EXHIBIT 2 - RATE BASE

OVERVIEW:

Rate Base Overview:

The rate base used for the purpose of calculating the revenue requirement used in this Application is the average of the balances at the beginning and the end of the 2013 Test Year, plus a working capital allowance, which is 13% of the sum of the cost of power and controllable expenses.

The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. The Peterborough Distribution Inc. (PDI) rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

PDI has provided its rate base calculations for the years 2009 OEB Approved, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and 2013 Test Year in the table below. PDI has calculated its 2013 rate base as $66,310,232 under CGAAP which will be used to determine the proposed revenue requirement. In 2013 PDI adopted MIFRS like policies required by the OEB for rate setting purposes.

Table 2-1: Summary of Rate Base

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 CGAAP Bridge	2013 CGAAP Test
Average Net Book Value of FA	44,685,354	43,932,852	44,067,398	45,240,916	49,620,065	54,238,640
Working Capital Allowance (15%)	10,410,461	10,162,625	10,586,404	11,386,707	13,647,704	
Working Capital Allowance (13)%						12,071,592
Rate Base	**55,095,815**	**54,095,477**	**54,653,802**	**56,627,623**	**63,267,769**	**66,310,232**

This exhibit will compare historical data with the 2012 Bridge Year and 2013 Test Year.

The Peterborough Distribution Inc. System:

PDI owns and operates the electricity distribution system in its licensed service area in the City of Peterborough, the Town of Norwood and the Village of Lakefield, serving approximately

44,000 Residential, General Service, Large Use, Street Light, Sentinel Light and Unmetered Scattered Load customers/connections.

Electricity is distributed to the City of Peterborough from the provincial transmission grid by three primary Hydro One Network Inc. sources: Otonabee Transformer Station, Dobbin Transformer Station and Dobbin Distribution Station.

Main supply circuits are either 44 kV or 27.6 kV, however, a significant portion of the distribution system supplies customers from 44/4.16 kV municipal substations which is the older legacy distribution system.

The Lakefield distribution system operates at 4.16 kV from a PDI owned 44/4.16 kV municipal substation supplied from a Hydro One 44 kV circuit from Otonabee TS.

The Norwood distribution system is supplied by 8.32 kV circuits from a Hydro One 44/8.32 kV distribution substation supplied from a Hydro One 44 kV circuit from Otonabee TS.

PDI monitors its distribution system through a supervisory and control system at its main office. The control center which operates the Supervisory Control and Data Acquisition ("SCADA") system is manned for ten hours a day, five days a week during daylight saving time and eight hours a day, five days a week during standard time.

An expanded description of PDI’s distribution system can be found in the Asset Management Plan that is included in this Application as Appendix C.

In managing its distribution system assets, PDI’s main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, public & worker safety and customer service requirements. This Application incorporates PDI’s 2013 Capital and Expense Budgets in determining the revenue requirement to bring these plans to fruition. Further information will be provided later in this Application. PDI considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements and system configuration, to determine investment needs of the system. Asset condition studies are performed both internally by staff and in some cases externally by qualified contractors under the LDC's direction. Per the Distribution System Code requirements, 1/3 of the distribution system is visually inspected and assessed annually. In addition to this, an external contractor performs an annual inspection and test for pole condition on a geographic sample. Annually, the entire overhead and portions of the underground system are inspected with infrared technology to identify any operating deficiencies. The results of these condition assessments have been incorporated into PDI's Asset Management Plan filed in Appendix C.

On an annual basis, PDI and its management team reviews capital projects identified for potential implementation and attempts to prioritize each project based on defined criteria on a relative basis. After examining all recommended projects they are listed in order from higher to lower priority and then moved forward based on appropriate financial parameters.

In addition to the capital needs of the network, PDI provides for maintenance planning for the assets. The same preparation and consideration steps are undertaken before the Finance Department establishes the recommended budget amounts. Further information on PDI's Capital and Operation, Maintenance & Administration amounts will follow later in this Application.

Capital Projects:

PDI's capital budget items include:

- **Customer Demand:**

These are projects that PDI undertakes to meet its customer service obligations in accordance with the OEB's Distribution System Code (the "DSC") and PDI's Conditions of Service. Activities include connecting new customers, building new subdivisions and relocating system plant for roadway reconstruction work. Capital contributions toward the cost of these projects are collected by PDI in accordance with the DSC and the provisions of its Conditions of Service. PDI uses the economic evaluation methodology from the DSC to determine the level of capital contribution for each project and those levels are injected into the annual capital budget.

- **Renewal:**

Renewal projects are completed when assets reach their end of useful life or are in a deteriorated condition and must be replaced. PDI completes visual inspections of its plant and performs predictive testing on certain assets where such testing is available, and replaces assets based on these inspection and testing activities if warranted. In some cases the projects involve spot replacement of assets; in others, the projects involve complete asset replacement within a geographic area. New assets require less maintenance, deliver better reliability and reduce safety risks to the general public.

- **Security:**

The probability and impact of asset failure are considered at peak load to determine the risk the failure creates. In these cases, projects are developed to add switching devices or create a backup feeder supply to reduce the risk to typical restoration times for PDI.

- **Capacity:**

Load growth caused by new customer connections and increased demand of existing customers over time can result in a need for capacity improvements on the system. Projects can take the form of new or upgraded feeders, transformers or voltage conversion projects, substations or transformer stations. These projects are not customer-specific, but rather, they benefit many customers.

- **Reliability:**

The main driver for these investments is an analysis of what measures could be undertaken to improve PDI reliability performance as measured by SAIDI, SAIFI and CAIDI indices. These indices are indicators of the reliability of PDI's distribution system. These activities will support maintenance of or improvement to the Service Quality Indices measured and submitted to the OEB each year by PDI. The Asset Management Report provided in Exhibit 2, Appendix C supports the capital and maintenance programs needed to maintain and enhance the reliability of PDI's distribution system.

- **Regulatory Requirements:**

These projects are system capital investments, which are being driven by regulatory requirements. These requirements may include, among others, directions from the OEB, the IESO, the Ministry of Energy or the Ministry of Environment.

- **Substations:**

Substation investments are undertaken to improve or maintain reliability to large numbers of customers and to maintain security and safety at the substations. PDI's long term system plan to eliminate the legacy 4.16 kV system will result in the eventual decommissioning of the 4.16 kV substations.

- **Customer Connections and Metering:**

Capital expenditures in this pool include meter installations, meter upgrades, and the capital components of retail meter verification activities. PDI has completed its smart meter program, as approved by Ontario Regulation 235/08 (Authorized Discretionary Metering Activity & Procurement).

Gross Assets – Property, Plant and Equipment and Accumulated Amortization:

The 2012 Bridge and 2013 Test Years' gross asset balances reflect the capital expenditure programs forecast for both years. Analyses of 2009 to 2013 capital programs are described in detail in PDI's written evidence at Exhibit 2, Tab 3, Schedule 2.

Budget Process:

PDI's Asset Management Plan, which sets out processes for determining the necessary distribution system investments to ensure safe, reliable delivery of electricity to its customers, accompanies this Exhibit as Appendix C.

The budget is prepared annually by management and is reviewed and approved by PDI's Board of Directors. The budget is prepared before the start of each fiscal year. Once approved, it provides a plan against which actual results may be evaluated.

Responsibilities:

- It is the responsibility of the Finance department to co-ordinate the development of the operating budget, capital budget and forecast processes.
- Each department is responsible for preparing its respective operating budget, and forecasts.
- The Vice-President Electric Utility Services is responsible for the capital budget.
- The CEO and CFO are responsible for presenting and recommending the budget to the Board of Directors for approval.

The budget is an important planning tool for PDI. It puts capital and operational plans into a common financial plan. 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.

The departmental Budget Plans represent the output of detailed work plans based on required activities for the year. PDI notes that these Budget Plans address both capital and operating requirements.

VARIANCE ANALYSIS OF RATE BASE

Table 2-2: 2009 Approved Rate Base vs. 2009 Actual Rate

	2009 Board Approved	2009 Actual	Variance
Gross Fixed Assets	72,653,300	70,178,533	(2,474,767)
Accumulated Depreciation	27,616,445	26,568,257	(1,048,188)
Net Book Value	45,036,855	43,610,276	(1,426,579)
Average Net Book Value	44,685,354	43,932,852	(752,502)
Working Capital Expenses	69,403,075	67,750,835	(1,652,240)
Working Capital Allowance (15%)	10,410,461	10,162,625	(247,836)
Rate Base	**55,095,815**	**54,095,477**	**(1,000,338)**

The 2009 actual rate base was $1,000,338 lower than approved by the Board. Average net fixed assets were $752,052 lower than the Board Approved amount of $44,685,354 and working capital allowance was $247,836 lower than the Board Approved amount of $10,410,461.

During 2009 stranded meters with a net book value of $942,092 were transferred from fixed assets to Account 1555, Smart Meter Capital and Recovery Offset Variance Account, Sub-account Stranded Meter Costs. The proposed disposition of the balance of this account is addressed in Exhibit 9 of this Application. The impact of the stranded meters adjustment on 2009 average net book value was a decrease of $471,046. The remaining $281,456 reduction is the result of lower than projected capital expenditures in 2009.

PDI notes that in the 2009 Cost of Service application it projected net capital expenditures of $4,423,000. The actual amount was $3,357,591 or $1,065,409 less than planned. The reduced capital spending was primarily the result of the delay of the completion of a line rebuild on Cumberland Avenue to 2010 (Board Approved amount $600,000), and a delay in completion of the Lansdowne Street West relocation project until 2011 (Board Approved amount $300,000).

Distribution expenses of $6,684,279 were $115,066 lower than the Board Approved amount of $6,799,345 and power supply expenses of $61,066,556 were $1,537,174 lower than the Board Approved amount of $62,603,730.

Table 2-3: 2009 Actual vs. 2010 Actual

	2009 Actual	2010 Actual	Variance
Gross Fixed Assets	70,178,533	74,143,970	3,965,437
Accumulated Depreciation	26,568,257	29,619,451	3,051,194
Net Book Value	43,610,276	44,524,519	914,243
Average Net Book Value	43,932,852	44,067,398	134,546
Working Capital Expenses	67,750,835	70,576,025	2,825,190
Working Capital Allowance (15%)	10,162,625	10,586,404	423,779
Rate Base	**54,095,477**	**54,653,802**	**558,325**

The rate base of $54,653,802 in 2010 was an increase of $558,325 comprised of an increase in net fixed assets of $134,546 and an increase in working capital allowance of $423,779.

During 2009 and 2010 stranded meters with a net book value of $2,006,479 were transferred from fixed assets to Account 1555, Smart Meter Capital and Recovery Offset Variance Account, Sub-account Stranded Meter Costs. The impact of the stranded meters adjustment on 2010 average net book value was a decrease of $1,474,286.

The increase in average net fixed assets, excluding the stranded meters adjustment, was $1,608,832. This increase is due to capital expenditures. Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2.

Distribution expenses were $383,757 lower than 2009 and power supply expenses were $3,208,947 higher than the previous year.

Table: 2-4: 2010 Actual vs. 2011 Actual

	2010 Actual	2011 Actual	Variance
Gross Fixed Assets	74,143,970	79,001,224	4,857,254
Accumulated Depreciation	29,619,451	33,043,912	3,424,461
Net Book Value	44,524,519	45,957,312	1,432,793
Average Net Book Value	44,067,398	45,240,916	1,173,518
Working Capital Expenses	70,576,025	75,911,382	5,335,357
Working Capital Allowance (15%)	10,586,404	11,386,707	800,303
Rate Base	**54,653,802**	**56,627,623**	**1,973,821**

Rate base increased by $1,973,821 in 2011 from $54,653,802 to $56,627,623 due to an increase in net fixed assets of $1,173,518 and an increase in working capital allowance of $800,303. Distribution expenses increased by $674,968 and power supply expenses increased by $4,660,389.

Table 2-5: 2012 Bridge Year (CGAAP) vs. 2011 Actual

	2011 Actual	2012 CGAAP Bridge	Variance
Gross Fixed Assets	79,001,224	92,046,556	13,045,332
Accumulated Depreciation	33,043,912	38,763,738	5,719,826
Net Book Value	45,957,312	53,282,818	7,325,506
Average Net Book Value	45,240,916	49,620,065	4,379,149
Working Capital Expenses	75,911,382	90,984,692	15,073,310
Working Capital Allowance (15%)	11,386,707	13,647,704	2,260,997
Rate Base	**56,627,623**	**63,267,769**	**6,640,146**

In 2012, the forecast rate base has increased by $6,640,146 from 2011. The average net book value of assets increased by $4,379,149. During 2012 smart meter assets were transferred from Account 1555 to fixed assets. The gross value of the smart meter assets transferred was $6,199,313 and the associated accumulated amortization was $1,551,124. The remaining increase in gross fixed assets includes $2,494,020 relating to prior year expenditures on capital projects that were completed in 2012 and transferred from work in process, and $4,351,999 for current year capital expenditures.

The 2012 working capital allowance increased by $2,260,997 from 2011. Distribution expenses increased by $506,329 and power supply expenses increased by $14,566,982. Detailed calculations of power supply expenses are provided in Exhibit 2 Tab 4 Schedule 1. The main driver of the increase is the cost of the commodity which is based on the forecast in the Ontario Energy Board *Regulated Price Plan Price Report May 1, 2012 to April 30, 2013*.

Table 2-6: 2013 Test Year (CGAAP) vs. 2012 Bridge Year (CGAAP)

	2012 CGAAP Bridge	2013 CGAAP Test	Variance
Gross Fixed Assets	92,046,556	96,632,056	4,585,500
Accumulated Depreciation	38,763,738	41,437,594	2,673,856
Net Book Value	53,282,818	55,194,462	1,911,644
Average Net Book Value	49,620,065	54,238,640	4,618,575
Working Capital Expenses	90,984,692	92,858,402	1,873,710
Working Capital Allowance (15%)	13,647,704		
Working Capital Allowance (13%)		12,071,592	(1,576,112)
Rate Base	**63,267,769**	**66,310,232**	**3,042,463**

The increase in rate base from 2012 to 2013 is $3,042,463. The average net book value of fixed assets is forecast to increase by $4,618,575 and working capital allowance is forecast to decrease by $1,576,112. The working capital allowance is decreasing from 15% in 2012 to 13% in 2013, distribution expenses are forecast to increase by $1,861,973 and power supply expenses are forecast to increase by $11,737.

ACCOUNTING CHANGES UNDER CGAAP

As summarized in Exhibit 1, Tab 2 Schedule 2, PDI has elected to defer implementation to IFRS until January 1, 2014. Accordingly, in this application, PDI has prepared its 2013 Test Year Budget on the basis of CGAAP while adopting prospectively MIFRS like regulatory accounting changes effective January 1, 2013. A summary of the key differences between IFRS, IFRS modified for rate regulatory purposes and CGAAP is summarized below together with an explanation of how PDI has reflected the necessary MIFRS requirements in the 2013 Test Year of this application.

(i) Measurement of Cost and Continuity of the Rate Base

Under IFRS, Sub paragraph 19(d) of IAS 16, capitalization of administration and other general overhead costs is not permitted as an element of cost for property plant and equipment ("PP&E"). PDI, like many other LDC's, has historically capitalized a portion of its administrative costs under CGAAP. To achieve continuity of the rate base, which is calculated utilizing the regulated net book value of property plant and equipment, LDC's may elect under the Deemed Cost provisions of IFRS 1. This election permits LDC's to deem the carrying amount of its PP&E as cost on transition to IFRS, regardless if the amount includes balances otherwise not eligible as cost for PP&E under IFRS. In this application PDI has achieved continuity of its rate base from its last rebasing period through to 2013 by remaining on CGAAP. For 2013 PDI has prospectively updated its capitalization rates eliminating capitalization of administrative costs consistent with the requirements of IAS 16. Further explanation of PDI's capitalization policy is provided in the next schedule at Exhibit 2, Tab 1, Schedule 4. By adopting this approach, for the purposes of this application there is no difference to record in variance account 1575 IFRS – CGAAP Transitional PP&E.

(ii) Componentization and Depreciation

IAS 16 requires that each item of property, plant and equipment with a cost that is significant in relation to the total cost of the items be depreciated separately. The depreciable amount of an asset is to be allocated on a systematic basis over its useful life. To assist electricity distributors with transition to IFRS the OEB commissioned a depreciation study EB-2010-0178, or the "Kinetrics Report" provides asset service life information which PDI has utilized in prospectively adopting new depreciation periods for its assets. Under IFRS the residual value and useful life of an asset must be reviewed at least annually. PDI's compliance with the IFRS requirements related to depreciation are discussed further in Exhibit 4.

(iii) Asset Retirement Obligations

IAS 37 requires asset retirement obligations be accrued to cover the cost of dismantling and removing PP&E items at the end of their useful life. The present value of these obligations is to be included in PP&E and amortized over the life of the asset. For rate setting purposes, the OEB requires distributors to identify separately in their rate applications the depreciation expense associated with amortizing asset retirement costs. PDI has assessed its PP&E and determined it has no planned retirements that require accrual of such a provision or inclusion in the cost of PP&E for amortization. Accordingly, depreciation expense in this rate application does not include any amortization expense for decommissioning or asset retirement reserves.

(iv) Gains and losses on PP&E

Modified IFRS requires a gain or loss on disposal of an asset pool of like assets to be charged or credited to income, and gains or losses to be reclassified as depreciation and disclosed separately. Where a distributor has reported a gain or loss on disposal of individual assets the amount should be identified separately in rate filings for review by the Board. PDI has not accounted for or identified any gains or losses on disposals in the 2013 Test Year that affect the revenue requirement in this application.

(v) Capitalization of Borrowing Costs

IAS 23 paragraphs 8 and 9 state that "an entity shall capitalize borrowing costs that are directly attributable to the acquisition, construction or production of a qualifying asset as part of the cost of that asset". Rate regulated reporting limits capitalization of interest to the Board's published interest rates for non arms length debt. PDI is not planning on incurring additional debt expense in 2013 related to the acquisition or construction of new assets. Accordingly PDI has not capitalized any interest in the 2013 Test Year. PDI did not capitalize any interest from 2009 through 2012.

(vi) Intangible Assets

IFRS requires certain assets that were previously included in PP&E to be recorded as intangible assets. The OEB requires distributors to include such intangible assets in rate base and the amortization expense in depreciation expense. PDI has complied with this requirement.

(viii) Customer Contributions

IFRS requires customer contributions to be recorded as revenue or deferred revenue instead of an offset to capital cost. In all years presented in this application PDI has treated customer contributions as an offset to capital cost, resulting in lower depreciation expense. The impact on the revenue requirement and rate base is immaterial whether treated as a reduction of PP&E cost / depreciation expense or as deferred revenue offset against the rate base and amortized into income.

CAPITALIZATION POLICY

(a) Capitalization of Burdens

As indicated earlier in Schedule 3 of this Exhibit, under IFRS, Sub paragraph 19(d) of IAS 16, capitalization of administration and other general overhead costs is not permitted as an element of cost for property plant and equipment ("PP&E"). PDI, like many other LDC's, has historically capitalized a portion of its administrative costs under CGAAP.

As outlined in Exhibit 1, Tab 1, Schedule 10, prior to 2012 corporate administrative costs were included in a burden rate and charged across both operating and capital activity to PDI from its affiliate service provider PUSI. For purposes of this rate application as explained in Exhibit 1, the operating portion of these costs are now being allocated to the administrative section of the USoA to achieve more comparability and transparency in our reporting. Up to and including 2012, capital projects were charged with a share of these corporate administrative costs. The amount applicable to the 2012 Bridge Year is $901,927. For 2013 this amount is estimated to be $950,363 and is now included in "General Administrative Salary and Expenses GL Account 5615", instead of being capitalized as it would have been previously.

For work that is directly attributable to capital activities, PDI will continue to be allocated a cost from its affiliate PUSI that will include overheads as described below. This cost includes direct labour, material from inventory, and vehicle costs directly associated with the capital job. The direct labour cost applied to capital jobs is based on the hours of work performed plus an amount for related burdens such as the cost of health benefits, CPP, EI, and other direct departmental burdens.

In accordance with the Board's filing guidelines, the capitalization of overheads as required in Appendix 2-D is provided below:

Table 2-7: Overhead Expense (Appendix 2-D)

Appendix 2-D
Overhead Expense

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that are currently

Nature of the Overhead Costs	(A) [1] Dollar	(B) Dollar Impact on PP&E Bridge Year	(C) Dollar Impact on PP&E Test Year	(D) Dollar Impact - PP&E Variance Test versus Bridge	(E) [1] Dollar Impact - PP&E Variance st versus Histo	(F) Directly Attributable? (Y/N)	(G) Reasons why the overhead costs are allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead
employee benefits				-			
costs of site preparation				-			
initial delivery and handling costs				-			
costs of testing whether the asset is functioning properly				-			
professional fees				-			
				-			
costs of opening a new facility				-			
costs of introducing a new product or service (including costs of advertising and promotional activities)				-			
costs of conducting business in a new location or with a new class of customer (including costs of staff training)				-			
administration and other general overhead costs		901,927	-	- 901,927		N	Capitalized in 2012 under CGAAP
				-			
				-			
				-			
Insert description of additional item(s) and new rows if needed.				-			
Total	$ -	$ 901,927	$ -	-$ 901,927	$ -		

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that were capitalized on self-constructed assets under CGAAP but are no longer capitalized under MIFRS or an alternate accounting standard and are included in OM&A.

Nature of the Overhead Costs	(A) [1] Dollar Impact on Historic Year	(B) Dollar Impact on OM&A Bridge Year	(C) Dollar Impact on OM&A Test Year	(D) Dollar Impact - OM&A Variance Test versus Bridge	(E) [1] Dollar OM&A Variance Test versus Historic	(F) Directly Attributable? (Y/N)	(G) Reasons why the overhead costs are not capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead
employee benefits				-			
costs of site preparation				-			
initial delivery and handling costs				-			
costs of testing whether the asset is functioning properly				-			
professional fees				-			
costs of opening a new facility				-			
costs of introducing a new product or service (including costs of advertising and promotional activities)				-			
costs of conducting business in a new location or with a new class of customer (including costs of staff training)				-			
administration and other general overhead costs		-	950,363	950,363		N	No longer capitalized with MIFRS policy under CGAAP
				-			
				-			
				-			
Insert description of additional item(s) and new rows if needed.				$ -			
Total	$ -	$ -	$ 950,363	$ 950,363	$ -		

(b) Capitalization Policy (2009 – 2012)

PDI has historically applied the following general capitalization policies and principles based on Canadian Generally Accepted Accounting Principles ("CGAAP"), as well as guidelines set out by the Ontario Energy Board, where applicable. As described earlier in this section for 2013 and subsequent years capitalization will conform to the Modified International Financial Reporting Standards (MIFRS). The capitalization policy prior to 2013 was as follows:

Definition of an Asset

CICA Handbook paragraph 1000.29 defines assets as economic resources controlled by an entity as a result of past transactions or events from which future economic benefits may be obtained. Assets have three essential characteristics:

1. They embody a future benefit that involves a capacity, singly or in combination with other assets, in the case of profit-oriented enterprises, to contribute directly or indirectly to future net cash flows and in the case of not-for-profit organizations, to provide services.

2. The entity can control access to the benefit.

3. The transaction or event giving rise to the entity's right to, or control of, the benefit has already incurred.

In addition, in identifying a benefit there must be:

A. An ability to earn income or supply a service.

B. A reasonable expectation that the benefit will be provided in future periods.

C. The future period must be identifiable and greater than one year.

The CICA Handbook specifically defines a capital asset as identifiable assets comprising property, plant and equipment and intangible properties that meet all of the following criteria:

1. Are held for use in the production of supply of goods and services, for rental to others, for administrative purposes or for the development, construction, maintenance or repair to other capital assets.

2. Have been acquired, constructed or developed with the intention of being used on a continuing basis.

3. Are not intended for sale in the ordinary course of business.

In regard to whether to capitalize intangible property costs, the CICA Handbook states that a degree of certainty as to future benefits to be derived from costs attributed to developing intangible properties varies and in many cases, the expected future benefits may be too uncertain to justify asset recognition. However, when future benefits are reasonably assured, such costs should be capitalized (subject to materiality considerations) (CICA s 3062.07).

2. Capitalizing Upgrades and Improvements – "Betterments"

Betterment is defined as the cost incurred to enhance the service potential of a capital asset. Service potential may be enhanced:

- when there is an increase in the previously assessed physical output or service capacity,
- associated operating costs are lowered,
- the life or useful life is extended, or
- the quality of output is improved.

The definition of betterment is more difficult to apply to tangible capital assets that are complex networks of systems and are very long-lived because identifying expenditures that extend their lives may not be practicable.

For complex network systems the following distinctions can be used to identify maintenance and betterments:

1. Maintenance and repairs maintain the predetermined service potential of a tangible capital asset for a given useful life. Such expenditures are expenses in the period in which they are made.
   a. *A repair or replacement is comprised of the repair of an existing component, or the replacement of an existing component with a similar component.*

Betterments increase service potential (and may or may not increase the useful life of a tangible capital asset). Such expenditures would be included in the cost of the related asset.

3. Capitalization Threshold

Theoretically, any item that meets the definition and recognition criteria would be recorded as a TCA. In practical terms departments shall treat as a capital asset any asset that in addition to the above conditions has a useful life in excess of one year and a per item cost greater than $5,000. This threshold may be changed at the discretion of the CFO and on an item-by-item basis if a department wishes to capitalize an amount lower than the amount prescribed above in order to ensure all material capital assets are included in the financial statements. Assets below the threshold are expensed in the period of purchase.

Land will always be capitalized, regardless of cost.

Table 2-8: Characteristics to Consider

Repairs = Expense	Betterments = Capital Assets
All items – life less than 1 year	Life of more than 1 year
All items under $5,000	Items greater than $5,000
Replacement of individual components of a TCA due to age, “wear-and-tear” and damage in order to maintain the TCA in an operating condition without significantly enhancing functionality, capacity, usability and efficiency	Replacement of motor and parts that prolong the useful life
System and equipment repairs, in cases where the service potential of a building isn’t enhanced, repairs – boilers, elevators, control system, etc.	The cost results in an increase in the capacity of the asset
Building repairs that are required in the normal maintenance process	The efficiency of the asset is increased by more than 10%
Repairs to restore assets damaged by fire, flood or similar events, to a condition just prior to the event	Significantly changes the character of the asset
	Reduction in operating cost

GROSS ASSET CONTINUITY STATEMENTS

The Gross Asset Continuity Statements appear on the following pages.

