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OVERVIEW:

MANAGER'S SUMMARY OF OPERATING COSTS

The operating costs presented in this Exhibit represent the annual expenditures required to sustain Norfolk Power Distribution Inc.'s ("Norfolk's") distribution operations. Norfolk follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance.

Historically, Norfolk has followed the Canadian Generally Accepted Accounting Principles (CGAAP) in preparation of its financial statements. As stated through this application, Norfolk will be converting to Modified International Financial Reporting Standards (MIFRS) in 2012 and has prepared this application under MIFRS. For clarity and ease of comparison to historical data, this Exhibit first presents all information including the 2011 Bridge year and 2012 Test year under CGAAP. At the end of this Exhibit, under Tab 4, the 2012 Test year will be presented under MIFRS with full explanation of changes from CGAAP.

Norfolk has not included any one-time or non-regulatory expenses in the 2011 Bridge year and 2012 test year, with the exception of the costs for preparing this application which have been spread over 4 years. In Norfolk's audited financial statements the years 2008, 2009 and 2010 included charitable contributions and fees paid to its parent company Norfolk Power Inc (NPI). In 2009 the audited financial statements included Property Taxes in 'Administrative and general expense', while in 2008 and 2010 Property Taxes were in included in 'Taxes other than amounts in lieu of corporate taxes'.

In order to provide a useful comparison to historical data these non-regulatory expenses have been removed from OM&A as illustrated in Table 1.1.

Table 1.1: OM&A Reconciliation to Audited Financial Statements

	2008	2009	2010
OM&A as per Audited Financial Statements	$5,266,457	$4,571,838	$4,925,355
Less Charitable Contributions	6,230	5,324	6,346
Less NPI Holdco Fees	85,729	48,993	63,708
Less Property Taxes		34,481	
OM&A Expense	5,174,498	4,483,040	4,855,301

A summary of Norfolk's operating costs for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year and the 2012 Test Year (CGAAP) and 2012 Test Year (IFRS) , is provided in Table 1.2 below. A summary of the variances as required by the Filing Requirements is provided in Tables 1.3 through 1.7.

Table 1.2 – Summary of OM&A Expenses:

Summary of OM&A Expenses							
Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test GAAP	2012 Test IFRS
Operations	1,201,788	1,185,564	1,060,932	1,106,741	1,144,900	1,226,500	1,288,506
Maintenance	718,374	1,507,433	1,025,443	1,115,511	1,151,200	1,165,100	1,248,605
Billing & Collecting	982,644	1,053,434	1,037,686	971,841	968,850	1,228,062	1,228,062
Community Relations	27,069	95,043	45,608	48,761	58,000	37,000	37,000
Administrative & General Expense	1,323,498	1,333,024	1,313,371	1,612,447	1,633,500	1,544,400	2,015,444
Total OM&A Expense	**4,253,373**	**5,174,498**	**4,483,040**	**4,855,301**	**4,956,450**	**5,201,062**	**5,817,617**
Year over Year % Increase		21.7%	-13.4%	8.3%	2.1%	4.9%	
CAGR from 2008 Approved						5.2%	
CAGR from 2008 Actual						0.1%	
GDP-IPI		2.1%	2.3%	1.3%	1.3%		

Norfolk is proposing recovery of 2012 Test Year OM&A costs, excluding amortization, PILs and Interest totaling $5,817,617.

1 **Table 1.3 Summary OM&A Expense Variances 2008 Approved vs. 2008 Actual**

OM&A: 2008 Approved vs 2008 Actual				
Description	2008 Approved	2008 Actual	Variance $	Variance %
Operations	1,201,788	1,185,564	(16,224)	-1.4%
Maintenance	718,374	1,507,433	789,059	109.8%
Billing & Collecting	982,644	1,053,434	70,790	7.2%
Community Relations	27,069	95,043	67,974	251.1%
Administrative & General Expense	1,323,498	1,333,024	9,526	0.7%
Total OM&A Expense	**4,253,373**	**5,174,498**	**921,125**	**21.7%**

2 **Table 1.4 Summary OM&A Expense Variances 2008 Actual vs. 2009 Actual**

OM&A: 2008 Actual vs 2009 Actual				
Description	2008 Actual	2009 Actual	Variance $	Variance %
Operations	1,185,564	1,060,932	(124,631)	-10.5%
Maintenance	1,507,433	1,025,443	(481,990)	-32.0%
Billing & Collecting	1,053,434	1,037,686	(15,749)	-1.5%
Community Relations	95,043	45,608	(49,435)	-52.0%
Administrative & General Expense	1,333,024	1,313,371	(19,653)	-1.5%
Total OM&A Expense - Controllables	**5,174,498**	**4,483,040**	**(691,458)**	**-13.4%**

1 **Table 1.5 Summary OM&A Expense Variances 2009 Actual vs. 2010 Actual**

OM&A: 2009 Actual vs 2010 Actual				
Description	2009 Actual	2010 Actual	Variance $	Variance %
Operations	1,060,932	1,106,741	45,809	4.3%
Maintenance	1,025,443	1,115,511	90,068	8.8%
Billing & Collecting	1,037,686	971,841	(65,845)	-6.3%
Community Relations	45,608	48,761	3,153	6.9%
Administrative & General Expense	1,313,371	1,612,447	299,076	22.8%
Total OM&A Expense	4,483,040	4,855,301	372,261	8.3%

2 **Table 1.6 Summary OM&A Expense Variances 2010 Actual vs. 2011 Bridge Year**

OM&A: 2010 Actual vs 2011 Bridge				
Description	2010 Actual	2011 Bridge	Variance $	Variance %
Operations	1,106,741	1,144,900	38,159	3.4%
Maintenance	1,115,511	1,151,200	35,689	3.2%
Billing & Collecting	971,841	968,850	(2,991)	-0.3%
Community Relations	48,761	58,000	9,239	18.9%
Administrative & General Expense	1,612,447	1,633,500	21,053	1.3%
Total OM&A Expense	**4,855,301**	**4,956,450**	**101,149**	**2.1%**

Table 1.7 Summary OM&A Expense Variances 2011 Bridge Year vs. 2012 Test Year

OM&A: 2011 Bridge vs 2012 Test				
Description	2011 Bridge	2012 Test	Variance $	Variance %
Operations	1,144,900	1,226,500	81,600	7.1%
Maintenance	1,151,200	1,165,100	13,900	1.2%
Billing & Collecting	968,850	1,228,062	259,212	26.8%
Community Relations	58,000	37,000	(21,000)	-36.2%
Administrative & General Expense	1,633,500	1,544,400	(89,100)	-5.5%
Total OM&A Expense	**4,956,450**	**5,201,062**	**244,612**	**4.9%**

Table 1.8 OM&A: 2012 compared to Historical Years

Required Total OM&A Comparison	**%**
2012 Test Year versus 2010 Actual	7.1%
2012 Test Year versus 2009 Actual	16.0%
2012 Test Year versus 2008 Approved	22.3%
Simple average variance % for all actual years	4.7%
Compound annual growth rate for actual years	0.1%

The table below sets out the OM&A cost per customer and Full Time equivalent employees.

Table 1.9 – OM&A Per Customer and FTE

Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 Test Year
Number of Customers (Excl. Connections)	18,835	18,662	18,803	18,893	19,097	19,303
Total OM&A Expense	$4,253,373	$5,174,498	$4,483,040	$4,855,301	$4,956,450	$5,201,062
OM&A Cost per Customer	$226	$277	$238	$257	$260	$269
Number of FTEEs	54.00	50.40	47.30	46.30	46.10	48.60
FTEEs / Customer	0.0029	0.0027	0.0025	0.0025	0.0024	0.0025
OM&A Cost per FTEE	$78,766	$102,669	$94,779	$104,866	$107,515	$107,018

The number of customers includes the average number of residential, GS<50 and GS>50 customers as found in Norfolk's Load Forecast.

Detailed information with respect to OM&A costs, arranged by USofA account, is provided in Exhibit 4, Tab 2, Schedule 2. Detailed information with respect to OM&A variances, arranged by USofA account, is provided in Exhibit 4, Tab 2, Schedule 3.

The variance used to determine the OM&A accounts requiring analysis has been prescribed by the Filing Requirements as 0.5% of distribution revenue for distributor's with distribution revenue exceeding $10 million.

Table 1.10 Materiality Threshold

Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 Test Year (CGAAP)	2012 Test Year (IFRS)
Distribution Revenue Requirement	11,531,615	11,780,013	11,469,002	11,715,604	12,893,338	12,941,119	12,686,869
Materiality - 0.5%	57,658	58,900	57,345	58,578	64,467	64,706	63,434

As indicated in Table 1.10 the lowest materiality limit during the past 4 years for Norfolk is $57,345. To ensure a thorough analysis, all variances greater than $50,000 have been provided with details.

OM&A Costs:

OM&A costs in this Exhibit represent Norfolk's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels. OM&A costs also include providing services to customers connected to Norfolk's distribution system, and meeting the requirements of the OEB's Standard Supply Service Code and Retail Settlement Code.

The proposed OM&A cost expenditures for the 2012 Test Year are the result of a business planning and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place.

OM&A Budgeting Process:

The operating budget is prepared annually by management and is reviewed and approved by the Board of Directors. The budget is prepared before the start of each fiscal year, and provides a plan against which actual results are evaluated. Once approved, the budget is only revised if a material change in plan is required. In such cases, the revised budget also needs to be approved by the Board of Directors.

The operating budget is a component of the overall budget process described in Exhibit 1, Tab 2, Schedule 2.

