	$	11,221	$	9,392

Actuarial assumptions	2016	2015
Discount (interest) rate	4.00%	4.10%
Salary levels	3.00%	3.00%
Medical Costs	5.70%	8.33%
Dental Costs	4.00%	4.00%

Medical costs are estimated to increase at a rate which declines over time from 5.7% per annum in 2016 to 4% by 2026.

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by ($1,371). A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by $1,718.

16. Share capital

		2016		2015
Authorized:				
Unlimited number of common shares				
Issued:				
1,407 common shares	$	76,108	$	76,108

Dividends

The holders of the common shares are entitled to receive dividends from time to time.

The Corporation paid aggregate dividends in the year on common shares of $3.41 (2015 - $3.34) per share which amount to total dividends paid in the year of $4,800 (2015 - $4,700).

17. Other revenue

	2016	2015
Services revenue	$ 5,936	$ 4,981
Contributions received from customers	281	126
Performance incentive payments under CDM programs	-	211
	$ 6,217	$ 5,318

18. Employee salaries and benefits

	2016	2015
Salaries, wages and benefits	$ 11,706	$ 12,169
CPP and EI remittances	440	446
Contributions to OMERS	1,226	1,275
Post-employment benefit plans	205	200
	$ 13,577	$ 14,090

19. Operating expenses

	2016	2015
Contract/consulting	$ 4,502	$ 5,032
Materials and supplies	350	157
Vehicles	566	615
Write down of material and supplies	-	8
General and administration	1,378	159
Other	1,981	1,452
	$ 8,777	$ 7,474

20. Finance income and costs

	2016	2015
Finance income		
Interest income on bank deposits	$ 427	$ 414
Finance costs		
Interest expense on long-term debt	5,901	5,948
Interest expense on customer deposits	17	21
Net interest expense on post-employment benefits	430	384
Other	53	-
	6,401	6,353
Net finance costs recognized in profit or loss	$ 5,974	$ 5,939

21. Commitments and contingencies

Contractual Obligations

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.

General Liability Insurance

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2016, no assessments have been made.

22. Related party transactions

(a) Parent and ultimate controlling party

The sole shareholder of the Corporation is Oakville Enterprises Corporation (formerly Oakville Hydro Corporation) which is wholly owned by The Corporation of the Town of Oakville. The Town of Oakville produces consolidated financial statements that are available for public use.

The following summarizes the Corporation's related party transactions recorded at the exchange amounts and balances with the Town of Oakville for the year ended December 31:

	2016	2015
Amounts due to:		
Promissory note	$ 67,946	$ 67,946
Finance Lease	10,500	10,920
Interest on promissory note	4,077	4,077
Accounts payable	38	45
Amounts due from:		
Energy receivable	663	327
Accounts receivable	30	12
Transactions:		
Revenue:		
Energy Sales	6,249	6,258
Rent	147	147
Other	37	95
Expenses:		
Interest on promissory notes	4,077	4,077
Interest on finance lease	1,055	1,034
Garage services	409	517
Property taxes	382	364
Tree trimming	501	301
Other	65	114

The Corporation delivers electricity to the Town of Oakville 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.

22. Related party transactions (continued)

(b) Outstanding balances with related parties

	2016	2015
Parent company	$ 380	$ 19
Other related parties	1,143	2,324
	$ 1,523	$ 2,343

(c) Transactions with parent

During the year, the corporation collected management fees of $130 (2015 - $130) and other revenue of $24 (2015 - $19) from its parent, and paid corporate governance charges of $17 (2015 - $10).

(d) Transaction with other related parties

In the ordinary course of business, the corporation incurred the following transactions with other related parties:

	2016	2015
Revenue:		
Billing administration fee	$ 740	$ 725
Management fees	532	598
Other	199	164
Expenses:		
Locating/construction services	1,532	1,303
Fleet and administration	636	168
Meter services	9	15
Other	19	24

(e) 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	$ 75	$ 83
Salaries, bonuses and other short-term benefits	1,732	1,834
	$ 1,807	$ 1,917

23. 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 the customer deposits approximates fair value because the amounts are payable on demand.

Compared with the carrying value of the Infrastructure Ontario debenture $20,279, the fair value is calculated as $20,726 using a discount rate of 3.80%. This discount rate is determined using indicative quoted rates for instruments with approximately the same terms and credit risk.

The fair value of the notes payable is calculated at $91,869 using a discount rate of 3.7%. This discount rate is determined using indicative quoted rates for instruments with approximately the same terms and credit risk.

The fair value of the capital lease liabilities is calculated at $14,376 using a discount rate of 3.1%. This discount rate is determined using indicative quoted rates for instruments with approximately the same terms and credit risk.

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 throughout the Province of Ontario. No single customer accounts for a balance in excess of 10% 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 $711 (2015 - $715). An impairment loss of $217 (2015 - $235) was recognized during the year.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2016, approximately $1,213 (2015 - $469) is considered 60 days past due. The Corporation has over 67 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. At December 31, 2016 the Corporation holds security deposits in the amount of $8,575 (2015 - $9,202).

23. Financial instruments and risk management (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 $35,000 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, $nil (2015 - $3,300) had been drawn under the Corporation's $35,000 credit facility.

The Corporation also has a facility for $16,000 (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which $14,921 has been drawn and posted with the IESO (2015 - $10,400).

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 $84,770 (2015 - $82,757) and long-term debt amounts to $98,725 (2015 - $99,584).

Financial Statements of

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

Year ended December 31, 2017
(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 Oakville Hydro Electricity Distribution Inc.

We have audited the accompanying financial statements of Oakville Hydro Electricity Distribution Inc. ("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 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 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 Oakville Hydro Electricity Distribution Inc. 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 5, 2018

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

Statement of Financial Position
December 31, 2017
(in thousands of dollars)

	Note	2017	2016
Assets			
Current assets			
Cash and cash equivalents	5	$ 21,771	$ 13,699
Accounts receivable	6	36,240	51,221
Materials and supplies	7	3,787	3,507
Prepaid expenses		845	732
Total current assets		62,643	69,159
Non-current assets			
Property, plant and equipment	8	193,033	184,452
Intangible assets	9	1,303	1,318
Deferred tax assets	10	9,367	10,487
Total non-current assets		203,703	196,257
Total assets		266,346	265,416
Regulatory balances	11	13,103	14,895
Total assets and regulatory balances		$ 279,449	$ 280,311

See accompanying notes to the financial statements.

	Note	2017	2016
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	12	$ 29,267	$ 36,319
Due to related parties	22	1,686	1,523
Long-term debt due within one year	13	476	458
Finance lease obligation	14	500	459
Customer deposits		9,091	8,575
Total current liabilities		41,020	47,334
Non-current liabilities			
Long-term debt	13	87,291	87,767
Financelease obligation	14	9,541	10,041
Post-employment benefits	15	11,958	11,221
Deferred revenue		23,309	18,080
Total non-current liabilities		132,099	127,109
Total liabilities		173,119	174,443
Equity			
Share capital	16	76,108	76,108
Retained earnings		14,364	10,743
Accumulated other comprehensive loss		(2,359)	(2,081)
Total equity		88,113	84,770
Total liabilities and equity		261,232	259,213
Regulatory balances	11	18,217	21,098
Total liabilities, equity and regulatory balances		$ 279,449	$ 280,311

See accompanying notes to the financial statements.

On behalf of the Board:

Director

Director

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

Statement of Comprehensive Income
Year ended December 31, 2017, with comparative information for 2016
(in thousands of dollars)

	Note	2017	2016
Revenue			
Sale of energy		$ 198,225	$ 223,433
Distribution revenue		39,624	41,580
Other	17	5,401	6,217
		243,250	271,230
Operating expenses			
Cost of power purchased		197,475	224,530
Employee salaries and benefits	18	14,183	14,166
Operating expenses	19	7,233	8,188
Depreciation and amortization		9,157	8,985
		228,048	255,869
Income from operating activities		15,202	15,361
Finance income	20	243	427
Finance costs	20	(6,251)	(6,401)
Income before income taxes		9,194	9,387
Income tax expense	10	2,262	2,616
Net income for the year		6,932	6,771
Net movement in regulatory balances	11	(753)	498
Tax on net movement		1,221	667
		468	1,165
Net income for the year and net movement in regulatory balances		7,400	7,936
Other comprehensive income			
Items that will not be reclassified to profit or loss:			
Re-measurements of post-employment benefits	15	(485)	(1,528)
Tax on re-measurements	10	128	405
Other comprehensive income for the year		(357)	(1,123)
Total comprehensive income for the year		$ 7,043	$ 6,813

See accompanying notes to the financial statements.

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

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, 2016	$ 76,108	$ 7,607	$ (958)	$ 82,757
Net income and net movement in regulatory balances	-	7,936	-	7,936
Other comprehensive income	-	-	(1,123)	(1,123)
Dividends	-	(4,800)	-	(4,800)
Balance at December 31, 2016	$ 76,108	$ 10,743	$ (2,081)	$ 84,770
Balance at January 1, 2017	$ 76,108	$ 10,664	$ (2,002)	$ 84,770
Net income and net movement in regulatory balances	-	7,400	-	7,400
Other comprehensive income	-	-	(357)	(357)
Dividends	-	(3,700)	-	(3,700)
Balance at December 31, 2017	$ 76,108	$ 14,364	$ (2,359)	$ 88,113

See accompanying notes to the financial statements.