GROSS ASSETS – PROPERTY, PLANT & EQUIPMENT and ACCUMULATED AMORTIZATION:

Table 2-9: Fixed Asset Continuity Schedule - 2009

			Cost				Accumulated Depreciation				
OEB	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1611	Computer Software (Formally known as Account 1925)		$ 57,747			$ 57,747	-$ 57,747			-$ 57,747	$ -
1612	Land Rights (Formally known as Account 1906)					$ -				$ -	$ -
1805	Land		$ 134,968			$ 134,968				$ -	$ 134,968
1808	Buildings		$ 296,412			$ 296,412	-$ 45,530	-$ 7,802		-$ 53,332	$ 243,080
1810	Leasehold Improvements					$ -				$ -	$ -
1815	Transformer Station Equipment >50 kV					$ -				$ -	$ -
1820	Distribution Station Equipment <50 kV		$ 3,259,205	$ 53,340		$ 3,312,545	-$ 770,169	-$ 124,948		-$ 895,117	$ 2,417,428
1825	Storage Battery Equipment					$ -				$ -	$ -
1830	Poles, Towers & Fixtures		$ 19,274,297	$ 580,780		$ 19,855,077	-$ 7,123,608	-$ 910,080		-$ 8,033,688	$ 11,821,389
1835	Overhead Conductors & Devices		$ 6,132,245	$ 633,295		$ 6,765,540	-$ 1,309,088	-$ 259,986		-$ 1,569,074	$ 5,196,466
1840	Underground Conduit		$ 12,905,907	$ 581,864		$ 13,487,771	-$ 3,901,929	-$ 553,183		-$ 4,455,112	$ 9,032,659
1845	Underground Conductors & Devices		$ 3,630,276	$ 592,675		$ 4,222,951	-$ 353,067	-$ 107,948		-$ 461,015	$ 3,761,936
1850	Line Transformers		$ 15,008,971	$ 997,484	-$ 37,861	$ 15,968,594	-$ 5,242,714	-$ 661,373	$ -	-$ 5,904,087	$ 10,064,507
1855	Services (Overhead & Underground)		$ 11,072,442	$ 616,331		$ 11,688,773	-$ 2,600,764	-$ 360,660		-$ 2,961,424	$ 8,727,349
1860	Meters		$ 3,034,971	$ 402,177	-$ 1,679,841	$ 1,757,307	-$ 1,255,278	-$ 57,011	$ 737,749	-$ 574,540	$ 1,182,767
1860	Meters (Smart Meters)					$ -				$ -	$ -
1905	Land					$ -				$ -	$ -
1908	Buildings & Fixtures					$ -				$ -	$ -
1910	Leasehold Improvements					$ -				$ -	$ -
1915	Office Furniture & Equipment (10 years)					$ -				$ -	$ -
1915	Office Furniture & Equipment (5 years)					$ -				$ -	$ -
1920	Computer Equipment - Hardware					$ -				$ -	$ -
1955	Communications Equipment					$ -				$ -	$ -
1955	Communication Equipment (Smart Meters)					$ -				$ -	$ -
1960	Miscellaneous Equipment		$ 82,385			$ 82,385	-$ 49,431	-$ 16,477		-$ 65,908	$ 16,477
1970	Load Management Controls Customer Premises		$ 1,633,219			$ 1,633,219	-$ 1,373,891	-$ 163,322		-$ 1,537,213	$ 96,006
1975	Load Management Controls Utility Premises					$ -				$ -	$ -
1980	System Supervisor Equipment					$ -				$ -	$ -
1985	Miscellaneous Fixed Assets					$ -				$ -	$ -
1995	Contributions & Grants		-$ 8,184,401	-$ 900,355		-$ 9,084,756				$ -	-$ 9,084,756
	Sub-total		**$ 68,338,644**	**$ 3,557,591**	**-$ 1,717,702**	**$ 70,178,533**	**-$ 24,083,216**	**-$ 3,222,790**	**$ 737,749**	**-$ 26,568,257**	**$ 43,610,276**
2055	Contract work in progress-electric		$ 2,405,424	$ 6,842,616	-$ 4,457,946	$ 4,790,094				$ -	$ 4,790,094
	Total		**$ 70,744,068**	**$ 10,400,207**	**-$ 6,175,648**	**$ 74,968,627**	**-$ 24,083,216**	**-$ 3,222,790**	**$ 737,749**	**-$ 26,568,257**	**$ 48,400,370**

	Transportation
	Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 3,222,790

Table 2-10: Fixed Asset Continuity Schedule - 2010

Year **2010**

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ 57,747			$ 57,747	-$ 57,747			-$ 57,747	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 134,968			$ 134,968	$ -			$ -	$ 134,968
47	1808	Buildings		$ 296,412	$ 115,146		$ 411,558	-$ 53,332	-$ 10,105		-$ 63,437	$ 348,121
13	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 3,312,545	$ 143,385		$ 3,455,930	-$ 895,117	-$ 133,283		-$ 1,028,400	$ 2,427,530
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 19,855,077	$ 1,722,528		$ 21,577,605	-$ 8,033,688	-$ 941,162		-$ 8,974,850	$ 12,602,755
47	1835	Overhead Conductors & Devices		$ 6,765,540	$ 1,153,716		$ 7,919,256	-$ 1,569,074	-$ 298,718		-$ 1,867,792	$ 6,051,464
47	1840	Underground Conduit		$ 13,487,771	$ 781,958		$ 14,269,729	-$ 4,455,112	-$ 585,370		-$ 5,040,482	$ 9,229,247
47	1845	Underground Conductors & Devices		$ 4,222,951	$ 390,979		$ 4,613,930	-$ 461,015	-$ 124,062		-$ 585,077	$ 4,028,853
47	1850	Line Transformers		$ 15,968,594	$ 1,547,126		$ 17,515,720	-$ 5,904,087	-$ 792,428		-$ 6,696,515	$ 10,819,205
47	1855	Services (Overhead & Underground)		$ 11,688,773	$ 785,098		$ 12,473,871	-$ 2,961,424	-$ 384,371		-$ 3,345,795	$ 9,128,076
47	1860	Meters		$ 1,757,307	$ 155,039	-$ 1,380,993	$ 531,353	-$ 574,540	-$ 21,351	$ 273,974	-$ 321,917	$ 209,436
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ 82,385			$ 82,385	-$ 65,908	-$ 16,477		-$ 82,385	$ -
	1970	Load Management Controls Customer Premises		$ 1,633,219			$ 1,633,219	-$ 1,537,213	-$ 17,841		-$ 1,555,054	$ 78,165
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 9,084,756	-$ 1,448,545		-$ 10,533,301	$ -			$ -	-$ 10,533,301
		Sub-total		**$ 70,178,533**	**$ 5,346,430**	**-$ 1,380,993**	**$ 74,143,970**	**-$ 26,568,257**	**-$ 3,325,168**	**$ 273,974**	**-$ 29,619,451**	**$ 44,524,519**
	2055	Contract work in progress-electric		$ 4,790,094	$ 5,486,295	-$ 6,794,975	$ 3,481,414				$ -	$ 3,481,414
		Total		**$ 74,968,627**	**$ 10,832,725**	**-$ 8,175,968**	**$ 77,625,384**	**-$ 26,568,257**	**-$ 3,325,168**	**$ 273,974**	**-$ 29,619,451**	**$ 48,005,933**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 3,325,168

Table 2-11: Fixed Asset Continuity Schedule – 2011

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)		$ 57,747			$ 57,747	-$ 57,747			-$ 57,747	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ -			$ -	$ -			$ -	$ -
N/A	1805	Land		$ 134,968			$ 134,968	$ -			$ -	$ 134,968
47	1808	Buildings		$ 411,558	$ 33,257		$ 444,815	-$ 63,437	-$ 10,770		-$ 74,207	$ 370,608
13	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 3,455,930	$ 10,321		$ 3,466,251	-$ 1,028,400	-$ 131,849		-$ 1,160,249	$ 2,306,002
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 21,577,605	$ 1,162,945		$ 22,740,550	-$ 8,974,850	-$ 980,155		-$ 9,955,005	$ 12,785,545
47	1835	Overhead Conductors & Devices		$ 7,919,256	$ 1,246,554		$ 9,165,810	-$ 1,867,792	-$ 341,743		-$ 2,209,535	$ 6,956,275
47	1840	Underground Conduit		$ 14,269,729	$ 762,011		$ 15,031,740	-$ 5,040,482	-$ 606,382		-$ 5,646,864	$ 9,384,876
47	1845	Underground Conductors & Devices		$ 4,613,930	$ 544,162		$ 5,158,092	-$ 585,077	-$ 134,226		-$ 719,303	$ 4,438,789
47	1850	Line Transformers		$ 17,515,720	$ 1,056,375		$ 18,572,095	-$ 6,696,515	-$ 752,903		-$ 7,449,418	$ 11,122,677
47	1855	Services (Overhead & Underground)		$ 12,473,871	$ 1,072,528		$ 13,546,399	-$ 3,345,795	-$ 414,053		-$ 3,759,848	$ 9,786,551
47	1860	Meters		$ 531,353	$ 379,911		$ 911,264	-$ 321,917	-$ 36,453		-$ 358,370	$ 552,894
47	1860	Meters (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment		$ 82,385			$ 82,385	-$ 82,385			-$ 82,385	$ -
	1970	Load Management Controls Customer Premises		$ 1,633,219			$ 1,633,219	-$ 1,555,054	-$ 15,927		-$ 1,570,981	$ 62,238
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants		-$ 10,533,301	-$ 1,410,810		-$ 11,944,111	$ -			$ -	-$ 11,944,111
		Sub-total		**$ 74,143,970**	**$ 4,857,254**	**$ -**	**$ 79,001,224**	**-$ 29,619,451**	**-$ 3,424,461**	**$ -**	**-$ 33,043,912**	**$ 45,957,312**
	2055	Contract work in progress-electric		$ 3,481,414	$ 6,203,278	-$ 6,268,063	$ 3,416,629				$ -	$ 3,416,629
		Total		**$ 77,625,384**	**$ 11,060,532**	**-$ 6,268,063**	**$ 82,417,853**	**-$ 29,619,451**	**-$ 3,424,461**	**$ -**	**-$ 33,043,912**	**$ 49,373,941**

		Less: *Fully Allocated Depreciation*	
Transfer Smart Meters from 1555 to Various Accounts	$ 6,199,313	**Transfer Smart Meters from 1555**	-$ 1,551,124
Revised Closing Balance Forward	$ 88,617,166	**Revised Closing Balance Forward**	-$ 34,595,036

Table 2-12: Fixed Asset Continuity Schedule – 2012 (CGAAP)

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 509,711	$ 625,000		$ 1,134,711	-$ 361,883	-$ 132,893		-$ 494,776	$ 639,935
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 134,968			$ 134,968	$ -			$ -	$ 134,968
47	1808	Buildings	$ 444,815	$ 21,516		$ 466,331	-$ 74,207	-$ 11,391		-$ 85,598	$ 380,733
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 3,466,251	$ 219,244		$ 3,685,495	-$ 1,160,249	-$ 136,284		-$ 1,296,533	$ 2,388,962
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 22,740,550	$ 897,108		$ 23,637,658	-$ 9,955,005	-$ 1,009,762		-$ 10,964,767	$ 12,672,891
47	1835	Overhead Conductors & Devices	$ 9,165,810	$ 1,525,501		$ 10,691,311	-$ 2,209,535	-$ 377,233		-$ 2,586,768	$ 8,104,543
47	1840	Underground Conduit	$ 15,031,740	$ 1,199,801		$ 16,231,541	-$ 5,646,864	-$ 630,111		-$ 6,276,975	$ 9,954,566
47	1845	Underground Conductors & Devices	$ 5,158,092	$ 470,913		$ 5,629,005	-$ 719,303	-$ 140,524		-$ 859,827	$ 4,769,178
47	1850	Line Transformers	$ 18,572,095	$ 1,393,682		$ 19,965,777	-$ 7,449,418	-$ 843,882		-$ 8,293,300	$ 11,672,477
47	1855	Services (Overhead & Underground)	$ 13,546,399	$ 1,514,450		$ 15,060,849	-$ 3,759,848	-$ 433,332		-$ 4,193,180	$ 10,867,669
47	1860	Meters	$ 911,264	$ 292,804		$ 1,204,068	-$ 358,370	-$ 48,165		-$ 406,535	$ 797,533
47	1860	Meters (Smart Meters)	$ 5,702,472			$ 5,702,472	-$ 1,221,004	-$ 380,165		-$ 1,601,169	$ 4,101,303
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 44,877			$ 44,877	-$ 25,984	-$ 8,975		-$ 34,959	$ 9,918
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 82,385			$ 82,385	-$ 82,385			-$ 82,385	$ -
	1970	Load Management Controls Customer Premises	$ 1,633,219	$ 5,000		$ 1,638,219	-$ 1,570,981	-$ 15,985		-$ 1,586,966	$ 51,253
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 11,944,111	-$ 1,319,000		-$ 13,263,111	$ -			$ -	-$ 13,263,111
		Sub-total	**$ 85,200,537**	**$ 6,846,019**	**$ -**	**$ 92,046,556**	**-$ 34,595,036**	**-$ 4,168,702**	**$ -**	**-$ 38,763,738**	**$ 53,282,818**
	2055	Contract work in progress-electric	$ 3,416,629	$ 922,609	-$ 3,416,629	$ 922,609				$ -	$ 922,609
		Total	**$ 88,617,166**	**$ 7,768,628**	**-$ 3,416,629**	**$ 92,969,165**	**-$ 34,595,036**	**-$ 4,168,702**	**$ -**	**-$ 38,763,738**	**$ 54,205,427**

Table 2-13: Fixed Asset Continuity Statement – 2013 (CGAAP with Kinetrics useful life)

Appendix 2-B
Fixed Asset Continuity Schedule

Year 2013 CGAAP Kinetrics useful life

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 1,134,711			$ 1,134,711	-$ 494,776	-$ 195,393		-$ 690,169	$ 444,542
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 134,968	$ 130,000		$ 264,968	$ -			$ -	$ 264,968
47	1808	Buildings	$ 466,331	$ 40,000		$ 506,331	-$ 85,598	-$ 9,482		-$ 95,080	$ 411,251
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 3,685,495	$ 75,000		$ 3,760,495	-$ 1,296,533	-$ 142,806		-$ 1,439,339	$ 2,321,156
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 23,637,658	$ 765,050		$ 24,402,708	-$ 10,964,767	-$ 543,558		-$ 11,508,325	$ 12,894,383
47	1835	Overhead Conductors & Devices	$ 10,691,311	$ 1,669,500		$ 12,360,811	-$ 2,586,768	-$ 206,478		-$ 2,793,246	$ 9,567,565
47	1840	Underground Conduit	$ 16,231,541	$ 625,200		$ 16,856,741	-$ 6,276,975	-$ 329,225		-$ 6,606,200	$ 10,250,541
47	1845	Underground Conductors & Devices	$ 5,629,005	$ 252,000		$ 5,881,005	-$ 859,827	-$ 94,941		-$ 954,768	$ 4,926,237
47	1850	Line Transformers	$ 19,965,777	$ 969,750		$ 20,935,527	-$ 8,293,300	-$ 485,443		-$ 8,778,743	$ 12,156,784
47	1855	Services (Overhead & Underground)	$ 15,060,849	$ 1,034,000		$ 16,094,849	-$ 4,193,180	-$ 224,042		-$ 4,417,222	$ 11,677,627
47	1860	Meters	$ 1,204,068	$ 205,000		$ 1,409,068	-$ 406,535	-$ 51,797		-$ 458,332	$ 950,736
47	1860	Meters (Smart Meters)	$ 5,702,472			$ 5,702,472	-$ 1,601,169	-$ 380,163		-$ 1,981,332	$ 3,721,140
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 44,877			$ 44,877	-$ 34,959	-$ 6,735		-$ 41,694	$ 3,183
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 82,385			$ 82,385	-$ 82,385			-$ 82,385	$ -
	1970	Load Management Controls Customer Premises	$ 1,638,219			$ 1,638,219	-$ 1,586,966	-$ 3,793		-$ 1,590,759	$ 47,460
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 13,263,111	-$ 1,180,000		-$ 14,443,111	$ -			$ -	-$ 14,443,111
		Sub-total	**$ 92,046,556**	**$ 4,585,500**	**$ -**	**$ 96,632,056**	-$ 38,763,738	**-$ 2,673,856**	**$ -**	**-$ 41,437,594**	**$ 55,194,462**
	2055	Contract work in progress-electric	$ 922,609	$ 1,271,000	-$ 787,609	$ 1,406,000				$ -	$ 1,406,000
		Total	**$ 92,969,165**	**$ 5,856,500**	**-$ 787,609**	**$ 98,038,056**	**-$ 38,763,738**	**-$ 2,673,856**	**$ -**	**-$ 41,437,594**	**$ 56,600,462**

Table 2-14: Gross Assets

	Description	2009 Board Approved	2009 Actual	Variance 2009 Approved to 2009 Actual	2010 Actual	Variance 2010 Actual to 2009 Actual	2011 Actual	Variance 2011 Actual to 2010 Actual	2012 CGAAP Bridge	Variance 2012 CGAAP Actual to 2011 Actual	2013 CGAAP Test	Variance 2013 CGAAP Actual to 2012 CGAAP
1805	Land	134,968	134,968	-	134,968	-	134,968	-	134,968	-	264,968	130,000
1808	Buildings & fixtures	421,412	296,412	(125,000)	411,558	115,146	444,815	33,257	466,331	21,516	506,331	40,000
1820	Distribution station equip.	2,208,053	3,312,545	1,104,492	3,455,930	143,385	3,466,251	10,321	3,685,495	219,244	3,760,495	75,000
1830	Poles, towers, fixtures	20,999,862	19,855,077	(1,144,785)	21,577,605	1,722,528	22,740,550	1,162,945	23,637,658	897,108	24,402,708	765,050
1835	OH conductors & devices	7,348,626	6,765,540	(583,086)	7,919,256	1,153,716	9,165,810	1,246,554	10,691,311	1,525,501	12,360,811	1,669,500
1840	UG conduit	13,648,735	13,487,771	(160,964)	14,269,729	781,958	15,031,740	762,011	16,231,541	1,199,801	16,856,741	625,200
1845	UG conductors & devices	4,093,689	4,222,951	129,262	4,613,930	390,979	5,158,092	544,162	5,629,005	470,913	5,881,005	252,000
1850	Line transformers	16,238,285	15,968,594	(269,691)	17,515,720	1,547,126	18,572,095	1,056,375	19,965,777	1,393,682	20,935,527	969,750
1855	Services	11,662,283	11,688,773	26,490	12,473,871	785,098	13,546,399	1,072,528	15,060,849	1,514,450	16,094,849	1,034,000
1860	Meters	4,746,661	1,757,307	(2,989,354)	531,353	(1,225,954)	911,264	379,911	1,204,068	292,804	1,409,068	205,000
1860	Smart meters	-	-	-	-	-	-	-	5,702,472	5,702,472	5,702,472	-
	Distribution Plant	81,502,574	77,489,938	(4,012,636)	82,903,920	5,413,982	89,171,984	6,268,064	102,409,475	13,237,491	108,174,975	5,765,500
1611	Computer software	57,747	57,747	-	57,747	-	57,747	-	1,134,711	1,076,964	1,134,711	-
1920	Computer hardware	-	-	-	-	-	-	-	44,877	44,877	44,877	-
1960	Miscellaneous equipment	82,385	82,385	-	82,385	-	82,385	-	82,385	-	82,385	-
1970	Load management controls	1,653,219	1,633,219	(20,000)	1,633,219	-	1,633,219	-	1,638,219	5,000	1,638,219	-
	General Plant	1,793,351	1,773,351	(20,000)	1,773,351	-	1,773,351	-	2,900,192	1,126,841	2,900,192	-
1995	Contributions & grants	(10,642,625)	(9,084,756)	1,557,869	(10,533,301)	(1,448,545)	(11,944,111)	(1,410,810)	(13,263,111)	(1,319,000)	(14,443,111)	(1,180,000)
	Total before WIP	**72,653,300**	**70,178,533**	**(2,474,767)**	**74,143,970**	**3,965,437**	**79,001,224**	**4,857,254**	**92,046,556**	**13,045,332**	**96,632,056**	**4,585,500**
2055	Work in process	2,098,787	4,790,094	2,691,307	3,481,414	(1,308,680)	3,416,629	(64,785)	922,609	(2,494,020)	1,406,000	483,391
	Total Gross Fixed Assets	**74,752,087**	**74,968,627**	**216,540**	**77,625,384**	**2,656,757**	**82,417,853**	**4,792,469**	**92,969,165**	**10,551,312**	**98,038,056**	**5,068,891**

Variance Analysis on Gross Assets:

The Gross Asset Variance analysis for the variances in Table 2-14 of Exhibit 2, Tab 2, Schedule 2 is provided as follows.

2009 Board Approved vs. 2009 Actual

The 2009 Board Approved Fixed Asset value, excluding work in process, was $72,653,300. The actual 2009 ending balance was $70,178,533, a decrease of $2,474,767 from the Board Approved amount. During 2009 stranded meters with a cost of $1,679,841 were transferred from fixed assets to the smart meter deferral account. The remaining variance of $794,926 is due to lower than projected capital expenditures during the 2008 bridge year and 2009 test year. The reduced capital spending was primarily the result of the delay of the completion of a line rebuild on Cumberland Avenue to 2010 (Board Approved amount $600,000), and a delay in completion of the Lansdowne Street West relocation project to 2011 (Board Approved amount $300,000).

2009 Actual vs. 2010 Actual

The variance in gross assets for 2009 Actual compared to 2010 Actual is $3,965,437. During 2010 stranded meters with a cost of $1,338,360 net of capital contributions were transferred from fixed assets to the smart meter deferral account. The remaining variance of $5,303,797 is due to capital expenditures during 2010 as described in Exhibit 2 Tab 3 Schedule 2.

2010 Actual vs. 2011 Actual

The increase of $4,857,254 for 2011 is a result of capital spending during the year as described in Exhibit 2 Tab 3 Schedule 2.

2011 Actual vs. 2012 Bridge Year (CGAAP)

The variances in gross assets for 2011 Actual compared to the 2012 Bridge Year on CGAAP basis are the result of capital expenditures in 2012 (net capital expenditures in 2012 - $6,846,019), plus the addition of Smart Meters, including $6,199,313 to the opening balance (broken into Account 1860 Smart Meters $5,702,242, Account 1611 Computer Software $451,964, and Account 1920 Computer Hardware $44,877).

2012 Bridge Year (CGAAP) vs. 2013 Test Year (CGAAP)

The increase of $4,585,500 for 2013 is a result of capital spending during the year as described in Exhibit 2 Tab 3 Schedule 2.

Table 2-15: Accumulated Amortization

	Description	2009 Board Approved	2009 Actual	Variance 2009 Approved to 2009 Actual	2010 Actual	Variance 2010 Actual to 2009 Actual	2011 Actual	Variance 2011 Actual to 2010 Actual	2012 CGAAP Bridge	Variance 2012 CGAAP Actual to 2011 Actual	2013 CGAAP Test	Variance 2013 CGAAP Actual to 2012 CGAAP
1805	Land	-	-	-	-	-	-	-	-	-	-	-
1808	Buildings & fixtures	54,628	53,332	(1,296)	63,437	10,105	74,207	10,770	85,598	11,391	95,080	9,482
1820	Distribution station equip.	656,834	895,117	238,283	1,028,400	133,283	1,160,249	131,849	1,296,533	136,284	1,439,339	142,806
1830	Poles, towers, fixtures	8,026,986	8,033,688	6,702	8,974,850	941,162	9,955,005	980,155	10,964,767	1,009,762	11,508,325	543,558
1835	OH conductors & devices	1,545,275	1,569,074	23,799	1,867,792	298,718	2,209,535	341,743	2,586,768	377,233	2,793,246	206,478
1840	UG conduit	4,012,656	4,455,112	442,456	5,040,482	585,370	5,646,864	606,382	6,276,975	630,111	6,606,200	329,225
1845	UG conductors & devices	451,003	461,015	10,012	585,077	124,062	719,303	134,226	859,827	140,524	954,768	94,941
1850	Line transformers	5,973,367	5,904,087	(69,280)	6,696,515	792,428	7,449,418	752,903	8,293,300	843,882	8,778,743	485,443
1855	Services	3,531,988	2,961,424	(570,564)	3,345,795	384,371	3,759,848	414,053	4,193,180	433,332	4,417,222	224,042
1860	Meters	1,700,639	574,540	(1,126,099)	321,917	(252,623)	358,370	36,453	406,535	48,165	458,332	51,797
1860	Smart meters	-	-	-	-	-	-	-	1,601,169	1,601,169	1,981,332	380,163
	Distribution Plant	25,953,376	24,907,389	(1,045,987)	27,924,265	3,016,876	31,332,799	3,408,534	36,564,652	5,231,853	39,032,587	2,467,935
1611	Computer software	57,747	57,747	-	57,747	-	57,747	-	494,776	437,029	690,169	195,393
1920	Computer hardware	-	-	-	-	-	-	-	34,959	34,959	41,694	6,735
1960	Miscellaneous equipment	65,932	65,908	(24)	82,385	16,477	82,385	-	82,385	-	82,385	-
1970	Load management controls	1,539,391	1,537,213	(2,178)	1,555,054	17,841	1,570,981	15,927	1,586,966	15,985	1,590,759	3,793
	General Plant	1,663,070	1,660,868	(2,202)	1,695,186	34,318	1,711,113	15,927	2,199,086	487,973	2,405,007	205,921
1995	Contributions & grants	-	-	-	-	-	-	-	-	-	-	-
	Total Accumulated Amortization	**27,616,446**	**26,568,257**	**(1,048,189)**	**29,619,451**	**3,051,194**	**33,043,912**	**3,424,461**	**38,763,738**	**5,719,826**	**41,437,594**	**2,673,856**

Variance Analysis on Accumulated Amortization:

Table 2-15 shows the changes in accumulated amortization from 2009 Actual to the 2013 Test Year. The change in accumulated amortization is a result of capital expenditures and amortization expense each year.

In addition, the following items of significance have impacted the variances in accumulated amortization over the 2009 to 2013 period:

- During 2009 accumulated amortization relating to stranded meters in the amount of $737,749 was transferred to Account 1555, Smart Meter Capital and Recovery Offset Variance Account, Sub-account Stranded Meter Costs.
- During 2010 accumulated amortization relating to stranded meters in the amount of $273,974 was transferred to Account 1555.
- At January 1, 2012 accumulated amortization of $1,551,124 for smart meter assets was transferred from Account 1555 to rate base.

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CAPITAL BUDGET:

PDI's annual capital plan is derived from a variety of inputs from several sources. Customer requirements and obligations are given first priority but are less predictable and schedules can change frequently and quickly. This includes the requirements of the municipalities and the Public Service on Highways Act. Operational and public safety needs can arise during the program year and can take precedence over previously scheduled projects. Storms and severe weather are more frequent and impactful and can disrupt the proposed project schedule and priorities. Finally, the program is completed with regular planned renewal programs that are necessary to maintain the quality of the distribution system performance. Lastly the capital program must account for the financial realities of the utility.

PDI's Asset Management Plan aids in identifying the capital renewal programs and projects required over a 3-5 year period based on the best available information for each year. The capital budget forecast is influenced significantly by condition data that is collected each year on aging infrastructure and as such, PDI may be required to adjust the capital project forecast as the knowledge of its system needs increases. As provided in Exhibit 2, Tab 3, Schedule 2, a significant portion of PDI's capital investments are customer or municipal driven. All proposed capital projects for the 2012 Bridge Year and 2013 Test Year are expected to be completed and in service in that year. Details of PDI's capital budget for these periods are provided in Table 2-16.

Provincial Sales Tax Impact

As a result of the implementation of HST in the province of Ontario on July 1, 2010, PDI has considered the reduction in capital expenditures relating to the purchase of products and services due to the increased input tax credit (ITC). Neither the 2012 Bridge Year forecast nor the 2013 Test Year budget for capital expenditures includes tax on purchases of products or services made after July 1, 2010.

Introduction:

PDI has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital spending. Below is an analysis of PDI's capital spending from 2007 to 2013.

Table 2-16 – Capital Spending Summary 2007 to 2013

Year	Total Distribution Plant $	Capital Contributions	Net Distribution Plant $	Intangible Plant	General Plant	Total Capital net of Contributions	Net Change Work In Progress
2007	6,094,725	(738,434)	5,356,291	-	13,916	5,370,207	(719,979)
2008	4,103,120	(555,079)	3,548,041	-	-	3,548,041	306,637
2009	4,457,946	(900,355)	3,557,591	-	-	3,557,591	2,384,670
2010	6,794,975	(1,448,545)	5,346,430	-	-	5,346,430	(1,303,680)
2011	6,268,064	(1,410,810)	4,857,254	-	-	4,857,254	(64,785)
2012	7,535,019	(1,319,000)	6,216,019	625,000	5,000	6,846,019	(2,494,020)
2013	5,765,500	(1,180,000)	4,585,500	-	-	4,585,500	483,391

The updated filing requirements for Exhibit 2 (Rate Base) request actual historical summary information for the last 5 years.

CAPITAL PROJECTS BY YEAR

Table 2-17 details PDI’s actual investment in construction projects for the years 2007 through 2011 plus projects for the 2012 Bridge Year and 2013 Test Year. Project descriptions are also provided.