Operating Work Plans:

Each Department Manager provides input for the preparation of the departmental budget. The following directives are provided to each manager:

- Outside expenses for all department budgets are built using previous year actual, current year forecast and current year budget as the base;

- Significant variances in spending from prior years must be explained and documented;
- Review the head count of the department for accuracy and outline any changes;
- Accounting prepares a total labour budget by department using projected wage and benefit costs. Overtime and account distribution are based on previous years actual plus any identified changes for the future year;

Income Tax, Large Corporation Tax and Ontario Capital Taxes:

Norfolk is subject to the payment of PILs under Section 93 of the *Electricity Act, 1998*, as amended. The Applicant does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the *Income Tax Act (Canada)* and the Ontario *Corporations Tax Act*. Please refer to Exhibit 4, Tab 3, Schedule 1 and Appendix D for further tax calculations and a copy of the 2010 Federal tax return.

One-Time Costs:

Norfolk has not included any one-time costs in the operating budget, with the exception of costs related to completing this Cost of Service application. The estimated costs for completing this application have been divided over four years. Table 2.19 provides these details as well as other regulatory expenses.

Regulatory Costs:

Regulatory costs as indicated in the variance analysis are presented in Table 2.19. Regulatory costs for the 2012 rate application (amounting to $189,500), include Norfolk's consulting costs as well as anticipated Board and Intervenor expenses. These costs have been spread over a four year period beginning with the 2012 OM&A budget (25% expenses relating to the 2012 cost of service application are included in OM&A for 2012). The costs that have been included are indicated below:

Table 1.11 - Regulatory Costs

Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One Time Cost?	Last Rebasing Year 2008	Last Year of Actuals 2010	2011 Bridge Year	% Change in Bridge Year vs. Last Year of Actuals	2012 Test Year "Actual" Expenditures	2012 Test Year - Requested for Recovery	% Change in Test Year "Actual" vs. Bridge Year	% Change in Test Year Requested vs. Bridge Year
1. OEB Annual Assessment	5655		Ongoing	53,653	66,523	77,316	16%	77,316	77,316	0%	0%
2. OEB Hearing Assessments (applicant initiated)	5655		Ongoing	-	-	-	0%	-	-	0%	0%
3. OEB Section 30 Costs (OEB initiated)	5655		One-Time	16,159	7,322	7,500	2%	7,500	1,875	0%	-75%
4. Expert Witness Cost for Regulatory Matters	5655		One-Time	-	-	-	0%	-	-	0%	0%
5. Legal Costs for Regulatory Matters	5655		Ongoing	-	-		0%		-	0%	0%
6. Consultants Costs for Regulatory Matters	5655		One-Time	41,551	86,987	64,084	-26%	120,000	30,000	87%	-53%
7. Operating Expenses associated with Staff Resources Allocated to Regulatory Matters	5615		Ongoing	-	-		0%		-	0%	0%
8. Operating Expenses associated with other resources	5605		Ongoing	-	-		0%		-	0%	0%
9. Other regulatory agency fees or assessments Note 1	5655		Ongoing	800	600	600	0%	600	600	0%	0%
10. Any Other Costs for Regulatory Matters	5655		One-Time	592	2,323	2,000	-14%	2,000	500	0%	-75%
11. Intervenor Costs (see #3)	5655		One-Time	-		-	0%	**60,000**	15,000	0%	0%
Sub-Total Ongoing Costs				54,453	67,123	77,916	16%	77,916	77,916	0%	0%
Sub-Total One-Time Costs				58,302	96,633	73,584	-24%	189,500	47,375	158%	-36%
Total Regulatory Costs Included in Rate Application				112,755	163,756	151,500	-7%	267,416	125,291	77%	-17%

Low Income Assistance Program (LEAP)

Norfolk has included $16,000 of expense for the Low Income Assistance Program (LEAP) under Community Relations. This amount is based on 0.12% of the 2012 Test year Revenue Requirement, rounded.

Charitable Contributions

Norfolk has not included any charitable donations in OM&A expenses for 2012.

Green Energy Act

Exhibit 2 of this application provides Norfolk's plan for capital spending under the Green Energy Act. Norfolk has not included any operating expenses related to the Green Energy Act in this application. Norfolk has requested a funding adder for the amount of revenue requirement related to capital expenditures for Green Energy Act projects, however these amounts do not include an operating expenses. Norfolk does intend to record incremental operating expenses related to the Green Energy Act in the prescribed deferral account and seek recovery on a historical/actual basis.

Inflation in 2011 Bridge and 2012 Test Year

The 2011 Bridge Year forecast is based on actual expenses as of June 30, 2011 plus expected expenditures for the remaining 6 months. No inflation has been applied to the expected expenditures except in cases where it is a known amount, such as increase to wages for union staff according to the collective agreement. In the 2012 Test Year expenses have been budgeted based on existing prices and increases if known.

DEPARTMENTAL AND CORPORATE OM&A ACTIVITIES:

OPERATIONS & MAINTENANCE

The expenses for this department include all costs relating to the operation (5000-5096) and maintenance (5105-5195) of Norfolk's electrical system. This includes both direct labour costs and non-capital material spending to support both scheduled and reactive maintenance events. In addition, costs are allocated from support departments to cover the costs of Labour Burden, Engineering and Stores. Norfolk's maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through an effective planned maintenance program, including predictive and preventative actions.

Norfolk's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with Norfolk's capital project work so that where maintenance programs have identified matters which require capital investments, Norfolk may adjust its capital spending priorities to address those matters.

Predictive Maintenance:

Predictive maintenance activities involve the testing of elements of the distribution system. These activities include infrared thermography testing, transformer oil analysis, planned visual inspections and pole testing. These evaluation tools are all administered using a grid system with appropriate frequency levels. Any identified deficiencies found are prioritized and addressed within a suitable time frame.

Preventative Maintenance:

Preventative maintenance activities include inspection, servicing and repair of network components. This includes overhead and pad-mounted load break switch maintenance and cleaning/inspection of underground vaults. Also included are regular inspection and repair of substation components and ancillary equipment. The work is performed using a combination of time and condition based methodologies.

Emergency Maintenance:

This item includes unexpected system repairs to the electrical system that must be addressed immediately. The costs include those related to repairs caused by storm damage, emergency tree trimming and on-call premiums. Norfolk constantly evaluates its maintenance data to adjust predictive and preventative actions. The ultimate objective is to reduce this emergency maintenance. An answering service company has been contracted to contact “on call” lineperson and supervisory staff in the event of service problems outside of normal business hours.

Service Work:

The majority of costs related to this work pertain to service upgrades requested by customers, and requests to provide safety coverage for work (overhead line cover ups). This includes service disconnections and reconnections by Norfolk for all service classes; assisting pre-approved contractors; the making of final connections after Electrical Safety Authority (“ESA”) inspection for service upgrades; and changes of service locations.

Network Control Operations:

Norfolk maintains a Supervisory Control and Data Acquisition (“SCADA”) system. Network operating costs are charged to account 5085.

Metering:

The metering department is responsible for the installation, testing, and commissioning of new and existing simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation and verifies meter multipliers for billing purposes.

Revenue Protection is another key activity performed by Metering, by proactively investigating potential diversion and theft of power.

Substation Services:

Substation services activities address the maintenance of all equipment at Norfolk's 12 substations. This includes both labour costs and non-capital material spending to support both scheduled and emergency maintenance events. As with the maintenance activities, substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of Norfolk's planned maintenance program (including predictive and preventative actions) for its substations.

ENGINEERING DEPARTMENT

Engineering delivers drafting services from the design technicians for capital projects and provides distribution system asset information to many departments within Norfolk. Engineering costs were allocated to operations, maintenance, capital, and Third Party receivable accounts based on total labour, truck and material costs. A standard overhead percentage is set at the beginning of the year for all jobs, and adjusted to actual at year end.

STORES/WAREHOUSE

Stores area is shared duties of other departments and is accountable for managing the procurement, control, and movement of materials within Norfolk's service centre. This includes monitoring inventory levels, issuing material receipts, material issues, and material returns as required. The cost of the stores department is allocated to all departmental, capital and Third Party receivable accounts as an overhead cost based on direct material costs. A standard overhead percentage is set at the beginning of the year and adjusted to actual at year end.

GARAGE/TRANSPORTATION FLEET

This area is shared duties of other departments and assists with the maintenance and control of approximately 19 fleet vehicles. Its objectives include keeping maintenance schedules to ensure vehicle reliability and safety, and the minimization of vehicle down time. Vehicle costs are allocated to operations, maintenance, capital and Third Party receivable accounts based on number of hours used. A standard "cost per hour" is set for all vehicles within the fleet (one rate for passenger vehicles and pickup and another rate for bucket trucks and work platforms). Costs are adjusted to actual at year end.

LABOUR BURDEN/SAFETY AND HEALTH

This department collects the cost of all employee benefits and payroll taxes such as EI, CPP, EHT, WSIB, and group insurances. Costs are allocated to all departments, capital and Third Party receivable amounts based on direct labour. An overhead rate is set at the beginning of each year and adjusted to actual at year end.

In addition, the cost of Safety and Health is included in this department. Costs include Health & Safety program supplies as well labour costs associated with safety meetings. Norfolk is committed to maximizing productivity and reducing risk of injury by initiating safety and health measures that focus on preventative actions. The commitment to safety and health is significant, and involves documenting unsafe behaviors, monitoring conformance to established standards and policies, determining the effectiveness of safety training and monitoring the resolution of safety recommendations/audits; commitment to continuous improvement in training; and identifying and correcting root causes for system deficiencies. Norfolk recently achieved the milestone of 250,000 hours without a loss-time incident and will be applying to the Infrastructure Health and Safety Authority (IHSA) in 2011 for the Bronze Medal for safety in the quest for zero lost time accidents.

CUSTOMER SERVICE

The Customer Service group is responsible for the customer care activities for the approximately 19,000 customers in Norfolk's service area. These activities include meter reading, billing, call centre, collections, and other back office functions. Norfolk aspires to achieve customer service excellence in its processes and customer programs. The costs associated with the Customer Service department are reported in accounts 5305 to 5340.