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

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	$	7,400	$	7,936
Adjustments for:				
Depreciation and amortization		9,157		8,985
Amortization of deferred revenue		(450)		(281)
Post-employment benefits		252		301
Gain on disposal of property, plant and equipment		(15)		(101)
Net finance costs		6,008		5,974
Income tax expense		2,262		2,616
		24,614		25,430
Change in non-cash operating working capital:				
Accounts receivable		15,149		(11,938)
Due to/from related parties		163		(820)
Materials and supplies		(280)		(196)
Prepaid expenses		(113)		(132)
Accounts payable and accrued liabilities		(6,071)		791
Customer deposits		516		(627)
		9,364		(12,922)
Regulatory balances		(1,089)		(1,464)
Contributions received from customers		3,684		5,165
Income tax received		84		244
Income tax paid		(2,247)		(753)
Interest paid		(6,251)		(6,399)
Interest received		243		427
Net cash from operating activities		28,402		9,728
Investing activities				
Purchase of property, plant and equipment		(15,273)		(15,044)
Proceeds on disposal of property, plant and equipment		114		399
Purchase of intangible assets		(554)		(564)
Net cash used by investing activities		(15,713)		(15,209)
Financing activities				
Dividends paid		(3,700)		(4,800)
Repayment of long-term debt		(458)		(440)
Repayment of finance lease		(459)		(421)
Net cash from financing activities		(4,617)		(5,661)
Change in cash and cash equivalents		8,072		(11,142)
Cash and cash equivalents, beginning of year		13,699		24,841
Cash and cash equivalents, end of year	$	21,771	$	13,699
Non-cash additions to property, plant and equipment	$	(1,995)	$	(4,518)
Non-cash contributions from customers		1,995		4,518

See accompanying notes to the financial statements.

1. Reporting entity

Oakville Hydro Electricity Distribution Inc. (the "Corporation") is a wholly owned subsidiary of Oakville Enterprises Corporation (formerly Oakville Hydro Corporation) and was incorporated on January 28, 2000 under the *Business Corporations Act* (Ontario), in accordance with the *Electricity Act.* The address of the Corporation's registered office is 861 Redwood Square, Oakville, Ontario L6K 0C7.

The principal activity of the Corporation is to distribute electricity to the residents and businesses in the Town of Oakville, under a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated by the OEB and adjustments to the Corporation's distribution and power rates require OEB approval.

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 5, 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) Notes 8, 9 – estimation of useful lives of its property, plant and equipment and intangible assets
(ii) Note 11 – recognition and measurement of regulatory balances
(iii) Note 15 – measurement of defined benefit obligations: key actuarial assumptions
(iv) Note 21 – 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 13 – 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.

Rate setting

(i) Distribution Rates

The Corporation files a "Cost of Service" ("COS") rate application every five years under which the OEB establishes the revenues required to recover the forecasted operating costs, including amortization and income taxes, of providing the regulated electricity distribution service and providing a fair return on the Corporation's rate base. 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 any registered interveners. Rates are approved based upon the review of evidence and information, including any revisions resulting from that review.

2. Basis of presentation (continued)

(e) Rate regulation (continued)

(i) Distribution Rates (continued)

In the intervening years, an Incentive Regulation Mechanism application ("IRM") is filed. An IRM application results 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 set by the OEB and a "stretch factor" determined by the relative efficiency of an electricity distributor.

On October 1, 2013, the Corporation submitted a COS rate application to the OEB to change distribution rates effective May 1, 2014. The application was approved by the OEB on May 1, 2014.

On August 15, 2016, the Corporation submitted an IRM Application to the OEB requesting approval to change distribution rates effective January 1, 2017. The IRM Application, which provided a mechanistic and formulaic adjustment to distribution rates and charges, was approved by the OEB on January 5, 2017. The GDP IPI-FDD for 2017 is 1.2%, the Corporation's stretch factor is 0.30% and the productivity factor determined by the OEB is 0%, resulting in a net adjustment of 0.9% to the previous year's rates.

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 the distribution charges will be collected through a fully fixed monthly charge instead of the current fixed and variable rate charge.

(ii) Electricity Rates

The OEB sets Ontario electricity prices for low-volume consumers twice each year (May and November) based on an estimate of how much it will cost to supply the province with electricity for the next year. In 2017, the OEB set new lower Regulated Price Plan (RPP) prices established under the *Fair Hydro Act, 2017*. All remaining consumers pay the market price for electricity. The Corporation is billed for the cost of the electricity that its customers use by the Independent Electricity System Operator and passes this cost on to the customer at cost without a mark-up.

2. Basis of presentation (continued)

(e) Rate regulation (continued)

(iii) Retail Transmission Rates

These are the costs of delivering electricity from generating stations across the Province to local distribution networks. These charges include the costs to build and maintain the transmission lines, towers and poles and operate provincial transmission systems. Retail transmission rates are passed through to the operators of transmission networks and facilities.

(iv) Wholesale Market Service Rates

These are the costs of administering the wholesale electricity system and maintaining the reliability of the provincial grid and include the costs associated with funding Ministry of Energy conservation and renewable energy programs. Wholesale charges are passed through to the Independent Electricity System Operator.

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 may 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 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, delivery, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billing related to electricity generated by third parties, along with the associated costs of providing electricity 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)

Customer billings for debt retirement charges and the Ontario Electricity Support Program are recorded on a net basis as the Corporation is acting as an agent for these billing streams.

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered.

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 Conservation and Demand Management ("MDM") 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 is consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on an 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.

(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 date of transition to IFRS, 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, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

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 nine months to construct.

3. Significant accounting policies (continued)

(d) Property, plant and equipment (continued)

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:

	Years
Buildings	10 - 60
Distribution equipment	15 - 60
PP&E	3 - 20

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 date of transition to IFRS, 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.

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

	Years
Computer software	4 - 5

(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.

(ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than 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.

3. Significant accounting policies (continued)

(f) Impairment (continued)

(ii) Non-financial assets (continued)

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.

The goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to CGUs that are expected to benefit from the synergies of the combination.

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. They are allocated first to reduce the carrying amount of any goodwill allocated to the CGU, and then to reduce the carrying amounts of the other assets in the CGU on a prorated basis, if applicable.

An impairment loss in respect of goodwill is not reversed. 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 and deposits. Interest is paid on customer deposits. Deposits are also received for planned chargeable work. No interest is paid on these 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

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of recognizing regulatory balances in accordance with its previous Generally Accepted Accounting Principles ("GAAP") when it adopts IFRS. An entity is permitted to apply the requirements of this standard in its first IFRS financial statements if it conducts rate-regulated activities and recognized amounts that qualify as regulatory deferral account balances in its financial statements in accordance with its previous GAAP. IFRS 14 is effective for periods beginning on or after January 1, 2016, however, early application was permitted. The Corporation elected to apply this Standard in its first IFRS financial statements as at December 31, 2015.

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account 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 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.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the amounts are returned to the customer at rates approved by the OEB the amounts are recognized as a reduction of revenue.

The probability of recovery of the regulatory deferral account 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.

3. Significant accounting policies (continued)

(j) Post-employment benefits

(i) Pension plan

The Corporation provides a pension plan for some of its full-time employees through Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan that provides pensions for employees of Ontario municipalities, local boards and public utilities. OMERS is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by investment earnings. To the extent that the plan finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

(ii) Post-employment benefits, other than pension

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Re-measurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

(k) 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)

(l) 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 and dividend income.

Finance costs comprise interest expense on borrowings, finance lease obligations, unwinding of the discount on provisions and net interest expense on post-employment benefits. Finance costs are recognized in profit or loss unless they are capitalized as part of the cost of qualifying assets.

(m) 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 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. Payments in lieu of taxes and payments under the Tax Acts are collectively 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 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. 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 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 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 intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. The Corporation does not expect the standard to have a material impact on the financial statements.

5. Cash and cash equivalents

	2017	2016
Bank balances	$ 21,771	$ 13,699
Cash and cash equivalents in the statement of cash flows	$ 21,771	$ 13,699

The Corporation has a mirror accounting agreement with certain related companies whereby the bank has the right of setoff between overdrafts in these related companies and the Corporation's bank account. As at December 31, 2017 the net overdraft totaled ($4) (2016 – ($2)).

6. Accounts receivable

	2017	2016
Trade receivables	$ 12,957	$ 18,719
Income tax receivable	168	-
Unbilled revenue	23,115	32,502
	$ 36,240	$ 51,221

7. Materials and supplies

Amount written down due to obsolescence in 2017 was $11 (2016 – $nil). The amount of materials and supplies consumed by the Corporation and recognized as an expense during 2017 was $272 (2016 - $290).

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	$ 14,800	$ 183,886	$ 5,576	$ 4,389	$ 208,651
Additions	133	16,294	920	(79)	17,268
Transfers	-	-	-	-	-
Disposals/retirements	-	(113)	(8)	-	(121)
Balance at December 31, 2017	$ 14,933	$ 200,067	$ 6,488	$ 4,310	$ 225,798
Balance at January 1, 2016	$ 13,568	$ 166,216	$ 5,216	$ 4,562	$ 189,562
Additions	1,232	17,705	800	(173)	19,564
Disposals/retirements	-	(35)	(440)	-	(475)
Balance at December 31, 2016	$ 14,800	$ 183,886	$ 5,576	$ 4,389	$ 208,651
Accumulated depreciation					
Balance at January 1, 2017	$ 2,230	$ 18,710	$ 3,259	$ -	$ 24,199
Depreciation	728	6,988	872	-	8,588
Disposals/retirements	-	(14)	(8)	-	(22)
Balance at December 31, 2017	$ 2,958	$ 25,684	$ 4,123	$ -	$ 32,765
Balance at January 1, 2016	$ 1,408	$ 12,155	$ 2,398	$ -	$ 15,961
Depreciation	822	6,558	1,035	-	8,415
Disposals/retirements	-	(3)	(174)	-	(177)
Balance at December 31, 2016	$ 2,230	$ 18,710	$ 3,259	$ -	$ 24,199
Carrying amounts					
At December 31, 2017	$ 11,975	$ 174,383	$ 2,365	$ 4,310	$ 193,033
At December 31, 2016	12,570	165,176	2,317	4,389	184,452

The Corporation has a finance lease agreement with the Town of Oakville for the head office at 861 Redwood Square. The leased building secures lease obligations (see note 14). At December 31, 2017 the net carrying amount of leased building was $2,898 (2016 - $3,139).