Table 2-17: Capital Projects 2007 to 2013

Projects	2007 Actual CGAAP	2008 Actual CGAAP	2009 Actual CGAAP	2010 Actual CGAAP	2011 Actual CGAAP	2012 Bridge CGAAP	2013 Test CGAAP
Overhead Distribution Renewal							
Springbrook/Daleview area	190,146						
Hunter St. - Belmont to Park	106,580						
Juliet Avenue	139,420						
Sherbrooke St.- Goodfellow to Wallis	229,431						
Ashburnham/Neal Drive area		391,415					
Romaine Street		210,167					
Erskine Avenue			129,136				
Hilliard Street and Hedonics Road			128,599				
Brealey Drive/Kawartha Heights			166,976				
Water Street North				120,862			
Insulator Replacement Program				88,611			
Ford Street/Brunswick Avenue area					103,813		
Cumberland Avenue OH line conversion						73,863	
Cumberland Avenue 27.6 kV extension						250,000	
Parkhill Road West 27.6 kV extension						260,000	225,000
Parkhill Road West Feeder							525,000
44kV OH River Crossing							136,000
44 kV Switches Upgrades/SCADA						290,661	50,000
other	132,325	84,733	151,986	160,700	45,123	515,983	126,000
	797,902	**686,315**	**576,697**	**370,173**	**148,936**	**1,390,507**	**1,062,000**
Pole Replacement Program				**787,323**	**612,201**	**500,944**	**550,000**
New 27.6 kV Feeder (M9)	**390,684**						
New 27.6 kV Feeder (M8)				**553,658**	**390,633**		
Substations							
MS1	88,783						
MS19				138,165			
MS65							130,000
other			53,340	120,366	43,578	217,075	115,000
	88,783	**-**	**53,340**	**258,531**	**43,578**	**217,075**	**245,000**
New Underground Subdivisions	**508,996**	**263,747**	**562,718**	**203,362**	**780,762**	**837,318**	**600,000**
New Underground Lines - Cumberland							
				271,489			
Underground Distribution Renewal:							
Cumberland Avenue feeder	947,599						
Cumberland Avenue 27.6 kV line	81,181						
Ashburnham by the Lake Subdivision	445,632						
Cherryhill Road area	262,834	898,942					
Marsdale, Maria, Walker	146,308						
Garside Road area		141,137					
Hilltop, Cottonwood, Ashdale, Bayleaf, Stocker, Whitefield			725,876				
St. Paul's Street/Herbert Street area				187,950			
George Street Vault Reconstruction				87,493			
University Heights					476,892	377,503	
Cameron Street/Orpington Road						148,362	
Stewart Drive						88,865	
Downtown underground vault rebuild							75,000
other	168,762		33,631	369,438		699,190	570,000
	2,052,316	**1,040,079**	**759,507**	**644,881**	**476,892**	**1,313,920**	**645,000**

Capital Projects 2007 to 2013 – continued

Projects	2007 Actual CGAAP	2008 Actual CGAAP	2009 Actual CGAAP	2010 Actual CGAAP	2011 Actual CGAAP	2012 Bridge MIFRS	2013 Test MIFRS
Overhead Distribution - Customer Demand							
Major Bennett Drive						154,169	
other	105,825	240,432	188,239	192,072	102,194	83,092	
	105,825	**240,432**	**188,239**	**192,072**	**102,194**	**237,261**	**-**
OH Distribution Lines - Customer Demand							
Line extension to new YMCA - Aylmer Street	201,753						
Line extension to new subdivision - Maria St.	95,257						
George Street/Argyle Street			158,793				
Carnegie Avenue				184,483			
Cumberland Avenue				167,157			
Heritage Trail				80,354			
other	213,181	298,296	127,917	152,176		351,099	225,000
	510,191	**298,296**	**286,710**	**584,170**	**-**	**351,099**	**225,000**
Relocations requested by Municipality							
Highway 7/Highway 115 intersection			341,986				
Lansdowne Street/Borden Avenue				243,340			
Borden Avenue/Erskine Avenue				211,350			
Romaine Street				116,467			
Lansdowne Street West					1,210,702		
Water Street North					183,199		
Hilliard Street/Towerhill Road					182,913		
Peterborough Regional Health Centre						87,175	
Parkhill Road West							242,000
Parkhill Road/Brealey Drive							361,000
Chemong Road							90,000
other	168,012			12,013	39,675	221,620	109,500
	168,012	**-**	**341,986**	**583,170**	**1,616,489**	**308,795**	**802,500**
Services							
Overhead Services	249,665	280,957	129,046	282,403	219,312	554,465	320,000
Overhead Services - Sherwood Drive						93,989	
Underground Services - Primary	373,106	391,578	263,976	218,379	506,545	560,378	455,000
Underground Services - Secondary		222,475	147,884	81,148	200,161	448,712	220,000
Underground Services - Residential	323,392	332,151	270,942	332,199	267,422	17,017	221,000
600V service upgrades					204,349	128,943	
	946,163	**1,227,161**	**811,848**	**914,129**	**1,397,789**	**1,803,504**	**1,216,000**
Transformers	**163,769**	**228,183**	**357,224**	**639,091**	**136,884**	**201,313**	**130,000**
Meters	**159,914**	**78,634**	**402,177**	**155,039**	**379,911**	**274,969**	**205,000**
Generation Connection							
Trent Rapids Power				595,310			
Trent University						85,000	75,000
other						13,314	10,000
	-	**-**	**-**	**595,310**	**-**	**98,314**	**85,000**
MDMR Integration						**625,000**	
Load Control						**5,000**	
Miscellaneous	**216,086**	**40,273**	**117,500**	**42,577**	**181,795**	**-**	**-**
Contributions and Grants	**(738,434)**	**(555,079)**	**(900,355)**	**(1,448,545)**	**(1,410,810)**	**(1,319,000)**	**(1,180,000)**
Total	**5,370,207**	**3,548,041**	**3,557,591**	**5,346,430**	**4,857,254**	**6,846,019**	**4,585,500**

Capital Expenditures - 2007

Overhead Distribution Renewal – $797,902

This project area includes eight (8) projects of various sizes that are considered renewal of existing assets. Four of these projects exceeded the materiality threshold:

- Springbrook/Daleview Area ($190,146), Overhead line rebuild in companion with an underground rebuild in the same neighbourhood. Age, condition and reliability were the prime drivers for the project.
- Hunter St. – Belmont to Park ($106, 580), Overhead line rebuild due to damage suffered in a major windstorm in the summer of 2006, completed in 2007.
- Juliet Ave. ($139,420), Overhead line rebuild from rear yard to front yard due to damage suffered in a major windstorm in the summer of 2006, completed in 2007.
- Sherbrooke St, Goodfellow to Wallis ($229,431), Overhead line rebuild due to age and condition. This section of line carries three circuits, two of which are major supply feeders.

New 27.6 kV Feeder (M9) - $390,684

This project was the reconstruction and rearrangement of 27.6 kV feeders egressing from Otonabee TS for the extension of the new M9 supply point to the PDI 27.6 kV distribution network. The new M9 feeder was commissioned late in 2007. The Asset Management Plan calls for the expansion of the 27.6 kV network and conversion of the legacy 4.16 kV system. This project was required to re-align existing 27.6 kV feeders in the vicinity of the Otonabee T.S. to allow for the new M9 feeder to extend to the north end of the Peterborough territory.

Substation Building Upgrades - $88,783

This project was the renovation and building of a new electric meter shop in a vacant part of the Municipal Substation #1. The meter shop was relocated from the main operations centre to make way for the required expansion and renovation for the Engineering Department.

New Underground Subdivisions - $508,996

This project area includes the assumption of underground line and transformer assets constructed on behalf of PDI by developers. This is a customer driven project and represents the assumption of six (6) subdivisions.

Underground Distribution Renewal - $2,052,316

This project area includes nine (9) projects related to the renewal and conversion of existing underground distribution assets. Five (5) of the projects exceeded the materiality threshold:

- Cumberland Ave ($947,599), main 600 A underground feeder line. The project was required to extend the 27.6 kV system to support conversion of the 4.16 kV underground residential system in the area and new residential subdivisions being constructed and planned. The project started in 2006 and was completed in 2007.
- Cumberland Ave ($81,181), renewal project to replace and convert older legacy 4.16 kV single phase underground lines. Companion project to the Cumberland Ave. 600 A main feeder listed above.
- Ashburnham by the Lake Subdivision ($445,632), 2006 underground renewal project. Conversion of older legacy 4.16 kV underground residential subdivision. Project also undertaken to relieve loading on a 4.16 kV substation (MS #3). Project was started in 2006 and completed in 2007.
- Cherryhill Rd Area Phase I ($262,834), 2006 underground renewal project to replace older legacy 4.16 kV underground residential subdivision. Conversion to 27.6 kV. Project was started in 2006 and completed in 2007.

- Marsdale, Maria, Walker Area ($146,308), renewal project to replace and convert older legacy 4.16 kV services. Companion project to Ashburnham by the Lake project listed above. Project was started in 2006 and completed in 2007.

<u>Overhead Distribution – Customers - $105,825</u>

This project area includes several small overhead distribution upgrades related to new customer service requests in 2007. No projects exceeded the materiality threshold.

<u>Overhead Distribution Line – Customers - $510,191</u>

This project area includes several overhead line extension or upgrades related to new customer service requests in 2007. Two (2) projects exceeded the materiality threshold:

- Aylmer St. ($201,753), 27.6 kV line extension to supply new YMCA constructed in 2007.
- Maria St ($95,257), 27.6 kV line extension to supply new residential subdivision planned for the area.

<u>Relocations – Municipalities - $168,012</u>

This project area includes five (5) projects related to requests by municipality to relocate overhead lines. None of the individual projects met the materiality threshold.

<u>Overhead Services - $249,665</u>

This project area includes expenditures to provide service in response to customer requests. No services exceeded the materiality threshold.

Underground Services Primary - $373,106

This project area includes expenditures to provide service in response to eleven (11) customer requests for high voltage services. No services exceeded the materiality threshold.

Underground Services Residential - $323,392

This project area includes expenditures to provide service in response to customer requests for low voltage services. No services exceeded the materiality threshold.

Transformers - $163,769

This project area includes expenditures to replace failed or damaged overhead and underground transformers during 2007. An amount of $86,118 was spent for the replacement of underground padmounted transformers.

Meters - $159,914

This project area includes expenditures to install new or replace failed or damaged revenue meters. An amount of $123,830 was spent for new general service class meters.

Capital Expenditures - 2008

Overhead Distribution Renewal – $686,315

This project area includes four (4) projects of various sizes that are considered renewal of existing assets. Two of these projects exceeded the materiality threshold:

- Ashburnham/Neal Dr Area ($391,415), Reconstruction of 44 kV circuits egressing from the Otonabee TS in conjunction with the new 27.6 kV M9 feeder supply point previously commissioned.
- Romaine St. ($210,167), Overhead line rebuild due to age and condition. Was related to customer demand extension of 27.6 kV on Aylmer St in 2007 for new YMCA.

New Underground Subdivisions - $263,747

This project area includes the assumption of underground line and transformer assets construction on behalf of PDI by developers. This is a customer driven project and represents the assumption of six (6) subdivisions. No subdivision project exceeded the materiality threshold.

Underground Distribution Renewal - $1,040,079

This project area includes two (2) projects related to the renewal and conversion of existing underground distribution assets. The two projects exceeded the materiality threshold:

- Cherryhill Rd Area, Phase II ($898,942) 2007 underground renewal project to replace older legacy 4.16 kV underground residential subdivision. Conversion to 27.6 kV to relieve substation loading (MS#18), age and condition were drivers for this project. Project was started in 2007 and completed in 2008.
- Garside Rd Area ($141,137) 2007 underground renewal project to replace older existing assets. Age and condition were the primary drivers for this project. Project was started in 2007 and completed in 2008.

<u>Overhead Distribution – Customers - $240,432</u>

This project area includes several small overhead distribution upgrades related to new customer service requests in 2008. No projects exceeded the materiality threshold.

<u>Overhead Distribution Line – Customers - $298,296</u>

This project area includes several overhead line extension or upgrades related to new customer service requests in 2008. No projects exceeded the materiality threshold.

<u>Overhead Services - $280,957</u>

This project area includes expenditures to provide service in response to customer requests. No service projects exceeded the materiality threshold.

<u>Underground Services Primary - $391,578</u>

This project area includes expenditures to provide service in response to eleven (11) customer requests for high voltage services. No service projects exceeded the materiality threshold.

<u>Underground Services Secondary - $222,475</u>

This project area includes expenditures to provide service in response to customer requests for low voltage services. One project exceeded the materiality threshold:

- Romaine St ($112,013) upgrade and replacement of existing underground services in connection with the Romaine St overhead line rebuild. Services were converted to 27.6 kV. Age and condition were the drivers for this project.

<u>Underground Services Residential - $332,151</u>

This project area includes expenditures to provide service in response to customer requests for low voltage services. No services exceeded the materiality threshold.

<u>Transformers - $228,183</u>

This project area includes expenditures to replace failed or damaged overhead and underground transformers during 2008. An amount of $70,214 was spent for replacement of overhead transformers.

<u>Meters - $78,634</u>

This project area includes expenditures to install new or replace failed or damaged revenue meters. An amount of $74,710 was spent for new general service class meters.

Capital Expenditures – 2009

Overhead Distribution Renewal – $576,697

This project area includes seven (7) projects of various sizes that are considered renewal of existing assets. Three (3) of these projects exceeded the materiality threshold:

- Erskine Ave ($129,136), Reconstruction of 4.16 kV circuit in connection with a new school being built in the area. In addition to the new school, age and condition were primary drivers for the project.
- Hilliard St and Hedonics Rd ($128,599), reconstruction of existing 4.16 kV assets and conversion to 27.6 kV in connection with an underground line renewal project in both areas. Age and condition were also drivers for the project.
- Brealey Dr/Kawartha Heights ($166,976), reconstruction of existing 4.16 kV assets and conversion to 27.6 kV in connection with an underground line renewal in the area. Age and condition were also drivers for the project.

New Underground Subdivisions - $562,718

This project area includes the assumption of underground line, transformers and construction of new residential subdivision assets by developers. This is a customer driven project area and represents the assumption of three (3) subdivisions.

Underground Distribution Renewal - $759,507

This project area includes two (2) projects related to the renewal and conversion of existing underground distribution assets. One project exceeded the materiality threshold:

- Various Areas ($725,876) 2008 underground renewal project to replace older legacy 4.16 kV underground residential lines and transformers. Age and condition were drivers for this project. Project was started in 2008 and completed in 2009.

<u>Overhead Distribution – Customers - $188,239</u>

This project area includes several small overhead distribution upgrades related to new customer service requests in 2009. No projects exceeded the materiality threshold.

<u>Overhead Distribution Line – Customers - $286,710</u>

This project area includes several overhead line extension or upgrades related to new customer service requests in 2008. One project exceeded the materiality threshold:

- George/Argyle St ($158,793), extension of three phase overhead line for a new customer service. The overhead line was also rebuilt due to age and condition and converted to 27.6 kV.

<u>Relocations – Municipalities - $341,986</u>

This project area includes one project related to a request by the Ministry of Transportation Ontario. An upgrade to the intersection of Highway #7 and Highway #115 required significant relocation of overhead lines. The project was started in 2007 and completed in 2009.

<u>Overhead Services - $129,046</u>

This project area includes expenditures to provide service in response to customer requests. No service projects exceeded the materiality threshold.

<u>Underground Services Primary - $263,976</u>

This project area includes expenditures to provide service in response to eight (8) customer requests for high voltage services. One service exceeded the materiality threshold:

- Costco Service ($87,592), project involved high voltage service with large 1000 kVA padmount transformer with longer than normal primary cable and separate riser pole.

<u>Underground Services Secondary - $147,884</u>

This project area includes expenditures to provide service in response to customer requests for low voltage services. No projects exceeded the materiality threshold.

<u>Underground Services Residential - $270,942</u>

This project area includes expenditures to provide service in response to customer requests for low voltage services. No services exceeded the materiality threshold.

<u>Transformers - $357,224</u>

This project area includes expenditures to replace failed or damaged overhead and underground transformers during 2009. The PCB contaminated transformer replacement program began this year. Two (2) areas exceeded the materiality threshold:

- Overhead Transformers ($159,451)
- Padmount Transformers ($182,594)

<u>Meters - $402,177</u>

This project area includes expenditures to install new or replace failed or damaged revenue meters. An amount of $311,336 was spent for new and replacement general service class meters. An amount of 90,840 was spent for new and replacement residential meters.

Capital Expenditures - 2010

Overhead Distribution Renewal – $370,173

This project area includes eight (8) projects of various sizes that are considered renewal of existing assets. Two of these projects exceeded the materiality threshold:

- Water St N. ($120,862), Reconstruction of 4.16 kV circuit bundled with a line extension to a new renewable generator (Robert G. Lake GS). Age and condition were drivers for the project along with the extension of a new circuit 44 kV circuit to the new generation station.
- 44 kV and 27.6 kV Insulator Replacement Program ($88,611), replacement of porcelain and suspect insulators. Age and condition were drivers for the project.

Pole Replacement Program - $787,323

The first significant year of the pole testing and replacement program that was initiated in latter part of 2008. This portion of the program includes some carryover work from 2009 and completed in 2010. A total of 47 poles and associated equipment were replaced to the end of 2010.

New 27.6 kV Feeder (M8) - $553,658

This project area includes two (2) projects required to provide for a new supply point for the 27.6 kV distribution system. The two projects exceeded the materiality threshold:

- Lansdowne St Bridge ($434,238), Installation of ducts and high voltage underground cable to connect the new feeder to grid crossing the Otonabee River. The project started in 2008 with the installation of ducts during the City of Peterborough bridge reconstruction and was completed in 2010.
- River Rd ($119,410), construction on new riser for bridge crossing and re-construction of overhead circuits at the eastern terminus of the bridge to allow for connection to the new

M8 feeder. Project was completed in 2010 after the commissioning of the new feeder position late in December 2009.

<u>Substation Upgrades - $258,531</u>

This project area included the costs for several building and equipment upgrades to various 4.16 kV substations. One project exceeded the materiality threshold:

- MS 19 ($86,346), Replacement of damaged equipment after a failure and fire at the substation, and ($51,819) building repairs following the fire.

<u>New Underground Subdivisions - $203,362</u>

This project area includes the assumption of underground line, transformers and construction of new residential subdivision assets by developers. This is a customer driven project and represents the assumption of three (3) subdivisions.

<u>New Underground Lines - $271,489</u>

This project was related to a previous year project (Cumberland Ave main feeder) to convert the local distribution line on Cumberland Ave. to 27.6 kV in anticipation of new subdivisions and significant proposed growth in the area. This new line replaced an existing 4.16 kV line abandoned due to age and condition.

<u>Underground Distribution Renewal - $644,881</u>

This project area includes five (5) projects related to the renewal and conversion of existing underground distribution assets. Three (3) projects exceeded the materiality threshold:

- St Paul’s, Hebert St Area ($187,950), 2010 underground renewal project to replace older 4.16 kV underground residential lines and transformers. The area was also converted to 27.6 kV. Age and condition were drivers for this project.

- George St Vault Reconstruction ($87,493), underground transformer vault rebuilt. Age and condition were the drivers for this project.
- Various Areas ($369,438), 2009 underground renewal project to replace older legacy 4.16 kV underground residential lines and transformers. Age and condition were drivers for this project. Project was started in 2009 and completed in 2010.

<u>Overhead Distribution – Customers - $192,072</u>

This project area includes several small overhead distribution upgrades related to new customer service requests in 2010. No projects exceeded the materiality threshold

<u>Overhead Distribution Line – Customers - $584,170</u>

This project area includes several overhead line extension or upgrades related to new customer service requests in 2010. Three (3) projects exceeded the materiality threshold:

- Carnegie Avenue ($184,483), rebuild of overhead line to facilitate the connection of condominium townhome development.
- Cumberland Avenue ($167,157), rebuild and conversion of an existing 4.16 kV line to facilitate new subdivision development in the area. The line was also converted to 27.6 kV to alleviate substation capacity limitations in the area (MS #21).
- Heritage Trail ($80,354), extension of 27.6 kV three phase line to facilitate the next phase of the subdivision. Related to the Cumberland Ave project noted above.

<u>Relocations – Municipalities - $583,170</u>

This project area includes five (5) projects related to a request by the City of Peterborough for line relocation due to road widening. Three projects exceeded the threshold materiality:

- Lansdowne and Borden ($243,340), project was to re-route a 44 kV line due to the closure of a road for a factory expansion.

- Borden and Erskine ($211,350), project is companion to the above project to re-route a 44 kV line and accommodate a road reconstruction and re-alignment due to the closure of a section of Erskine Ave.
- Romaine St. ($116,467), project to reconstruct 4.16 kV lines to accommodate a road intersection rebuild.

<u>Overhead Services - $282,403</u>

This project area includes expenditures to provide service in response to customer requests. No services exceeded the materiality threshold.

<u>Underground Services Primary - $218,379</u>

This project area includes expenditures to provide service in response to six (6) customer requests for high voltage services. No services exceeded the materiality threshold.

<u>Underground Services Secondary - $81,148</u>

This project area includes expenditures to provide service in response to customer requests for low voltage services. No projects exceeded the materiality threshold.

<u>Underground Services Residential - $332,199</u>

This project area includes expenditures to provide service in response to customer requests for low voltage services. No services exceeded the materiality threshold.

<u>Transformers - $639,091</u>

This project area includes expenditures to replace failed or damaged overhead and underground transformers during 2010. The PCB contaminated transformer replacement program continued in earnest this year. Two areas exceeded the materiality threshold:

- Overhead Transformers ($332,666)
- Padmount Transformers ($276,124)

<u>Meters - $155,039</u>

This project area includes expenditures to install new or replace failed or damaged revenue meters. An amount of $142,930 was spent for new and replacement general service class meters.

<u>Generation Connections – Mid-Size ($595,310)</u>

This project included the extension of a 44 kV line and connection of an 8 MW renewable generator. The project began in 2009 and was competed in 2010.

Capital Expenditures - 2011

Overhead Distribution Renewal – $148,936

This project area includes four (4) projects of various sizes that are considered renewal of existing assets. One of these projects exceeded the materiality threshold:

- Ford, Brunswick Area ($103,813), Reconstruction of 4.16 kV circuit and relocation of line from the rear yard to the front yard. Age and condition were drivers for the project along with access problems to the rear yard.

Pole Replacement Program - $612,201

Annual testing and replacement program project for poles and associated equipment replaced in 2011. A total of 29 poles and associated equipment were replaced to the end of 2011.

New 27.6 kV Feeder (M8) - $390,633

This project area includes two (2) projects required to provide for a new supply point for the 27.6 kV distribution system. The two projects exceeded the materiality threshold:

- Otonabee TS Feeder Egress ($306,214), construction of feeder egress and circuit rearrangements to integrate the new feeder position into the 27.6 kV distribution network. The multi-year project began in 2008 and was completed in early 2011.
- Otonabee TS Area ($84,220), reconstruction of existing circuits to accommodate the new feeder position’s integration into the existing 27.6 kV distribution grid. Work was started in 2010 and completed in 2011.

<u>New Underground Subdivisions - $780,762</u>

This project area includes the assumption of underground line, transformers and construction of new underground residential subdivision assets by developers. This is a customer driven project and represents the assumption of eight (8) subdivisions during 2011.

<u>Underground Distribution Renewal - $476,892</u>

This project area includes several projects related to the 2011 annual renewal and conversion program of existing underground distribution line and transformer assets. One project exceeded the materiality threshold. Age and condition were the drivers for this project as well as preparation for a future conversion to relieve limited substation (MS #21) capacity in the area.

- University Heights Area ($476,564), 2010 underground renewal project to replace older legacy 4.16 kV underground residential lines and transformers. Age and condition were drivers for this project. Project was started in 2010 and completed in 2011.

<u>Overhead Distribution – Customers - $102,194</u>

This project area includes several small overhead distribution upgrades related to new customer service requests in 2011. No projects exceeded the materiality threshold.

<u>Lansdowne St W. – Road Relocation ($1,210,702)</u>

This project was a major road relocation project initiated by the City of Peterborough. The project involved the relocation of several circuits including 44, 27.6 and 4.16 kV circuits and some underground lines and services. The project began in 2009 and was completed in 2011.

<u>Relocations – Municipalities - $405,787</u>

This project area includes seven (7) projects related to requests by the City of Peterborough for line relocations due to road widening. Two (2) projects exceeded the threshold materiality:

- Water St N ($183,199), project was to relocate a three circuit overhead line to accommodate a left turn lane at the intersection of University Heights.
- Hilliard St ($182,913), project was to relocate overhead and underground lines to accommodate the installation of a sewer and upgrade the intersection at Towerhill Rd.

<u>Overhead Services New - $141,563</u>

This project area includes expenditures to provide service in response to customer requests. No services exceeded the materiality threshold.

<u>Overhead Services Renewal - $77,749</u>

This project was to replace the overhead services in the Brunswick/Ford area to relocate services from an inaccessible rear yard line to the new overhead line in the front yards. This was a companion project to the overhead distribution renewal project noted previously.

<u>600 V Service Upgrades - $204,349</u>

The project area includes ten (10) customer service upgrades to obsolete delta service configuration. There were several drivers for this project including upgrading the service to allow for installation of smart meters, eliminate the obsolete voltage configuration, eliminate PCB contaminated transformers and improve the safety level of the customer's service. Age and condition of the service and transformers in some cases was an additional driver. No projects exceeded the materiality threshold.

Underground Services Primary - $506,545

This project area includes expenditures to provide service in response to twelve (12) customer requests for high voltage services. One project exceeded the materiality threshold:

- 140 King St ($114,408), reconstruction and rehabilitation of an underground downtown transformer vault. A new vacuum switch was also installed to improve operation of the downtown underground loop. Age and condition were the drivers for this project.

Underground Services Secondary - $200,161

This project area includes expenditures to provide service in response several customer requests for low voltage services. No projects exceeded the materiality threshold.

Underground Services Residential - $267,422

This project area includes expenditures to provide services in response to customer requests for low voltage services. No services exceeded the materiality threshold.

Transformers - $136,884

This project area includes expenditures to replace failed or damaged overhead and underground transformers during 2011. The PCB contaminated transformer replacement continued this year. One area exceeded the materiality threshold

- Overhead Transformers ($118,633)

Meters - $379,911

This project area includes expenditures to install new or replace failed or damaged revenue meters. Two areas exceeded the materiality threshold:

- Primary Metering Unit Replacement ($245,894), replacement or elimination of PCB contaminated primary metering units project was substantially completed in 2011.
- General Service Meters ($132,473), new or replacement meters for general service class customers.

Capital Expenditures - 2012

Overhead Distribution Renewal - $1,099,846

This project area includes thirteen (13) overhead line renewal projects started in 2011 valued at a total of $290,850 and completed in 2012. Only one of the 2011 projects exceeded the materiality threshold, Cumberland Ave overhead line conversion ($73,863) completed for a future underground conversion in two existing underground residential subdivisions.
The remaining expenditures are for six (6) overhead line renewal projects proposed to be constructed in 2012. Projects above the materiality threshold are as followings:

- Parkhill Rd 27.6 kV extension ($260,000). Phase I of a combination project of overhead line renewal and conversion of one 4.16 kV circuit to 27.6 kV to close a gap in the 27.6 kV grid to improve operations and load restoration as described in the Asset Management Plan.
- Cumberland Ave 27.6 kV extension ($250,000). Phase I of a combination project of overhead line renewal and conversion of a 4.16 kV circuit to 27.6 kV to accommodate future conversions of underground residential subdivisions and commercial load in the north-east area of the Peterborough territory. The decommissioning of a legacy 4.16 kV substation (MS #21) in the north end and to facilitate future load growth is the ultimate objective as described in the Asset Management Plan.

44 kV Switches Upgrades/SCADA - $276,661

This 2012 project is the completion of a multi-year project started in 2010 to renew the SCADA controls and communication for remote controlled 44 kV switches and upgrade a 27.6 kV recloser.

Pole Replacement Program - $500,944

The 2012 expenditure for the ongoing pole replacement program determined from the pole testing completed in 2011 as described in the Asset Management Plan.

Substations Building Upgrades - $217,075

The project area includes several proposed substation upgrades for 2012 ($170,000) and the remaining amount is for miscellaneous substation upgrades started in 2011 and completed in 2012. None of the projects exceed the materiality threshold.