Meter Reading:

Prior to June 2011 all meter reading services were contracted out to a non-affiliated third party under a service contract agreement. The transition to fully electronic meter reading in conjunction with TOU billing began in June 2011. Contractor services for manual meter reading will continue to be necessary for approximately 500 meters which do not have electronic reading capabilities. These meters will be replaced by the end of 2012, at which time contracted services for manual meter reading will end.

Billing:

Norfolk performs monthly billing and issues 228,000 electricity invoices annually to customers. An annual billing schedule is created based on the meter reading schedule to ensure timely billing of services. The billing functions include the VEE processes (verification, estimation and edit); Electronic Billing Transactions (EBT) and retailer settlement functions for 2,500 retailer accounts; account adjustments; processing meter changes; and other various account related field service orders and mailing services. Norfolk offers customers a number of billing and payment options including walk-in counter service, an equal payment plan and a preauthorized payment plan.

Collections:

Collections involve a combination of activities, including the collection of overdue active accounts, security deposits and final bills for service termination. In an effort to minimize credit losses, Norfolk enforces a prudent credit policy in accordance with the Distribution System Code. Active overdue accounts are collected by in-house staff through notices, letters and direct telephone contact. Final bill collections are turned over to a collection agency after collection methods are exhausted.

Community Relations:

Norfolk is committed to providing consumer information and responses, in a timely and proactive manner, on electricity distribution and related issues. Norfolk maintains a presence in the communities it serves, where staff is available to answer customer questions in a friendly environment.

Since LDCs are the "face-to-the-customer" for the electricity industry, Norfolk has an important role to play in educating the public about electricity safety and energy conservation. Norfolk continues to participate with the OPA in administering programs directed at Energy Conservation. Norfolk is very active in the community promoting conservation initiatives, attending a number of community events each year, distributing compact florescent light bulbs and energy conservation handbooks.

ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include expenses incurred in connection with the general administration of the utility's operations. Within Norfolk, the following functional areas are considered to be part of general administration and, as such, all expenses incurred within these functional areas are accounted for as administrative and general expenses:

- Executive Management (5605);
- Finance and Administrative Services (5615)

Executive Salaries and Expenses: 5605

This account includes expenses for Executive Management including salaries and related expenses. Consistent with Section 6-4 of the 2006 EDR Handbook which states that… "In cases where there are three or fewer, full time equivalents (FTEs) in any category, the applicant may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three or fewer FTEs." Norfolk has aggregated account 5605 with account 5615.

Administrative Services: 5615

Administrative Services is comprised of several sub-accounts: Accounting/Finance, Corporate Administration and Personnel Administration. The Finance department is responsible for the preparation of statutory, management and Board of Directors financial reporting in accordance with GAAP; all daily accounting functions, including accounts payable, accounts receivable, and general accounting; treasury functions including cash management, risk management, accounting systems and internal control processes; preparation of consolidated budgets and forecasts; and supporting tax compliance. The department is also responsible for all regulatory reporting and compliance with applicable codes and legislation governing Norfolk, including development and preparation of rate filings, performance reporting, and compliance.

The Corporate Administration and Personnel Administration department is responsible for providing support services required to operate an effective corporation as well as human resource-related support services.

Expenses included in Administrative Services include salary and related payroll burdens associated with the Accounting Supervisor, Financial & Regulatory Analyst, Accounts Payable Clerk, Accounts Receivable Clerk, and the Administrative Assistant, as well as incidental expenses relating to corporate services support and human resource support.

Outside Service Employed: 5630

Outside Services Employed include, but are not limited to, consulting and professional fees of accountants and auditors, actuaries, legal services, public relations counsel and tax consultants.

Employee Post-Retirement Benefits: 5645

Employee Post-Retirement Benefits include annual expenses for post-retirement benefits provided to eligible Norfolk employees in accordance with company policy and as provided in the collective bargaining agreement between Norfolk and its union. The annual expense and liability are determined in accordance with Section 3461 of the CICA Handbook and supported by an actuarial valuation that is completed every three years.

Regulatory Expenses: 5655

Regulatory Expenses include those expenses incurred in connection with Decisions and Orders on Cost Awards for hearings, proceedings, technical sessions, and other matters before the OEB or other regulatory bodies, including annual assessment fees paid to a regulatory body. Annual fees assessed by the OEB are included in this expenditure category.

Miscellaneous General Expense: 5665

Membership dues, Board of Directors remuneration and expenses and other miscellaneous costs are included in this account. Norfolk is a member of the Electrical Distributor Association and the Niagara-Erie Power Alliance Group (NEPA). NEPA has a membership of 9 small LDCs, which have worked together on common issues which have been mutually beneficial to the members. These include Conditions of Service, Economic Evaluation process, Smart Meter procurement, RFP for Collection Agency services and Audit services, CDM programs, IESO and settlement issues, joint training sessions and International Financial Reporting Standards.

Maintenance of General Plant: 5675

Expenses under Maintenance of General Plant include all costs of operating the service centre and office building. These include items such as: building utility costs, maintenance & repairs to the office building, lawn care & snow removal, and burdened salaries for facilities personnel.

Electrical Safety Authority ("ESA"): 5680

Expenses under Electrical Safety Authority ("ESA") fees include all annual charges from the ESA as well as annual audit expenses.

OM&A DETAILED COSTS TABLES

Table 2.1 Detailed Account by Account Operation Expenses

USoA	Distribution Expenses - Operation	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test GAAP
5005	Operation Supervision and Engineering	164,676	91,550	76,118	87,569	87,400	90,500
5010	Load Dispatching	200,322	332,229	284,274	276,605	294,700	307,200
5012	Station Buildings and Fixtures Expense	35,320	44,809	23,257	35,289	29,000	35,500
5014	Transformer Station Equipment - Operation Labour	2,102	1,190	4,414	2,651	6,000	3,500
5015	Transformer Station Equipment - Operation Supplies & Expenses	1,596	140	31,649	28,300	25,000	26,000
5016	Distribution Station Equipment - Operation Labour	73,376	43,723	7,628	9,855	11,000	16,000
5017	Distribution Station Equipment - Operation Supplies and Expenses	26,316	8,537	8,618	29,878	33,800	30,000
5020	O/H Distribution Lines and Feeders - Operation Labour	180,451	74,498	83,022	80,472	93,000	86,900
5025	O/H Distribution Lines and Feeders - Operation Supplies & Expenses	8,020	58,107	30,605	44,709	42,000	44,400
5030	Overhead Subtransmission Feeders - Operation	0	0	0	0	0	0
5035	Overhead Distribution Transformers - Operation	152	1,463	164	0	1,000	1,000
5040	Underground Distribution Lines and Feeders - Operation Labour	116,975	106,696	123,532	115,268	137,000	125,000
5045	U/G Distribution Lines and Feeders - Operation Supplies & Expenses	435	285	230	54	1,000	1,000
5050	Underground Subtransmission Feeders - Operation	0	0	0	0	0	0
5055	Underground Distribution Transformers - Operation	0	989	448	1,970	3,000	2,500
5060	Street Lighting and Signal System Expense	0	0	0	0	0	0
5065	Meter Expense	191,034	208,371	142,115	124,009	145,000	214,300
5070	Customer Premises - Operation Labour	699	0	0	0	0	0
5075	Customer Premises - Materials and Expenses	87	0	0	0	0	0
5085	Miscellaneous Distribution Expense	159,806	177,860	226,959	245,877	211,000	215,700
5090	Underground Distribution Lines and Feeders - Rental Paid	0	0	0	0	0	0
5095	Overhead Distribution Lines and Feeders - Rental Paid	40,421	35,118	17,900	24,235	25,000	27,000
5096	Other Rent	0	0	0	0	0	0
	TOTAL OPERATING EXPENSES	1,201,788	1,185,564	1,060,932	1,106,741	1,144,900	1,226,500

Table 2.2 Detailed Account by Account Maintenance Expenses

USoA	Distribution Expenses - Maintenance	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
5105	Maintenance Supervision and Engineering	51,652	57,207	69,750	81,690	126,300	130,000
5110	Maintenance of Structures	8,709	6,622	17,035	16,777	17,300	14,300
5112	Maintenance of Transformer Station Equipment	8,016	2,885	59,887	189,764	67,100	80,000
5114	Maintenance of Distribution Station Equipment	61,338	59,352	42,956	81,441	40,800	49,500
5120	Maintenance of Poles, Towers and Fixtures	40,967	72,645	84,204	65,997	70,000	70,400
5125	Maintenance of Overhead Conductors & Devices	138,993	393,599	314,062	313,079	386,000	377,600
5130	Maintenance of Overhead Services	30,138	17,225	9,861	3,904	12,000	10,500
5135	Overhead Distribution Lines & Feeders - Right of Way	261,066	571,378	216,880	254,542	275,000	263,300
5145	Maintenance of Underground Conduit	64	0	56,779	777	0	0
5150	Maintenance of Underground Conductors and Devices	5,774	77,615	45,799	21,009	40,800	34,000
5155	Maintenance of Underground Services	11,673	50,729	32,773	18,965	32,900	45,000
5160	Maintenance of Line Transformers	72,843	190,502	59,256	45,286	62,000	65,500
5165	Maintenance of Street Lighting and Signal Systems	0	0	0	0	0	0
5170	Sentinel Lights - Labour	0	0	0	0	0	0
5172	Sentinel Lights - Materials and Expenses	0	0	0	0	0	0
5175	Maintenance of Meters	27,142	7,674	16,202	22,280	21,000	25,000
5178	Customer Installations Expenses - Leased Property	0	0	0	0	0	0
5195	Maintenance of Other Installations on Customer Premises	0	0	0	0	0	0
	TOTAL MAINTENANCE EXPENSES	718,374	1,507,433	1,025,443	1,115,511	1,151,200	1,165,100

Table 2.3 Detailed Account by Account Billing & Collecting Expenses

USoA	Billing & Collecting Expenses	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
5305	Supervision	85,929	87,340	120,552	142,062	144,690	172,740
5310	Meter Reading Expense	215,527	198,725	185,789	199,978	120,900	234,395
5315	Customer Billing	470,606	488,791	456,607	476,382	485,550	586,501
5320	Collecting	230,815	255,657	224,406	206,463	216,710	256,895
5325	Collecting - Cash Over and Short	0	0	0	0	0	0
5330	Collection Charges	(98,916)	(88,345)	(120,507)	(118,352)	(117,000)	(132,877)
5335	Bad Debt Expense	70,000	68,167	167,383	53,224	98,000	100,000
5340	Miscellaneous Customer Accounts Expenses	8,683	43,099	3,456	12,084	20,000	10,409
	TOTAL BILLING & COLLECTING EXPENSES	982,644	1,053,434	1,037,686	971,841	968,850	1,228,062

For several years Norfolk has provided water and sewer billing services to its affiliate Norfolk Energy Inc (NEI). Since (at least) 2002 thru 2011 Norfolk has allocated 35% of its Billing and Collecting expenses (excluding bad debt expense) to its affiliate NEI for this service. Minor variances from the 35% occur each year due to year-end adjustments that occur after the cost allocation has occurred. The expense amount reported on Norfolk's financial statements and to the OEB is subsequent to this allocation. For greater clarity Table 2.4 has been provided to illustrate the total Billing and Collecting expense before the allocation, the amount allocated, and the net amount Norfolk's reports as its own expense.