At December 31, 2017 property plant and equipment with a carrying amount of $193,033 (2016 - $184,452) are subject to a general security agreement.

There were no borrowing costs capitalized as part of the cost of property, plant and equipment in 2016 and 2017.

9. Intangible assets

	Computer software	Total
Cost or deemed cost		
Balance at January 1, 2017	$ 2,978	$ 2,978
Additions	554	554
Balance at December 31, 2017	$ 3,532	$ 3,532
Balance at January 1, 2016	$ 2,414	$ 2,414
Additions	564	564
Balance at December 31, 2016	$ 2,978	$ 2,978
Accumulated amortization		
Balance at January 1, 2017	$ 1,660	$ 1,660
Amortization	569	569
Balance at December 31, 2017	$ 2,229	$ 2,229
Balance at January 1, 2016	$ 1,090	$ 1,090
Amortization	570	570
Balance at December 31, 2016	$ 1,660	$ 1,660
Carrying amounts		
At December 31, 2017	$ 1,303	$ 1,303
At December 31, 2016	1,318	1,318

10. Income tax expense

Current tax expense

	2017	2016
Current year	$ 1,013	$ 1,212
Adjustment for prior years	-	752
	$ 1,013	$ 1,964

Deferred tax expense

	2017	2016
Origination and reversal of temporary differences	$ 1,249	$ 652
	$ 1,249	$ 652

Reconciliation of effective tax rate

	2017	2016
Income before taxes	$ 9,194	$ 9,387
Canada and Ontario statutory Income tax rates	26.5%	26.5%
Expected tax provision on income at statutory rates	2,436	2,488
Increase (decrease) in income taxes resulting from:		
Permanent differences	15	14
Prior year adjustment	-	752
Other	(189)	(638)
Income tax expense	$ 2,262	$ 2,616

Significant components of the Corporation's deferred tax balances

	2017	2016
Deferred tax assets (liabilities):		
Property, plant, equipment and intangibles	$ 2,755	$ 3,813
Capital Lease obligation	2,661	2,782
Post-employment benefits	3,169	2,974
Other tax reserves	782	918
	$ 9,367	$ 10,487

11. Regulatory balances

The Corporation has determined that certain debit and credit balances arising from rate-regulated activities qualify for regulatory accounting treatment in accordance with IFRS 14 and the OEB's prescribed accounting procedures for electricity distributors. The regulatory balances are comprised of regulatory debit variances of $13,103 and regulatory credit balances for $18,217 for a net regulatory liability of $5,114.

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers' Acceptances three-month rate plus a spread of 25 basis points, with the exception of the tax balances. In 2017, the rate was 1.1% for the period January 2017 to September 2017 and 1.5% for the period October 2017 to December 2017.

The regulatory balances for the Corporation consist of the following:

(a) Settlement Variance

This account includes the variances between amounts charged by the Corporation, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by the Corporation such as commodity charges, retail transmission rates and wholesale market services charges. The Corporation has deferred the variances and related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. This account also includes variances between the amounts approved for disposition by the OEB and the amounts collected or paid through OEB approved rate riders.

Settlement variances are reviewed annually as part of a COS or IRM application submitted to the OEB and a request for disposition is made if the aggregate of the settlement accounts exceeds the OEB's prescribed materiality level.

In the Corporation's 2017 IRM application, submitted in August 2016, the OEB approved the Corporation's request for the disposition of the 2015 audited balances of the settlement variance accounts over a 12-month period beginning January 1, 2017.

(b) Stranded Meters

The stranded meter account relates to the provincial government's directive to install smart meters for all Ontario customers by December 2010. In its 2014 cost of service application, the Corporation received approval from the OEB for the recovery of the stranded meter costs associated with the Province's smart meter initiative over a five-year period beginning on May 1, 2014 and ending on April 30, 2019.

(c) Customer Liability for Deferred Taxes

The customer liability for deferred taxes variance account relates to the expected regulatory liability relating to deferred taxes arising from timing differences in the determination of income taxes.

11. Regulatory balances (continued)

(d) Other

This deferral account includes the allowable costs associated with the transition to IFRS, the installation of interval meters for General Service greater than 50 kilowatts, as directed by the OEB, and other miscellaneous regulatory accounts.

Reconciliation of the carrying amount for each class of regulatory balances

Regulatory deferral account debit balances	January 1, 2017	Additions/ transfers	Recovery/ reversal	December 31, 2017	Remaining years
Settlement variances	$ 9,152	$ (2,132)	$ (171)	$ 6,849	2
Stranded meters	1,607	(735)	-	872	2
Other regulatory accounts	1,386	1,414	-	2,800	3
Income tax	2,750	(168)	-	2,582	Note 1
	$ 14,895	$ (1,621)	$ (171)	$ 13,103	

Regulatory deferral account debit balances	January 1, 2016	Additions/ transfers	Recovery/ reversal	December 31, 2016	Remaining years
Settlement variances	$ 5,875	$ 3,277	$ -	$ 9,152	2
Stranded meters	2,347	-	(740)	1,607	3
Other regulatory accounts	930	500	(44)	1,386	3
Income tax	3,171	(421)	-	2,750	Note 1
	$ 12,323	$ 3,356	$ (784)	$ 14,895	

Regulatory deferral account credit balances	January 1, 2017	Additions/ transfers	Recovery/ reversal	December 31, 2017	Remaining years
Settlement variances	$ (7,086)	$ 1,522	$ (21)	$ (5,585)	2
Other regulatory liabilities	(785)	(10)	-	(795)	3
Customer liability for deferred taxes	(13,227)	1,390	-	(11,837)	Note 1
	$ (21,098)	$ 2,902	$ (21)	$ (18,217)	

Regulatory deferral account credit balances	January 1, 2016	Additions/ transfers	Recovery/ reversal	December 31, 2016	Remaining years
Settlement variances	$ (5,011)	$ (2,075)	$ -	$ (7,086)	2
Other regulatory liabilities	(861)	76	-	(785)	3
Customer liability for deferred taxes	(14,314)	1,087	-	(13,227)	Note 1
	$ (20,186)	$ (912)	$ -	$ (21,098)	

1. These balances will be recovered over the life of the related capital assets.

The “Additions/Transfers” column consists of new additions to regulatory balances (for both debits and credits). The “Recovery/Reversal” column consists of amounts collected or paid through rate riders or transactions reversing an existing regulatory balance to recover. Recoveries and reversals occur as a result of the approval of an application. There were no reversals of regulatory balances for the year ended December 31, 2017.

12. Accounts payable and accrued liabilities

	2017	2016
Accounts payable – energy purchases	$ 7,000	$ 10,889
Debt retirement charge payable to OEFC	538	432
Payroll payable	2,163	2,161
Interest payable	4,143	4,144
Trade payables	15,423	18,693
	$ 29,267	$ 36,319

13. Long-term debt

	2017	2016
Notes Payable	$ 67,946	$ 67,946
Ontario Infrastructure loans	19,821	20,279
Capital lease liabilities (note 14)	10,041	10,500
	$ 97,808	$ 98,725

The Corporation has unsecured promissory notes $67,946 (2016 - $67,946) which are held by The Corporation of the Town of Oakville and were issued effective February 1, 2000 for a 20 year term. The notes bear interest at a rate of 6% (2016 – 6%), payable annually no later than 30 days after the end of the fiscal year. Interest rates are reviewed annually. The Corporation of the Town of Oakville has the option to change the terms of the promissory notes with one year notice. The Corporation of the Town of Oakville and the Corporation have set the interest rates for 2018 at 6%. The Corporation has made the assumption that in 2020, the promissory notes will be renewed for a further 20 year term.

The Corporation has a $19,821 (2016 - $20,279) debenture with Infrastructure Ontario due October 2042 bearing interest at a fixed interest rate of 4% for the entire term of the debenture. Interest is payable in monthly principal and interest installments of $105. The debenture was issued on October 1, 2012. Security is in the form of a pari passu first charge, dated August 31, 2016 on the assets of the Corporation, which replaced the original second charge agreement dated October 1, 2012.

Proceeds were used to replace working capital used in the 2010-2011 construction of a transmission station in Oakville.

13. Long -term debt (continued)

Repayment of the long term debt for the years ended December 31:

2018	$	976
2019		1,041
2020		1,109
2021		1,184
2022		1,262
Thereafter		92,236
		97,808
Current portion		976
Long-term portion	$	96,832

14. Finance lease

The Corporation has a finance lease arrangement with the Town of Oakville for the head office at 861 Redwood Square. The assets under finance lease are included in property, plant and equipment (see Note 8). The property under finance lease is amortized on a straight-line basis over the term of the lease agreement of 20 years.

Future minimum payments under finance lease arrangements are as follows for the years ended December 31:

2017	Less than one year	Between one and five years	More than five years	Total
Future minimum lease payments payments	$ 1,345	$ 5,380	$ 9,415	$ 16,140
Less: interest	845	2,891	2,363	6,099
Present value of minimum lease payments	$ 500	$ 2,489	$ 7,052	$ 10,041

2016	Less than one year	Between one and five years	More than five years	Total
Future minimum lease payments payments	$ 1,345	$ 5,380	$ 10,760	$ 17,485
Less: interest	886	3,096	3,003	6,985
Present value of minimum lease payments	$ 459	$ 2,284	$ 7,757	$ 10,500

15. Post-employment benefits

(a) OMERS pension plan

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2017, the Corporation made employer contributions of $1,153 to OMERS (2016 - $1,226) which has been recognized in profit or loss. The Corporation estimates that a contribution of $1,220 to OMERS will be made during the next fiscal year.