New Underground Subdivisions - $837,318

The project area is for new underground residential subdivisions proposed to be assumed in 2012.

Underground Rehabilitation Program - $1,313,920

This the annual program for 2012 of rehabilitating underground lines and transformers as described in the Asset Management Plan. The 2012 program ($635,000) is for a north end subdivision covering several streets to be completed in 2012.

The additional amount is for thirteen (13) projects started in late 2010, through 2011 and completed in 2012. Only three (3) projects exceeded the materiality threshold:

- Cameron St area rehabilitation project ($148,362)
- 2011 underground rehabilitation project ($377,503) for phase II of the University Heights Subdivision.
- Stewart Drive ($88,865)

Overhead Distribution – Customer Demands - $237,261

A total of eight (8) customer demand projects started in 2011 and completed in 2012 for new or upgraded overhead customer services. One project exceeded the materiality threshold:

- Major Bennett Rd ($154,169) extension for a new customer and proposed future customer.

<u>Overhead Distribution Line Extensions - $351,099</u>

This project area includes four (4) smaller overhead line renewal projects carried over from 2011 ($86,099) and several smaller projects ($275,000) that are proposed for 2012 or may be a result of new customer service requests. One project below the materiality threshold is expected to remain in WIP and carry over to 2013.

<u>Relocations Municipality - $308,795</u>

A customer demand project area with several municipality road relocations. There are five (5) projects ($218,295) started in 2011 and completed in 2012. One (1) project, the Hospital Access Road ($87,175) exceeded the materiality threshold.

There are three (3) project areas proposed by the City for 2012:

- Parkhill Rd W. widening ($242,000) scheduled for 2012.
- Parkhill Rd W. at Brealey Drive intersection reconstruction ($161,000).
- Various Small Relocations ($100,000).

All of the proposed projects (except one small relocation) are now expected to be delayed and remain in WIP ($412,500) at the end of 2012.

<u>Overhead Services - $495,652</u>

The project includes customer demand for new and upgraded overhead services. A total of sixteen (16) projects started in 2011 and completed in 2012 for a total cost of $140,652. No projects exceeded the materiality threshold.

New and upgraded services proposed for completion in 2012 for a total cost of $355,000. No projects are expected to exceed the materiality threshold.

<u>Overhead Services Renewal - $152,802</u>

Two backyard overhead service renewal projects started in 2010 and completed in 2012. The projects were initiated in one case by the discovery of rotten poles and the other from the result of damage during a wind storm. One project for Sherwood Dr. ($93,989) exceeded the materiality threshold.

<u>600 V Service Replacement Program - $128,943</u>

This is phase II of a combined renewal project to replace obsolete 600 V services, replace PCB contaminated transformers (also near end of life), replace Primary Metering Units (PMU) and install new smart meters. A total of nine (9) projects are included in this area, none exceeding the materiality threshold. Phase I of the project began in 2010 and is completed in 2011.

<u>New Underground Primary Services - $560,378</u>

A customer demand project area for new underground high voltage services ($295,378) with a total of twenty one (21) projects started in 2011 and completed in 2012. No projects exceeded the materiality threshold.

New customer services proposed for 2012 at a cost of $320,000 with two (2) projects ($55,000) started in 2012 but expected to be in WIP at the end of the year.

<u>New Underground Secondary Services - $448,712</u>

A customer demand area for new underground low voltage services ($172,712) started in 2011 and completed in 2012.

New customer services proposed for 2012 at a cost of $276,000. No projects in this area exceeded the materiality threshold.

<u>Transformers - $201,313</u>

This project area is for the replacement of overhead and underground transformers ($185,000) proposed in 2012 due to failure, car accidents, leaks, or condition, etc. The remainder is for work started in 2011 and completed in 2012.

<u>Meters - $274,969</u>

This project area includes expenditures to install new or replace failed or damaged revenue or seal expired meters and upgrades for 600 V services. Two areas exceeded the materiality threshold:

- Smart Meter Replacement (GS>50kW) $89,084, Phase I of a project to install smart meters and upgrade the installation (3 element) for larger customer class on meters that are seal expired. Phase I of the project began in 2010 and completed in 2012. Phase II to be completed in 2013.
- General Service Meters ($155,000), new or replacement meters for general service class customers.

<u>Generation Connections – Small/Mid-Size - $98,314</u>

The 44 kV portion of the line required to connect the upgraded 3.9 MW generating station at Trent University is proposed for 2012. The project may be delayed and a portion is expected to remain in WIP ($75,000) at the end of 2012 and carry over into 2013.

<u>MDM/R - $625,000</u>

This project is to integrate the smart meter infrastructure with the IESO meter data management repository and prepare for the implementation of TOU billing for customers. The project was initiated in late 2009 and expected to be completed in 2012.

Capital Expenditures - 2013

Overhead Distribution Renewal - $1,062,000

The expenditures in this project area are for three (3) overhead line renewal projects proposed to be constructed in 2013. Projects above the materiality threshold are as followings:

- Parkhill Rd 27.6 kV extension ($750,000). Phase II of a combination project of overhead line renewal of a 44 kV feeder and conversion of one 4.16 kV circuit to 27.6 kV to close a gap in the 27.6 kV grid to improve operations and load restoration as described in the Asset Management Plan.
- 44 kV river crossing replacement ($136,000) for the M7 feeder. Originally identified from the pole testing program in 2010, the project has been delayed and is expected to be completed in 2013.
- Various smaller overhead line renewal projects ($126,000) associated with customer requests for new or upgraded services anticipated in 2013.

Pole Replacement Program - $550,000

The 2013 proposed expenditure for the ongoing pole replacement program determined from the pole testing completed in 2012 as described in the Asset Management Plan.

Substation Building Upgrades - $115,000

The project area includes several proposed substation upgrades for 2013. None of the projects exceed the materiality threshold.

MS #65 Substation - $130,000

The project started in 2012 and includes costs for acquisition of the land and design for the proposed new substation. The new substation is to provide a new supply point to the 27.6 kV grid to accommodate future load conversion from the 4.16 kV system and expected load growth on the 27.6 kV distribution system from new and existing customers. The construction of the station is expected to begin in 2014 after acquisition of major equipment late in 2013. Major equipment purchases are expected to remain in WIP at the end of 2013. The $130,000 to be added to fixed assets in 2013 covers the acquisition of the land only.

<u>New Underground Subdivisions - $600,000</u>

The project area is for proposed new underground residential subdivisions expected to be assumed in 2013.

<u>Underground Rehabilitation Program - $645,000</u>

This the annual program for 2013 of rehabilitating underground lines and transformers as described in the Asset Management Plan. The 2013 program specific projects ($500,000) have not been determined at this time.

The additional amount ($145,000) is for four (4) projects. Two (2) projects ($60,000) are delayed from 2012 and are to be carried over into 2013 and the other two (2) are smaller projects proposed for completion in 2013. Only one of the proposed 2013 projects exceeds the materiality threshold:

- Downtown Underground vault rebuild ($75,000)

<u>Overhead Distribution Line - Customer Demands - $225,000</u>

Various overhead line construction projects related to customer demand for new services proposed for 2013. No projects are expected to exceed the materiality threshold.

<u>Relocations Municipality - ($802,500)</u>

A customer demand project area with several municipality road relocations. There are three projects started in 2012 and carried over to 2013. Two projects exceed the materiality threshold:

- Parkhill Rd W Road Relocation ($242,000)
- Parkhill at Brealey ($361,000) intersection relocation.

There are two additional project areas for proposed relocations by the City for 2013:

- Chemong Rd widening Phase I ($90,000) scheduled to begin in 2013.
- Various Small Relocations ($109,500).

<u>Overhead Services - $320,000</u>

New and upgraded services proposed for completion in 2013. No projects are expected to exceed the materiality threshold.

<u>New Underground Primary Services - $455,000</u>

New customer services proposed for 2013 at a cost of $400,000 with two (2) projects ($55,000) started in 2012 but expected to be in WIP at the end of the 2012. No projects are expected to exceed the materiality threshold.

<u>New Underground Secondary Services - $220,000</u>

New general service class customer services proposed for 2013. No projects in this area are expected to exceed the materiality threshold.

<u>New Underground Residential Secondary Services - $221,000</u>

New underground residential customer services proposed for 2013. No projects in this area are expected to exceed the materiality threshold.

<u>Transformers - $130,000</u>

This project area is for the replacement of overhead and underground transformers proposed in 2013 due to failure, car accidents, leaks, or age/condition, etc.

<u>Meters - $205,000</u>

This project area includes expenditures to install new or replace failed or damaged revenue or seal expired meters and upgrades for 600 V services. One area exceeded the materiality threshold:

- New general service class meters ($125,000) proposed for 2013.

<u>Generation Connections – Small/Mid-Size - $85,000</u>

Two projects to connect Trent University and London Street Generating Stations. One project started in 2012 and will carry over to 2013. One project exceeds the materiality threshold:

- Final service connection ($75,000) for the upgraded 3.9 MW generating station at Trent University. The project began in 2012 and carries over to 2013.

Asset Management Plan Summary:

PDI is an infrastructure-based business with its distribution system assets the key element in the delivery of electricity to its existing and new customers. PDI's distribution assets range in age from new to some that are over 60 years old.

Asset management is the professional management of physical infrastructure with a systematic methodology integrating best practices in all aspects of selection, design, construction, operation, maintenance, replacement and disposition. The goal is to use an Asset Management Plan to optimize the whole life business impact of costs, performance and risk exposures of PDI's physical assets. Performance of the assets is directly related to reliability of the distribution system which is another key regulatory and customer satisfaction measure second only to rates. Accompanying this Schedule as Appendix C is a copy of our Asset Management Plan. It is important to note that PDI's Asset Management Plan is in its second generation of development. PDI has completed a review of current assets and their age and has reviewed current strategies in dealing with maintenance and capital improvements. Also under continuous review are the current and potential future activities expected to form the major parts of the Asset Management Plan in the future. The Asset Management Plan has also been integrated with the overall system plan for the distribution system to maximize and leverage the limited capital investment available for renewal and improvements to the distribution system.

The main tenants of the Asset Management Plan are the ongoing renewal programs for first generation underground high voltage cables and transformers, systematic replacement of poles based on the annual testing program and other renewal projects both overhead and underground that can be bundled with other customer driven work or are identified as priorities through annual operational inspection programs.

The overall system plan centres around the eventual decommissioning of the legacy 4.16 kV distribution system in the main Peterborough territory. All capital projects are evaluated for the opportunity to convert to the newer 27.6 kV distribution system under development since 1987. One of the end objectives of the overall system plan is the eventual elimination of the 44-4.16 kV municipal substations. Since transformer station 27.6 kV supply points are fully utilized at the present time, PDI will be embarking on a plan to build larger scale 44 -27.6 kV substations (MS#65) to augment and enhance the supply points to the 27.6 kV distribution system and make better use of the capacity of the existing 44 kV transformer station supply points.

PDI has provided the forecast for 2014, 2015 and 2016 capital expenditures in Table 2-18. The annual replacement costs are engineering estimates only and the actual expenditure levels in the capital budgets could be adjusted based on project scope, prevailing construction costs and other outside influences (e.g. relocation requests, system expansions, etc.).

Table 2-18 – 2014 to 2016 Distribution System Capital Expenditure Forecast

Projects	2014 Forecast	2015 Forecast	2016 Forecast
Overhead Distribution Renewal	**1,010,000**	**735,000**	**885,000**
Pole Replacement Program	**550,000**	**550,000**	**550,000**
Substations			
MS65	1,796,000		
other	70,000	70,000	70,000
	1,866,000	**70,000**	**70,000**
New Underground Subdivisions	**500,000**	**450,000**	**400,000**
Underground Distribution Renewal	**500,000**	**500,000**	**500,000**
Overhead Distribution - Customer Demand	**50,000**	**50,000**	**50,000**
OH Distribution Lines - Customer Demand	**175,000**	**175,000**	**175,000**
Relocations requested by Municipality			
Chemong Road 44 kV	140,000		
Parkhill Road West	250,000		
Armour Road north 44 kV		200,000	
Armour Road north 27.6 kV/4.16 kV		300,000	
Chemong Road 27.6 kV/4.16 kV		400,000	
Sherbrooke Street west 44 kV			250,000
Sherbrooke Street west 27.6 kV/4.16 kV			500,000
	390,000	**900,000**	**750,000**
Services			
Overhead Services	310,000	310,000	250,000
Underground Services	570,000	520,000	520,000
	880,000	**830,000**	**770,000**
Transformers	**150,000**	**150,000**	**175,000**
Meters	**155,000**	**160,000**	**165,000**
Contributions and Grants	**(1,005,000)**	**(925,000)**	**(870,000)**
Total	**5,046,000**	**3,470,000**	**3,445,000**

The three year capital expenditure forecast includes the regular renewal programs and predicted customer demand requests. The following are currently identified projects that are expected to be constructed in the years noted:

<u>2014 – 2016</u>

- Annual Pole Replacement - $550,000
- Annual Underground Line and Transformer Rehabilitation - $500,000

<u>2014</u>

- Chemong Rd 44 kV Subtransmission - $140,000: Phase II of road relocation project by the City of Peterborough.
- MS #65 44-27.6kV Substation - $525,000: New substation construction and commissioning phase to provide a supply point to the 27.6 kV grid to facilitate continued conversion of 4.16 kV load and de-commission of 4.16 kV substations as discussed in Asset Management Plan.
- Parkhill Rd W - $250,000: Road relocation project by the City of Peterborough.
- Cumberland Ave/Water St N 27.6 kV - $300,000: Phase II of a combination line renewal and expansion project to convert existing 4.16 kV load to 27.6 kV, support load growth in the northeast and de-commission the MS #21 4.16 kV substation as discussed in Asset Management Plan.

<u>2015</u>

- Armour Rd N. 44kV Subtransmission - $200,000: Road relocation by the City of Peterborough.
- Armour Rd N. 4.16 kV - $300,000: Road relocation by the City of Peterborough.
- Chemong Rd 27.6 kV/4.16 kV - $400,000: Road relocation by the City of Peterborough.
- Fairbairn Rd 27.6 kV - $150,000: Related to Chemong Rd relocation by the City of Peterborough.

2016

- Sherbrooke St W 44 kV Subtransmission - $250,000: Road relocation by the City of Peterborough.
- Sherbrooke St W 27.6 kV - $500,000: Road relocation by the City of Peterborough

SERVICE QUALITY & RELIABILITY PERFORMANCE

PDI tracks service reliability statistics SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index) including and excluding loss of supply related incidents. However, reliability statistics excluding loss of supply have only been recorded since 2010. The following shows results for the past three years.

Table 2-19: Service Quality and Reliability Performance 2009-2011

Year	SAIDI	SAIFI	CAIDI
Including Loss of Supply			
2009	4.60	1.77	2.60
2010	2.22	1.59	1.39
2011	5.16	2.73	1.89
Excluding Loss of Supply			
2010	2.11	1.51	1.40
2011	5.01	2.67	1.88

In addition to the reliability indices, PDI also measures service quality indicators ("SQIs"). The table below summarizes PDI's reported SQIs for the historical year 2009. In 2010, the SQI's were replaced by the Electricity Service Quality Requirements (ESQRs).

Table 2-20 - Reported Service Quality Indicators (SQIs)

Indicator	OEB Minimum Standard	2009	2010	2011
Low Voltage Connections	90% within 5 days	100.00%	99.00%	95.30%
High Voltage Connections	90% within 10 days	100.00%	100.00%	100.00%
Telephone Accessibility	65% of calls answered within 30 seconds	78.30%	73.00%	77.90%
Appointments - Met	90% of the time	97.80%	95.00%	98.60%
Written Responses to Inquiries	80% within 10 days	99.10%	99.70%	99.30%
Emergency Response - Urban Areas	80% within 60 minutes	91.90%	100.00%	94.90%
Emergency Response - Rural Areas	80% within 120 minutes	N/A	N/A	N/A
Telephone Call Abandon Rate	Abandoned after 30 seconds - less than 10% of the time	2.80%	1.70%	1.40%
Appointments Scheduling	90% within 5 days	81.50%	92.20%	96.60%
Rescheduling a Missed Appointment	Call in advance and reschedule within 1 day - 100% of the time	94.90%	32.60%	1.40%
Reconnection Performance Standard	85% within 2 days			100.00%

Rescheduling Missed Appointments

PDI did not achieve its target for this measurement. On August 1, 2012 PDI implemented a new procedure using an auto-dialer to inform customers in advance when appointments must be rescheduled. The process is still being refined which includes correcting invalid phone numbers. PDI expects to achieve the target level of 100% in 2013.

ALLOWANCE FOR WORKING CAPITAL:

Overview and Calculation by Account:

PDI's working capital allowance is forecast to be $12,071,592 for 2013 based on the methodology outlined on page 17 of the Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 28, 2012. Namely, 13% of the sum of Cost of Power and Controllable Expenses (Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General), as illustrated in the table below. PDI has provided its Cost of Power calculations below.

Table 2-21 - Working Capital Calculation

	2013 Test Year
Operations	1,939,510
Maintenance	1,440,822
Billing & Collecting	2,474,467
Administration & General	3,383,992
Taxes other than Income Taxes	105,000
Total Operating Expenses for Working Capital Allowance	9,343,791
Cost of Power	83,514,611
Total Base for Working Capital Allowance	92,858,402
Working Capital Allowance (13%)	**12,071,592**

Cost of Power:

PDI has calculated cost of power for the 2012 Bridge year and 2013 Test year based on the results of the load forecast which is discussed in detail in Exhibit 3. The electricity prices used in the calculation were the published prices in the OEB's Regulated Price Plan Report – May 1, 2012 to April 30, 2013. PDI will update the electricity prices should the OEB publish a revised Regulated Price Plan Report prior to a Decision. The cost of power calculations for the 2012 Bridge Year and the 2013 Test Year are provided in the following Tables.

Table 2-22 – Cost of Power Calculation 2012

2012 Load Forecast	kWh	kW	2011 %RPP
Residential	294,333,518		91%
General Service < 50 kW	113,597,004		85%
General Service 50 to 4,999 kW	348,573,781	856,761	10%
Large User	55,262,516	116,439	0%
Street Lighting	5,513,077	15,150	0%
Sentinel Lighting	732,275	2,092	24%
Unmetered Scattered Load	1,646,926		9%
TOTAL	819,659,097	990,442	

Electricity - Commodity RPP	2012	2012 Loss			
Class per Load Forecast RPP	Forecasted	Factor		2012	
Residential	267,843,501	1.0487	280,887,479	$0.08069	$22,664,811
General Service < 50 kW	96,557,453	1.0487	101,259,801	$0.08069	$8,170,653
General Service 50 to 4,999 kW	34,857,378	1.0487	36,554,932	$0.08069	$2,949,617
Large User	0	1.0171	0	$0.08069	$0
Street Lighting	0	1.0487	0	$0.08069	$0
Sentinel Lighting	175,746	1.0487	184,305	$0.08069	$14,872
Unmetered Scattered Load	148,223	1.0487	155,441	$0.08069	$12,543
TOTAL	399,582,301		419,041,959		$33,812,496

Electricity - Commodity Non-RPP	2012	2012 Loss			
Class per Load Forecast	Forecasted	Factor		2012	
Residential	26,490,017	1.0487	27,780,081	$0.07877	$2,188,237
General Service < 50 kW	17,039,551	1.0487	17,869,377	$0.07877	$1,407,571
General Service 50 to 4,999 kW	313,716,403	1.0487	328,994,392	$0.07877	$25,914,888
Large User	55,262,516	1.0171	56,207,505	$0.07877	$4,427,465
Street Lighting	5,513,077	1.0487	5,781,564	$0.07877	$455,414
Sentinel Lighting	556,529	1.0487	583,632	$0.07877	$45,973
Unmetered Scattered Load	1,498,703	1.0487	1,571,690	$0.07877	$123,802
TOTAL	420,076,796		438,788,240		$34,563,350

Transmission - Network		Volume			
Class per Load Forecast		Metric		2012	
Residential		kWh	308,667,560	$0.0066	$2,037,206
General Service < 50 kW		kWh	119,129,178	$0.0060	$714,775
General Service 50 to 4,999 kW		kW	856,761	$2.4345	$2,085,785
Large User		kW	116,439	$2.8683	$333,982
Street Lighting		kW	15,150	$1.8350	$27,800
Sentinel Lighting		kW	2,092	$1.8487	$3,867
Unmetered Scattered Load		kWh	1,727,131	$0.0060	$10,363
TOTAL					$5,213,778

Transmission - Connection		Volume			
Class per Load Forecast		Metric		2012	
Residential		kWh	308,667,560	$0.0047	$1,450,738
General Service < 50 kW		kWh	119,129,178	$0.0043	$512,255
General Service 50 to 4,999 kW		kW	856,761	$1.6613	$1,423,337
Large User		kW	116,439	$2.0352	$236,977
Street Lighting		kW	15,150	$1.2884	$19,519
Sentinel Lighting		kW	2,092	$1.3191	$2,760
Unmetered Scattered Load		kWh	1,727,131	$0.0043	$7,427
TOTAL					$3,653,012

Wholesale Market Service					
Class per Load Forecast				2012	
Residential			308,667,560	$0.0052	$1,605,071
General Service < 50 kW			119,129,178	$0.0052	$619,472
General Service 50 to 4,999 kW			365,549,324	$0.0052	$1,900,856
Large User			56,207,505	$0.0052	$292,279
Street Lighting			5,781,564	$0.0052	$30,064
Sentinel Lighting			767,937	$0.0052	$3,993
Unmetered Scattered Load			1,727,131	$0.0052	$8,981
TOTAL			857,830,200		$4,460,717

Rural Rate Assistance					
Class per Load Forecast				2012	
Residential			308,667,560	$0.0013	$401,268
General Service < 50 kW			119,129,178	$0.0013	$154,868
General Service 50 to 4,999 kW			365,549,324	$0.0013	$475,214
Large User			56,207,505	$0.0013	$73,070
Street Lighting			5,781,564	$0.0013	$7,516
Sentinel Lighting			767,937	$0.0013	$998
Unmetered Scattered Load			1,727,131	$0.0013	$2,245
TOTAL			857,830,200		$1,115,179

Low Voltage					
Class per Load Forecast				2012	
Residential			294,240,107	$0.0009	$266,882
General Service < 50 kW			112,158,205	$0.0008	$92,884
General Service 50 to 4,999 kW			862,025	$0.3187	$274,710
Large User			113,561	$0.3904	$44,334
Street Lighting			14,877	$0.2471	$3,676
Sentinel Lighting			1,993	$0.2530	$504
Unmetered Scattered Load			1,632,744	$0.0008	$1,352
TOTAL			409,023,512		$684,342

Table 2-23 – Summary of Cost of Power Calculation 2012

	2012
4705-Power Purchased	$68,375,845
4708-Charges-WMS	$4,460,717
4714-Charges-NW	$5,213,778
4716-Charges-CN	$3,653,012
4730-Rural Rate Assistance	$1,115,179
4750-Low Voltage	$684,342
TOTAL	**83,502,874**

Table 2-24 – Cost of Power Calculation 2013

Electricity - Commodity RPP	2013	2013 Loss			
Class per Load Forecast RPP	**Forecasted**	**Factor**		**2013**	
Residential	267,758,497	1.0550	282,485,215	$0.08069	$22,793,732
General Service < 50 kW	95,334,474	1.0550	100,577,870	$0.08069	$8,115,628
General Service 50 to 4,999 kW	35,071,561	1.0550	37,000,496	$0.08069	$2,985,570
Large User	0	1.0171	0	$0.08069	$0
Street Lighting	0	1.0550	0	$0.08069	$0
Sentinel Lighting	167,459	1.0550	176,669	$0.08069	$14,255
Unmetered Scattered Load	146,947	1.0550	155,029	$0.08069	$12,509
TOTAL	**398,478,938**		**420,395,279**		**$33,921,695**

Electricity - Commodity Non-RPP	2013	2013 Loss			
Class per Load Forecast	**Forecasted**	**Factor**		**2013**	
Residential	26,481,610	1.0550	27,938,098	$0.07877	$2,200,684
General Service < 50 kW	16,823,731	1.0550	17,749,036	$0.07877	$1,398,092
General Service 50 to 4,999 kW	315,644,045	1.0550	333,004,467	$0.07877	$26,230,762
Large User	53,896,862	1.0171	54,818,498	$0.07877	$4,318,053
Street Lighting	5,413,675	1.0550	5,711,427	$0.07877	$449,889
Sentinel Lighting	530,285	1.0550	559,451	$0.07877	$44,068
Unmetered Scattered Load	1,485,797	1.0550	1,567,516	$0.07877	$123,473
TOTAL	**420,276,004**		**441,348,494**		**$34,765,021**

Transmission - Network		Volume			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	310,423,313	$0.0063	$1,955,667
General Service < 50 kW		kWh	118,326,906	$0.0057	$674,463
General Service 50 to 4,999 kW		kW	862,025	$2.3111	$1,992,226
Large User		kW	113,561	$2.7230	$309,227
Street Lighting		kW	14,877	$1.7420	$25,916
Sentinel Lighting		kW	1,993	$1.7550	$3,498
Unmetered Scattered Load		kWh	1,722,545	$0.0057	$9,819
TOTAL					**$4,970,815**

Transmission - Connection		Volume			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	310,423,313	$0.0046	$1,427,947
General Service < 50 kW		kWh	118,326,906	$0.0042	$496,973
General Service 50 to 4,999 kW		kW	862,025	$1.6162	$1,393,205
Large User		kW	113,561	$1.9799	$224,839
Street Lighting		kW	14,877	$1.2534	$18,647
Sentinel Lighting		kW	1,993	$1.2833	$2,558
Unmetered Scattered Load		kWh	1,722,545	$0.0042	$7,235
TOTAL					**$3,571,404**

Wholesale Market Service					
Class per Load Forecast				**2013**	
Residential			310,423,313	$0.0052	$1,614,201
General Service < 50 kW			118,326,906	$0.0052	$615,300
General Service 50 to 4,999 kW			370,004,963	$0.0052	$1,924,026
Large User			54,818,498	$0.0052	$285,056
Street Lighting			5,711,427	$0.0052	$29,699
Sentinel Lighting			736,120	$0.0052	$3,828
Unmetered Scattered Load			1,722,545	$0.0052	$8,957
TOTAL			**861,743,773**		**$4,481,068**

Rural Rate Assistance					
Class per Load Forecast				**2013**	
Residential			310,423,313	$0.0013	$403,550
General Service < 50 kW			118,326,906	$0.0013	$153,825
General Service 50 to 4,999 kW			370,004,963	$0.0013	$481,006
Large User			54,818,498	$0.0013	$71,264
Street Lighting			5,711,427	$0.0013	$7,425
Sentinel Lighting			736,120	$0.0013	$957
Unmetered Scattered Load			1,722,545	$0.0013	$2,239
TOTAL			**861,743,773**		**$1,120,267**

Low Voltage					
Class per Load Forecast				**2013**	
Residential			294,240,107	$0.0009	$266,882
General Service < 50 kW			112,158,205	$0.0008	$92,884
General Service 50 to 4,999 kW			862,025	$0.3187	$274,710
Large User			113,561	$0.3904	$44,334
Street Lighting			14,877	$0.2471	$3,676
Sentinel Lighting			1,993	$0.2530	$504
Unmetered Scattered Load			1,632,744	$0.0008	$1,352
TOTAL			**409,023,512**		**$684,342**

1 **Table 2-25 – Summary of Cost of Power Calculation 2013**

	2013
4705-Power Purchased	$68,686,716
4708-Charges-WMS	$4,481,068
4714-Charges-NW	$4,970,815
4716-Charges-CN	$3,571,404
4730-Rural Rate Assistance	$1,120,267
4750-Low Voltage	$684,342
TOTAL	**83,514,611**

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GREEN ENERGY PLAN

PDI has submitted a basic Green Energy Plan to the OPA and has provided a copy in Appendix D. The OPA provided a Letter of Comment which has been provided at the end of Appendix D. As part of its plan PDI has estimated capital spending requirements in excess of the amount funded by the generator of $207,000 in 2012. This amount is an estimate. The actual costs and the amount to be invoiced to the generator will be determined when the project is complete. PDI is not requesting a funding adder at this time.