Table 2.4 Billing and Collecting Expenses – Cost Allocation

2008 Total Expense	2008 - As per OEB Trial Balance	2009 Total Expense	2009 - As per OEB Trial Balance	2010 Total Expense	2010 - As per OEB Trial Balance	2011 Total Expense	2011 - As per OEB USofA	2012 Total Expense	2012 - As per OEB USofA
128,993	87,340	187,417	120,552	216,923	142,062	222,600	144,690	234,000	172,740
293,499	198,725	288,838	185,789	305,357	199,978	186,000	120,900	317,521	234,395
771,426	488,791	709,867	456,607	727,415	476,382	747,000	485,550	794,497	586,501
377,581	255,657	348,875	224,406	315,260	206,463	333,400	216,710	348,000	256,895
-	-	-	-	-	-	-	-	-	-
(130,477)	(88,345)	(187,348)	(120,507)	(180,719)	(118,352)	(180,000)	(117,000)	(180,000)	(132,877)
100,676	68,167	167,383	167,383	53,224	53,224	98,000	98,000	100,000	100,000
14,124	43,099	4,606	3,456	17,594	12,084	20,000	20,000	14,100	10,409
(502,388)	-	(481,951)	-	(483,214)	-	(458,150)	-	(400,056)	-
1,053,434	1,053,434	1,037,686	1,037,686	971,841	971,841	968,850	968,850	1,228,062	1,228,062

Beginning in 2012 the allocation of expense to NEI will change significantly. The need for the change and the rationale for the new expense allocation are fully disclosed under Exhibit 4, Tab 2, Schedule 5: 'Charges to Affiliates for Services Provided'.

Table 2.5 Detailed Account by Account Community Relations Expenses

USoA	Community Relations Expenses	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
5405	Supervision	0	0	0	0	0	0
5410	Community Relations - Sundry	12,132	12,524	6,253	20,604	27,000	25,500
5415	Energy Conservation	0	55,745	32,000	18,066	20,000	0
5420	Community Safety Program	5,852	2,040	4,075	4,075	4,000	4,000
5425	Miscellaneous Customer Service & Information Expenses	9,085	24,734	3,280	6,017	7,000	7,500
	TOTAL COMMUNITY RELATIONS EXPENSES	27,069	95,043	45,608	48,761	58,000	37,000

Table 2.6 Detailed Account by Account General & Administrative Expenses

USoA	General & Administrative Expenses	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
5605	Executive Salaries and Expenses NB1	0	0	0	0	0	0
5610	Management Salaries and Expenses	0	0	0	0	0	0
5615	General Administrative Salaries and Expenses	614,079	755,027	749,908	831,069	919,300	918,700
5620	Office Supplies and Expenses	164,256	121,356	119,514	112,219	115,000	113,300
5625	Administrative Expense Transferred-Credit	0	0	0	0	0	0
5630	Outside Services Employed	85,229	75,511	156,506	176,413	128,000	106,500
5635	Property Insurance	29,084	7,649	7,970	19,181	16,500	19,200
5640	Injuries and Damages	44,757	41,625	38,124	29,847	31,800	41,000
5645	Employee Pensions and Benefits	48,385	68,961	54,471	62,463	77,400	79,700
5650	Franchise Requirements	0	0	0	0	0	0
5655	Regulatory Expenses	76,618	112,755	67,435	163,756	151,500	125,000
5660	General Advertising Expenses	4,721	5,154	2,038	1,401	4,000	4,000
5665	Miscellaneous Expenses	84,757	58,798	62,632	63,758	65,000	68,000
5670	Rent	0	0	0	0	0	0
5675	Maintenance of General Plant	162,431	75,142	42,526	50,440	56,000	56,000
5680	Electrical Safety Authority Fees	9,181	11,046	12,246	12,453	13,000	13,000
5681	Special Purpose Charge - Expense (See Acc't 56560)	0	0	0	89,447	56,000	0
5685	Independent Market Operator Fees and Penalties	0	0	0	0	0	0
5695	OM&A Contra Account	0	0	0	0	0	0
	TOTAL GENERAL & ADMINISTRATIVE EXPENSES	1,323,498	1,333,024	1,313,371	1,612,447	1,633,500	1,544,400

NB1: Accounts 5605 and 5610 have been combined with 5615 as each account recorded compensation for less than three employees.

VARIANCE ANALYSIS ON OM&A COSTS:

Norfolk has provided a detailed OM&A expense analysis covering the periods from Norfolk's last cost of service application. An analysis of expense changes by cost driver is provided in Table 2.7 with explanations below.

Table 2.7 Cost Driver Table

		2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
	Total OM&A - Opening Balance	4,593,282	5,174,498	4,483,040	4,855,301	4,956,450
A	Payroll & Benefits	255,787	(268,416)	79,617	257,521	213,725
B	Change in Allocation of Water & Sewer Billing					58,094
C	Third Party Professional Services	10,407	25,202	200,068	(117,042)	(245,500)
D	Smart Meter - Electronic Reading Expenses					234,395
E	Tree Trimming Services	209,477	(346,252)	42,193	22,909	(14,000)
F	PCB Testing Program	34,110	(94,832)	(10,886)	9,046	(5,072)
G	O/H & U/G Maintenance Expenses	65,675	(35,856)	(276)	(24,131)	47,409
H	Bad Debt Write-Offs	15,357	66,707	(114,159)	44,776	2,000
I	Energy Conservation Spending	(37,743)	(23,745)	(13,934)	1,934	(20,000)
J	Station Maintenance Program	49,945	30,214	54,586	(94,787)	53,229
K	Special Purpose Charge	-	-	89,447	(33,447)	(56,000)
L	Miscellaneous	(21,799)	(44,480)	45,606	34,369	(23,668)
	Total OM&A - Closing Balance	5,174,498	4,483,040	4,855,301	4,956,450	5,201,062

A. Payroll & Benefits

Year over year changes in compensation and benefits are detailed under "Employee Compensation and Benefits" in Exhibit 4, Tab 2, Schedule 4. This includes details of employee compliment, base wages, overtime and benefits by employee category.

B. Change in Allocation Method for Water & Sewer Billing Service

For several years Norfolk has provided water and sewer billing services to its affiliate Norfolk Energy Inc (NEI), who has provided the service for the County of Norfolk. Since at least 2002 thru 2011 Norfolk has used the same method for allocating expenses for this service. Namely, 35% of Norfolk's Billing and Collecting expenses (excluding bad debt expense) is allocated each year to NEI. In 2012 the methodology will change as a result of a new agreement between Norfolk and NEI. This change will result in reduction in the amount of expense allocated, by $117,932 compared to 2011. The need for this change and the rationale for the new amount allocated are fully disclosed under Exhibit 4, Tab 2, Schedule 5: 'Charges to Affiliates for Services Provided'.

C. Third Party Professional Services

Norfolk utilizes a number of third party services for various activities including: audit, legal, regulatory services, collection services, human resources, meter reading, and consulting services to fill temporary vacancies. Individual amounts fluctuate annually based on requirements for different services each year. In addition, increases and decreases in this account are to some degree offset be changes in payroll and benefits.

In 2010 a number of factors resulted in the increased expenses for Third Party Professional Services. These included: increased costs for Norfolk's Cost of Service application which was denied (+$77,000); increased legal fees for arbitration and collective bargaining (+$50,000); a customer satisfaction survey (+$24,000); increased fees for a contracted control room operator (+26,000); and a change in billing fees, partially offset by miscellaneous items.

In 2011 meter reading expenses decreased by $87,000 from $243,000 to $156,000. The remainder was due to reduced legal fees for arbitration and collective bargaining (-$30,000).

In 2012 meter reading expenses will be completely replaced by electronic meter reading expenses, resulting in a reduction of $156,000. A $46,000 reduction in expenses is expected from the replacement of the contracted control room operator with a new full time position, with the remaining decrease of $43,000 from reduced regulatory related expenses and the elimination of collective agreement expenses.

D. Smart Meter - Electronic Meter Reading

In July 2011, Norfolk began Time of Use billing and will be seeking recovery for the installation of smart meters and related expenses as part of this application. The expenses of $234,395 for Electronic Meter Reading are outlined in detail under the heading 5310 – Meter Reading Expenses found in Exhibit 4, Tab 2, Schedule 2.

These expenses began at various times during 2010 and 2011 and have been reported under account 1555, Smart Meter Operating Expenses for both years. It is also noted that these expenses are being offset by a significant reduction in the meter reading contractor expenses as reported under 'C. Third Party Professional Services.'