(b) Post-employment benefits other than pension

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expense and re-measurements recognized for post-employment benefit plans.

Reconciliation of the obligation		2017		2016
Defined benefit obligation, beginning of year	$	11,221	$	9,392
Included in profit or loss				
Current service cost		188		205
Interest cost		447		430
		11,856		10,027
Included in OCI				
Actuarial losses arising from:				
changes in financial assumptions		485		1,528
		485		1,528
Benefits paid		(383)		(334)
Defined benefit obligation, end of year	$	11,958	$	11,221

Actuarial assumptions	2017	2016
Discount (interest) rate	3.60%	4.00%
Salary levels	3.00%	3.00%
Medical Costs	5.70%	5.70%
Dental Costs	4.00%	4.00%

Medical costs are estimated to increase at a rate which declines over time from 5.7% per annum in 2016 to 4% by 2026.

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by ($1,461). A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by $1,794.

16. Share capital

		2017		2016
Authorized:				
Unlimited number of common shares				
Issued:				
1,407 common shares	$	76,108	$	76,108

Dividends

The holders of the common shares are entitled to receive dividends from time to time.

The Corporation paid aggregate dividends in the year on common shares of $2.63 (2016 - $3.41) per share which amount to total dividends paid in the year of $3,700 (2016 - $4,800).

17. Other revenue

		2017		2016
Services revenue	$	4,397	$	5,936
Amortization of deferred revenue		450		281
Performance incentive payments under CDM programs		554		-
	$	5,401	$	6,217

18. Employee salaries and benefits

		2017		2016
Salaries, wages and benefits	$	12,448	$	12,295
CPP and EI remittances		394		440
Contributions to OMERS		1,153		1,226
Post-employment benefit plans		188		205
	$	14,183	$	14,166

19. Operating expenses

		2017		2016
Contract/consulting	$	3,606	$	4,502
Materials and supplies		279		350
Vehicles		599		566
Write down of material and supplies		11		-
General and administration		1,362		1,378
Other		1,376		1,392
	$	7,233	$	8,188

20. Finance income and costs

		2017		2016
Finance income				
Interest income on bank deposits	$	243	$	427
Finance costs				
Interest expense on long-term debt		5,824		5,901
Interest expense on customer deposits		23		17
Net interest expense on post-employment benefits		447		430
Other		(43)		53
		6,251		6,401
Net finance costs recognized in profit or loss	$	6,008	$	5,974

21. Commitments and contingencies

Contractual Obligations

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.

General Liability Insurance

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2017, no assessments have been made.

22. Related party transactions

(a) Parent and ultimate controlling party

The sole shareholder of the Corporation is Oakville Enterprises Corporation which is wholly owned by The Corporation of the Town of Oakville. The Town of Oakville produces consolidated financial statements that are available for public use.

The following summarizes the Corporation's related party transactions recorded at the exchange amount and balances with the Town of Oakville for the year ended December 31:

	2017	2016
Amounts due to:		
Promissory note	$ 67,946	$ 67,946
Finance Lease	10,041	10,500
Interest on promissory note	4,077	4,077
Accounts payable	353	38
Amounts due from:		
Energy receivable	587	663
Accounts receivable	198	30
Transactions:		
Revenue:		
Energy Sales	6,183	6,249
Rent	147	147
Other	177	37
Expenses:		
Interest on promissory notes	4,077	4,077
Interest on finance lease	946	1,055
Garage services	417	409
Property taxes	375	382
Tree trimming	349	501
Other	69	65

The Corporation delivers electricity to the Town of Oakville 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.

22. Related party transactions (continued)

(b) Outstanding balances with related parties

	2017	2016
Parent company	$ 59	$ 380
Other related parties	1,627	1,143
	$ 1,686	$ 1,523

(c) Transactions with parent

During the year, the corporation collected management fees of $92 (2016 - $130) and other revenue of $20 (2016 - $24) from its parent, and paid corporate governance charges of $19 (2016 - $17).

(d) Transaction with other related parties

In the ordinary course of business, the corporation incurred the following transactions with other related parties under common control:

	2017	2016
Revenue:		
Billing administration fee	$ 339	$ 740
Management fees	505	532
Other	169	199
Expenses:		
Locating/construction services	1,117	1,532
Fleet and administration	1,348	636
Meter services	22	9
Other	62	19

(e) 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	$ 90	$ 75
Salaries, bonuses and other short-term benefits	1,388	1,732
	$ 1,478	$ 1,807

23. 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 the customer deposits approximates fair value because the amounts are payable on demand.

The Infrastructure Ontario debenture of $19,821 has a fair value estimated at $20,224 using a discount rate of 3.81%. This discount rate is determined using indicative quoted rates for instruments with approximately the same terms and credit risk.

The fair value of long term debt is estimated at $90,332 using a discount rate of 3.77%. This discount rate is determined using indicative quoted rates for instruments with approximately the same terms and credit risk.

The fair value of the finance lease liabilities is estimated at $13,153 using a discount rate of 3.51%. This discount rate is determined using indicative quoted rates for instruments with approximately the same terms and credit risk.

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 Province of Ontario. No single customer accounts for a balance in excess of 10% 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 $554 (2016 - $711). An impairment loss of $104 (2016 - $217) was recognized during the year.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2017, approximately $523 (2016 - $1,213) is considered 60 days past due. The Corporation has over 70 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. At December 31, 2017 the Corporation holds security deposits in the amount of $9,091 (2016 - $8,575).

23. Financial instruments and risk management (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 $35,000 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, $nil (2016 - $nil) had been drawn under the Corporation's $35,000 credit facility.

The Corporation also has a facility for $16,000 (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which $14,921 has been drawn and posted with the IESO (2016 - $14,921).

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 $88,113 (2016 - $84,770) and long-term debt amounts to $97,808 (2016 - $98,725).

24. Comparative information

Certain comparative information has been reclassified to conform to the presentation adopted in the current year. There is no impact to comprehensive income or retained earnings as a result of the reclassification.

Financial Statements of

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

Year ended December 31, 2018
(Expressed in thousands of dollars)

KPMG LLP
Commerce Place
21 King Street West, Suite 700
Hamilton Ontario L8P 4W7
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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Oakville Hydro Electricity Distribution Inc.

Opinion

We have audited the financial statements of Oakville Hydro Electricity Distribution Inc. (the "Entity"), which comprise:

- the statement of financial position as at December 31, 2018
- the statements of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2018, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRSs).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the ***"Auditors' Responsibilities for the Audit of the Financial Statements"*** section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

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

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, 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.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or have no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit 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.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Hamilton, Canada

April 4, 2019

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

Statement of Financial Position
December 31, 2018
(in thousands of dollars)

	Note	2018	2017
Assets			
Current assets			
Cash and cash equivalents	6	$ 27,643	$ 21,771
Accounts receivable	7	34,943	36,240
Materials and supplies	8	3,925	3,787
Prepaid expenses		914	845
Total current assets		67,425	62,643
Non-current assets			
Property, plant and equipment	9	206,994	193,033
Intangible assets	10	1,325	1,303
Deferred tax assets	12	6,986	9,367
Total non-current assets		215,305	203,703
Total assets		282,730	266,346
Regulatory balances	13	11,148	13,103
Total assets and regulatory balances		$ 293,878	$ 279,449

See accompanying notes to the financial statements.

	Note	2018	2017
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	14	$ 38,060	$ 29,267
Due to related parties	24	1,607	1,686
Long-term debt due within one year	15	496	476
Finance lease obligation	16	544	500
Customer deposits		7,672	9,091
Total current liabilities		48,379	41,020
Non-current liabilities			
Long-term debt	15	86,795	87,291
Finance lease obligation	16	8,996	9,541
Post-employment benefits	17	11,596	11,958
Deferred revenue	11	29,044	23,309
Total non-current liabilities		136,431	132,099
Total liabilities		184,810	173,119
Equity			
Share capital	18	76,108	76,108
Retained earnings		19,420	14,364
Accumulated other comprehensive loss		(1,832)	(2,359)
Total equity		93,696	88,113
Total liabilities and equity		278,506	261,232
Regulatory balances	13	15,372	18,217
Total liabilities, equity and regulatory balances		$ 293,878	$ 279,449

See accompanying notes to the financial statements.

On behalf of the Board:

Marie Oswald Director

Cliff Lonsky Director

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

Statement of Comprehensive Income
Year ended December 31, 2018, with comparative information for 2017
(in thousands of dollars)

	Note	2018	2017
Revenue			
Sale of energy		$ 191,572	$ 198,225
Distribution revenue		41,188	39,624
Other		6,093	5,401
	19	238,853	243,250
Operating expenses			
Cost of power purchased		191,073	197,475
Employee salaries and benefits	20	13,802	14,183
Operating expenses	21	9,319	7,233
Depreciation and amortization	9,10	9,124	9,157
		223,318	228,048
Income from operating activities		15,535	15,202
Finance income	22	476	243
Finance costs	22	6,167	6,251
Income before income taxes		9,844	9,194
Income tax expense	12	2,994	2,262
Net income for the year		6,850	6,932
Net movement in regulatory balances	13	(116)	(753)
Tax on net movement		2,122	1,221
		2,006	468
Net income for the year and net movement in regulatory balances		8,856	7,400
Other comprehensive income			
Items that will not be reclassified to profit or loss:			
Re-measurements of post-employment benefits	17	717	(485)
Tax on re-measurements	12	(190)	128
Other comprehensive income for the year		527	(357)
Total comprehensive income for the year		$ 9,383	$ 7,043

See accompanying notes to the financial statements.