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Appendix C

Asset Management Plan

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PETERBOROUGH DISTRIBUTION INC.

Peterborough Distribution Inc.

ASSET MANAGEMENT PLAN

Prepared by: J.T. Guilbeault, P.Eng., V.P. Electric Utility *September 2012*

ASSET MANAGEMENT REPORT

Table of Contents

1.0 BACKGROUND

1.1 PDI's Current System

Peterborough Distribution Incorporated (PDI) is the electrical distributor for the City of Peterborough, as well as the Village of Lakefield and the Town of Norwood. In total PDI supplies electricity to over 35,000 customers.

Electricity is distributed to the City of Peterborough from the provincial transmission grid by two primary Hydro One Network Inc. sources:

- Otonabee Transformer Station (TS): south-east of the City of Peterborough.
- R.L. Dobbin Transformer Station (TS): north-west of the City of Peterborough (one supply from Dobbin DS).

Main supply circuits are either 44 kV or 27.6 kV, however, a significant portion of the distribution system supplies customers from 44/4.16 kV municipal substations which is the older legacy distribution system.

The Lakefield distribution system operates at 4.16 kV from a PDI owned 44/4.16 kV municipal substation supplied from a Hydro One 44 kV circuit from Otonabee TS.

The Norwood distribution system is supplied by 8.32 kV circuits from a Hydro One 44/8.32 kV distribution substation supplied from a Hydro One 44 kV circuit from Otonabee TS.

1.2 Historical Context

The modern day Peterborough Distribution Inc. (PDI) system was constructed over a period of sixty to seventy years using 44 kV sub-transmission and 4.16 kV distribution systems. The original sole source of bulk grid system supply was from R.L. Dobbin TS with four 44 kV dedicated circuits.

R.L. Dobbin TS has one main 230 kV supply circuit from the large Cherrywood switching station on the shores of Lake Ontario. Dobbin TS also has two 230 kV circuits from the east that originate from the Ottawa River generation facilities. These two 230 kV circuits from the east cannot provide sufficient voltage support to Dobbin TS without the 230 kV circuit from Cherrywood. In the late 1970's concern began to arise due to load growth in the Peterborough area and its effect on Dobbin TS. In fact, during the 1980's an automatic load rejection scheme was added to Dobbin TS and was actually armed several times in the late 1980's and early 1990's. The scheme is still in place but has not been armed since the mid 1990's.

After a regional study was completed, it was decided to introduce a new TS in the south-east area of the City of Peterborough to relieve Dobbin TS and provide an alternate source of supply from the provincial grid to the City of Peterborough and the surrounding area. Peterborough Distribution Inc. participated in a regional supply study to determine the distribution voltage level that would be supplied to the City of Peterborough and surrounding area. The final decision was to provide two voltages: 44 kV to support the existing sub-transmission supply points at Dobbin TS and introduce 27.6 kV distribution. The introduction of 27.6 kV direct distribution supplies from the 230 kV transmission network was seen as the most efficient voltage system overall for high-density urban areas for the foreseeable future. The 27.6 kV system was less restrictive than the 4.16 kV system in supplying medium sized loads (500 to 3000 kW) and provided a less costly alternative to 44 kV for medium sized loads. The 27.6 kV voltage level could carry more load capacity on the same size lines and would not experience the voltage drop that is prevalent on the 4.16 kV system. The 44 kV system would be retained to supply larger sized commercial and industrial loads (>3000 kW).

The new south-east TS was approved and the planning and design began in the mid 1980's. In the interim a temporary solution was required to fill the gap until the new TS and the 27.6 kV direct supplies were constructed and commissioned. This temporary measure was Dobbin HVDS, a 115 kV to 27.6 kV high voltage distribution station supplied and supported from the local 115 kV grid that stretches from Peterborough to Port Hope and on to Belleville. Two 27.6 kV limited capacity shared (with Hydro One) feeders were constructed and commissioned in 1987.

Since 1987 Peterborough has been expanding the 27.6 kV distribution system with the objective of eliminating some of the 4.16 kV system and reducing the number of 44-4.16 kV substations and distribution feeders. It was expected that this conversion would lead to improved efficiency in the delivery of electricity.

Otonabee TS, the new south-east transformer station was energized and finally commissioned in January of 1992. Initially, Peterborough received two 44 kV feeders and two 27.6 kV feeders from the new TS. Peterborough was asked to convert and transfer as much load as it could to the new TS to relieve the load on Dobbin TS

Currently, the two transformer stations (Dobbin and Otonabee) supply Peterborough with six (6) dedicated 44 kV feeders and four (4) dedicated 27.6 kV feeders. In addition, Peterborough still uses the one shared limited capacity 27.6 kV circuit from Dobbin HVDS. The 27.6 kV system from Otonabee TS has been expanded since 1992 to cover most areas of the City with selected conversions of the 4.16 kV overhead and underground system. Two municipal substations have been retired. A third is to be retired in 2012. A number of 4.16 kV feeders have been eliminated over this time period.

In 2002, Peterborough added two additional territories in Lakefield and Norwood. They are relatively low growth areas and will remain using the existing 4.16 kV and 8.32 kV distribution voltages for the foreseeable future. Recently, 44 kV sub-transmission was added to the Lakefield territory with two larger customers being supplied at 44 kV level.

1.3 Asset Summary

PDI's distribution assets are made up of the following major groups:

Asset Description	Quantity
TS Supply Points	11
Municipal Substations	16
Breaker Stations	6
SCADA System	1
Distribution Transformers	3864
Meters	35,501
Poles	10,000
Overhead Conductors (equivalent circuit km)	386
Underground Cables (equivalent circuit km)	168

Table 1

1.4 System Growth

Since its inception over 100 years ago, the Peterborough distribution network has experienced several cycles of relatively steady growth and as such, the infrastructure has varying ages reflecting those periods of growth. The City anticipates future growth at about 0.5 - 1% annually and has identified future growth areas in the four corners of the City. Most of this new growth area is not currently in the PDI territory. PDI will respond to the forecasted growth with continued expansion of the 27.6 kV network within the City of Peterborough.

PDI has been working on a long term model to study future grid configurations in order to develop a longer term infrastructure plan to meet anticipated future electrical demands. It remains PDI's objective to systematically replace existing legacy 4.16 kV distribution system in the City of Peterborough with a 27.6 kV distribution system over time.

Recent growth in the system load is shown in Table 2. Load, population and customer growth has been increasing at a steady rate, although, consumption growth per capita has remained stable with growth being offset with recent conservation efforts. The assumption is that the Peterborough area will continue to grow at a relatively steady and lower rate for the foreseeable future.

Conservation programs and targets are expected to have a mitigating effect on system load growth.

System Growth			
Year	**Customers (Average)**	**Annual Consumption kWh**	**Demand MW**
2000	30,344	741,828,624	132.938
* 2001	32,596	770,563,486	139.017
2002	32,677	808,921,986	134.213
2003	32,844	805,996,163	139.532
2004	33,230	790,191,455	151.842
2005	33,484	822,852,234	143.290
2006	33,698	810,188,267	150.074
2007	34,004	820,191,487	144.554
2008	34,200	825,000,000	148.222
2009	34,299	747,836,759	138.000
2010	34,918	837,923,903	155.100
2011	35,406	848,545,506	161.697

Table 2

*Lakefield Distribution and Norwood Distribution were added in 2001

1.5 Historical Capital & Maintenance Planning

Capital planning through the later 1980's and into the 1990's focused on voltage conversion and 27.6 kV system expansion, encouraging removal of 4.16 kV plant while retaining system options that preserved reliability. This philosophy in combination with good preventative maintenance techniques has resulted in a good reliability record at the utility (data is provided in section 2.3).

Reliability trends demonstrate a good record. PDI believes the record can be sustained over the long term by obtaining and analyzing condition information on in-service infrastructure more consistently than has been done historically. In recent years, the utility has been working at establishing long term funding levels for capital infrastructure renewal, system improvements and maintenance activities which support the sustainability philosophy. Any gaps in data pertaining to asset age and condition must be captured to assist in determining what funding and in what proportion (between capital and maintenance) is optimum for the utility. In addition this data will assist in establishing predictive tools for predicting infrastructure failures before they occur so that replacement or refurbishment strategies can be planned.

In addition to a long term strategy for system expansion and ongoing maintenance efforts, PDI continues to develop its' asset management strategy for long term system renewal. The system renewal strategy recognizes that existing infrastructure has a limited lifespan and that maintaining the system in a good working order requires an ongoing re-investment of capital. Failure to do so will have negative consequences on future system reliability, public safety and the financial health of the utility. In the past PDI capital budgets have recognized both system expansion and to a lesser degree plant renewal. In the last decade, capital spending has been set to match depreciation allowances for renewal of existing infrastructure plus customer requirements and system enhancements. The asset management plan is meant to take a long term view of the utilities' assets and provide a framework for decision making and evaluating progress.

In a highly regulated environment where expenditures and revenues require increasing justification, spending levels demand a more measured approach to the needs analysis. Future spending levels need to target long term objectives both in terms of an overall infrastructure plan and a regular maintenance schedule.

2.0 ASSET MANAGEMENT APPROACH

2.1 General

As each item of infrastructure has a finite lifespan, as each item reaches its functional limits the overall reliability of the system begins to decrease and affects the service level to the customer. A comprehensive long term asset management approach is required to verify the effectiveness of the expenditures to ensure that corporate objectives for safety, reliability and efficiency are being met and maintained. The asset management approach views assets over their entire life spans, helping to determine optimal points to spend on maintenance and replacement to maximize life spans and reliability. In addition, a long term plan for the entire electric distribution system is being developed in order to have a road map which will help guide system expansion plans, system renewal, conversion and routine maintenance.

Further study and a more in-depth review of each category of infrastructure is underway, some infrastructure should be replaced on a timed schedule, some based on condition data and some more minor elements are appropriate to run to failure.

The criteria for many years to determine the annual capital budget commitment required to maintain current in-service infrastructure was based on depreciation or in some cases the total replacement cost divided by the average lifespan. In the case of lifespan if an element lasts 50 years the average annual capital replacement cost is 1/50th the initial cost. Alternatively, the annual capital cost could be determined by what elements of infrastructure reached the end of their lifespan in the current year, however, the annual capital replacement budget could vary widely year to year. Neither of these alternatives takes into account PDI's strategic objectives or infrastructure plan, but simply arrives at a dollar figure for annual capital expenditure. Good decisions which enhance system safety and reliability rely on access to data and information about capital assets, their age, condition and historical track record. Some of this information is available from the present database but other information needs to be acquired in the field.

Some infrastructure has reached an age approaching its predicted service life and therefore may require more significant financial inputs earlier in the life cycle of the asset. In addition, the nature of the infrastructure itself means that cycles of budget spikes will occur in relation to the age of infrastructure. The annual costs demonstrated in the plan do not include system expansion or customer demand, which is expected to continue at a similar pace to recent expenditures in order to match load growth in the City. Some allowance for system enhancements in advance of end of asset life cycle needs to be considered to improve the reliability and operation of the distribution system. Finally, the investigation of activities which could extend the life of some items of infrastructure needs to be part of the ongoing plan which may mitigate annual capital requirements or proposed increases. New design and equipment standards will also be considered to facilitate extending the life of assets or make replacement easier and more efficient.

The Ontario Energy Board has recently provided Typical Useful Life (TUL) guidelines that they are encouraging the LDC's to adopt. PDI is currently reviewing this information and making adjustments to the traditional life spans of many assets. The adoption of IFRS accounting standards may have an effect on the determination of optimum capital spending levels. Detailed analysis of the assets by class will assist in developing a more effective strategy for the division of labour and expenditures related to the three categories of activities; system expansion, system renewal and system maintenance.

A review of the data (see Table 12) reveals that annual capital expenditures are expected to rise in the coming 15 years from $3M to about $4M in a 15 year planning horizon for infrastructure renewal exclusive of system expansion or enhancement expenditures. Each class of assets is looked at in subsequent sections that show a more specific timetable for replacing the assets based on projected life cycle (assets are predicted to be replaced at the limit of their life spans or TUL).

Decisions about the specific capital budget will be made using the asset inventory information and based on a series of evaluation criteria as follows:

- Safety: Public and worker safety is a primary objective.
- Regulatory Compliance: Ensure the utility complies with all regulatory obligations (safety, environmental, operational, etc).
- Efficiency/ Losses: Maximize efficiencies and minimize losses.
- Reliability: Ensure we are meeting acceptable reliability service levels.
- Condition/Age: Evaluate the relationship between age and operating condition and determine the impact on other criteria.
- Expansion/Conversion: Decisions should be made considering system enhancements and growth forecasts.

2.2 System Plan

The main tenets of the system plan are to maintain the existing 44 kV sub-transmission grid and the 27.6 kV distribution grid. PDI's six 44 kV feeder positions are not fully loaded at present and provide sufficient load capacity for the City of Peterborough for the foreseeable future. The continued growth and enhancement of the 27.6 kV grid is the main thrust for distribution. It is the system of the future as the legacy 4.16 kV system is eventually eliminated. The 27.6 kV grid distributes electricity more efficiently and provides more flexibility for servicing the customer. There can be some operational challenges at the 27.6 kV level given the higher electrical stress and longer feeders with more customers affected when disturbances are experienced. Currently there are four main 27.6 kV feeders and one other smaller capacity supply point. There is some load capacity remaining on these feeder positions but a plan is required to continue to add additional 27.6 kV supply points. There are three significant needs currently in the 27.6 kV grid at the moment.

The first is the Parkhill Rd. W. gap (from Monaghan Rd. to Wallis Dr.) in the 27.6 kV grid. Completing this connection will allow some load balancing to occur and relieve pressure on the Otonabee TS 27.6 kV feeder designated the M8 which is extremely long and heavily loaded serving a large number of customers. This connection will also allow considerable more flexibility during operation of the 27.6 kV grid both during normal operations and emergency situations. Phase I of this project is underway in 2012.

The second need is for a new supply source to handle normal system and conversion load growth. A feeder position is currently available at Otonabee TS but it is far removed from the northern sections of the Peterborough territory and would take several millions of dollars and a significant construction period to get it there. At the moment there is a significant amount of new development taking place in the north and north-west regions of Peterborough. The proposed solution is to build a new 44-27.6 kV substation (designated MS #65) in the north to provide that new source of supply. This project is underway in 2012.

The third need after the construction of the new 44-27.6 kV substation will be to expand the grid in the north and north-east sections of Peterborough where no 27.6 kV currently exists. There is some development activity beginning in that area and a larger potential for more. The current 4.16 kV substation capacity in the north region is inadequate to supply the new development. Relief will also be needed for the Otonabee TS feeder designated the M9 as it is also very long and serves a large number of customers including the busy Chemong Road commercial section and the downtown business area.

As noted, the long term system plan of eliminating the 4.16 kV system will take a couple of decades at its current pace. It needs to be done in an orderly fashion to maintain system reliability for those customers still served by the legacy system. The next substation slated for de-commissioning is MS #21 (Water St. N.) which will occur after the construction of the new 44-27.6 kV substation and some expansion of the 27.6 kV takes place on Water St. N. This will help with growth and expansion in the north and north-east sections of the City.

In the longer term the next substation for consideration to be de-commissioned is MS #19 (Parkhill Rd. W.). This is a more modern indoor station configuration and the property should be retained for a future 44 – 27.6 kV substation to provide a new 27.6 kV source in the north-west region of Peterborough. The new north-end and west-end sources will compliment all of the 27.6 kV sources from Otonabee TS located in the south-east extremity of the City and address the growth occurring in the north and north-west areas. The planning term for this would be five to eight years.

Subsequently, substations MS 35 (Sherbrooke St. W.) and MS 18 (Lansdowne St. W.) would be de-commissioned and provide potential new sites for 44 – 27.6 kV substations and new west end 27.6 kV sources to balance those from the south-east. The timing of these would be dependent on system load growth and the pace of conversion from 4.16 kV to 27.6 kV. Into the future all of the indoor configured substation sites should be retained for similar redevelopment. Any outdoor configured substation sites that are decommissioned would have to be evaluated for future use and value to PDI as required.

The majority of newer indoor stations have relatively more modern equipment that can be re-deployed at older stations to extend their useful life while conversion is ongoing.

2.3 Infrastructure Assets

2.3.1 Poles

Typical industry practice has linked pole replacement to other works, failures or age and condition assessments. Voltage conversion projects, customer servicing needs or municipal reconstruction projects have initiated pole replacements, otherwise poles have been replaced due to failure from accidents or deterioration. On average the utility has replaced between 20 and 30 poles per year as a result of accidents or individual condition assessments. The current inventory of poles shows approximately 10,000 poles in service. Average total estimated replacement cost for a wood pole is $5,000 (installed excluding hardware and transformer replacements).

PDI's poles are predominantly western red cedar with a small portion of concrete poles and on average existing poles have been in service for 32 years. Industry average life expectancy for western red cedar poles is about 50 plus years with many exceeding that. Closer investigation of the data reveals pockets of poles near or past their anticipated lifespan. Based on available data to simply replace poles based on their normal life expectancy the utility should annually replace a total of 200 poles per year. This is not practical given current economic realities and probably unnecessary.

The utility began to perform systematic pole inspections in late 2008, therefore data linking age with condition is only partly available to confirm specifics about when poles should be taken out of service. In combination with changing standards and planned system upgrades it may not be wise to replace groups of poles in kind. For example, many older poles are located in back yard distribution systems which the utility wishes to remove, so until a plan for the replacement of the backyard systems is completed or required, these poles may be best left in place. Backyard replacements are under review based on most urgent priorities. In some cases only transformers and primary conductor will be removed allowing for the installation of smaller less expensive poles.

Table 3 shows the age distribution of PDI in service poles based on available data. Typical useful life (TUL) under the Kinetrics report is 45 years. The predominant use of western red cedar by PDI and preliminary testing results probably extends that TUL beyond that to 55 or 60 years. Table 3 indicates about 20% of poles beyond the TUL of 45 years, in addition, the table shows a slightly increasing age trend.

Pole Assets 2011	
Age	Number
5	252
10	240
15	1,241
20	1,364
25	1,472
30	1,470
35	591
40	674
45	764
50	483
55	608
60	417
65+	424
Total	10,000
Average Age	32

Table 3

PDI has undertaken a formal pole testing regime since 2008 which includes an estimated 1,000 poles per year to be tested. The pole's condition is evaluated and the results of those tests have assisted the utility in developing a pole testing cycle and replacement program. The benefits of a testing program have been established by industry experts wherein as many as two thirds of unnecessary poles replacements may be eliminated (for poles which remain in good condition past their anticipated lifespan) furthermore, certain deterioration mechanisms can be deterred or reversed using repair or life extension techniques.

The pole's condition once tested is classified as hazard (immediate replacement), recommended for replacement (replacement is scheduled) and not recommended for replacement (placed back in testing schedule). Poles that are classed as a hazard are reviewed by line staff and replaced as soon as possible or reclassified if warranted. Poles tagged for replacement are placed on the replacement schedule and the remaining poles with expected life remaining of 5 plus years are returned to the testing schedule. Since the program began in 2008 the PDI has tested 3,698 poles to the end of 2011. PDI has replaced 74 poles deemed to require more imminent replacement. The approximately 82 poles on the replacement list are less urgent and have been scheduled for replacement. Some poles scheduled for replacement will be part of a larger planned overhead line re-build or road relocation projects by the Municipality. Most of the poles tested expected to be at or near the end of life were deemed to have significant service life left.

The number of poles to be replaced may decrease or increase as the testing moves into newer or older areas of the service territory. As the testing program continues PDI will evaluate the results and reassess the ongoing expenditure level in the program. Initial evaluation suggests that the program levels may need to be ramped up in the coming years to catch up and smooth the peak replacement periods.

2.3.2 Underground Cable

The largest portion of underground primary high voltage cable assets is located in the underground residential subdivisions throughout the PDI territory. The remaining minority portion of assets is located in the downtown Peterborough underground system and the municipal substations. Those assets are managed separately on an individual case basis. About two thirds of the downtown assets have been converted to 27.6 kV and replaced in the last 20 years.

Most residential developments in Peterborough have been serviced using underground primary cable and secondary services since the late 1950's, prior to this most areas were serviced by overhead lines, either from street front pole lines or rear yard pole lines. A City of Peterborough Bylaw in 1994 made new underground residential servicing mandatory (except for main feeder lines which can remain overhead).

Underground servicing in Peterborough initially utilized direct buried primary high voltage cable supplying transformers which in turn supply secondary "buss" cables which provide several radial supply cables connecting up to sixteen residences. Prior to the 1970's submersible transformers contained in concrete vaults were utilized, since the mid 1980's primary cables have been contained in ducts and pad mounted transformers have been utilized. Direct buried cables have an average life expectancy of about 30 years depending on the in-situ conditions, rated operating voltage, the manufacture generation and their design standard specifications. Table 4 shows a summary of the existing in-service underground primary high voltage cables.

Underground Distribution Assets - 2011							
Infrastructure Category	Qty	Unit	Age Profile (Years)				
			5	10	20	30	40
44 kV Underground Distribution Lines							
Main Feeders - Three Phase	0.4	km	0.0	0.4	0.0	0.0	0.0
Station Supplies - Three Phase	1.3	km	0.0	0.3	0.0	0.4	0.6
27.6 kV Underground Distribution Lines							
Main Feeders - Three Phase	1.3	km	1.0	0.0	0.3	0.0	0.0
Distribution - Three Phase	13.0	km	0.2	5.4	7.4	0.0	0.0
Distribution - Single Phase	79.7	km	16.0	25.0	28.2	10.5	0.0
4.16 Underground Distribution Lines							
Station Supplies - Three Phase	11.7	km	0.0	2.8	7.3	0.4	1.2
Distribution - Three Phase	4.3	km	0.0	0.0	1.5	1.6	1.2
Distribution - Single Phase	57.0	km	5.0	5.0	18.0	21.0	8.0
Total Underground Primary Line Assets	168.7	km*	22.2	38.9	62.7	33.9	11.0

Table 4

**circuit kilometres*

PDI has had an underground rehabilitation program in place since the early 1990's wherein the underground primary cables are replaced and the submersible transformers are removed from the underground vaults and replaced with above ground pad-mounted transformers. Where possible the system voltage is converted from 4.16 kV to 27.6 kV and the load transferred to the new 27.6 kV distribution system as part of the overall distribution system strategy. To date, approximately 80% of the rehabilitation projects have also completed a voltage conversion.

The asset management strategy in this program is age and condition based. High voltage primary cables that are not 27.6 kV rated are targeted for replacement. PDI began installing 27.6 kV rated cables in 1985 prior to the introduction of the 27.6 kV system in 1987. Distribution system primary cables installed prior to 1985 and rated for operation below 27.6 kV are considered to be first generation cables and do not fit in the long term system strategy. These cables are targeted for replacement and conversion. Of those first generation assets considered for replacement the program first targets areas that have submersible transformers still in service, decreased reliability performance, oldest assets in service and whether the load conversion aids in the overall system plan.

Underground residential distribution design has improved since 1985 so once the first generation cables have been replaced, the strategy may change from replacement to rejuvenation options. Newer generation cables are expected to have longer service life due to cable design improvements (e.g. jackets, tree retardant insulation) and installation in ducts. Recently, individual services in ducts have replaced the direct buried "buss" system allowing for improved service life and easier and less costly replacement. Primary high voltage cable is targeted in this program because of the higher impact to a larger number of customers. Secondary low voltage cables typically have a longer life span and impact far fewer customers upon failure. Secondary low voltage cables are targeted for replacement on an ad hoc basis due to failure or other actions initiating replacement (e.g. customer service upgrade).

The current capital expenditure for this program is on average $500,000 per year. The actual amount varies each year depending on the scope of a project or contractor pricing.

2.3.3 Municipal Substations

PDI currently owns six (6) breaker stations and sixteen (16) distribution substations situated throughout the city with one located in Lakefield. Distribution substations convert incoming 44 kV sub-transmission voltage to a local distribution voltage of 4.16 kV. Breaker Stations are system control points on the 44 kV sub-transmission system that provide system protection, by way of fault and overload protection, in addition these stations provide the utility with the ability to redistribute load between 44 kV feeders to facilitate maintenance, construction activities and outage restoration. There is significantly less equipment in a breaker station and they can be bypassed in an emergency situation.

The PDI distribution system reached its all time peak winter load in December of 1989 at 156 MW. There was only four 44 kV sub-transmission feeders supplying the City at the time. During that period most substations were overloaded and were difficult to take out of service for maintenance. Currently, there are no 4.16 kV substations that are overloaded and all but one has peak loads less than 75% of their capacity. This is primarily due to the 27.6 kV conversion program underway since 1987. Today, substations are easily removed for maintenance and can be supplied by other substations if a failure occurs.

The long term distribution system plan is to eliminate the 4.16 kV distribution system by converting existing load to the 27.6 kV system. Generally, this is accomplished by converting the outside edges of the system first and collapsing the system towards the middle. This method reduces the need to maintain long interties between the remaining substations in order to maintain reliability and provide opportunities to take substations out of service for maintenance and repair. Unfortunately, for the most part, the substations on the outside edge of the system are the newer stations with older stations located in the core. However, as the newer stations on the outer edge are decommissioned the equipment still has a significant amount of remaining service life. The equipment from the newer stations can be kept as system spares or redeployed in the older stations to keep them in service until they can be decommissioned.

PDI has not constructed or added to a 4.16 kV substation since 1979. PDI decommissioned its first substation (MS #24) in the early 2000's. Another substation (MS #6) was recently decommissioned in 2009. In 2012, the substation (MS #36) on Neal Drive will be decommissioned by the end of June. The average age of existing substations is 45 years old; they range in age from 15 to 63 years. Most substations have had upgrades over the decades to some of the equipment, the age in the table will reflect the largest and oldest element typically the power transformer and switchgear. The typical life expectancy of a substation is 60 years.

PDI will likely keep most substation properties after decommissioning to determine if there may be a future use. Table 5 lists the stations, their locations and age.

Distribution Stations - 2011	Year of Installation	Age (Yrs)
M.S. #1, Aylmer Street	1956	55
M.S. #2, Romaine Street	1948	63
M.S. #3, Clifton Street	1950	61
B.S. #4, Auburn Street (breaker station)	1968	43
M.S. #5, Upper High Street	1951	60
M.S. #7, Bellevue Street	1955	56
M.S. #8, Simcoe Street	1956	56
M.S. #9, Ashburnham Drive	1971	40
M.S. #10, Erskine Avenue	1958	53
B.S. #11, Lansdowne Street W. (breaker station)	1960	51
M.S. #12, Langton Street	1965	46
B.S. #13, Jackson Park (breaker station)	1960	51
B.S. #14, Erskine Avenue (breaker station)	1996	15
M.S. #18, Lansdowne Street W.	1978	33
M.S. #19, Wallis Drive	1976	35
M.S. #21, Water Street N.	1966	45
B.S. #21A, Water Street N. (breaker station)	1971	40
M.S. #26, Francis Stewart Road	1972	39
M.S. #29, McDonnell Street	1973	38
B.S. #34, High Street N. (breaker station)	1976	35
M.S. #35, Sherbrooke Street W.	1977	34
M.S. #54 Lakefield	1968	43
Average Station Age		45

Table 5

Distribution substation equipment replacement costs average over $1.5 Million per station, breaker stations cost about $165-$200K depending on the configuration and size. PDI has a regular maintenance and inspection program for distribution and breaker stations. Upgrades to smaller components like insulators, SCADA, battery/charger banks are included in its ongoing capital renewal program; typically these replacements are assessed at the time of the regular maintenance schedule or if a deteriorating condition is identified in a monthly inspection. At this time there is no plan to make wholesale replacements at the 4.16 kV substations.

As the 27.6 kV system grid is expanded and the ongoing voltage conversion program continues many substations will eventually become redundant. It is difficult to predict accurately when a substation can be fully decommissioned but the system plan can be used as guideline for the foreseeable future. Until the time for decommissioning is determined, substations should continue to be maintained and upgraded as necessary. Eventually, parts salvaged from those stations identified as redundant and decommissioned could be used as spares and upgrades for those stations that remain in service.