E. Tree Trimming Services

Norfolk utilizes contractors to complete tree trimming services on a cyclical basis throughout its territory, as well as miscellaneous work required each year. The cycle has been created with the intent of creating a steady volume of tree trimming each year. However small changes do occur each year as a result of the volume of trees to be trimmed in any one area and the amount of miscellaneous (demand) trimming required. A notable exception to these small changes occurred in 2008 when a significant amount of work was required to complete a backlog of uncompleted work. In 2009 and 2010 the work load returned to a normal level, with the expenses forecasted at a sustainable level in the 2012 test year.

F. PCB Testing Program

Norfolk tests transformers for PCB content and replaces any defective equipment it finds as a result of the testing. Changes in expense reflect the high number of transformers inspected and replaced during 2008. In 2008 over 800 transformers were tested. In addition, while testing transformers, other deficiencies that were found were often repaired at the same time and not reported separately by line staff. Reduced expenses for 2009 through 2012 (as compared to 2008) reflect a lower number of transformers that require(d) testing as part of Norfolk's cyclical testing schedule.

G. Overhead & Underground Maintenance Expenses

The increase in 2008 of $65, 675 was a result in increased demand work for trouble/service calls. The subsequent decreases in 2009 and 2010 were primarily the result of decreases in these calls, as a result of the major tree trimming activity in 2008 and the regular schedule now followed. Other minor fluctuations each year are the result of the difference in the annual maintenance schedules. The increase in 2012 is related to the installation of animal guards on transformers and other equipment to reduce outages and trouble calls.

H. Bad Debt Write-Offs

Prior to 2009, as part of its Allowance for Doubtful Accounts calculation, Norfolk wrote off bad debt for uncollectable accounts in the preceding year. For example on December 31, 2008 accounts deemed uncollectable for 2007 were written off. This lag meant in some cases accounts were outstanding for between one and two years before they were written off. In 2009 a change in policy occurred advancing the write off date from one year to six months. The increase of $66,000 in 2009 was largely the result of a one-time occurrence of 18 months of bad debt being written off during this change in policy. In 2010, the reduction in bad debts was a combination of improved collections and a return to a 12 month period for write offs. The increase in the 2011 bridge year is reflective of the slow payments occurring during the later part of 2010 and early 2011.

I. Energy Conservation Spending

Energy Conservation spending includes amounts spent in excess of OPA funded programs Norfolk has participated in. This amount has declined over the past four years as Norfolk has utilized the OPA programs to achieve its energy conservation targets. In the 2012 test year Norfolk has removed the CDM related spending from its OM&A expenses and is not seeking recovery for these expenses through rates.

J. Station Maintenance Program

In 2008 station maintenance increased almost $50,000 due to significant repairs required at one of Norfolk’s substations. In 2009 the station maintenance increased further due to an emergency repair on the secondary cables and bushings at the Bloomsburg Transformer Station. In 2010 the Bloomsburg TS required further maintenance work related to the T1 relays which needed to be re-calibrated due to construction of T2. In 2011 relatively little station maintenance was budgeted, with an expected return to routine (normal) levels of maintenance budgeted for the 2012 Test Year.

K. Special Purpose Charge

Beginning in May 2010 the Special Purpose Charge was recorded in administrative expenses, with an offsetting amount reported in Other Revenue. Expenses and revenue continued to be recorded until April 30 2011.

L. Miscellaneous

Changes in miscellaneous expenses represent various year over year changes as described in the account by account variance analysis below.

Variance Analysis by Account:

Consistent with the Ontario Energy Board Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 22 2011, Norfolk has provided variance analyses for the 2012 Test Year vs. 2008 Actual (last rebase year) and between the 2012 Test Year and 2010 Actual (Most Current Actual). Norfolk has reviewed the variance of each USoA account and provided explanations for variances exceeding a materiality threshold of $50,000. The variances are indicated in the following tables and an explanation of each variance is presented in the following section.

Table 2.8 ~ 2008 Actual to 2012 Test Year – Operating Expenses - Account Variances

USoA	Distribution Expenses - Operation	2008 Actual	2012 Test	Variance - $	Variance - %
5005	Operation Supervision and Engineering	91,550	90,500	(1,050)	-1%
5010	Load Dispatching	332,229	307,200	(25,029)	-8%
5012	Station Buildings and Fixtures Expense	44,809	35,500	(9,309)	-21%
5014	Transformer Station Equipment - Operation Labour	1,190	3,500	2,310	194%
5015	Transformer Station Equipment - Operation Supplies & Expenses	140	26,000	25,860	18471%
5016	Distribution Station Equipment - Operation Labour	43,723	16,000	(27,723)	-63%
5017	Distribution Station Equipment - Operation Supplies and Expenses	8,537	30,000	21,463	251%
5020	O/H Distribution Lines & Feeders - Operation Labour	74,498	86,900	12,402	17%
5025	O/H Distribution Lines & Feeders - Operation Supplies & Expenses	58,107	44,400	(13,707)	-24%
5030	Overhead Subtransmission Feeders - Operation	0	0	0	0%
5035	Overhead Distribution Transformers - Operation	1,463	1,000	(463)	-32%
5040	Underground Distribution Lines and Feeders - Operation Labour	106,696	125,000	18,304	17%
5045	U/G Distribution Lines and Feeders - Operation Supplies & Expenses	285	1,000	715	251%
5050	Underground Subtransmission Feeders - Operation	0	0	0	0%
5055	Underground Distribution Transformers - Operation	989	2,500	1,511	153%
5060	Street Lighting and Signal System Expense	0	0	0	0%
5065	Meter Expense	208,371	214,300	5,929	3%
5070	Customer Premises - Operation Labour	0	0	0	0%
5075	Customer Premises - Materials and Expenses	0	0	0	0%
5085	Miscellaneous Distribution Expense	177,860	215,700	37,840	21%
5090	Underground Distribution Lines and Feeders - Rental Paid	0	0	0	0%
5095	Overhead Distribution Lines and Feeders - Rental Paid	35,118	27,000	(8,118)	-23%
5096	Other Rent	0	0	0	0%
	TOTAL OPERATING EXPENSES	1,185,564	1,226,500	40,936	3%

Table 2.9 ~ 2008 Actual to 2012 Test Year – Maintenance Expenses - Account Variances

USoA	Distribution Expenses - Maintenance	2008 Actual	2012 Test	Variance - $	Variance - %
5105	Maintenance Supervision and Engineering	57,207	130,000	72,793	127%
5110	Maintenance of Structures	6,622	14,300	7,678	116%
5112	Maintenance of Transformer Station Equipment	2,885	80,000	77,115	2673%
5114	Maintenance of Distribution Station Equipment	59,352	49,500	(9,852)	-17%
5120	Maintenance of Poles, Towers and Fixtures	72,645	70,400	(2,245)	-3%
5125	Maintenance of Overhead Conductors & Devices	393,599	377,600	(15,999)	-4%
5130	Maintenance of Overhead Services	17,225	10,500	(6,725)	-39%
5135	Overhead Distribution Lines & Feeders - Right of Way	571,378	263,300	(308,078)	-54%
5145	Maintenance of Underground Conduit	0	0	0	0%
5150	Maintenance of Underground Conductors and Devices	77,615	34,000	(43,615)	-56%
5155	Maintenance of Underground Services	50,729	45,000	(5,729)	-11%
5160	Maintenance of Line Transformers	190,502	65,500	(125,002)	-66%
5165	Maintenance of Street Lighting and Signal Systems	0	0	0	0%
5170	Sentinel Lights - Labour	0	0	0	0%
5172	Sentinel Lights - Materials and Expenses	0	0	0	0%
5175	Maintenance of Meters	7,674	25,000	17,326	226%
5178	Customer Installations Expenses - Leased Property	0	0	0	0%
5195	Maintenance of Other Installations on Customer Premises	0	0	0	0%
	TOTAL MAINTENANCE EXPENSES	1,507,433	1,165,100	(342,333)	-23%

Table 2.10 ~ 2008 Actual to 2012 Test Year – Billing & Collecting Exp. - Account Variances

USoA	Billing & Collecting Expenses	2008 Actual	2012 Test	Variance - $	Variance - %
5305	Supervision	87,340	172,740	85,400	98%
5310	Meter Reading Expense	198,725	234,395	35,670	18%
5315	Customer Billing	488,791	586,501	97,710	20%
5320	Collecting	255,657	256,895	1,238	0%
5325	Collecting - Cash Over and Short	0	0	0	0%
5330	Collection Charges	(88,345)	(132,877)	(44,532)	50%
5335	Bad Debt Expense	68,167	100,000	31,833	47%
5340	Miscellaneous Customer Accounts Expenses	43,099	10,409	(32,690)	-76%
	TOTAL BILLING & COLLECTING EXPENSES	1,053,434	1,228,062	174,628	17%

Table 2.11 ~ 2008 Actual to 2012 Test Year – Community Relations Expenses

USoA	Community Relations Expenses	2008 Actual	2012 Test	Variance - $	Variance - %
5405	Supervision	0	0	0	0%
5410	Community Relations - Sundry	12,524	25,500	12,976	104%
5415	Energy Conservation	55,745	0	(55,745)	-100%
5420	Community Safety Program	2,040	4,000	1,960	96%
5425	Miscellaneous Customer Service & Information Expenses	24,734	7,500	(17,234)	-70%
	TOTAL COMMUNITY RELATIONS EXPENSES	95,043	37,000	(58,043)	-61%

Table 2.12 ~ 2008 Actual to 2012 Test Year – General & Admin. Exp. - Account Variances