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

Statement of Changes in Equity
Year ended December 31, 2018, with comparative information for 2017
(in thousands of dollars)

	Share capital	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance at January 1, 2017	$ 76,108	$ 10,664	$ (2,002)	$ 84,770
Net income and net movement in regulatory balances	-	7,400	-	7,400
Other comprehensive income	-	-	(357)	(357)
Dividends	-	(3,700)	-	(3,700)
Balance at December 31, 2017	$ 76,108	$ 14,364	$ (2,359)	$ 88,113
Balance at January 1, 2018	$ 76,108	$ 14,364	$ (2,359)	$ 88,113
Net income and net movement in regulatory balances	-	8,856	-	8,856
Other comprehensive income	-	-	527	527
Dividends	-	(3,800)	-	(3,800)
Balance at December 31, 2018	$ 76,108	$ 19,420	$ (1,832)	$ 93,696

See accompanying notes to the financial statements.

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

Statement of Cash Flows
Year ended December 31, 2018, with comparative information for 2017
(in thousands of dollars)

	2018	2017
Operating activities		
Net Income and net movement in regulatory balances	$ 8,856	$ 7,400
Adjustments for:		
Depreciation and amortization	9,124	9,157
Amortization of deferred revenue	(674)	(450)
Post-employment benefits	355	252
(Gain)/loss on disposal of property, plant and equipment	48	(15)
Net finance costs	5,691	6,008
Income tax expense	2,994	2,262
	26,394	24,614
Change in non-cash operating working capital:		
Accounts receivable	1,297	15,149
Due to/from related parties	(79)	163
Materials and supplies	(138)	(280)
Prepaid expenses	(69)	(113)
Accounts payable and accrued liabilities	8,595	(6,071)
Customer deposits	(1,419)	516
	8,187	9,364
Regulatory balances	(1,689)	(1,089)
Contributions received from customers	2,485	3,684
Income tax received	260	84
Income tax paid	(864)	(2,247)
Interest paid	(6,167)	(6,251)
Interest received	476	243
Net cash from operating activities	29,082	28,402
Investing activities		
Purchase of property, plant and equipment	(17,898)	(15,273)
Proceeds on disposal of property, plant and equipment	17	114
Purchase of intangible assets	(552)	(554)
Net cash used by investing activities	(18,433)	(15,713)
Financing activities		
Dividends paid	(3,800)	(3,700)
Repayment of long-term debt	(476)	(458)
Repayment of finance lease	(501)	(459)
Net cash from financing activities	(4,777)	(4,617)
Change in cash and cash equivalents	5,872	8,072
Cash and cash equivalents, beginning of year	21,771	13,699
Cash and cash equivalents, end of year	$ 27,643	$ 21,771
Non-cash additions to property, plant and equipment	$ (4,723)	$ (1,995)
Non-cash contributions from customers	4,723	1,995

See accompanying notes to the financial statements.

1. Reporting entity

Oakville Hydro Electricity Distribution Inc. (the "Corporation") is a wholly owned subsidiary of Oakville Enterprises Corporation (formerly Oakville Hydro Corporation) and was incorporated on January 28, 2000 under the *Business Corporations Act* (Ontario), in accordance with the *Electricity Act.* The address of the Corporation's registered office is 861 Redwood Square, Oakville, Ontario L6K 0C7.

The principal activity of the Corporation is to distribute electricity to the residents and businesses in the Town of Oakville, under a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated by the OEB and adjustments to the Corporation's distribution and power rates require OEB approval.

The financial statements are for the Corporation as at and for the year ended December 31, 2018.

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 4, 2019.

(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) Notes 3 (d), (e). 9, 10 – estimation of useful lives of its property, plant and equipment and intangible assets
(ii) Notes 3 (i), 13 – recognition and measurement of regulatory balances
(iii) Notes 3 (j), 17 – measurement of defined benefit obligations: key actuarial assumptions
(iv) Notes 3 (h), 23 – 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) Notes 3 (k), 16 – leases: whether an arrangement contains a lease
(ii) Note 3(b) – determination of the performance obligation for contributions from customers and the related amortization period

(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.

Rate setting

(i) Distribution Rates

The Corporation files a "Cost of Service" ("COS") rate application every five years under which the OEB establishes the revenues required to recover the forecasted operating costs, including amortization and income taxes, of providing the regulated electricity distribution service and providing a fair return on the Corporation's rate base. The Corporation estimates electricity usage and the costs to service each customer class in order to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and any registered interveners. Rates are approved based upon the review of evidence and information, including any revisions resulting from that review.

2. Basis of presentation (continued)

(e) Rate regulation (continued)

(i) Distribution Rates (continued)

In the intervening years, an Incentive Regulation Mechanism application ("IRM") is filed. An IRM application results 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 set by the OEB and a "stretch factor" determined by the relative efficiency of an electricity distributor.

On October 1, 2013, the Corporation submitted a COS rate application to the OEB to change distribution rates effective May 1, 2014. The application was approved by the OEB on May 1, 2014.

On August 14, 2017 the Corporation submitted an IRM Application to the OEB requesting approval to change distribution rates effective January 1, 2018. The IRM Application, which provided a mechanistic and formulaic adjustment to distribution rates and charges, was approved by the OEB on December 14, 2017. The GDP IPI-FDD for 2018 is 1.5%, the Corporation's stretch factor is 0.30% and the productivity factor determined by the OEB is 0%, resulting in a net adjustment of 1.2% to the previous year's rates.

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 the distribution charges will be collected through a fully fixed monthly charge instead of the current fixed and variable rate charge.

(ii) Electricity Rates

The OEB sets Ontario electricity prices for low-volume consumers twice each year (May and November) based on an estimate of how much it will cost to supply the province with electricity for the next year. In 2017, the OEB set new lower Regulated Price Plan (RPP) prices established under the *Fair Hydro Act, 2017*. All remaining consumers pay the market price for electricity.

As required under the Ontario Fair Hydro Plan Act, 2017, the OEB set the 2018 electricity prices such that the monthly bill for the proxy customer described under the Ontario Fair Hydro Plan Act, 2017 increased by the rate of inflation relative to the bill on July 1, 2017.

The Corporation is billed for the cost of the electricity that its customers use by the Independent Electricity System Operator and passes this cost on to the customer at cost without a mark-up.

2. Basis of presentation (continued)

(e) Rate regulation (continued)

(iii) Retail Transmission Rates

These are the costs of delivering electricity from generating stations across the Province to local distribution networks. These charges include the costs to build and maintain the transmission lines, towers and poles and operate provincial transmission systems. Retail transmission rates are passed through to the operators of transmission networks and facilities.

(iv) Wholesale Market Service Rates

These are the costs of administering the wholesale electricity system and maintaining the reliability of the provincial grid and include the costs associated with funding Ministry of Energy conservation and renewable energy programs. Wholesale charges are passed through to the Independent Electricity System Operator.

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 and all financial liabilities 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 may include short-term investments with maturities of three months or less when purchased.

(b) Revenue recognition

Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that the Corporation has the right to bill. 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)

Customer billings for debt retirement charges are recorded on a net basis as the Corporation is acting as an agent for this billing stream.

Capital contributions

Developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. The developer is not a customer and therefore the contributions are scoped out of IFRS 15 *Revenue from Contracts with Customers*. Cash contributions, received from developers 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.

Certain customers are also required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 *Revenue from Contracts with Customers*. The contributions are received to obtain a connection to the distribution system in order receive ongoing access to electricity. The Corporation has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Revenue is recognized on a straight-line basis over the useful life of the related asset.

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered.

Government grants and the related performance incentive payments under Conservation and Demand Management ("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.

3. Significant accounting policies (continued)

(c) Materials and supplies

Materials and supplies, the majority of which is consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on an 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.

(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 date of transition to IFRS, 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, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

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 six months to construct.

3. Significant accounting policies (continued)

(d) Property, plant and equipment (continued)

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:

	Years
Buildings	10 - 60
Distribution equipment	15 - 60
PP&E	3 - 20

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 date of transition to IFRS, 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.

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:

	Years
Computer software	4 - 5

(f) Impairment

(i) Financial assets measured at amortized cost

A loss allowance for expected credit losses on financial assets measured at amortized cost is recognized at the reporting date. The loss allowance is measured at an amount equal to the lifetime expected credit losses for the asset.

(ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than 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.

3. Significant accounting policies (continued)

(f) Impairment (continued)

(ii) Non-financial assets (continued)

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.

The goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to CGUs that are expected to benefit from the synergies of the combination.

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. They are allocated first to reduce the carrying amount of any goodwill allocated to the CGU, and then to reduce the carrying amounts of the other assets in the CGU on a prorated basis, if applicable.

An impairment loss in respect of goodwill is not reversed. 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 and deposits. Interest is paid on customer deposits. Deposits are also received for planned chargeable work. No interest is paid on these 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

The Corporation elected to apply the requirements of IFRS 14, effective December 31, 2015.

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account 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 or loss or other comprehensive income ("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.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the amounts are returned to the customer at rates approved by the OEB the amounts are recognized as a reduction of revenue.

The probability of recovery of the regulatory deferral account 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.

3. Significant accounting policies (continued)

(j) Post-employment benefits

(i) Pension plan

The Corporation provides a pension plan for some of its full-time employees through Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan that provides pensions for employees of Ontario municipalities, local boards and public utilities. OMERS is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by investment earnings. To the extent that the plan finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

(ii) Post-employment benefits, other than pension

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Re-measurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

(k) 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)

(l) 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 lease obligations, and unwinding of the discount on provisions and net interest expense on post-employment benefits. Finance costs are recognized in profit or loss unless they are capitalized as part of the cost of qualifying assets.

(m) 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 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. Payments in lieu of taxes and payments under the Tax Acts are collectively 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 evaluating the adoption of the following new and revised standards along with any subsequent amendments.