2.3.4 Overhead Conductors

Overhead conductors compose a significant part of the PDI's infrastructure as it has approximately 386 km of overhead primary conductor operating at high voltages of 4.16 kV, 8.32 kV, 27.6 kV and 44 kV. Associated with the high voltage conductors are a proportional amount of low voltage secondary conductors.

The key attribute for overhead conductor is the size or current carrying capacity. The majority of the primary high voltage system is 556.5 MCM Aluminum installed primarily in the last 40 years particularly on the 27.6 kV and 44 kV systems which now form the critical backbones of the distribution system. This conductor can carry full system feeder capacity so the ability to serve loads on existing feeders is not restricted by conductor size. Smaller portions of the 8.32 kV and 4.16 kV systems have smaller conductor sizes and may present load carrying restrictions in some situations. Overhead conductor has a typical useful life 60 years but it may be replaced when the overhead line is rebuilt, relocated or replaced for other reasons.

Secondary conductors carry localized load and current sizes are more than adequate throughout the distribution system. Secondary low voltage conductors typically have the same life span but there are examples in the system where they have been in service long after their predicted life expectancy. Secondary conductors usually are replaced when overhead lines are rebuilt or based on other factors such as failure, condition assessment or increased load growth.

Table 6 shows the age distribution of the various categories of overhead primary line conductor currently in service.

Overhead Primary Line Assets - 2011														
Infrastructure Category	Qty	Unit	Age Profile (Years)											
			5	10	15	20	25	30	35	40	45	50	55	60
44 kV Overhead Distribution Lines														
	68.2	km	2.5	8.7	7.8	6.9	7.9	8.3	8.2	8.2	6.0	1.3	1.2	1.2
27.6 kV Overhead Distribution Lines														
	119.3	km	5.5	35.9	29.1	25.6	23.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4.16 kV Overhead Distribution Lines														
	186.2	km	1.0	16.8	16.8	17.8	13.9	15.0	15.3	15.6	20.0	19.0	18.0	17.0
8.32 kV Overhead Distribution Lines														
	12.0	km	0.1	0.1	1.1	1.5	1.8	1.8	1.8	1.8	0.5	0.5	0.5	0.5
Total Overhead Assets	**385.7**	**km***	9.0	62.5	54.8	50.8	46.9	26.9	23.9	25.3	25.0	20.3	20.2	20.2

Table 6

**circuit kilometers*

Overhead lines are rebuilt for a variety of reasons during the lifespan. Road relocations, new customers or load growth prompt decisions to rebuild. Age, condition and safety assessments are made during annual inspections to recommend other overhead line rebuilds.

2.2.5 O/H & U/G Service Lines

PDI has a significant number of individual service lines both underground and overhead, Table 7 shows the inventory and age distribution. There is no formal replacement program for services. Currently they are replaced as they fail or are upgraded. Typically, a service will be removed or customer will request an upgrade for various reasons due to load growth, building changes or insurance purposes several years before the service life expires or failure occurs.

Overhead services may be replaced during an overhead line reconstruction or storm activity. Overhead services are an average age of 30 years old with a service life of 60 years depending on voltage level, material and loading cycles. Most modern era overhead services are aluminum conductors.

Underground services are a relatively more recent addition to the system with an average age of 20 years. The life expectancy for underground service wires is 35 years for direct buried services and about 40 years for services in duct banks and is dependent on the voltage and material of the asset. Most underground service assets are copper cables but aluminum has been used recently.

Service Line Assets -2011							
Infrastructure Category	Quantity	Unit	Age Profiles (Years)				
			1-5	6-10	11-20	21-30	>30
Secondary (LV) Service Lines							
Overhead Residential (18,848 Customers)	377.0	km	50.0	50.0	75.0	75.0	127.0
Underground Residential (12,565 Customers)	126.0	km	25.2	25.2	25.2	25.2	25.2
Overhead Commercial (733 Customers)	15.0	km	1.0	2.0	4.0	5.0	3.0
Underground Commercial (488 Customers)	24.0	km	6.0	6.0	5.0	4.0	3.0
Primary (HV) Service Lines							
Overhead Industrial (158 Customers)	8.0	km	1.0	1.0	2.0	2.0	2.0
Underground Industrial (238 Customers)	18.0	km	5.0	4.0	3.0	3.0	3.0
Total Service Line Assets	**568.0**	**km***	88.2	88.2	114.2	114.2	163.2

Table 7

*circuit kilometres

2.3.6 Distribution Transformers

PDI operates nearly 3,900 thousand distribution transformers of varying types including pole-mounted, vault, submersible and pad mounted styles serving residential, commercial and industrial customers. Table 8 shows the current inventory of in-service transformers and their approximate age.

Distribution transformers are inspected regularly as part or PDI's annual inspection program required by the Distribution System Code. Transformers are replaced for a variety of reasons including overload conditions, leaks, rusting tanks, customer upgrades, equipment failure, age and condition. PDI has a number of transformer rehabilitation programs underway on both the capital and maintenance sides.

Since underground distribution in the industry is still relatively new, introduced in the 1960's and did not become prevalent until the 1970's, the underground transformer fleet is younger than the overhead assets and represents about 35% of the asset group. As part of the underground cable replacement program, areas with submersible transformers are given priority. These are the oldest transformers in the underground asset group and have some operational and safety issues associated with their continued service. Most of the submersibles were installed prior to 1970. As well, areas with first generation underground cables usually have the oldest pad-mounted transformers so this program provides for the replacement of the longest serving underground assets with the least remaining service life.

The overhead distribution system has a relatively older fleet of transformers particularly on the 4.16 kV system. A couple of targeted programs have been initiated recently by PDI for the overhead transformer asset group. The first initiative was to test all transformers with an in-service date before 1982 for PCB contamination (PCB's were banned in 1979 for new transformers). Any transformer that tested positive for PCB contamination was replaced. There are only three known PCB contaminated transformers left in service at the end of 2011. Additionally, in connection with the Smart Meter Initiative all 600 Volt delta transformer banks were targeted for replacement. The 600 Volt delta transformer banks are an obsolete connection configuration and most of the transformers would have an in-service date prior to 1982 with some among the oldest in fleet. There were only five (5) known installations of 600 Volt delta banks left in-service at the end of 2011. Once the 600 Volt delta banks are eliminated, PDI will embark on a new program to eliminate all existing 240 Volt delta banks. This is another older obsolete connection configuration that has created some reliability issues particularly on the 27.6 kV system.

Finally, several years ago PDI instituted a practice to scrap all transformers returned from the field for any reason that had an in-service date prior to 1982. There were two reasons for this, first the higher likelihood of these transformers being contaminated with PCB's and secondly, in 1982, low loss transformers were introduced so all transformers built prior to would have higher loss core steel utilized in their design and manufacture. Transformers with in-service dates of 1982 or later are assessed for condition. Some are returned to inventory while others are sent out to be re-built using the existing low loss cores if deemed to be still serviceable.

The average age of in-service transformers is 25 years, the typical useful life expectancy is about 40 years. It is estimated that less than ten percent of the in-service transformers are over the 40 year typical useful life. The cost of transformer replacement due to the conversion program is captured in the regular transformer replacement program discussed in this report.

Distribution Transformer Assets - 2011	Quantity	Age Profiles (Years)				
		5	10	20	30	>30
5kVA, O/H, 1Ø	5	0	0	0	0	5
10kVA, O/H, 1Ø	40	14	0	0	3	23
15kVA, U/G pad, 1Ø	1	0	0	0	0	1
15kVA, O/H, 1Ø	155	15	25	25	63	27
15kVA, O/H, 3Ø	1	0	0	0	1	0
25kVA, O/H 1Ø	378	55	56	56	57	154
25kVA, U/G pad, 1Ø	25	4	6	0	7	8
37kVA, O/H, 1Ø	49	5	0	0	27	17
37kVA, U/G pad, 1Ø	1	1	0	0	0	0
37kVA, U/G pad, 3Ø	1	0	0	0	0	1
45kVA, O/H, 1Ø	5	1		1	0	3
45kVA, O/H, 3Ø	34	2	3	5	5	19
50kVA, O/H, 1Ø	895	120	100	135	140	400
50kVA, O/H, 3Ø	4	0	0	0	3	1
50kVA, U/G pad, 1Ø	636	130	120	150	91	145
50kVA, U/G sub, 1Ø	7	1	0	0	1	5
75kVA, O/H, 1Ø	521	25	49	80	75	292
75kVA, O/H, 3Ø	40	3	3	3	10	21
75kVA, U/G pad, 1Ø	171	10	15	20	32	94
75kVA, U/G pad, 3Ø	31	2	0	0	10	19
75kVA, U/G vault, 1Ø	2	0	0	0	0	2
75kVA, U/G sub, 1Ø	20	3	0	0	0	17
100kVA, O/H, 1Ø	254	25	25	25	47	132
100kVA, U/G pad, 1Ø	161	10	15	16	25	95
100kVA, U/G sub, 1Ø	20	0	0	0	9	11
112kVA, O/H, 3Ø	15	1	2	2	2	8
150kVA, O/H, 1Ø	12	0	0	0	0	12
150kVA, O/H, 3Ø	19	1	0	0	1	17
150kVA, U/G pad, 3Ø	82	8	8	9	11	46
167kVA, O/H, 1Ø	34	1	3	3	7	20
167kVA, U/G pad, 1Ø	20	0	0	0	7	13
167kVA, U/G sub, 1Ø	3	0	0	0	0	3
167kVA, U/G vault, 1Ø	15	3	0	0	12	0
200kVA, O/H 1Ø	12	0	0	0	0	12
200kVA, O/H 3Ø	2	0	0	0	0	2
225kVA, U/G pad, 3Ø	26	2	2	2	5	15
250kVA, O/H, 1Ø	9	0	1	1	6	1
250kVA, U/G vault, 1Ø	7	4	3	0	0	0
300kVA, U/G pad, 3Ø	47	6	6	6	6	23
333kVA, O/H, 1Ø	6	0	0	3	0	3
333kVA, O/H, 3Ø	3	0	0	0	3	0
450kVA, U/G pad, 3Ø	6	0	0	0	0	6
500kVA, U/G pad, 3Ø	57	11	11	11	12	12
750kVA, U/G pad, 3Ø	15	5	5	5	0	0
750kVA, U/G sub, 1Ø	3	0	0	0	0	3
1000kVA, U/G pad, 3Ø	14	4	5	5	0	0
Total	**3864**	**472**	**273**	**563**	**678**	**1688**

Table 8

2.3.7 Wholesale and Retail Meters

There are 14 wholesale meter installations with the first installation having taken place in 2004. The main instrument transformers are oil filled units that have an approximate in-service life of 40 years. The wholesale meters are inspected and re-sealed on a six year rotation period.

Due to the smart meter initiative all residential and small commercial metering has been replaced with an anticipated service life of 20 years. The majority of the residential single phase meters were installed in 2009. Single phase small commercial were installed in the latter half of 2009. Three phase small commercial installations were ongoing from 2010 to the first half of 2012. About 1/3 of the three phase large commercial meters were replaced over the last three years when their seal dates became due. By the end of 2012 about 90 percent of the three commercial meters will have been replaced and all of them will be completed by the end of 2013.

After these initiatives have been completed a regular in-situ testing and inspection program will be re-started in the next few years.

2.4 Reliability

2.4.1 System Performance

The three most common measures of system reliability are SAIDI, SAIFI and CAIDI. These measure the average experience for sustained outages defined as greater than 1 minute in duration. While there are no set standards for these indices they do allow utilities to measure and track their ongoing performance of their distribution system. Currently, the utility industry does not set standards for average outage rates but the regulator requires the LDC to maintain its reliability within the most recent three year range for their system's performance. A fourth measure, MAIFI was added recently by the regulator to track the frequency of momentary outages (less than1 minute) commonly referred to as re-closures.

PDI's internal targets are a SAIDI $\leq$ 2.0, SAIFI $\leq$ 2.0 and CAIDI $\leq$ 1.0. There are some industry guidelines (IEEE Std. 1366- 2003) to support this although some utilities strive for more stringent targets. The targets translate to an average customer having 2 sustained outages of 1 hour in duration each during any given year for an availability of 99.98% (ASAI). The internal target for MAIFI based on historical performance is 6.0 momentary outages per year. The protection schemes and the length of the 44 kV and 27.6 kV feeders supplying the majority of customers would suggest a lower target would likely be unobtainable without significant investment in additional to automated protection schemes. These targets have been deemed to be reasonable expectations for PDI's customers in balance with distribution rates and the financial performance for the utility.

PDI has maintained its' system reliability within the majority of the OEB target ranges since 2008, however, has not met its' internal targets due to several significant weather events.

PDI continues to review its reliability performance annually to influence the capital and maintenance activities to sustain and improve supply and availability of electricity to its customers.

Table 9 shows PDI's recent historic reliability indexes which includes all cause codes.

Service Reliability				
Year	**SAIDI**	**SAIFI**	**CAIDI**	**MAIFI**
2000	0.72	1.67	0.43	6.87
2001	1.10	1.23	0.89	4.04
2002	1.31	1.19	1.10	4.70
2003*	9.32	2.70	3.46	6.76
2004*	2.31	2.45	0.94	6.57
2005	2.07	1.82	1.14	5.81
2006*	5.49	2.64	2.08	6.17
2007	1.35	1.69	0.80	4.49
2008	2.91	2.15	1.36	4.39
2009*	4.60	1.77	2.60	4.36
2010	2.22	1.59	1.39	6.04
2011*	5.17	2.73	1.89	8.65

Table 9

*Note: Major events contributed to abnormal reliability statistics in these years: August 2003 was the eastern North America Blackout, in July 2004 Peterborough experienced a major flood event, in July 2006 Peterborough was hit with a significant windstorm causing significant damage and extended outages, in September 2009 a severe thunderstorm damaged a critical element, 2011 Peterborough experienced four major storms accounting for 65% of customer outages.

2.4.2 Operation and Maintenance Strategy

In addition to the end of life replacement of infrastructure that has been discussed thus far, maintenance and refurbishment play an important role in ensuring a safe and reliable electrical delivery system. A well planned and specific maintenance program can extend the usable life of some components of the system. Expenditures on maintenance need to be undertaken with their effectiveness on the safety, reliability and longevity of the system as key determinants. Maintenance spending should be optimized to provide maximum life of assets where possible and expenditures avoided where longevity cannot be improved. Part of the ongoing asset management strategy will attempt to better address these issues and provide tools for measuring effectiveness of current maintenance activities.

PDI has several programs which help staff evaluate assets and minimize outages based on in-field observations, inspections and other actions; section 5 outlines the details of some of these activities. Maintenance activities can have a significant effect on reliability of the system as these activities help to identify problems and potential problems before they impact the system. In addition, they ensure those elements of the distribution system which allow flexibility to switch and provide alternate supply points are working effectively to ensure that problems are minimized when they do occur.

PDI Outage Statistics 2007 -2011						
Interruption Type	**Frequency**	**% of Total**	**No. of Customers**	**% of Total**	**Customer Outages Hrs**	**% of Total**
0-Unknown/Other	107	5.6%	268,813	20.4%	4,389	0.7%
1-Schedule Outage	890	46.2%	23,390	1.8%	72,059	12.1%
2-Hydro One Outage	62	3.2%	137,544	10.4%	42,993	7.2%
3-Tree Contacts	111	5.8%	110,591	8.4%	105,351	17.6%
4-Lightning	47	2.4%	120,467	9.1%	134,286	22.5%
5-Defective Equipment	421	21.8%	177,449	13.5%	72,807	12.2%
6-Adverse Weather	115	6.0%	210,974	16.0%	108,320	18.1%
7-Adverse Environment	4	0.2%	2,532	0.2%	217	0.0%
8-Human Element	36	1.9%	29,813	2.3%	4,792	0.8%
9-Foreign Interference	134	7.0%	236,486	17.9%	52,662	8.8%
Total	1927	100.0%	1,318,059	100.0%	597,876	100.0%

Table 10

PDI Defective Equipment Outage Statistics 2007 to 2011						
Equipment Type	Frequency	% of Total	No. of Customers	% of Total	Customer Outage Hrs.	% of Total
Connectors	16	3.8%	7,661	4.3%	7,718	10.6%
Customer Equipment	11	2.6%	16,442	9.3%	5,533	7.6%
Fuse/Arrester/Protection	85	20.2%	59,791	33.7%	14,116	19.4%
O/H Conductor	40	9.5%	13,749	7.7%	5,205	7.1%
O/H Transformer	72	17.1%	25,466	14.4%	4,163	5.7%
Pole	24	5.7%	9,607	5.4%	6,423	8.8%
Switch	36	8.6%	24,128	13.6%	19,614	26.9%
U/G Cable	91	21.6%	14,601	8.2%	7,012	9.6%
U/G Transformer	46	10.9%	6,004	3.4%	3,024	4.2%
Total	421	100.0%	177,449	100.0%	72,806	100.0%

Table 11

Ongoing programs such as tree trimming, lightning and animal protection have been very effective in providing reliable service to customers. Preceding Tables 10 and 11 indicate these programs are effective in mitigating outages and PDI will continue them into the future to help maintain or improve system reliability. A significant number of the Foreign Interference and Unknown outages are attributed to birds flying into and landing on overhead lines. This continues to be an issue with no practical solution available.

Further analysis of Tables 10 and 11 demonstrates that the predominant controllable cause of outages is defective equipment (apart from scheduled outages). Outages caused by defective equipment are spread amongst a number of equipment categories with no one category being overwhelmingly predominant. Underground cable failures do have the largest impact with frequency and complexity and cost to repair although this has been reduced in recent years with the underground rehabilitation program. As well, underground transformer failure contributions to outages are being reduced by the same program. Fuse failures and overhead transformers are next on the list. This equipment is more susceptible to environmental factors and is more difficult to mitigate effectively.

This information combined with our reliability statistics shows that although the utility has a good reliability record, more work is needed to better understand the equipment failures and whether we can ensure it is trending positively. These trends will help guide the direction of current and future asset management programs.

Finally, an additional element in keeping the system reliable is the redundant aspect of 44 kV, 27.6 kV and 4.16 kV distribution systems. The system plan and design philosophy will be to maintain the grid nature of the distribution system used in Peterborough. Infrastructure and maintenance programs will continue to have a focus on reinforcing the grid structure which assists in minimizing the extent and duration of outages. The grid structure has and will continue to allow for the integration of distributed generation as the Province continues to promote the connection of renewable generation.

2.5 Regulatory Requirements

PDI as an electrical distributor is governed by the Electricity Act 1998. Several regulations and OEB codes guide the utility's actions including the Distribution System Code and Ontario Reg. 22/04 administered by the Electrical Safety Authority. Other organizations like the Canadian Standards Association, IEEE and others provide standards and guidelines for the safe operation of the distribution system.

Some of the regulations and standards deal specifically with service levels, design standards and safety practices, however, maintenance, safe operations and good utility practice are topics particularly raised in the various documents.

In the past the Electrical Industry has conformed to good industry practice and safe working practices. There were less formal requirements for regulatory reporting and record keeping. With the new regulatory requirements, ESA requirements and the Distribution System Code, a greater requirement for reporting and information gathering is occurring. This requires the utility to undertake and create new formal ongoing processes, which will require the allocation of staff and other resources adding cost to the OM&A budget.

3.0 IMPLEMENTATION

3.1 Planning for the Future

The condition and valuation of PDI's assets have been reviewed based on the best information possible, consisting of existing GIS data, information contained in DESS program and other operational and financial databases. These informational databases have been created for other purposes and are maintained by various staff. Staff continues to review and verify their contents to confirm their accuracy. Since the basis for any long term asset management strategy is infrastructure data, it is imperative that the utility verify that the existing data is accurate and reliable and that systems are in place to ensure it is continually updated and confirmed for quality and accuracy.

The first steps on data verification are presently underway and based on their results the effort will be expanded into a quality assurance program. In addition a work order system has been introduced and implemented in 2011 which will have the ability to facilitate data acquisition and quality control into the regular business practice. As a result of these two programs it is assumed that going forward data will be more reliable and accurate.

In addition, longer term planning for the utility in general is ongoing. The system plan involves determining the future grid in terms of condition, supply and structure. Having a stated goal of eliminating (or minimizing) the 4.16 kV grid, the distribution system will be replaced by a 27.6 kV system, in order to do so the ultimate 27.6 kV distribution system needs to be thoroughly planned to ensure that every opportunity to replace the 4.16 kV system is taken and that no more than the minimum expenditures should be made on parts of that system which are approaching impending removal, at the same time efforts to ensure the existing system remains safe and reliable continue, including analysis of potential vulnerabilities.

3.2 Asset Management Plan

Since deregulation in 1998, incorporation of the LDC and the introduction of OEB regulatory oversight emphasis on cost efficiency for operating and maintaining the electrical distribution system has been a more prominent activity. The Asset Management Plan will assist in decision making around capital and maintenance activities and budgets to ensure spending is targeted to maximize benefit to the utility and its' customers.

In its simplest form asset management is simply planning for the replacement of assets based on their anticipated life spans, this is a technical and financial exercise wherein expenditures are projected into the future based on the anticipated life of each asset component. The reality is that there can be more art or expert judgment than theoretical science to elements of the plan. PDI is currently reviewing the Depreciation Study (EB2010-0178) completed by the OEB in July of 2010 in preparation for transitioning to IFRS and reevaluating the typical useful life (TUL) of its asset components. Initially PDI has adopted the Typical Useful Life in the Kinetrics report but will continue to evaluate these against actual experience.

Table 12 summarizes the annualized cost related to each category of infrastructure based on replacement at end of predicted or typical useful life and the asset management plan strategies. Other factors can affect the baseline assumptions such as premature failure, extended service life strategies, changing expectations for reliability and service levels or premature replacements due to customer demand or unexpected events like accidents. These annual costs do not include other capital budget items such as customer connections, expansion, system upgrades and reliability improvements.

Combined Assets Annual Replacement Costs									
Year	Poles	O/H Lines	U/G Cables	Transformers	Meters	Stations	SCADA	Services	Total Annualized
2010	$841,000	$379,000	$480,000	$697,060	$25,000	$200,000	$25,000	$250,000	**$2,899,070**
2015	$1,091,000	$399,000	$776,750	$697,060	$50,000	$200,000	$25,000	$250,000	**$3,490,825**
2020	$764,000	$421,000	$776,750	$272,920	$191,596	$200,000	$25,000	$250,000	**$2,903,286**
2025	$674,000	$535,000	$1,360,000	$272,920	$191,596	$200,000	$25,000	$250,000	**$3,510,541**
2030	$591,000	$530,000	$1,360,000	$233,460	$191,596	$200,000	$25,000	$250,000	**$3,383,086**
2035	$1,470,000	$524,000	$1,746,000	$233,460	$191,596	$200,000	$25,000	$250,000	**$4,642,091**
2040	$1,472,000	$520,000	$1,019,000	$411,520	$191,596	$200,000	$25,000	$250,000	**$4,091,156**
2045	$1,364,000	$956,000	$800,000	$419,400	$191,596	$200,000	$25,000	$250,000	**$4,208,041**
2050	$1,241,000	$1,051,000	$800,000	$500,000	$191,596	$200,000	$25,000	$250,000	**$4,260,646**

Table 12

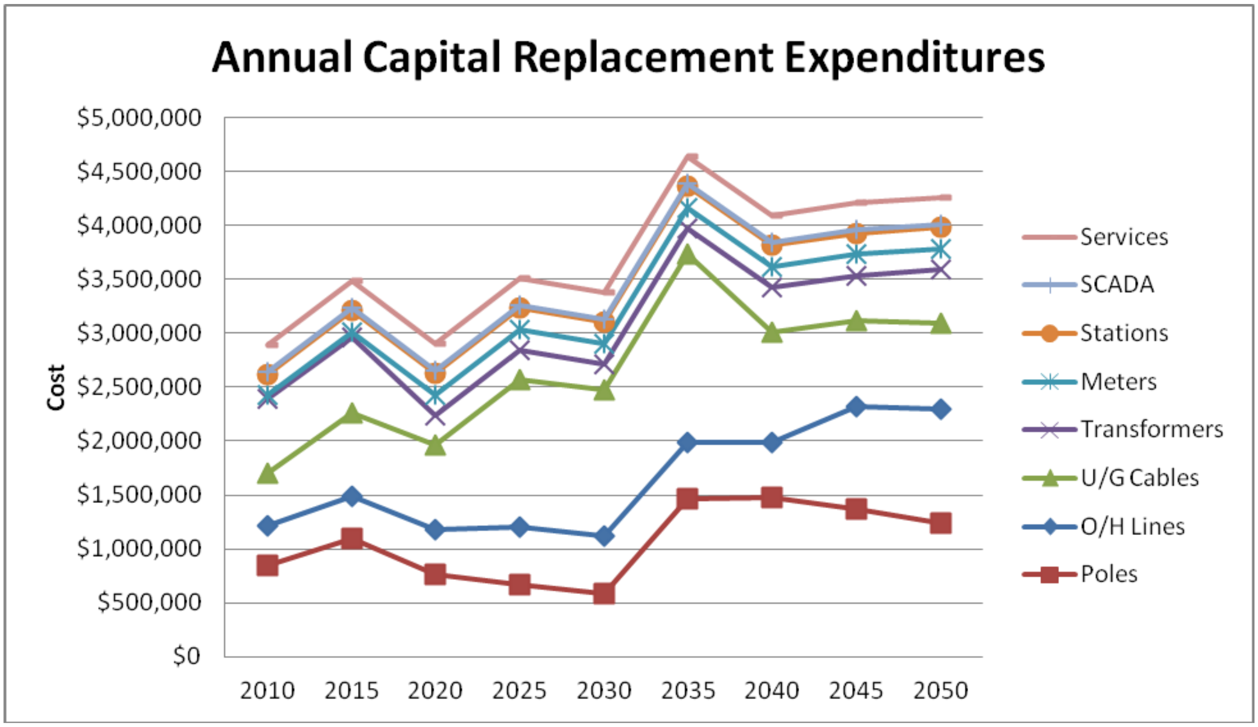


Figure 1

Figure 1 demonstrates the estimated annual expenditures for utility infrastructure replacement in five year intervals based on expected life span and plan strategies. The figures demonstrate a generally increasing demand for capital replacement expenditures over time as well as a potential spike in the years from 2030 to 2040. As a starting point this information allows the utility to anticipate future costs, however, it does not provide any mechanism to track asset condition, accommodate expansion related redundancies or direct funds to maintenance activities which could extend asset life. The sight line will assist in directing funds perhaps in advance to smooth the effects on the capital expenditures for the utility.

3.3 Data Verification and Updating:

The utility has undertaken a systematic process to verify and analyze existing data to determine its completeness and accuracy. In addition, staff continues to assess whether the data presently being collected will meet the utility's long term needs. Changes to the data dictionary have been made and will continue over time. PDI has developed a process to ensure changes and upgrades in the field are quickly and accurately reflected in the data. In addition several internal processes have been reviewed to ensure data is being delivered and updated as necessary and that appropriate staff are involved and enabled.

Currently, PDI has reviewed and updated data on about 60% of the overhead assets within the city, work will be undertaken on underground assets, although there is some base information already collected. Substations and transformer data is reasonably captured but requires some additional review and enhancement.

3.4 Physical Condition Assessment

Condition assessment will generally be gathered from annual inspections and ad hoc observations as PDI carries out capital works, maintenance activities and emergency repairs. Day to day work by staff is documented with opportunities to note deficiencies or conditions of existing assets. Some infrastructure may require more detailed review, for example, poles need to be physically investigated and tested in order to ascertain their condition and expected service life. Annual infrared inspections can identify problem areas throughout the system as well as analysis of outage statistics and causes are used to identify problem assets.

The initial focus will be on overhead assets which are more accessible and comprise the bulk of the distribution system. Underground assets are more of a challenge and require more research to complete an inventory and condition assessment.

The value of condition information to the utility is to target spending based on the condition of the asset class, some assets may outperform their anticipated life spans while some may underperform. Some assets could benefit from maintenance interventions, which could potentially extend their service life, others should be monitored simply to help predict their failures.