USoA	General & Administrative Expenses	2008 Actual	2012 Test	Variance $	Variance %
5605	Executive Salaries and Expenses	0	0	0	0%
5610	Management Salaries and Expenses	0	0	0	0%
5615	General Administrative Salaries and Expenses	755,027	918,700	163,673	22%
5620	Office Supplies and Expenses	121,356	113,300	(8,056)	-7%
5625	Administrative Expense Transferred-Credit	0	0	0	0%
5630	Outside Services Employed	75,511	106,500	30,989	41%
5635	Property Insurance	7,649	19,200	11,551	151%
5640	Injuries and Damages	41,625	41,000	(625)	-2%
5645	Employee Pensions and Benefits	68,961	79,700	10,739	16%
5650	Franchise Requirements	0	0	0	0%
5655	Regulatory Expenses	112,755	125,000	12,245	11%
5660	General Advertising Expenses	5,154	4,000	(1,154)	-22%
5665	Miscellaneous Expenses	58,798	68,000	9,202	16%
5670	Rent	0	0	0	0%
5675	Maintenance of General Plant	75,142	56,000	(19,142)	-25%
5680	Electrical Safety Authority Fees	11,046	13,000	1,954	18%
5681	Special Purpose Charge - Expense (See Acc't 56560)	0	0	0	
5685	Independent Market Operator Fees and Penalties	0	0	0	0%
5695	OM&A Contra Account	0	0	0	0%
	TOTAL GENERAL & ADMINISTRATIVE EXPENSES	1,333,024	1,544,400	211,376	16%

2008 ACTUAL VERSUS 2012 TEST YEAR:

5105 – Line Maintenance Supervision and Expenses $72,793

This account includes portions of compensation for the Operations Manager, Lines Supervisor and Lead Hands (when acting in a supervisory capacity) related to the supervision of maintenance projects. Amounts are recorded here based on individual weekly time sheets. At the end of 2010 and in early 2011 Norfolk reorganized some responsibilities of the Operations Manager related to maintenance and capital projects. With this change it was no longer appropriate to capitalize a significant portion (approximately $40,000) of this individual's compensation. This change began in 2011 and continues in the 2012 test year. The remaining increase of $32,000 reflects increases in the number of hours the other individuals charge time to this account and increases in compensation over the four year period.

5112 – Maintenance of Transformer Station Equipment $77,115

In 2008 the transformer station was relatively new and in that year required relatively little maintenance. Maintenance in 2008 is budgeted at $80,000 and is reflective of the station maintenance required on an ongoing basis.

5135 – O/H Distribution Lines & Feeders – Right of Way (Tree Trimming) ($308,078)

In 2008 significant tree trimming work was completed in order to catch up on previously uncompleted work. The amount of tree trimming expense budgeted for the 2012 test year is reflective of a level that is sustainable and will prevent future accumulations of incomplete work.

5160 – Maintenance of Transformers ($125,002)

Norfolk tracks separately the costs for overhead transformer maintenance, underground (pad mount) transformer maintenance, and PCB maintenance within sub-accounts of 5160. In 2008 an increased amount of expense occurred, primarily related to PCB testing and replacement of transformers. Over 800 transformers were tested for PCBs and approximately 30 transformers were changed using transformer stock that had previously been removed from service and held for future use. The amount budgeted for 2012 test year reflects a normal level of activity for transformer maintenance.

5305 – Billing & Collecting Supervision $94,568

Prior to 2009 the Billing and Collecting Supervisor's expense was allocated among various billing and collecting expense accounts. Since 2009 the expenses have been reported in 5305 – Billing & Collecting Supervision.

5310 Meter Reading Expense $35,670

While this account does not exceed the materiality limit, meter reading expenses for 2012 have changed significantly from previous years and a full disclosure is appropriate as forecast expenses are not directly comparable to historical expenses. Previously Norfolk employed a third party contractor to read meters and supply that data for billing purposes. This constituted the majority of expense in this account, with the balance from internal staff time for data editing and verification. In 2012 Norfolk has forecast expenses based on electronic meter reading of its smart meters. A summary of expenses is below.

Table 2.13: 2012 Meter Reading Expenses

	2012 Meter Reading Expenses	
A.	Sensus Meter Reading Charges	40,194
B.	Harris ODS Fees	30,027
C.	Tower Rentals	62,000
D.	Sensus Base Station Service	120,300
E.	Data Edit - Internal Labor	65,000
F.	Total Expenses before allocation	317,521
G.	Less Allocation for Water & Sewer Billing	(83,126)
H.	Net Meter Reading Expense	234,395

A. Sensus Meter Reading Charges:

This charge is based on 10 cents per meter read, per month. Norfolk's customer forecast for 2012 is 19,248, creating a total expense of $23,098. The additional $17,096 is for Sensus charges for 14,247 water meters, charged at the same rate. This amount is allocated to the affiliate Norfolk Energy Inc (NEI) as part of the $83,126 on line G.

B. Harris ODS Fees

Harris ODS (Operational Data Store) fees are for external secondary checks on interval data for validating, editing and estimating. Total expenses are based on 19,248 meters, at 13 cents per month. This amount does not include any expense for water meters.

C. Tower Rentals

At the time of application Norfolk rents 2 towers for meter reading and uses 5 FNPs. This has produced only 83% of our RIS. Sensus advises Norfolk the solution is to replace the FNPs with 3 additional gateway base stations located on towers in strategic areas to improve reliability. The tower rental fee is $14,000 per year per tower for 4 of the towers. The fifth tower is rented through Sensus and is $6,000 per year.

D. Sensus Base Station Service

Each of the 5 towers has a gateway base station which collects interval data from our smart meters. Norfolk pays Sensus approximately $2,000 per station per month for the two stations currently in existence. The 3 additional towers are expected to be in service by November 2011 and are budgeted for the full 2012 year.

E. Data Editing – Internal Labour

Internal review of interval data is required on a daily basis to ensure accuracy of billing quantities. Data editing includes exception handling, file prep work for sending to the ODS and the MDMR and verification of return files sent. Errors such as "no data", "some checks skipped or failed", are examples of data needing follow up.

G. Allocation for Water and Sewer Billing

Norfolk will allocate a total of $340,218 to its affiliate NEI for providing it water and sewer billing services. Historically the allocation amount is applied to 5205 – Billing and Collecting Supervision, 5310 – Meter Reading, 5315 – Billing Expenses, 5230 – Collection Expenses, 5330 –Collection Fees and 5340 – Miscellaneous Billing and Collecting, as a percentage of expense in each account. For 5310 – Meter Reading, the allocation amount will be $70,685.

5315 – Customer Billing Expenses $97,710

The greatest contributing factor to increase in Customer Billing Expenses is the change in allocation of expenses to NEI for the water and sewer billing services provided. In 2008 before the allocation to the affiliate, the total expenses for account 5315 was $771,426. $282,635 of this amount was allocated to the affiliate, leaving a net expense to this account of $488,791. In the 2012 test year the total expense before allocation is $794,659. $176,903 is allocated to the affiliate, leaving a net expense of $617,756. (Table 2.4 Billing and Collecting Expenses – Cost Allocation, contains these details).

The increase in expense before allocation is $23,233 over a four year period. This amount reflects inflationary increases to wages and other expenses.

The change in allocation of expenses is fully disclosed under Exhibit 4, Tab 2, Schedule 5: ‘Charges to Affiliates for Services Provided’.

5415 – Energy Conservation ($55,745)

Norfolk has not budgeted any amount under Energy Conservation for recovery through rates as it intends to fund all projects through OPA programs and Tier 2 OEB-Approved Programs.

5615 – General Administrative Salaries & Expenses $163,673

Within the USoA account 5615, Norfolk has reported the costs for senior management, the accounting department, and the administrative assistant. In 2010, Norfolk created a new position, Financial Analyst, which accounts for a significant portion of the increase. The remainder is attributable to pay increases for both management and union positions, and miscellaneous expenses such as travel reimbursement, conference attendance, offsite training, and human resource related expenses.

2010 ACTUAL VERSUS 2012 TEST YEAR:

Table 2.14 ~ 2010 Actual vs. 2012 Test Year – Operating Expenses – Account Variances

USoA	Distribution Expenses - Operation	2010 Actual	2012 Test	Variance - $	Variance - %
5005	Operation Supervision and Engineering	87,569	90,500	2,931	3%
5010	Load Dispatching	276,605	307,200	30,595	11%
5012	Station Buildings and Fixtures Expense	35,289	35,500	212	1%
5014	Transformer Station Equipment - Operation Labour	2,651	3,500	849	32%
5015	Transformer Station Equipment - Operation Supplies & Expenses	28,300	26,000	(2,300)	-8%
5016	Distribution Station Equipment - Operation Labour	9,855	16,000	6,145	62%
5017	Distribution Station Equipment - Operation Supplies and Expenses	29,878	30,000	122	0%
5020	O/H Distribution Lines & Feeders - Operation Labour	80,472	86,900	6,428	8%
5025	O/H Distribution Lines & Feeders - Operation Supplies & Expenses	44,709	44,400	(309)	-1%
5030	Overhead Subtransmission Feeders - Operation	0	0	0	0%
5035	Overhead Distribution Transformers - Operation	0	1,000	1,000	
5040	Underground Distribution Lines and Feeders - Operation Labour	115,268	125,000	9,732	8%
5045	U/G Distribution Lines and Feeders - Operation Supplies & Expenses	54	1,000	946	1753%
5050	Underground Subtransmission Feeders - Operation	0	0	0	0%
5055	Underground Distribution Transformers - Operation	1,970	2,500	530	27%
5060	Street Lighting and Signal System Expense	0	0	0	0%
5065	Meter Expense	124,009	214,300	90,291	73%
5070	Customer Premises - Operation Labour	0	0	0	0%
5075	Customer Premises - Materials and Expenses	0	0	0	0%
5085	Miscellaneous Distribution Expense	245,877	215,700	(30,177)	-12%
5090	Underground Distribution Lines and Feeders - Rental Paid	0	0	0	0%
5095	Overhead Distribution Lines and Feeders - Rental Paid	24,235	27,000	2,765	11%
5096	Other Rent	0	0	0	0%
	TOTAL OPERATING EXPENSES	1,106,741	1,226,500	119,759	11%