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 intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. The Corporation does not expect the standard to have a material impact on the financial statements.

5. Change in accounting policy

The Corporation has initially applied IFRS 15 *Revenue from Contracts with Customers* and IFRS 9 *Financial Instruments* from January 1, 2018 on a retrospective basis. The following practical expedients have been used in the initial application of these new standards:

For complete contracts, the Corporation did not restate contracts that:

(i) Began and ended within the same annual reporting period; or

(ii) Were completed at the beginning of January 1, 2016

There are no transitional impacts to report as adoption of these standards did not have a material impact on comparative information.

6. Cash and cash equivalents

	2018	2017
Bank balances	$ 27,643	$ 21,771
Cash and cash equivalents in the statement of cash flows	$ 27,643	$ 21,771

The Corporation has a mirror accounting agreement with certain related companies whereby the bank has the right of setoff between overdrafts in these related companies and the Corporation's bank account. As at December 31, 2018 the net overdraft totaled ($6) (2017 - ($4)).

7. Accounts receivable

	2018	2017
Trade receivables	$ 13,530	$ 12,957
Income tax receivable	-	168
Unbilled revenue	21,413	23,115
	$ 34,943	$ 36,240

8. Materials and supplies

Amount written down due to obsolescence in 2018 was $60 (2017 - $11). The amount of inventories consumed by the Corporation and recognized as an expense during 2018 was $242 (2017 - $272).

9. Property, plant and equipment

	Land and buildings	Distribution equipment	Other fixed assets	Construction in-Progress	Total
Cost or deemed cost					
Balance at January 1, 2018	$ 14,933	$ 200,067	$ 6,488	$ 4,310	$ 225,798
Additions	194	19,986	1,926	515	22,621
Transfers	-	-	-	-	-
Disposals/retirements	-	(82)	(67)	-	(149)
Balance at December 31, 2018	$ 15,127	$ 219,971	$ 8,347	$ 4,825	$ 248,270
Balance at January 1, 2017	$ 14,800	$ 183,886	$ 5,576	$ 4,389	$ 208,651
Additions	133	16,294	920	(79)	17,268
Transfers	-	-	-	-	-
Disposals/retirements	-	(113)	(8)	-	(121)
Balance at December 31, 2017	$ 14,933	$ 200,067	$ 6,488	$ 4,310	$ 225,798
Accumulated depreciation					
Balance at January 1, 2018	$ 2,958	$ 25,684	$ 4,123	$ -	$ 32,765
Depreciation	719	6,991	884	-	8,594
Disposals/retirements	-	(21)	(62)	-	(83)
Balance at December 31, 2018	$ 3,677	$ 32,654	$ 4,945	$ -	$ 41,276
Balance at January 1, 2017	$ 2,230	$ 18,710	$ 3,259	$ -	$ 24,199
Depreciation	728	6,988	872	-	8,588
Disposals/retirements	-	(14)	(8)	-	(22)
Balance at December 31, 2017	$ 2,958	$ 25,684	$ 4,123	$ -	$ 32,765
Carrying amounts					
At December 31, 2018	$ 11,450	$ 187,317	$ 3,402	$ 4,825	$ 206,994
At December 31, 2017	11,975	174,383	2,365	4,310	193,033

The Corporation has a finance lease agreement with the Town of Oakville for the head office at 861 Redwood Square. The leased building secures lease obligations (see note 16). At December 31, 2018 the net carrying amount of leased building was $2,657 (2017 - $2,898).

At December 31, 2018 property plant and equipment with a carrying amount of $204,337 (2017 - $190,135) are subject to a general security agreement.

There were no borrowing costs capitalized as part of the cost of property, plant and equipment in 2017 and 2018.

10. Intangible assets

	Computer software	Total
Cost or deemed cost		
Balance at January 1, 2018	$ 3,532	$ 3,532
Additions	552	552
Balance at December 31, 2018	$ 4,084	$ 4,084
Balance at January 1, 2017	$ 2,978	$ 2,978
Additions	554	554
Balance at December 31, 2017	$ 3,532	$ 3,532
Accumulated amortization		
Balance at January 1, 2018	$ 2,229	$ 2,229
Amortization	530	530
Balance at December 31, 2018	$ 2,759	$ 2,759
Balance at January 1, 2017	$ 1,660	$ 1,660
Amortization	569	569
Balance at December 31, 2017	$ 2,229	$ 2,229
Carrying amounts		
At December 31, 2018	$ 1,325	$ 1,325
At December 31, 2017	1,303	1,303

11. Deferred revenue

Deferred revenue relates to capital contributions received from customers and others. The amount of deferred revenue received from customers is $2,485 (2017 - $3,684). Deferred revenue is recognized as revenue on a straight-line basis over the life of the related asset for which the contribution was received. During the year, the Corporation also recognized non-cash contributions in the amount of $4,723 (2017 - $1,995).

12. Income tax expense

Current tax expense

	2018	2017
Current year	$ 920	$ 1,013
Adjustment for prior years	(307)	-
	$ 613	$ 1,013

Deferred tax expense

	2018	2017
Origination and reversal of temporary differences	$ 2,381	$ 1,249
	$ 2,381	$ 1,249

Reconciliation of effective tax rate

	2018	2017
Income before taxes	$ 9,844	$ 9,194
Canada and Ontario statutory Income tax rates	26.5%	26.5%
Expected tax provision on income at statutory rates	2,609	2,436
Increase (decrease) in income taxes resulting from:		
Permanent differences	195	15
Other	190	(189)
Income tax expense	$ 2,994	$ 2,262

Components of the Corporation's deferred tax balances

	2018	2017
Deferred tax assets (liabilities):		
Property, plant, equipment and intangibles	$ 666	$ 2,755
Finance Lease obligation	2,528	2,661
Post-employment benefits	3,074	3,169
Other tax reserves	718	782
	$ 6,986	$ 9,367

13. Regulatory balances

The Corporation has determined that certain debit and credit balances arising from rate-regulated activities qualify for regulatory accounting treatment in accordance with IFRS 14 and the OEB's prescribed accounting procedures for electricity distributors. The regulatory balances are comprised of regulatory debit variances of $11,148 and regulatory credit balances for $15,372 for a net regulatory liability of $4,224.

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers' Acceptances three-month rate plus a spread of 25 basis points, with the exception of the tax balances. In 2018, the rate was 1.5% for the period January to March 2018, 1.89% from April to September and 2.17% for the period October to December.

The regulatory balances for the Corporation consist of the following:

(a) Settlement Variance

This account includes the variances between amounts charged by the Corporation, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by the Corporation such as commodity charges, retail transmission rates and wholesale market services charges. The Corporation has deferred the variances and related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. This account also includes variances between the amounts approved for disposition by the OEB and the amounts collected or paid through OEB approved rate riders.

Settlement variances are reviewed annually as part of a COS or IRM application submitted to the OEB and a request for disposition is made if the aggregate of the settlement accounts exceeds the OEB's prescribed materiality level.

In the Corporation's 2018 IRM application, submitted in August 2017, Oakville Hydro did not seek OEB approval for this disposition of the 2016 audited balances as they were below the OEB's prescribed materiality level.

(b) Stranded Meters

The stranded meter account relates to the provincial government's directive to install smart meters for all Ontario customers by December 2010. In its 2014 cost of service application, the Corporation received approval from the OEB for the recovery of the stranded meter costs associated with the Province's smart meter initiative over a five-year period beginning on May 1, 2014 and ending on April 30, 2019.

(c) Customer Liability for Deferred Taxes

The customer liability for deferred taxes variance account relates to the expected regulatory liability relating to deferred taxes arising from timing differences in the determination of income taxes.

13. Regulatory balances (continued)

(d) Other (continued)

This deferral account includes the allowable costs associated with the transition to IFRS, the installation of interval meters for General Service greater than 50 kilowatts, as directed by the OEB, the transition to monthly billing and other miscellaneous regulatory accounts.

Reconciliation of the carrying amount for each class of regulatory balances

Regulatory deferral account debit balances	January 1, 2018	Additions/ transfers	Recovery/ reversal	December 31, 2018	Remaining years
Settlement variances	$ 6,849	$ (58)	$ (60)	$ 6,731	2
Stranded meters	872	-	(756)	116	1
Lost revenue adjustment mechanism	467	591	-	1,058	3
Other regulatory accounts	2,333	(655)	-	1,678	3
Income tax	2,582	(1,017)	-	1,565	Note 1
	$ 13,103	$ (1,139)	$ (816)	$ 11,148	

Regulatory deferral account debit balances	January 1, 2017	Additions/ transfers	Recovery/ reversal	December 31, 2017	Remaining years
Settlement variances	$ 9,152	$ (2,132)	$ (171)	$ 6,849	2
Stranded meters	1,607	(735)	-	872	2
Lost revenue adjustment mechanism	-	467	-	467	3
Other regulatory accounts	1,386	947	-	2,333	3
Income tax	2,750	(168)	-	2,582	Note 1
	$ 14,895	$ (1,621)	$ (171)	$ 13,103	

Regulatory deferral account credit balances	January 1, 2018	Additions/ transfers	Recovery/ reversal	December 31, 2018	Remaining years
Settlement variances	$ (5,585)	$ (316)	$ (51)	$ (5,952)	2
Other regulatory liabilities	(795)	(1)	74	(722)	3
Customer liability for deferred taxes	(11,837)	3,139	-	(8,698)	Note 1
	$ (18,217)	$ 2,822	$ 23	$ (15,372)	

Regulatory deferral account credit balances	January 1, 2017	Additions/ transfers	Recovery/ reversal	December 31, 2017	Remaining years
Settlement variances	$ (7,086)	$ 1,522	$ (21)	$ (5,585)	2
Lost revenue adjustment mechanism	(30)	30	-	-	3
Other regulatory liabilities	(755)	(40)	-	(795)	3
Customer liability for deferred taxes	(13,227)	1,390	-	(11,837)	Note 1
	$ (21,098)	$ 2,902	$ (21)	$ (18,217)	

1. These balances will be recovered over the life of the related capital assets.

The "Additions/Transfers" column consists of new additions to regulatory balances (for both debits and credits). The "Recovery/Reversal" column consists of amounts collected or paid through rate riders or transactions reversing an existing regulatory balance to recover. Recoveries and reversals occur as a result of the approval of an application. There were no reversals of regulatory balances for the year ended December 31, 2018.