The utility will include condition assessments and the collection of relevant data in their normal business practices, providing better information in a more cost effective manner than doing annual programs or one time assessments with third parties. Presently staff is working to direct information currently collected and additional data to the central GIS database where it can be used by all staff to evaluate assets and help direct the utilities' resources to the points in the system which requires the most urgent attention.

3.5 Modeling the System

PDI uses its engineering software system (DESS) to do short and long term load and system models to aid in the development of the system plan. The system models assist in the decision-making process for capital expansion but can also aid in the prioritization of some asset replacement programs. The utility needs to determine how the 27.6 kV system can expand incrementally to supplant the 4.16 kV system easing the removal of the 4.16 kV system and associated substations, prior to investing in rebuilding or refitting them.

Further, a rationalization of longer term capital improvements can be better accommodated if the longer term system has been properly planned and modeled allowing long, middle and short term plans to be developed and implemented more easily. The system model can cover a 20-year horizon demonstrating the structure of the electrical system including sub-transmission, primary feeder circuits and the distribution grid but needs to be flexible and regularly updated with current information on load growth, conservation efforts, weather trends and other factors that become evident. System expansion as well as any planned load intensification should be included in the ultimate plan.

Once the 20 year plan is established it will be broken down into smaller logical steps which will allow the utility to plan shorter time horizons such as five and ten year plans which when implemented will build toward the 20 year system. Using this methodology the utility will be better able to plan their shorter term work to ensure that it is consistent with the long term goals and does not veer off course or expend resources that do not fit the long term objectives.

Maintenance and retrofit activities can also be tailored to conform to the long term objectives ensuring financial resources are all utilized with a common goal. Finally the system model is used for operating purposes to investigate switching options to minimize outages and to identify potential vulnerabilities within the existing system and model options which could help in designing the most robust system possible.

In the end, planning, engineering, constructing and maintaining the electrical distribution system should become a seamless process with all departments working toward the same objectives. The introduction of the Work Order System, developed by the Engineering group in cooperation with Operations, Purchasing, Finance, Payroll and IT will be the first step towards a fully integrated work process across all departmental boundaries. This will aid in the collection of data, not only for infrastructure but also for materials, labour and equipment and all other inputs into the system.

4 0 CAPITAL PROGRAMS

4.1 General

The capital plan includes expenditures for customer demand, system growth, expansion, replacing aged or suspect infrastructure and to provide upgrades to equipment and facilities which will assist in system capacity and reliability. The planning process to develop the specific program for infrastructure renewal is guided by the system plan and the Asset Management Plan and would adjust to changes or alterations of the plan. The infrastructure renewal will be accomplished with specific projects or ongoing programs within the annual capital budget.

PDI considers the following criteria to develop infrastructure renewal projects or programs:

- Public and Worker Safety
- Environmental Risk
- Infrastructure Age and Condition
- Load Growth
- Voltage Conversion
- Customer Requirements
- Regulatory Compliance
- Planned Programs/ Long Term Objectives (System Plan)

If necessary, competing projects can be evaluated using a scoring system to determine the priority ranking of specific projects. Potential projects are submitted to the Engineering Department and basic information is collected to begin the evaluation process. Once accepted as a potential project they are given a preliminary evaluation and scored based on the evaluation criteria and prioritized in the project file based on their rating (the rating is the accumulated score of the relevant criteria). Each year they are reviewed and re-evaluated if necessary.

The projects are categorized initially and scored with slightly different criteria depending on the category of urgent, current or planned. The standard project scope form and evaluation tables are illustrated in Appendix A.

4.2 Current Capital Programs

4.2.1 Pole Replacement Program

Every year a section of the territory is chosen for pole testing. A sampling of poles is taken and approximately one thousand poles in the section over the age of 15 years are targeted for formal testing for structure and condition. Poles are evaluated as hazard, scheduled for replacement or remaining service life of 5 plus years. Current expenditures are in the $550,000 range depending on number of poles on the list and the resources available for the year.

4.2.2 Underground Rehabilitation Program

Every year a section of the underground distribution system is targeted for replacement of first generation underground cable, submersible transformer replacement and conversion if possible. The age, condition and reliability performance of sections is reviewed prior to determining the area targeted for replacement. Current expenditures are targeted at $500,000 depending on the scope and/or section of the system chosen.

4.2.3 Scheduled Projects

There are a few scheduled renewal projects on the current list that are in varying stages of progress. Two of the major projects are in response to City of Peterborough road relocation projects: Parkhill Rd. W. (Wallis to West City Limits). Chemong Rd. (Parkhill Rd. W. to Sunset Blvd.).

Related to the City relocation project on Parkhill Rd. W. is the renewal of Parkhill Rd. W. (Wallis to Monaghan Rd.). This is a combination renewal and expansion project. Other significant projects include the replacement of the 20M7 Otonabee River crossing and the rehabilitation of a downtown transformer vault.

Other projects are chosen based on customer connection requirements, reliability issues or age and condition related drivers that may come from inspection programs.

4.2.4 Miscellaneous Ongoing Programs

These are smaller initiatives but are annual programs to replace aging or suspect assets. Backyard overhead lines are replaced as a result of inspection condition or a result of reliability issues experienced due to a storm. Insulator replacement is done on ad hoc basis if the insulators are identified separately from scheduled projects. Individual transformer replacements are done in response to identified overloading or condition inspections. PDI is currently nearing completion of its program to replace PCB contaminated transformers and 600 Volt delta configured customer services. A future program to replace 240 V delta configured customer services is being planned. There is a standing order to replace obsolete open wire overhead services if discovered upon inspection or customer requested upgrades. Finally, there may be smaller renewal initiatives identified yearly from reliability performance in specific areas of the distribution system.

Annual upgrades or roof replacements for substation buildings are considered and replacement of smaller elements of the substation equipment such SCADA RTU's and battery banks for control systems. Replacement of station ground grids are being considered as a future program to extend the useful life of some of the 4.16 kV municipal substations.

4.2.5 Meters

The mandated installation of smart meters for most of PDI's residential and small commercial customers is virtually complete. There are a small number of larger commercial customers left with conventional meters. While not mandated at this point any meter that is due for seal renewal is being replaced with a new smart meter. This will allow PDI to read all of the customer meters remotely and obtain better load profile information to provide to the Engineering and Operating teams.

PDI has virtually completed its replacement of PCB contaminated primary metering units and has replaced oil filled primary metering units at sensitive locations with dry type units.

5.0 MAINTENANCE PROGRAMS

The following programs are ongoing annual activities to improve and maintain the operation and reliability of the electric distribution system, substations, SCADA equipment and meters. Maintenance programs would include both preventative and reactive activities.

5.1 Maintenance Programs – Preventative

5.1.1 Overhead Distribution - Tree Trimming of Overhead Lines

Tree trimming reduces incidental and permanent contact with live overhead lines specifically during storms or severe wind conditions. Incidental contact can cause feeder breakers to open and reclose creating momentary outages for customers. More severe contact can produce extended outages with blown protective fuses and damage to the overhead distribution system. Tree trimming also maintains appropriate safety clearances to maintain public safety.

The current annual program covers approximately 1/3 of the Peterborough territory's overhead line circuits which are trimmed as necessary at an average cost of approximately $200,000 annually. Every three years the Lakefield and Norwood territories are completed.

PDI has been performing the tree trimming annually for several decades and operating experience suggests that this has positively affected PDI's reliability performance indices. Tree contact outage frequency accounts for only 6% of all customer outages. Recently it appears that wind storms have become more frequent and violent therefore the tree trimming program becomes more critical in mitigating damage and loss of service to the customers.

5.1.2 Overhead Distribution - Infrared Thermography Inspection

The annual program performs an infrared thermography inspection of the distribution system including overhead lines, switches, overhead transformers, pad mounted transformers and municipal substations. Infrared inspection identifies "hot" spots on equipment that would indicate tracking, loose connections or overload conditions. These "hot" spots allow the LDC to repair these potential system problems on a planned or controlled basis and will avoid future unplanned outages to customers.

Each year the entire overhead system is inspected and approximately 6 pieces of faulty equipment are identified for repair or replacement. The potential “faults” are categorized as serious, intermediate and minor. A small portion of the underground system is also inspected as well as substations. The program annually costs less than $10,000 to perform the inspection. Repair costs can vary depending on the type of fault identified but generally are minor in nature and repairs are completed shortly after the inspection.

5.1.3 Overhead Distribution - Primary Line Patrol and Inspection

There are over 386 km of 44 kV, 27.6 kV, 8 kV and 4 kV overhead lines within the Peterborough, Lakefield and Norwood territories. Inspections are expected to identify defective equipment and information on line condition that will be used in the capital infrastructure program.

On an annual basis a systematic line patrol would be conducted on 33% of all overhead line circuits, in accordance with the Distribution System Code – Appendix “C”. Condition based information will be collected about the conductor and associated equipment such as insulators or transformers on these circuits. This program would include rear-yard pole line inspections as well and be combined with the pole assessment program. Minor preventive maintenance will be completed as a result of the inspections.

It is expected that initially the preventive maintenance on these components would not require significant effort. Cost of the inspection program is approximately $30,000 annually. The additional cost for repairs is dependent on the amount of minor preventative maintenance identified and performed.

5.1.4 Overhead Distribution - Switch Inspection and Preventive Maintenance

There are over 1,000 overhead distribution switches in the Peterborough, Lakefield and Norwood electric systems. The switches are inspected annually through the Infrared Inspection program for faults, loose connections, etc.

This inspection and maintenance program focuses on major three phase gang-operated switches that are load interrupter (or air break), motor operated or re-closer switch types that account for approximately 76 switch installations. The major switches are integral to the operation of the distribution system; in particular the remote controlled motorized devices. Excluded in this program would be single phase live line openers (LLO’s) which account for approximately 400 switches. These LLO’s will be run to failure unless they are identified as a “hot” spot on the infrared inspection.

Best practice has suggested that these major switches should be inspected and operated every 5 years or approximately 16 annually. The inspection and maintenance program would require 16 switches be inspected at a cost of approximately $30,000 annually. Remote controlled motor operated switches would be by-passed and function tested annually. Additional costs would be maintenance if minor repairs are required or a capital expenditure if the switch is to be replaced.

5.1.5 Underground Distribution – Transformer Vault Inspection

An annual program is conducted to inspect and maintain all major transformer vaults in Peterborough's downtown core due to the sensitive commercial nature of the customers and the physical conditions. The vaults are inspected twice a year to inspect and maintain all transformers, switches, connections and associated auxiliary equipment. Infrared inspection is performed on the electrical equipment. A visual structural integrity is performed as well as inspecting for water and debris accumulating in the vault. If poor structural integrity is noted then the vault would be referred to the capital replacement program.

The cost of the program is approximately $60,000 annually. The inspection program is subject to the Confined Space Regulations introduced in late 2006 adding to the labour cost and customer outages to perform the inspections. Additional maintenance cost may be incurred due to the nature and extent of repairs required.

5.1.6 Underground Distribution – Pad Mount Transformers

The annual program includes painting and refurbishing approximately 25 residential pad mounted transformers or switchgear that are rated to be in poor condition. In addition, a program is in place to rehabilitate or level transformer vaults or support structures that are in poor condition. As well residential submersible transformers are targeted for replacement under the capital enhancements program.

Painting and refurbishment can extend the life of the asset and prevent environmental issues from spills or leaks. The program cost is approximately $10,000 depending on the amount of transformer foundation work that is required.

5.1.7 Overhead Distribution – Animal Protection, Switch Replacement

PDI's territory has many areas that are heavily treed and animal intrusion on the distribution system can be a significant problem at times. This program works in concert with the tree trimming program. As maintenance, repair or outage restoration is performed on overhead transformers crews are directed to install squirrel guards on the transformer bushings and insulated transformer leads to mitigate the interference from animals.

Additionally, if the transformer fused switch has a porcelain insulator and is damaged in any way it is replaced with a new switch with a polymer insulator. If a review of a feeder's reliability reveals an abnormal high number of momentary outages a capital replacement program for all porcelain switches might be initiated.

5.1.8 Overhead Distribution – Services

The preventative maintenance program requires the replacement of open wire secondary services when they are discovered or repairs are required. Additionally, replacement of split bolt connectors or "insul-link" connectors is required when they are discovered or repairs are necessary. The program is completed on an ad-hoc basis and included in regular maintenance expenditures.

5.1.9 Underground Distribution – Services

The preventative maintenance program requires the inspection and testing of underground neutral connections when the iron water main on the street is replaced with a PVC water main. The replacement of ductile iron water main with PVC affects the grounding system for the underground services and may identify where buried neutral connections may be defective. The program cost is dependent on the amount of water main replacement that is undertaken by the municipality.

5.1.10 Substations – Equipment Preventive Maintenance

There are sixteen (16) 44 - 4.16 kV municipal substations that are maintained on a five-year cycle or about 3 stations per year. Additionally, there are six (6) 44 kV inline breaker stations that are visited and inspected annually and maintained on a five-year rotation.

Monthly inspections are performed on all municipal substations and breaker stations in between maintenance cycles. Annual inspections are conducted on private customer substations that contain PDI owned transformers.

Preventive maintenance is completed on the substation breakers, transformers, switches, batteries, SCADA equipment and protective relay devices. The maintenance data is collected and tracked using a computerized maintenance management system (CMMS).

Emphasis is placed on assessing the condition of power transformers in the substations, as these are critical components. Annual transformer oil sampling and testing is performed and along with its analysis is a valuable technique to ensure that the transformer is operating in an optimal manner. This is an example of a condition-based approach to completing preventive maintenance in the 4.16 kV substations.

During the course of ongoing voltage conversion, municipal substations will be de-commissioned. Equipment from these stations will be used for spares and upgrades for substations that remain in service depending on the assessed condition.

5.1.11 Substations - Protection and Coordination System Studies

During substation maintenance existing protective relay settings are confirmed. A detailed coordination review for each of the feeders leaving the substation may be performed if there are any identified reliability issues related to the particular substation or feeder to ensure that protective devices are operating correctly based on changes to the distribution system configuration or customer loading.

A coordination study by the Engineering Department will be performed prior to a planned maintenance event at the substation if significant reliability issues have been identified. Protective device settings are adjusted or new devices are installed as required. Costs to perform these studies can range up to $10,000 depending on the size and complexity of the system under study. Protective relaying provides mitigation for damage on the distribution system for faults in addition to improving reliability.

5.1.12 Substations - SCADA Preventive Maintenance

The preventative maintenance plan for the SCADA system compliments the substation and switch maintenance programs to ensure the field equipment is in operation and fully functional when needed. Many of the field devices are exposed to contamination and corrosion and are susceptible to problems if not regularly inspected and maintained.

During regular inspections and maintenance, obsolete equipment will be identified and replaced under the capital replacement program.

5.1.13 Meters – Re-Verification Program

In accordance with Industry Canada (Measurement Canada section) regulations, meters are subject to re-verification of the seal at scheduled intervals. Typically, 250 demand meters (commercial) and 3 or more residential single phase sample groups are re-verified annually. Cost of the program is $65,000 for re-sealing and changing out of the meters.

This program has been largely suspended due to the smart meter initiative. All residential meters were replaced in 2009 with smart meters. Additionally, all general service meters under 50 kW (small commercial) have been replaced in

2009 and 2010. The new smart meters are expected to have a seal period of ten (10) years.

In addition, PDI will replace all remaining revenue meters due for re-seal with smart meters. Ongoing maintenance of the data collection network will be required. Costs of this maintenance is not determined at this time but is not expected to be significant.

Once all of the meters have been replaced, the re-verification program will be reactivated as well as the in-situ testing of the larger commercial meters.

5.2.1 Maintenance Program – Reactive

5.2.1 Overhead Distribution Maintenance

PDI repairs leaning poles, pulled anchors, slack guys and badly damaged poles as they are identified through accidents, regular inspection or customer complaints. The Distribution System Code identifies the inspection cycle period to be 3 years. A visual inspection is also performed in connection with our annual infrared inspection.

5.2.2 Underground Distribution Maintenance

PDI repairs cable faults, leaking transformers and faulty connectors as they occur. Due the nature of underground systems, inspection of most of the plant is impractical**.**

5.2.3 Services

Services are repaired on as needed basis.

5.2.4 Substation Maintenance

PDI responds to non-operational breakers and relays as reported. Emergency repairs currently are very infrequent.

5.2.5 Meter Maintenance

Meter replacement or repair is typically due to vandalism. Meter failures are rare and repairs are very infrequent.

APPENDIX A – PROJECT EVALUATION

PETERBOROUGH DISTRIBUTION INC.
1867 Ashburnham Drive, PO Box 4125, Station Main
Peterborough ON K9J 6Z5

PROJECT SCOPE DOCUMENT

Project Name: ______________________________ Rev. ______

Budget: Capital: ☐ Amount $__________________
Operations: ☐ Amount $__________________
Not Budgeted: ☐ Amount $__________________

Priority (1-5): _____

Project Objective: ____

Project Description: ____

Timeline: ____

Project Risks: ____

Alternatives: ____

Approval:

Electric Distribution Engineer	Engineering Manager	Operations Manager

c: Purchasing Manager
VP Electric Utility

Peterborough Distribution Inc.

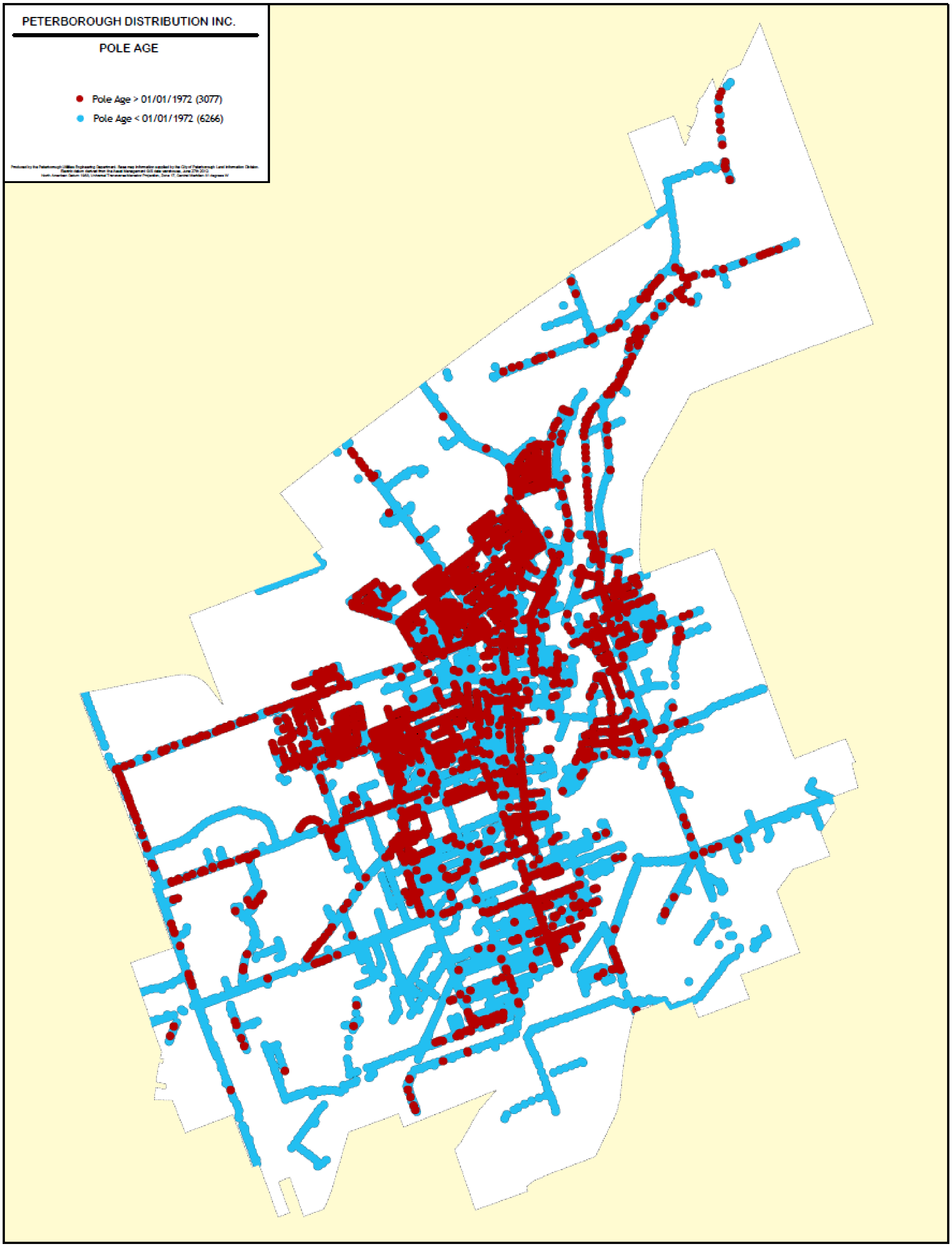
Capital Project Criteria

Project Name:

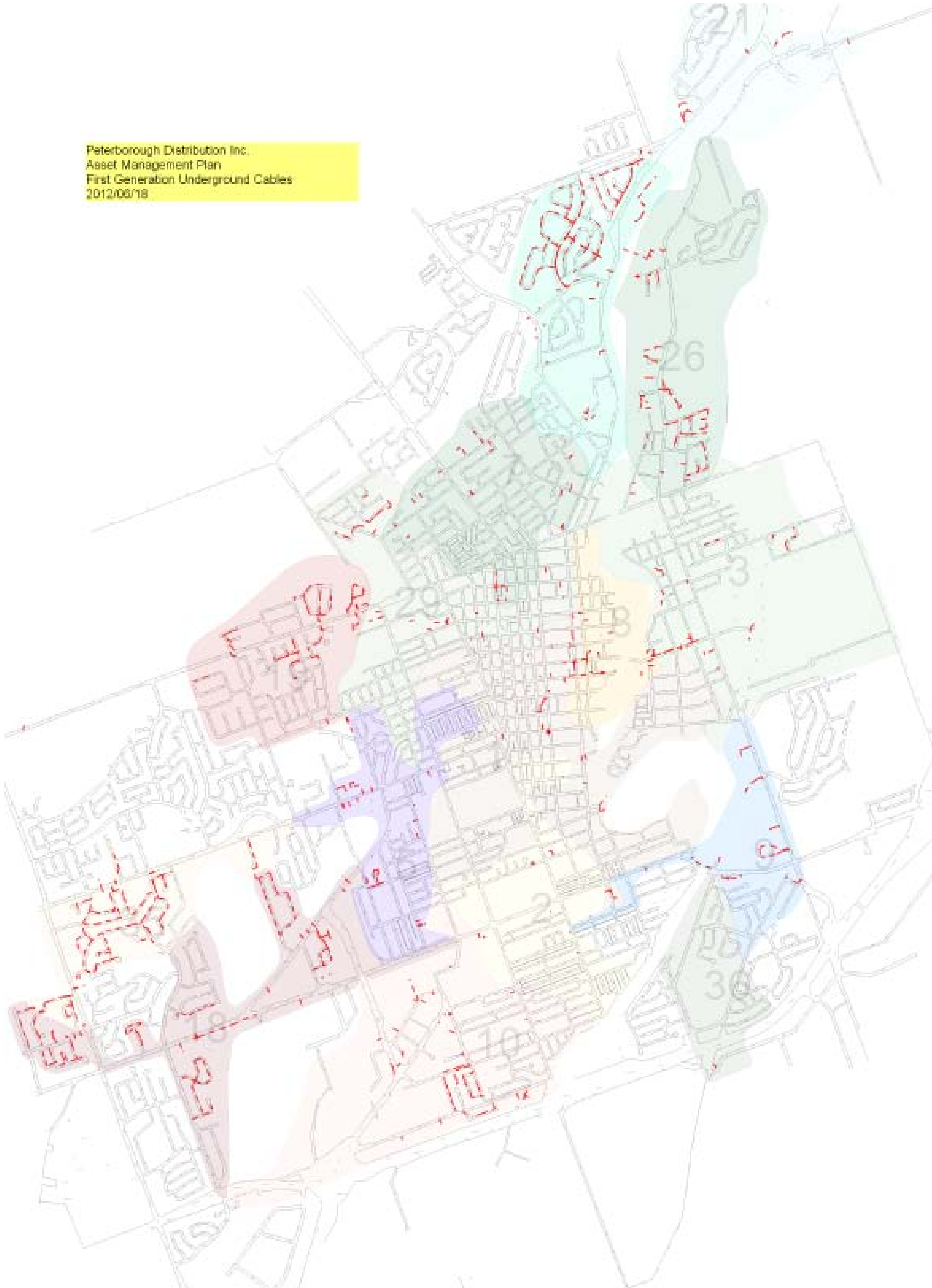
Category

Urgent:						
	Criteria			Max Score		Actual Score
	Safety Issue		Public	10		
			Worker	10		
	Imminent Failure			10		
	Environmental			8		
	Urgent Customer Need			8		
	Regulatory Obligation			8		
	Other (Note)			5		
			Total	59		0
Current Project						
(within 1 Year)	**Criteria**					
	Potential Safety Issue			8		
	Infrastructure Condition			5		
	Infrastructure Age			5		
	Reliability			5		
	City Related Work			8		
	Customer Requirement			8		
	Environmental			8		
	Regulatory			8		
	Interdependence			8		
	Opportunity			8		
			Total	71		0
Planned Projects						
(Up to 5 Years)	**Criteria**					
	Function			5		
	Long Term Objectives			8		
	Ongoing Program			5		
	Load Growth			8		
	Reliability Improvement			8		
	Conversion			8		
			Total	42		0

APPENDIX B – POLE AGES



APPENDIX C – U/G CABLE REPLACEMENT



Appendix D

Green Energy Plan and OPA Letter of Comment

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Peterborough
Distribution Inc.

Basic Green Energy Act Plan – Peterborough Distribution Inc.

Prepared by: J.T. Guilbeault, P.Eng., VP Electric Utility

Date: June 30, 2012 (Revised Section 2.1 as per OPA letter)

Forward

Peterborough Distribution Inc. has had renewable generation connected to its distribution system for over one hundred years. In the early 1900's General Electric and The American Cereal Company built run of the river hydraulic generating stations on the Otonabee River in the City of Peterborough. These two renewable generating stations are still in operation today and connected to the Peterborough Distribution Inc.'s electrical distribution system. Two additional run of the river hydraulic generation facilities have been connected to the distribution system since then, the latest connection occurred in December of 2009.

1.0 Current Assessment of the Distributor's System (EB -2009-0397 Section 4.2.1)

1.1 Current Capacity

Peterborough Distribution Inc. (PDI) distribution system supplies three distinct territories: City of Peterborough, Village of Lakefield and the Village of Norwood.

PDI's distribution system is served by four different voltage levels: 44 kV, 27.6 kV, 8.32 kV and 4.16 kV.

In the Peterborough territory there are three voltage levels. The 44 kV and 27.6 kV systems are primarily constructed to handle two way and full capacity power flow with significant capacity still available for the connection of renewable generation. The 4.16 kV system is the legacy distribution system connected through 44 – 4.16 kV municipal substations. The 4.16 kV system has some areas that may be limited in available capacity for connecting larger scale FIT renewable generation. There is still significant capacity available for micro-FIT connections.

In the Lakefield territory, the primary distribution voltage is 4.16 kV from a PDI owned 44 – 4.16 kV, 10,000 kVA substation supplied from Hydro One Network Inc's Otonabee TS M27. At present, capacity is available on the 4.16 kV system throughout the territory for up to 1000 kW of renewable generation connections. PDI's 44 kV system is geographically limited to the extreme southern portion of the PDI territory and is embedded within the Hydro One Networks Inc. Otonabee TS M27 feeder.

In the Norwood territory, the primary distribution voltage is 8.32 kV from a shared Hydro One Networks Inc. owned 10,000 kVA distribution substation. At present, there is capacity available on the 8.32 kV system throughout the PDI territory for up to 1000 kW of renewable generation connections. The 44 kV feeder is owned by Hydro One Networks Inc. and the distribution station is supplied by the Otonabee TS M28 feeder.

The available capacity for PDI feeders connected to Dobbin TS, Dobbin DS and Otonabee TS is shown in Appendix A.

1.2 Limiting Factors

Presently, the main limiting factor in connecting renewable generation will be any upstream transformer station or transmission system capacity constraints at the three main transformer station sources to the PDI system: Dobbin TS, Dobbin DS, and Otonabee TS.