Table 2.15 ~ 2010 Actual vs. 2012 Test Year – Maintenance Expenses – Account Variances

USoA	Distribution Expenses - Maintenance	2010 Actual	2012 Test	Variance - $	Variance - %
5105	Maintenance Supervision and Engineering	81,690	130,000	48,310	59%
5110	Maintenance of Structures	16,777	14,300	(2,477)	-15%
5112	Maintenance of Transformer Station Equipment	189,764	80,000	(109,764)	-58%
5114	Maintenance of Distribution Station Equipment	81,441	49,500	(31,941)	-39%
5120	Maintenance of Poles, Towers and Fixtures	65,997	70,400	4,403	7%
5125	Maintenance of Overhead Conductors & Devices	313,079	377,600	64,521	21%
5130	Maintenance of Overhead Services	3,904	10,500	6,596	169%
5135	Overhead Distribution Lines & Feeders - Right of Way	254,542	263,300	8,758	3%
5145	Maintenance of Underground Conduit	777	0	(777)	-100%
5150	Maintenance of Underground Conductors and Devices	21,009	34,000	12,991	62%
5155	Maintenance of Underground Services	18,965	45,000	26,035	137%
5160	Maintenance of Line Transformers	45,286	65,500	20,214	45%
5165	Maintenance of Street Lighting and Signal Systems	0	0	0	0%
5170	Sentinel Lights - Labour	0	0	0	0%
5172	Sentinel Lights - Materials and Expenses	0	0	0	0%
5175	Maintenance of Meters	22,280	25,000	2,720	12%
5178	Customer Installations Expenses - Leased Property	0	0	0	0%
5195	Maintenance of Other Installations on Customer Premises	0	0	0	0%
	TOTAL MAINTENANCE EXPENSES	1,115,511	1,165,100	49,589	4%

Table 2.16 ~ 2010 Actual vs. 2012 Test Year – Billing & Collecting Exp - Variances

USoA	Billing & Collecting Expenses	2010 Actual	2012 Test	Variance - $	Variance - %
5305	Supervision	142,062	172,740	30,678	22%
5310	Meter Reading Expense	199,978	234,395	34,417	17%
5315	Customer Billing	476,382	586,501	110,118	23%
5320	Collecting	206,463	256,895	50,432	24%
5325	Collecting - Cash Over and Short	0	0	0	0%
5330	Collection Charges	(118,352)	(132,877)	(14,524)	12%
5335	Bad Debt Expense	53,224	100,000	46,776	88%
5340	Miscellaneous Customer Accounts Expenses	12,084	10,409	(1,675)	-14%
	TOTAL BILLING & COLLECTING EXPENSES	971,841	1,228,062	256,221	26%

Table 2.17 ~ 2010 Actual vs. 2012 Test Year – Community Relations Exp. – Variances

USoA	Community Relations Expenses	2010 Actual	2012 Test	Variance - $	Variance - %
5405	Supervision	0	0	0	0%
5410	Community Relations - Sundry	20,604	25,500	4,896	24%
5415	Energy Conservation	18,066	0	(18,066)	-100%
5420	Community Safety Program	4,075	4,000	(75)	-2%
5425	Miscellaneous Customer Service & Information Expenses	6,017	7,500	1,483	25%
	TOTAL COMMUNITY RELATIONS EXPENSES	48,761	37,000	(11,761)	-24%

Table 2.18 ~ 2010 Actual vs. 2012 Test Year – General & Admin Exp.– Account Variances

USoA	General & Administrative Expenses	2010 Actual	2012 Test	Variance $	Variance %
5605	Executive Salaries and Expenses	0	0	0	0%
5610	Management Salaries and Expenses	0	0	0	0%
5615	General Administrative Salaries and Expenses	831,069	918,700	87,631	11%
5620	Office Supplies and Expenses	112,219	113,300	1,081	1%
5625	Administrative Expense Transferred-Credit	0	0	0	0%
5630	Outside Services Employed	176,413	106,500	(69,913)	-40%
5635	Property Insurance	19,181	19,200	19	0%
5640	Injuries and Damages	29,847	41,000	11,153	37%
5645	Employee Pensions and Benefits	62,463	79,700	17,237	28%
5650	Franchise Requirements	0	0	0	0%
5655	Regulatory Expenses	163,756	125,000	(38,756)	-24%
5660	General Advertising Expenses	1,401	4,000	2,599	186%
5665	Miscellaneous Expenses	63,758	68,000	4,242	7%
5670	Rent	0	0	0	0%
5675	Maintenance of General Plant	50,440	56,000	5,560	11%
5680	Electrical Safety Authority Fees	12,453	13,000	547	4%
5681	Special Purpose Charge - Expense Portion	89,447	0	(89,447)	-100%
5685	Independent Market Operator Fees and Penalties	0	0	0	0%
5695	OM&A Contra Account	0	0	0	0%
	TOTAL GENERAL & ADMINISTRATIVE EXPENSES	1,612,447	1,544,400	(68,047)	-4%

2010 ACTUAL VERSUS 2012 TEST YEAR:

5065 – Meters – Operating Expense $90,291

In 2009 Norfolk began installation of Smart Meters. The installation of new meters significantly reduced the need for meter maintenance expenses. As a result, the 2010 expense in account 5065 was relatively low compared to both historical amounts and future expected expenses. In 2012, with the anticipated inclusion of smart meters to rate base and the disposition of the smart meter deferral accounts, Meter Operating Expense is expected to return to a more normal level.

5112 – Maintenance of Transformer Station Equipment ($109,764)

This variance reflects a return to normal levels of maintenance activity for the Bloomsburg Transformer Station, from unusually high levels in 2010. During this time repairs were required, including repairs to the secondary cables and bushings, and the re-calibration of the T1 relays, that are not expected to re-occur on an annual basis. The 2012 Test Year expense reflects an expected return to normal levels of maintenance.

5125 – Maintenance of Overhead Conductors & Devices $64,521

The increase in 2012 is related to the installation of animal guards on transformers and other equipment. This project is part of an increased annual maintenance plan aimed at reducing outages and trouble calls.

5315 – Customer Billing $110,118

The greatest contributing factor to increase in Customer Billing Expenses is the change in allocation of expenses to the affiliate NEI for the water and sewer billing services provided. In 2010 before the allocation of expenses to the affiliate, the gross expenses for account 5315 was $727,415. Out of the gross expense amount, $251,033 was allocated to the affiliate, leaving a net expense to this account of $476,382. In the 2012 test year the total expense before allocation is $794,659. Out of the gross expense amount, $207,999 is allocated to the affiliate, leaving a net expense of $586,501. (Table 2.4 Billing and Collecting Expenses – Cost Allocation, contains these details).

The increase in expense before allocation is $67,082. Approximately half of this amount is due to the vacancy of a position part way through 2010 that was not filled until 2011. The remainder is a result of wage increases and inflationary increases to other expenses.

The change in allocation of billing expenses is fully disclosed under Exhibit 4, Tab 2, Schedule 5: 'Charges to Affiliates for Services Provided'.

5320 – Collecting $50,432

In 2010 before the allocation to the affiliate, the gross expenses for account 5315 was $315,260. $108,797 of this amount was allocated to the affiliate, leaving a net expense to this account of $206,463. In the 2012 test year the total expense before allocation is $348,000. Out of the gross expense amount, $91,105 is allocated to the affiliate, leaving a net expense of $256,895. (Table 2.4 Billing and Collecting Expenses – Cost Allocation, contains these details).

The increase in expense before allocation is $32,740. Part of this amount is due to the vacancy of a position part way through 2010 which was not filled until 2011. The remainder is a result of wage increases and inflationary increases to other expenses.

The change in allocation of billing expenses is fully disclosed under Exhibit 4, Tab 2, Schedule 4: 'Charges to Affiliates for Services Provided'.

5615 – General Administrative Salaries & Expenses $87,631

Account 5615 contains the burdened salaries and expenses of executives, the accounting department, and the administrative assistant. Approximately $50,000 of this increase is due to annual inflationary increases in compensation. The remainder is from merit increases to compensation.

5630 – Outside Services Employed ($69,913)

This variance reflects a reduction in services for 2012 relative to 2010. Cost reductions are related to collective bargaining which spanned 2010 and 2011, and consulting fees for regulatory services. 2010 included expenses for Norfolk's 2011 cost of service application which was denied. In comparison 2012 includes 25% of the expected consulting fees for the 2012 cost of service application.

5681 – Special Purpose Charge – Expense Portion ($89,447)

The variance reflects elimination of the Special Purpose Charge in 2012 relative to 2010.

EMPLOYEE COMPENSATION, INCENTIVE PLAN EXPENSES, PENSION EXPENSE AND POST RETIREMENT BENEFITS:

Compensation/Performance System

Union

Norfolk's unionized staff is represented by the Power Workers Union. The current collective agreement expires December 31, 2013 and Norfolk will be entering formal negotiations prior to that date. The current agreement, which was entered into in March 2011, includes annual wage increases of 1.5% Jan 1, 2011, 1.5% July 1, 2011, 1.5% Jan 1, 2012, 1.5% July 1, 2012, 2.0% Jan 1, 2013 and 2.0% July 1, 2013.

Executive/Management

Executive and Management compensation plan consists of salaries and benefits. Each position within the company has been placed on a pay scale which is reviewed annually by senior management and the Board of Directors' Compensation Committee. Each employee's position within their respective range is reviewed based on performance and an inflationary adjustment. Changes to senior management compensation, if any, are approved by the Board of Directors. Norfolk does not offer any incentive or bonus compensation.

Benefits

A comprehensive and competitive benefits package exists which includes medical insurance, life insurance, vacation and a company-sponsored retirement plan. The plans are designed to address the health and welfare needs of the employee population with similar plans for both union and management employees.

All full time staff participates in the OMERS pension plan.