14. Accounts payable and accrued liabilities

	2018	2017
Accounts payable – energy purchases	$ 7,000	$ 7,000
Debt retirement charge payable to OEFC	(13)	538
Payroll payable	1,513	2,163
Interest payable	4,141	4,143
Trade payables	25,419	15,423
	$ 38,060	$ 29,267

15. Long-term debt

	2018	2017
Notes Payable	$ 67,946	$ 67,946
Ontario Infrastructure loans	19,345	19,821
Finance lease liabilities (note 14)	9,540	10,041
	$ 96,831	$ 97,808

The Corporation has unsecured promissory notes $67,946 (2017 - $67,946) which are held by The Corporation of the Town of Oakville and were issued effective February 1, 2000 for a 20 year term. The notes bear interest at a rate of 6% per annum(2017 – 6%), payable annually no later than 30 days after the end of the fiscal year. Interest rates are reviewed annually. The Corporation of the Town of Oakville has the option to change the terms of the promissory notes with one year notice. The Corporation of the Town of Oakville and the Corporation have set the interest rates for 2019 at 6%. For the purposes of the repayment schedule below, the Corporation has made the assumption that in 2020, the promissory notes will be renewed for a further term of at least 10 years.

The Corporation has a $19,345 (2017 - $19,821) debenture with Infrastructure Ontario due October 2042 bearing interest at a fixed interest rate of 4% per annum for the entire term of the debenture. Interest is payable in monthly principal and interest installments of $105. The debenture was issued on October 1, 2012. Security is in the form of a pari passu first charge, dated August 31, 2016 on the assets of the Corporation, which replaced the original second charge dated October 1, 2012.

Repayment of the long term debt for the years ended December 31:

2019	$ 1,040
2020	1,109
2021	1,183
2022	1,262
2023	1,349
Thereafter	90,888
	96,831
Current portion	1,040
Long-term portion	$ 95,791

16. Finance lease

The Corporation has a finance lease arrangement with the Town of Oakville for the head office at 861 Redwood Square. The assets under finance lease are included in property, plant and equipment (see Note 9). The property under finance lease is amortized on a straight-line basis over the term of the lease agreement of 20 years.

Future minimum payments under finance lease arrangements are as follows for the years ended December 31:

2018	Less than one year	Between one and five years	More than five years	Total
Future minimum lease payments payments	$ 1,345	$ 5,380	$ 8,070	$ 14,795
Less: interest	(801)	(2,669)	(1,785)	(5,255)
Present value of minimum lease payments	$ 544	$ 2,711	$ 6,285	$ 9,540

2017	Less than one year	Between one and five years	More than five years	Total
Future minimum lease payments payments	$ 1,345	$ 5,380	$ 9,415	$ 16,140
Less: interest	(845)	(2,891)	(2,363)	(6,099)
Present value of minimum lease payments	$ 500	$ 2,489	$ 7,052	$ 10,041

17. Post-employment benefits

(a) OMERS pension plan

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2018, the Corporation made employer contributions of $1,046 to OMERS (2017 - $1,153) which has been recognized in profit or loss. The Corporation estimates that a contribution of $1,146 to OMERS will be made during the next fiscal year.

17. Post-employment benefits (continued)

(b) Post-employment benefits other than pension

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expense and re-measurements recognized for post-employment benefit plans.

Reconciliation of the obligation		2018		2017
Defined benefit obligation, beginning of year	$	11,958	$	11,221
Transfer liability		176		-
Included in profit or loss				
Current service cost		201		188
Interest cost		409		447
		12,744		11,856
Included in OCI				
Actuarial (gains)/losses arising from:				
changes in demographic assumptions		(1,525)		-
changes in financial assumptions		808		485
		12,027		485
Benefits paid		(431)		(383)
Defined benefit obligation, end of year	$	11,596	$	11,958

Actuarial assumptions	2018	2017
Discount (interest) rate	3.85%	3.60%
Salary levels	3.00%	3.00%
Medical Costs	6.20%	5.70%
Dental Costs	4.00%	4.00%

Medical costs are estimated to increase at a rate which declines over time from 6.2% per annum in 2016 to 4% by 2040.

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by ($1,716). A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by $1,739.

18. Share capital

	2018	2017
Authorized:		
Unlimited number of common shares		
Issued:		
1,407 common shares	$ 76,108	$ 76,108

Dividends

The holders of the common shares are entitled to receive dividends from time to time.

The Corporation paid aggregate dividends in the year on common shares of $2.70 (2017 - $2.63) per share which amount to total dividends paid in the year of $3,800 (2017 - $3,700).

19. Revenue from contracts with customers and other sources

	2018	2017
Revenue from contracts with customers:		
Energy sales	$ 191,572	$ 198,225
Distribution revenue	41,188	39,624
Ancillary services	3,705	2,385
Other regulatory service charges	754	869
Pole and duct rental	252	241
Miscellaneous	412	407
Revenue from other sources:		
Amortization of deferred revenue	674	450
CDM programs	249	663
Other	47	386
	$ 238,853	$ 243,250

The following table disaggregates revenues from contracts with customers by type of customer:

	2018	2017
Revenue from contracts with customers:		
Residential	$ 85,193	$ 88,647
Commercial	107,168	109,975
Large Users	26,168	26,299
Other	14,231	12,928
	$ 232,760	$ 237,849

20. Employee salaries and benefits

	2018	2017
Salaries, wages and benefits	$ 12,173	$ 12,448
CPP and EI remittances	382	394
Contributions to OMERS	1,046	1,153
Post-employment benefit plans	201	188
	$ 13,802	$ 14,183

21. Operating expenses

	2018	2017
Contract/consulting	$ 4,635	$ 3,606
Materials and supplies	389	279
Vehicles	486	599
Write down of material and supplies	60	11
General and administration	2,372	1,362
Other	1,377	1,376
	$ 9,319	$ 7,233

22. Finance income and costs

	2018	2017
Finance income		
Interest income on bank deposits	$ 476	$ 243
Finance costs		
Interest expense on long-term debt	5,794	5,824
Interest expense on customer deposits	40	23
Net interest expense on post-employment benefits	409	447
Other	(76)	(43)
	6,167	6,251
Net finance costs recognized in profit or loss	$ 5,691	$ 6,008

23. Commitments and contingencies

Contractual Obligations

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.

General Liability Insurance

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2018, no assessments have been made.

24. Related party transactions

(a) Parent and ultimate controlling party

The sole shareholder of the Corporation is Oakville Enterprises Corporation which is wholly owned by The Corporation of the Town of Oakville. The Town of Oakville produces consolidated financial statements that are available for public use.

The following summarizes the Corporation's related party transactions recorded at the exchange amount and balances with the Town of Oakville for the year ended December 31:

	2018	2017
Amounts due to:		
Promissory note	$ 67,946	$ 67,946
Finance Lease	9,540	10,041
Interest on promissory note	4,077	4,077
Accounts payable	117	353
Amounts due from:		
Energy receivable	645	587
Accounts receivable	52	198
Transactions:		
Revenue:		
Energy Sales	6,178	6,183
Rent	147	147
Other	193	177
Expenses:		
Interest on promissory notes	4,077	4,077
Interest on finance lease	934	946
Garage services	400	417
Property taxes	399	375
Tree trimming	520	349
Other	70	69

The Corporation delivers electricity to the Town of Oakville 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.

24. Related party transactions (continued)

(b) Outstanding balances with related parties

	2018	2017
Parent company	$ 79	$ 59
Other related parties	1,528	1,627
	$ 1,607	$ 1,686

(c) Transactions with parent

During the year, the corporation collected management fees of $4 (2017 - $92) and other revenue of $22 (2017 - $20) from its parent, and paid corporate governance charges of $22 (2017 - $19).

(d) Transaction with other related parties

In the ordinary course of business, the corporation incurred the following transactions with other related parties under common control:

	2018	2017
Revenue:		
Billing administration fee	$ 344	$ 339
Management fees	105	505
Other	152	169
Expenses:		
Locating/construction services	1,325	1,117
Fleet and administration	79	1,348
Meter services	110	22
Other	6	62

(e) 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:

	2018	2017
Directors' fees	$ 81	$ 90
Salaries, bonuses and other short-term benefits	1,128	1,388
	$ 1,209	$ 1,478

25. 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 the customer deposits approximates fair value because the amounts are payable on demand.

The Infrastructure Ontario debenture of $19,345 has a fair value estimated at $20,027 using a discount rate of 3.66%. This discount rate is determined using indicative quoted rates for instruments with approximately the same terms and credit risk.

The fair value of the notes payable with The Corporation of the Town of Oakville is estimated at $91,569 using a discount rate of 3.61%. This discount rate is determined using indicative quoted rates for instruments with approximately the same terms and credit risk.

The fair value of the finance lease liabilities is estimated at $12,415 using a discount rate of 3.27%. This discount rate is determined using indicative quoted rates for instruments with approximately the same terms and credit risk.

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 Province of Ontario. No single customer accounts for a balance in excess of 10% of total accounts receivable.