Dobbin TS and Otonabee TS are 230 kV connected transformer stations that currently have capacity available. Dobbin DS is a 115 kV connected high voltage distribution station that is smaller in scale with more limited capacity available. The available capacity at these three sources is shown from the most recently available DG List of Station Capacity table from Hydro One Networks Inc. in Appendix B.

There are virtually no limiting factors on the 44 kV and 27.6 kV systems in the Peterborough territory with the exception of thermal and short circuit capacity of the individual feeders due to the potential scale and number of connections if concentrated in a specific area. There may be a requirement to upgrade overhead or underground line capacity in some pockets of the 4.16 kV system in Peterborough.

Overhead line capacity on the 4.16 kV and 8.32 kV systems in Lakefield and Norwood territories respectively may be a limiting factor as the number of connections grow or concentrate in a specific area.

Protection system upgrades and automated SCADA devices may be required to accommodate some larger scale renewable generators.

1.3 Expenditures Included in Current Plans and Rates

In 2012, PDI has capital expenditures of approximately $207K to fund the connection of a 3.9 MW hydraulic renewable generator due to be in service in early 2013.

In 2011, PDI spent approximately $26,000 in OMA expenditures to connect micro-Fit and FIT generators. In 2012, there has been about $21,000 of OMA expenditures budgeted for renewable generation connections.

2.0 Planned Development of the System to Accommodate Renewable Generation Connection (EB -2009-0397 Section 4.2.2)

2.1 Renewable Generation Forecast (2013-2017)

Peterborough Territory:

This is the territory where it is expected that most significant activity will occur. To date there have been 42 micro-Fit connections and 2 Fit connection for a total installed capacity of 0.336 MW. Presently, there are 55 micro-Fit connections and 4 Fit connections in the queue.

The forecast in the Peterborough territory for the next five years is 25 micro-Fit connections per year and 6 Fit connections per year for a forecast capacity of 1.0 MW per year.

Additionally, in 2013 the connection of a 3.9 MW upgraded (from 1.6 MW) run of the river hydraulic generating station at Trent University is scheduled. In 2015, the connection of a new 6 MW run of the river hydraulic generating station at the existing London St. G.S. site is scheduled.

Lakefield Territory:

This territory will see limited activity occur. To date there have been 2 micro-Fit connections and 0 Fit connections for a total installed capacity of 0.02 MW. There are 5 micro-Fit connections and 1 Fit connection in the queue.

The forecast in the Lakefield territory for the next five years is 2 micro-Fit connections per year and 1 Fit connection per year for a forecast capacity of 0.145 MW per year.

Norwood Territory:

Activity in this area is currently non-existent. To date there have been 0 micro-Fit connections and 0 Fit connections for a total installed capacity of 0.0 MW. There are currently no renewable generation connections in the queue.

The forecast for the next five years is 1 micro-Fit connection per year and 2 Fit connections for the entire five year period for a forecast capacity of 0.300 MW.

2.2 Infrastructure Projects and Activities (2013 – 2017)

A 44 kV line extension will be completed late in 2012 to accommodate the connection of the 3.9 MW Trent University G.S. upgrade at an estimated cost of $750,000. The majority of this expansion is funded by the generator with the exception of the $207,000 expansion allowance as prescribed by the Distribution System Code. In 2014, a protection upgrade and minor line connections will be competed for the 6.0 MW London St. G.S. expansion expected to be connected in 2015. The estimated cost for those upgrades is $175,000.

Other distribution line and transformer upgrades will take place on an ad hoc basis dependant on number, location and size of renewable generation connections requested.

2.3 Provincial Ratepayer Cost Recovery

At this time it is anticipated that no cost recovery from the provincial ratepayers will be sought by PDI.

2.4 Expenditure Prioritization

Expenditures will be prioritized on a first come- first served basis with regard to application date, connection request date and date of commercial operation unless the required infrastructure expenditure is significant and beyond the means of the LDC at the time.

2.5 Consultation

Consultation through TAT's, DAT's, Threshold CIA's and CIA's will take place with Hydro One Networks Inc. as required upon receipt of connection requests.

There are no other affected distributors or transmitters in our area.

2.6 OPA Letter

Pending (see Appendix C)

3.0 Smart Grid Plan (EB -2009-0397 Section 4.4)

3.1 General

Peterborough Distribution Inc. has no specific plans for significant smart grid projects or expenditures at this time. Staff is generally engaging in educational opportunities only at this time restricted to conferences and consultations with suppliers and manufacturers. These activities will assist staff in determining the expected costs and benefits to be accrued with smart grid investments beyond AMI and current SCADA equipment.

Appendix A – Peterborough Distribution Inc Generation Capacity Allocation

Peterborough
Distribution Inc.

Generation Capacity Allocation

May 25, 2012

Peterborough Territory

Transformer Station	Voltage Level kV	Feeder	Buss	Feeder Rated Capacity MW	Allowable CAE Capacity MW	Allocated CAE Capacity MW	Allowable microFIT Capacity MW	Allocated microFIT Capacity MW	Allocated Non-CAE Capacity MW	Total Allocated Capacity MW
Otonabee TS	44	128M25	B	30	-----	-----	1.0	0.036	-----	0.000
		128M26	Y	30	-----	-----	1.0	0.050	4.10	4.150
	27.6	128M8	JQ	19	1.0	0.698	1.0	0.254		0.866
		128M9	JQ	19						
		128M11	JQ	19						
		128M12	JQ	19						
Dobbin TS	44	20M4	Y	30	2.0	0.075	2.0	0.177	17.50	6.073
		20M6	Y	30						
		20M7	B	30						11.594
		20M8	B	30						
Dobbin DS	27.6	2001-1 F1/F2	---	Hydro One Networks	-----	-----	1.0 (+ Hydro One Networks)	0.033	-----	0.032 (+ Hydro One Networks)

Peterborough Distribution Inc.

Generation Capacity Allocation

May 25, 2012

Lakefield Territory (4.16 kV Distribution)

Transformer Station	Voltage Level kV	Feeder	Buss	Feeder Rated Capacity MW	Allowable CAE Capacity MW	Allocated CAE Capacity MW	Allowable microFIT Capacity MW	Allocated microFIT Capacity MW	Allocated Non-CAE Capacity MW	Total Allocated Capacity MW
Otonabee TS	44	128M27	B	Hydro One Networks	-----	0.090 + Hydro One Networks	1.0 + Hydro One Networks	0.030 + Hydro One Networks	0.0 + Hydro One Networks	0.110 + Hydro One Networks

Norwood Territory (8.32 kV Distribution)

Transformer Station	Voltage Level kV	Feeder	Buss	Feeder Rated Capacity MW	Allowable CAE Capacity MW	Allocated CAE Capacity MW	Allowable microFIT Capacity MW	Allocated microFIT Capacity MW	Allocated Non-CAE Capacity MW	Total Allocated Capacity MW
Otonabee TS	44	128M28	Y	Hydro One Networks	-----	0.0 + Hydro One Networks	1.0 + Hydro One Networks	0.0 + Hydro One Networks	0.0 + Hydro One Networks	0.0 + Hydro One Networks

Appendix B – Hydro One Networks Inc. DG List of Station Capacity

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
CROW RIVER DS	Total	F1,F2	27.6	0.5	N/A	5.3		
CROWLAND TS	QY	M13, M14, M15, M16, M17, M18, M19, M20, M21, M22	27.6	27.6	TC	67.6		
CROWN HILL DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	MIDHURST TS - DESN1	M4
CROYDON DS	Total	F1,F2	8.32	1.0	N/A	3.4	NAPANEE TS	M2
CROZIER DS	Total	F1,F2	25	0.3	N/A	3.2	FORT FRANCES TS	M1
CRYSLER DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	CHESTERVILLE TS	M4
CRYSTAL FALLS TS	EZ	M1, M2	44	5.3	401.3	25.3		
CULTUS DS	Total	F1,F2	8.32	0.3	N/A	1.3	TILLSONBURG TS	M2
CUMBERLAND DS	T1	F2,F4	8.32	1.7	TC	4.6		
CUMBERLAND DS	T2	F1,F3	8.32	0.3	TC	3.2		
CUMBERLAND DS	Total	F1, F2, F3, F4	8.32	2.0	TC	4.9		
CUMBERLAND TS	B	M22,M24,M26,M28,M30	27.6	16.7	77.7	32.7		
CUMBERLAND TS	Q	M21,M23,M25,M27,M29	27.6	19.2	80.7	35.2		
CUMBERLAND TS	Total	M21,M23,M25,M27,M29,M22,M24,M26,M28,M30	27.6	43.7	N/A	Sum of Buses		
CURRIE DS	T1-1	F1,F2	8.32	0.6	N/A	1.1	WOODSTOCK TS	M4
CURRIE DS	T1-2	F1,F2	8.32	0.6	N/A	1.1	WOODSTOCK TS	M4
CURRIE DS	Total	F1,F2	8.32	0.6	N/A	1.1	WOODSTOCK TS	M4
CURVE INN DS	Total	F1,F2,F3	8.32	0.6	N/A	3.0	WILSON TS DESN2	M13
DACK DS	Total	F1,F2	12.47	0.5	N/A	1.9	KIRKLAND LAKE TS	M62
DARTFORD DS	Total	F2,F3	8.32	1.2	TC	3.6	SIDNEY TS	R8S
DEEP RIVER DS	T1	F1	12.5	0.6	151.7	5.4		
DEEP RIVER DS	T2	F2,F3	12.5	1.4	21.8	6.2		
DEEP RIVER DS	T3	F5	12.5	0.7	19.7	6.4		
DEEP RIVER DS	Total	F1,F2,F3,F5	12.5	2.7	N/A	12.3		
DEERHURST DS	Total	F1,F2,F3	12.47	1.8	N/A	4.6	MUSKOKA TS	M4
DELAWARE DS	Total	F1,F2,F3,F4	8.32	1.3	N/A	3.7	LONGWOOD TS	M23
DELHI DS #2	Total	F1,F2	8.32	0.7	N/A	3.1	NORFOLK TS	M1
DELORO DS #1	Total	F1,F2,F3	12.47	1.3	N/A	4.1	HAVELOCK TS	M2
DEMORESTVILLE DS	Total	F1,F2	8.32	0.9	N/A	2.3	PICTON TS	M5
DES JOACHIMS DS	Total	F1,F2,F3	12.48	0.6	18.9	6.6		
DESERONTO DS	Total	F1,F2	4.16	0.6	N/A	2.1	NAPANEE TS	M4
DETWEILER TS	BY	M11, M12, M13	27.6	6.3	95.6	26.3		
DEVLIN DS	Total	F1,F2	12.47	0.7	N/A	1.6	FORT FRANCES TS	M1
DEWITT CORNERS DS	Total	F1,F2,F3,F4	8.32	1.4	N/A	5.0	SMITHS FALLS TS	M21
DICKENSON ROAD DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	NEBO TS DESN1	M5
DIRLETON DS	Total	F1,F2,F3	12.47	1.4	N/A	4.3	ARNPRIOR TS	M2
DIXONS CORNERS DS	Total	F1,F2,F3	8.32	1.6	N/A	TC	MORRISBURG TS	M25
DOANE DS	Total	F1,F2	27.6	2.4	N/A	5.0	BROWN HILL TS	M3
DOBBIN DS	T1	F1	27.6	1.4	238.3	13.4		
DOBBIN DS	T2	F2	27.6	1.2	238.9	13.2		
DOBBIN DS	Total	F1,F2	27.6	2.6	N/A	14.6		
DOBBIN TS	BY	M1, M2, M3, M4, M5, M6, M7, M8	44	30.1	469.9	90.1		
DOMINION DRIVE DS	Total	F1,F2,F3	12.47	1.5	N/A	5.0	MARTINDALE TS	M6
DOMVILLE DS	Total	F1,F2	8.32	0.6	N/A	2.0	BROCKVILLE TS	B1R
DORCAS BAY DS	Total	F1,F2	12.47	1.2	N/A	4.1	OWEN SOUND TS	M24
DORCHESTER DS	Total	F1, F2	8.32	0.2	N/A	0.5	HIGHBURY TS	M11
DORCHESTER POND DS	Total	F1,F2,F3	8.32	0.6	N/A	4.2	BUCHANAN TS	M21
DORSET DS	Total	F1,F2	12.48	1.1	N/A	4.0	MINDEN TS	M2
DOUGLAS POINT TS	DJ	M1, M2, M3, M4, M5, M6, M8	44	12.4	353.6	52.4		
DOVER CENTRE DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	WALLACEBURG TS	M3
DRAYTON DS	Total	F1,F2,F3	8.32	2.5	N/A	4.9	PALMERSTON TS	M2
DRESDEN DS	Total	F1,F2	8	0.5	N/A	1.4	WALLACEBURG TS	M1
DRUMBO DS	Total	F1,F2	8	0.4	N/A	1.3	WOLVERTON DS	F2
DRUMMOND DS	T1	F1,F2	8.32	0.8	N/A	2.2	SMITHS FALLS TS	M26
DRUMMOND DS	T2	F4	27.6	0.6	N/A	5.0	SMITHS FALLS TS	M26
DRYDEN COLONIZATN DS	Total	F1,F2,F3	12.47	0.4	N/A	3.3	DRYDEN TS	M1
DRYDEN GOVERNMENT DS	Total	F1,F2	12.47	0.7	N/A	2.1	DRYDEN TS	M3
DRYDEN RURAL DS	Total	F1,F2,F3	25	1.1	N/A	4.0	DRYDEN TS	M1
DRYDEN TS	TY	M1, M3	44	6.0	552.8	20.4		
DRYDEN WILDE DS	Total	F1,F2,F3	12.47	2.1	N/A	5.0	DRYDEN TS	M1
DUBLIN DS	Total	F1,F2	8.32	1.0	N/A	2.4	SEAFORTH TS	M2
DUFF DS	Total	F1,F2	8.32	0.8	N/A	3.2	NEBO TS DESN1	M6
DUFFERIN TS DESN1	A1A2	For any information or inquiries please contact Toronto Hydro	13.8	9.4	TC	9.4		
DUFFERIN TS DESN1	A3A4	For any information or inquiries please contact Toronto Hydro	13.8	4.7	TC	4.7		
DUFFERIN TS DESN1	Total	For any information or inquiries please contact Toronto Hydro	13.8	14.1	TC	Sum of Buses		
DUFFERIN TS DESN2	A5A6	For any information or inquiries please contact Toronto Hydro	13.8	13.9	TC	13.9		
DUFFERIN TS DESN2	A7A8	For any information or inquiries please contact Toronto Hydro	13.8	8.1	TC	8.1		
DUFFERIN TS DESN2	Total	For any information or inquiries please contact Toronto Hydro	13.8	22.0	TC	Sum of Buses		
DUNBOYNE DS	Total	F1,F2,F3	8	0.8	N/A	3.2	EDGEWARE TS	M4
DUNCHURCH DS	Total	F1,F2,F3	12.5	0.9	N/A	3.8	PARRY SOUND TS	M3
DUNDALK VICTORIA DS	Total	F1,F2,F3,F4	4.16	0.7	N/A	3.1	ORANGEVILLE TS 44 KV - DESN1	M45
DUNDAS SYDENHAM DS	Total	F1,F2	8.32	0.5	N/A	1.9	DUNDAS TS	M3
DUNDAS TS	BY	M1, M2, M3, M4, M5, M6, M7, M8	27.6	29.6	92.0	69.6		
DUNDAS TS #2	JQ	M11, M12, M13, M14, M15, M16	27.6	11.8	115.6	51.8		
DUNEDIN DS	Total	F1,F2,F3	8.32	1.4	N/A	3.8	STAYNER TS	M2
DUNLOP DS	Total	F1,F2	8.32	0.8	N/A	2.2	GODERICH TS	M2
DUNNVILLE TS	BY	M1, M2	27.6	7.2	TC	16.2		

Station Name	Bus Name	Feeder Name	Voltage (kV)	Minimum Load (MW)	Short Circuit Capacity (MVA)	Thermal Capacity (MW)	Upstream TS	Upstream TS feeder
NAKINA DS	Total	F1,F2	12.47	0.6	N/A	2.0	LONGLAC TS	M2
NAPANEE DS #2	Total	F1,F2,F3	8.32	1.1	N/A	3.5	NAPANEE TS	M1
NAPANEE INDUSTRIALDS	Total	F1,F2,F3	4.16	0.9	N/A	3.3	NAPANEE TS	M1
NAPANEE MILL DS	Total	F4,F5,F6	4.16	0.6	N/A	3.0	NAPANEE TS	M3
NAPANEE NORTH DS	Total	F7,F8,F9	4.16	0.5	N/A	2.9	NAPANEE TS	M1
NAPANEE TS	B	M1,M3	44	12.6	457.0	52.6		
NAPANEE TS	Y	M2,M4	44	14.0	457.0	54.0		
NAPANEE TS	Total	M1,M2,M3,M4	44	26.6	N/A	66.6		
NAVAN DS DESN1	T1	F1,F2,F3	8.32	0.5	TC	3.4		
NAVAN DS DESN2	T2	F4	27.6	0.6	TC	7.8		
NEBO TS DESN1	BY	M3, M4, M5, M6, M7, M8	27.6	23.0	3.0	63.0		
NEBO TS DESN2	JQ	M51, M52, M53, M54, M61, M62, M63, M64	13.8	15.0	48.1	15.0		
NELSON TS DESN1	BQ	M1,M2,M3,M4,M5,M6	13.8	6.8	168.7	22.8		
NELSON TS DESN2	PK	M31,M32,M33,M34,M35,M36	13.8	12.4	0.0	12.4		
NELSON TS DESN2	YJ	M11,M12,M13,M14,M15,M16	13.8	8.0	0.0	8.0		
NELSON TS DESN2	Total	M11,M12,M13,M14,M15,M16,M31,M32,M33,M34,M35,M36	13.8	15.2	N/A	Sum of Buses		
NEPEAN TS	JQ	M23, M24, M25, M26, M27, M28	44	40.7	TC	100.7		
NESTLETON DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	WILSON TS DESN2	M12
NESTOR FALLS DS	Total	F1, F2	12.5	0.7	140.9	2.1		
NEUSTADT DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	HANOVER TS	M5
NEW LISK HALIBTON DS	Total	F1,F2,F3	12.47	1.8	N/A	3.2	DYMOND TS	M2
NEW LISKEARD DS #1	Total	F1,F2	12.5	0.5	N/A	1.9	DYMOND TS	M2
NEW LISKEARD DS #2	Total	F2	4.16	0.3	N/A	1.3	DYMOND TS	M2
NEWBORO DS	Total	F1,F2,F3	8.32	1.5	N/A	5.0	CROSBY TS DESN1	M5
NEWINGTON DS	Total	F1, F2	27.6	0.4	147.2	7.6		
NEWPORT DS	Total	F1	8.32	0.4	N/A	1.3	BRANTFORD TS	M27
NEWTON TS	B	M1,M3,M6,M8,M10	13.8	8.5	24.6	8.5		
NEWTON TS	Y	M2,M4,M5,M7,M9	13.8	5.7	25.3	5.7		
NEWTON TS	Total	M1,M2,M3,M4,M5,M6,M7,M8,M9,M10	13.8	14.4	N/A	Sum of Buses		
NEWTONVILLE DS	Total	F1,F2	8.32	0.8	N/A	3.2	PORT HOPE TS DESN1	M18
NIPIGON DS	Total	F1, F2	4.16	0.8	165.3	2.3		
NOBLETON DS	Total	F4,F5,F6	8.32	0.9	N/A	3.3	KLEINBURG TS 44 KV	M24
NOELVILLE DS	Total	F1,F2	12.47	1.1	N/A	2.6	MARTINDALE TS	M5
NORFOLK TS	BY	M1, M2, M3, M4, M5, M6	27.6	15.9	74.4	55.9		
NORTH AUGUSTA DS	Total	F2,F3	8.32	0.8	N/A	2.3	BROCKVILLE TS	M4
NORTH AUGUSTA DS #2	T1	F51,F52,F53	8.32	1.4	N/A	5.0	BROCKVILLE TS	M4
NORTH AUGUSTA DS #2	T2	F56,F57	8.32	1.0	N/A	4.6	BROCKVILLE TS	M4
NORTH BAY TS	Y	M1, M3	22	5.7	128.9	25.7		
NORTH COBALT DS	Total	F1,F2,F3	12.47	6.1	N/A	5.0	DYMOND TS	M2
NORTH PORCUPINE DS	Total	F2	4.16	0.2	N/A	1.7	HOYLE DS	F2
NORTH SHORE DS	Total	F1, F2	24.9	1.8	445.8	TC		
NORTHBROOK DS	Total	F1, F2, F3	12.5	1.7	18.2	7.7		
NORTHCOTE DS	Total	F1,F2,F3	12.47	1.3	N/A	TC	COBDEN TS	M2
NORWICH NORTH DS	Total	F1,F2,F3	8.32	1.0	N/A	3.4	TILLSONBURG TS	M3
NORWOOD DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	OTONABEE TS DESN2	M28
NOTTAWAGA DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	WAUBAUSHENE TS	M7
OAKVILLE TS	E	M43,M45,M47,M49,M51	27.6	28.1	101.1	53.1		
OAKVILLE TS	Z	M44,M46,M48,M50,M52	27.6	24.4	72.4	49.4		
OAKVILLE TS	Total	M43,M45,M47,M49,M51,M44,M46,M48,M50,M52	27.6	52.5	N/A	Sum of Buses		
OAKWOOD DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	LINDSAY TS	M8
ODESSA DS	Total	F1,F2,F3	8.32	1.3	N/A	3.7	KINGSTON GARDINER TS DESN1	M14
OIL SPRINGS DS	Total	F1,F2	8.32	0.5	N/A	2.4	WANSTEAD TS	M4
OMEMEE CHURCH DS	Total	F1,F2	8.32	0.5	N/A	2.9	DOBBIN TS	M2
OMEMEE DS	Total	F1,F2,F3	8.32	1.1	N/A	3.5	DOBBIN TS	M2
ONAPING DS	Total	F1,F2,F3	12.47	0.9	N/A	3.8	LARCHWOOD TS	M3
OPS DS	Total	F1,F2,F3	12.47	1.2	N/A	4.1	LINDSAY TS	M6
ORANGEVILLE DS #3	Total	F1,F2,F3	12.47	0.9	N/A	3.8	ORANGEVILLE TS DESN2	M3
ORANGEVILLE TS DESN1	EZ	M23,M24,M25,M26	27.6	9.2	92.5	25.2		
ORANGEVILLE TS DESN1	JQ	M45,M46	44	6.3	742.1	22.3		
ORANGEVILLE TS DESN2	BY	M1,M2,M3,M4,M5,M6	44	27.8	531.5	67.8		
ORILLIA TS	BY	M1,M2,M3,M4,M5,M6, M7, M8	44	40.4	312.1	100.4		
ORO DS	Total	F1,F2,F3	8.32	1.5	N/A	3.9	MIDHURST TS - DESN1	M4
ORONO DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	WILSON TS DESN2	M13
OSGOODE DS	T2	F4	27.6	0.9	TC	5.0	HAWTHORNE TS	M1
OSGOODE DS	T3	F5,F7	27.6	2.1	TC	5.0	HAWTHORNE TS	M1
OSGOODE DS	Total	F4,F5,F7	27.6	3.0	TC	5.0	HAWTHORNE TS	M1
OSLER DS	Total	F1,F2,F3	8.32	1.2	N/A	3.6	STAYNER TS	M1
OSPRINGE DS	Total	F1,F2,F3	8.32	0.6	N/A	3.0	FERGUS TS	M2
OSTRANDER DS	Total	F1,F2,F3	8.32	0.9	N/A	3.3	TILLSONBURG TS	M3
OTONABEE DS	Total	F1,F2,F3	8.32	0.9	N/A	2.3	OTONABEE TS DESN2	M28
OTONABEE TS DESN1	JQ	M8,M9,M10,M11,M12	27.6	14.3	52.0	39.3		
OTONABEE TS DESN2	BY	M25,M26,M27,M28	44	12.2	708.2	37.2		
OTTER LAKE DS	Total	F1,F2,F3	8.32	0.8	N/A	3.2	SMITHS FALLS TS	M25
OTTERVILLE DS	Total	F1,F2	8.32	0.9	N/A	3.3	TILLSONBURG TS	M1
OTTO HOLDEN TS	Y	M1	13.8	1.1	N/A	1.1		
OUELLETTE DS	Total	F1,F3	12.5	0.3	N/A	1.8	MARTINDALE TS	M5
OUSTIC DS	Total	F1,F2,F3	8.32	0.5	N/A	2.9	FERGUS TS	M2

OPA Letter of Comment:

Peterborough Distribution Inc.

Basic Green Energy Act Plan

June 20, 2012

ONTARIO
POWER AUTHORITY

Introduction

On March 25, 2010, The Ontario Energy Board (the "OEB") issued its Filing Requirements for Distribution System Plans. As a condition of Licence, Ontario Distributors are required to file a Green Energy Act Plan as part of their cost of service application.

The Filing Requirements distinguish between Basic and Detailed Green Energy Act Plans ("Plan" or "GEA Plan") and outline the specific information and level of detail which must be provided for each type of Plan. Recognizing the importance of coordinated planning in achieving the goals of the *Green Energy and Green Economy Act, 2009* (the "GEA"), distributors must consult with embedded and host distributors, upstream transmitters and the OPA in preparing their Plans. For both Basic and Detailed Plans, distributors are required to submit as part of the Plan, a letter of comment from the OPA.

The OPA will review distributors' Basic Plans to ensure consistency with regard to FIT and microFIT applications received, as well as with integrated Plans for the region or the system as a whole.

Peterborough Distribution Inc. - Basic Green Energy Act Plan

The OPA has reviewed the Basic GEA Plan from Peterborough Distribution Inc. ("PDI") on June 4, 2012 and has provided its comments below.

OPA FIT/microFIT Applications Received

PDI's GEA Plan indicates that there are 25 connected microFIT and 1 connected FIT projects in its distribution system, and that 60 microFIT and 6 FIT projects have applied to the FIT/microFIT program to be connected within PDI's service territory.

According to OPA's information, as of June 7, 2012, there are 44 connected microFIT projects, totalling 0.3 MW in PDI's distribution system. There are also 7 Capacity Allocation Exempt ("CAE") applications, for a total capacity of 1 MW, that have received FIT contracts in PDI's service area.

In addition, 67 microFIT applications, with 0.6 MW of capacity have applied to connect in PDI's service territory. The OPA has also received 31 FIT CAE applications, totaling 6.3 MW of capacity, proposing to connect to PDI's distribution system.

Upstream Transmission Constraints

According to the information provided in PDI's GEA Plan, PDI's distribution system is supplied from Otonabee TS, Dobbin TS and Dobbin DS. The OPA confirms that there are no currently known upstream transmission constraints at these stations.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 1-800-797-9604 Toll Free
info@powerauthority.on.ca www.powerauthority.on.ca

Further details on capacity at the above mentioned stations may be found in the updated Transmission Availability Table for Small FIT 2012 available on the OPA's FIT website as follows: http://fit.powerauthority.on.ca/sites/default/files/TAT%20Table%20Final%20-%20April%205%20for%20posting.pdf

Economic Connection Test

The OPA received a directive dated April 5, 2012 from the Minister of Energy with respect to the Feed-in Tariff Program Review. The directive states that "[g]iven the transmission projects planned through the Long Term Energy Plan and changes to the FIT Program, the OPA shall not run the Economic Connection Test ". A link to the full directive is provided on the OPA's website: http://www.powerauthority.on.ca/sites/default/files/page/FIT-ReviewApril-2012.pdf

Opportunities for Integrated Solutions

The OPA is not aware of any opportunities for integrated solutions among neighbouring LDCs at this time.

Conclusion

The OPA finds that PDI's GEA Plan is reasonably consistent with the OPA's information regarding renewable energy generation applications to date.

The OPA appreciates the opportunity to comment on Peterborough Distribution Inc.'s Basic GEA Plan.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 1-800-797-9604 Toll Free
info@powerauthority.on.ca www.powerauthority.on.ca