The carrying amount of accounts receivable is reduced through the use of an allowance for estimated credit losses 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, 2018 is $938 (2017 - $554). An impairment loss of $545 (2017 - $104) was recognized during the year.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2018, approximately $946 (2017 - $523) is considered 60 days past due. The Corporation has over 72 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. At December 31, 2018 the Corporation holds security deposits in the amount of $7,672 (2017 - $9,091).

25. Financial instruments and risk management (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 $35,000 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, 2018, $nil (2017 - $nil) had been drawn under the Corporation's $35,000 credit facility.

The Corporation also has a facility for $16,000 (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which $14,921 has been drawn and posted with the IESO (2017 - $14,921).

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, to comply with covenants related to its credit facilities, to prudently manage 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, 2018, shareholder's equity amounts to $93,696 (2017 - $88,113) and long-term debt amounts to $96,831 (2017 - $97,808).

26. Comparative information

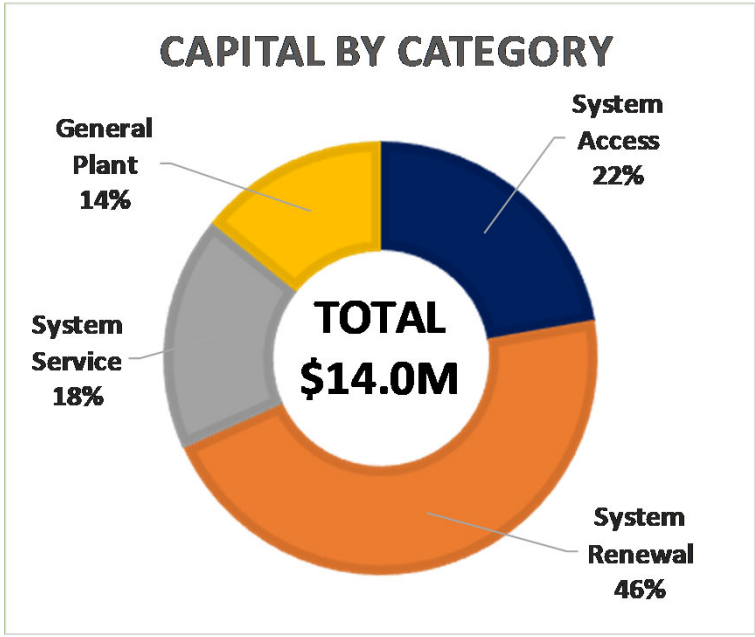
Certain comparative information has been reclassified to conform to the presentation adopted in the current year. There is no impact to comprehensive income or retained earnings as a result of the reclassification.

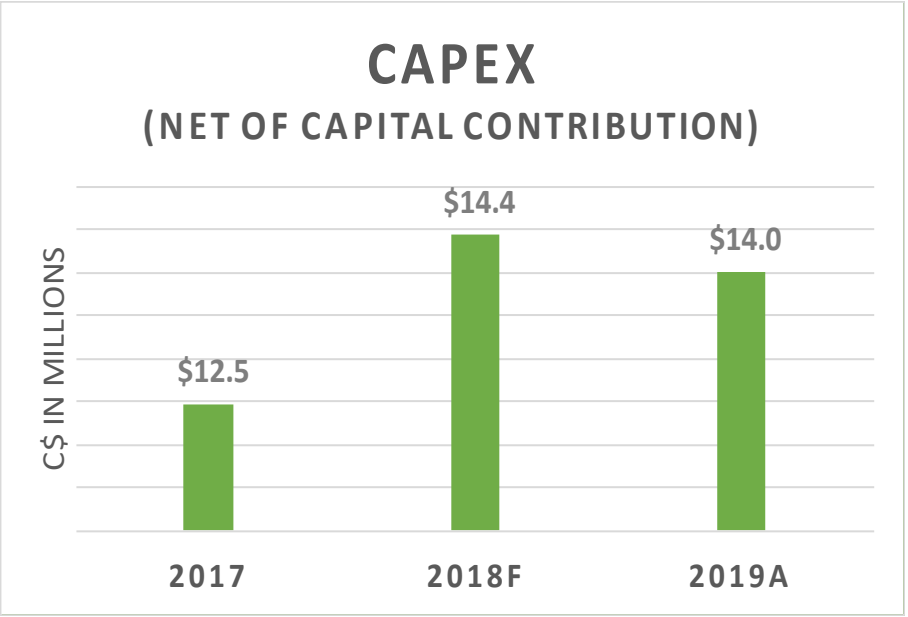
Appendix 7

2019 Business Plan

Capital Related Items

Oakville Hydro – Capital Plan





- CapEx in line with OEB framework
- See Appendix for a breakdown of capex projects

OH Capital

Category	Description	Total
System Service	Facilities Capital Projects	2,205,500
System Access	New Development Investment	1,500,000
System Access	Metrolinx electrification X-ING conflicts: Constr	1,500,000
System Access	New Services	1,200,000
General Plant	IT Capital Projects (OHEDI) - General Plant	1,110,000
System Service	SECC - BESS	1,000,000
System Renewal	SGF - Downtown (2019)	991,000
General Plant	SGF - Utilismart (2019)	944,374
System Renewal	Replace O/H Assets @ Lakeshore Rd(Maple Grove Dr to Devon Rd)	850,000
System Access	New General Services	800,000
System Access	Multi-Residential New and Replacement Meters	730,000
System Access	Dundas St Widening(Bronte Rd to Tremaine Rd)	720,000
System Renewal	MS LV Brk replacement	720,000
System Access	Distribution System Inspection/Energization	600,000
System Renewal	Replace UG Assets @ Riverview West St	550,000
System Renewal	Replace O/H Assets @ Rebecca St (Sunset Dr to Third Line)	530,000
General Plant	2019 Vehicles	518,000
System Access	Feeder Metering for New Bronte TS T3 & T4	500,000
System Renewal	Bronte TS Egress FDR Repl (2019 work)	500,000
System Renewal	Replace UG Assets @ Devon Rd (Devon MS to SC25 to SW221-7	500,000
System Access	Metrolinx Grade Separation : Kerr St (Interim OH Reloc Constr)	500,000
System Access	Metrolinx Grade Separation : Burloak Dr (Interim OH Reloc-Constr)	500,000
System Access	Residential Underground Services	475,000
System Renewal	27.6kV Air insulated switchgear upgrades -4 locations(SC75,SC95,SC81,SC90)	450,000
System Renewal	Vault Transformer Replacement@Falgarwood-WhiteElefants Bldg)	450,000
System Renewal	Replace O/H Assets @ McDonald Rd, Douglas rd, Watson Ave, Gloucester Ave	410,000
System Renewal	Replace UG Assets @ Viewmont Rd(W ph from tx4192 to sw13x12)	350,000
System Renewal	Replace UG Assets @ Falgarwood(ExP/LOC)	350,000
System Access	New and Replacement Residential Meters	317,000
System Renewal	MS TX replacement	280,000
System Service	27.6kV Additions (31M8 at 403)	265,000
System Renewal	MS 27.6kV switchgear replacement	210,000
System Access	New and Replacement Commercial Meters	202,000
System Renewal	Vault Transformer Replacement (3 locations)	200,000
System Renewal	Replace O/H Assets @ Saxon, Seabrook, Swann 4kv OH RBD	200,000
System Renewal	Replace O/H Assets @ Forestwood Dr, Burgundy Dr, Chelsea Gate, Dunwood, dia	200,000

OH Capital

Category	Description	Total
System Renewal	Replace UG Assets @ Marlborough Crt(SW161x24 to TV78)	180,000
System Renewal	Residential / Commercial Meter Sampling	158,900
System Access	Sensus RNI Upgrade	150,000
System Renewal	Gang-Op Replacements(S5054-L,S2031-L, S2070-L)	150,000
System Renewal	Livefront Transformer Replacements (3 locations)	150,000
System Renewal	27.6kV Submersible Switchgear Replacement(1 location)	140,000
System Renewal	Replace RTUs	120,000
System Renewal	Replace O/H Assets @ Maple Ave 4 Kv OH RBD	115,000
General Plant	SCADA - PDS, Data Forward, Stakeholder Email, DSE	110,000
System Renewal	Replace O/H Assets @ Trelawn Ave	100,000
System Renewal	Replace O/H Assets @ Tennyson	100,000
System Access	Brookmill Bridge Rehabilitation-Hydro relocation	100,000
General Plant	Maximo - Asset Register	100,000
System Service	PQView - Phase 2 of Pilot Project	100,000
System Renewal	2019 Cable Testing Program	100,000
System Access	Primary Meter Unit Replacement (2 Locations)	98,000
System Renewal	Radio Replacement & Upgrades (Replace Transit Radio System)	80,000
System Renewal	Replace UG Assets @ Warminster&Rebecca	75,000
System Renewal	Upgrade to MS Ground Grid	75,000
System Renewal	Radio Study and Pilot (WIMAX)	75,000
System Renewal	P&C Tools	60,000
General Plant	SCADA - Brocade switches	60,000
System Renewal	MS 48V DC Supply Upgrade	54,000
General Plant	Meter Tools	50,000
General Plant	SCADA - Servers, Redwood Core layer-3 switch Cisco 3850	48,000
General Plant	Control Room - Workstations (OH, HHH)	36,500
System Renewal	MS 120/240V AC Supply Upgrade	30,000
General Plant	CYME - Python module	30,000
General Plant	Control Room - Radio recording	30,000
System Renewal	MS Fan Control Upgrades	20,000
General Plant	Hazard Hamlet	20,000
General Plant	eWaste Stations for OEC	18,500
System Access	AMI Repeater Installations (3 Locations)	17,000
System Renewal	2019 Wood Pole Testing Program	16,000
General Plant	Emergency Decent Kits - OPS	7,000
General Plant	Sit Stand Ergo Stations	2,800