All full time staff participates in Post-Retirement Benefits. The accrued expense is based on an actuarial valuation. The latest copy of the valuation has been provided as Appendix C.

Employee Compensation and Benefits:

The employee complement, compensation and benefit information is provided in Table 2.29 below. Norfolk has aggregated the executive and management together in the management category.

Table 2.19: Employee Compensation

	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Number of Employees (FTEs including Part-Time)[1]						
Executive						
Management	14.5	14.5	13.7	14.6	14.2	15.0
Non-Union	1.5	1.5	1.6	1.5	1.6	1.6
Union	34.4	34.4	32.0	30.3	30.4	32.0
Total	50.4	50.4	47.3	46.4	46.2	48.6
Number of Part-Time Employees						
Executive	-					
Management	-					
Non-Union	1.5	1.5	1.6	1.5	1.6	1.6
Union	-	-	-	-	-	-
Total	1.5	1.5	1.6	1.5	1.6	1.6
Total Salary and Wages						
Executive						
Management	$ 1,113,996	$ 1,113,996	$ 1,132,778	$ 1,261,348	$ 1,185,086	$ 1,324,087
Non-Union	$ 58,266	$ 58,266	$ 72,940	$ 35,414	$ 34,391	$ 34,726
Union	$ 1,884,801	$ 1,884,801	$ 1,861,030	$ 1,863,317	$ 1,821,114	$ 1,972,886
Total	$ 3,057,063	$ 3,057,063	$ 3,066,748	$ 3,160,079	$ 3,040,591	$ 3,331,699
Current Benefits						
Executive						
Management	$ 185,681	$ 185,681	$ 190,947	$ 216,336	$ 243,566	$ 271,900
Non-Union						
Union	$ 349,837	$ 349,837	$ 339,251	$ 330,741	$ 342,885	$ 391,373
Total	$ 535,518	$ 535,518	$ 530,198	$ 547,077	$ 586,451	$ 663,273
Accrued Pension and Post-Retirement Benefits						
Executive						
Management	$ 20,887	$ 20,887	$ 26,799	$ 25,632	$ 31,042	$ 36,910
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ 33,584	$ 33,584	$ 41,364	$ 36,831	$ 46,358	$ 53,590
Total	$ 54,471	$ 54,471	$ 68,163	$ 62,463	$ 77,400	$ 90,500
Total Benefits (Current + Accrued)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ 206,568	$ 206,568	$ 217,746	$ 241,968	$ 274,608	$ 308,810
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ 383,421	$ 383,421	$ 380,615	$ 367,572	$ 389,243	$ 444,963
Total	$ 589,989	$ 589,989	$ 598,361	$ 609,540	$ 663,851	$ 753,773
Total Compensation (Salary, Wages, & Benefits)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ 1,320,564	$ 1,320,564	$ 1,350,524	$ 1,503,316	$ 1,459,694	$ 1,632,897
Non-Union	$ 58,266	$ 58,266	$ 72,940	$ 35,414	$ 34,391	$ 34,726
Union	$ 2,268,222	$ 2,268,222	$ 2,241,645	$ 2,230,889	$ 2,210,357	$ 2,417,849
Total	$ 3,647,052	$ 3,647,052	$ 3,665,109	$ 3,769,619	$ 3,704,442	$ 4,085,472
Compensation - Average Yearly Base Wages						
Executive						
Management	$ 76,880	$ 76,880	$ 82,685	$ 86,691	$ 83,752	$ 88,272
Non-Union	$ 38,844	$ 38,844	$ 45,588	$ 23,609	$ 21,494	$ 21,704
Union	$ 54,791	$ 54,791	$ 58,157	$ 61,536	$ 59,945	$ 61,653
Total	$ 170,515	$ 170,515	$ 186,430	$ 171,836	$ 165,191	$ 171,629
Compensation - Average Yearly Overtime						
Executive						
Management	$ 1,581	$ 1,581	$ 2,358	$ 2,857	$ 2,473	$ 2,829
Non-Union	$ -	$ -	$ 737	$ 91	$ 625	$ 897
Union	$ 2,760	$ 2,760	$ 4,999	$ 3,877	$ 4,937	$ 4,767
Total	$ 4,341	$ 4,341	$ 8,094	$ 6,825	$ 8,035	$ 8,493
Compensation - Average Yearly Incentive Pay						
Executive		$ -	$ -	$ -	$ -	$ -
Management		$ -	$ -	$ -	$ -	$ -
Non-Union		$ -	$ -	$ -	$ -	$ -
Union		$ -	$ -	$ -	$ -	$ -
Total						
Compensation - Average Yearly Benefits						
Executive						
Management	$ 14,256	$ 14,256	$ 15,894	$ 16,630	$ 19,407	$ 20,587
Non-Union						
Union	$ 11,146	$ 11,146	$ 11,894	$ 12,139	$ 12,812	$ 13,905
Total	$ 25,402	$ 25,402	$ 27,788	$ 28,769	$ 32,219	$ 34,492
Total Compensation	$ 3,647,052	$ 3,647,052	$ 3,665,109	$ 3,769,619	$ 3,704,442	$ 4,085,472
Total Compensation Charged to OM&A	$ 1,925,576	$ 1,925,576	$ 1,657,160	$ 1,736,777	$ 1,994,298	$ 2,208,023
Total Compensation Capitalized	$ 1,721,476	$ 1,721,476	$ 2,007,949	$ 2,032,842	$ 1,710,144	$ 1,877,449

Change in Employee Compensation & Benefits

2008 Actual vs 2008 Approved

In the decision for Norfolk's 2008 application the Board stated "The Board will not make specific disallowance with respect to this category of costs, and the company will have to manage this area, as with all areas of OM&A, within the envelop of funding approved by the Board in this Decision" (EB-2007-0753 p16). Based on this direction Norfolk has set the 2008 approved equal to the 2008 actual.

2009 Actual vs. 2008 Actual

Management:
Change in FTE: -0.8
Change in Wages: +$18,782

In 2008, the V.P. Engineering position was vacant for 4 months. In 2009 this position was filled for the entire year, representing an increase of 0.3 FTE over 2008. In 2009 two management positions (Technical Services Supervisor and Distribution Engineer) which consolidated into a single position for a decrease of 0.7 FTE. In addition the Manager of Finance position was vacant for part of the year for a decrease of 0.4 FTE.

The net reduction of 0.8 FTE represents a reduction in compensation of approximately $48,800. This was offset by an average management inflationary increase of 2.5%, or $27,700, plus progression within compensation bands of approximately $7,500. In addition beginning January 1, 2009, three management staff moved from a 35-hour work week to a 40-hour work weeks (to be consistent with the rest of management) and their salaries were adjusted accordingly. This represents an increase in salaries of $32,400.

Non-Union:
Change in FTE: +0.1
Change in Wages: +$14,674

Non-union employees includes student employees during summer months as well as occasional professional on short term employment contracts. In 2009 the FTE was roughly equivalent to 2008, however the wages increased by $14,674. This was the result of less student employee time at a lower rate and the use of a short term contract position in the finance department.

Union:
Change in FTE: -2.4
Change in Wages: -$23,771

The reduction of 2.4 FTEs in 2009 was the effect of the removal of the Meter Foreperson position (carryover from 2008) and an additional three positions eliminated in early 2009 (engineering clerk, customer service representative, stores assistant). These reductions were partially offset by the new position of Lineman Apprentice which started in mid 2009.

The change in wages were due to elimination of the positions, offset by termination pay, a 3% inflation increase as per the collective agreement, and progression by some individuals within job classifications and pay grades, as per the collective agreement.

2010 Actual vs. 2009 Actual

Management:
Change in FTE: +0.9
Change in Wages: +$128,570

In January 2010 a new management position, Accounting Supervisor, was created (+1.0 FTE). An additional +0.4 FTE relates to the Manager of Finance position being vacant for part of the year in 2009 and filled for a full year in 2010. These increases were offset from savings realized from the elimination of one management position part way through 2009 and the temporary vacancy of the VP Engineering position before being replaced in late 2010 (-0.5 FTE).

Increases to wages of $128,570 are from the new accounting supervisor position, inflationary increase 2.0%, and merit increases within existing compensation bands.

Non-Union:
Change in FTE: -0.1
Change in Wages: -$37,526

The short term employment contract in 2009 was not continued into 2010. Additional summer students were utilized in 2010, but at a lower rate resulting in a decrease in wages of $37,526.

Union:
Change in FTE: -1.7
Change in Wages: +$2,287

A new position of Engineering Distribution Technologist was created in March 2010 (+0.7 FTE).

This increase was offset from the continuation of the three positions that were eliminated in 2009 (Included as partial year in 2009, but not in 2010). In addition a lineman apprentice position was also vacated during the year as well as one linemen position, both of which were not filled. A customer service position was vacated late in the year and not filled until 2011. These changes amounted to a reduction of 1.7 FTE.

Changes in wages reflect the savings from the decrease in FTE, offset by inflationary increases and advancement within positions.

<u>2011 Bridge vs. 2010 Actual</u>

Management:
Change in FTE: -0.4
Change in Wages: -$76,262

The Accounting Supervisor left on maternity leave in March 2011, with the position filled temporarily with a contractor (-0.75 FTE). The replacement for the VP of Engineering resulted in a +0.3 FTE compared to 2010. In addition the Distribution Manager position was vacated for a short time before being filled (-0.1) in early 2011.

The reduction in wages includes the savings from the Accounting Supervisor. Also when the positions of VP of Engineering and the Distribution Manager were vacated, the positions were restructured and changed. The replacement positions were Distribution Engineer and Manager of Operations respectively. When these positions were filled additional savings in compensation occurred. The savings were partially offset from a 2.5% inflationary increase to management wages.

Non-Union:
Change in FTE: +0.1
Change in Wages: -$1,023

The changes in the non-union group in 2011 relates to a small difference in the number of hours and rates paid for summer student employees.

Union:
Change in FTE: + 0.1
Change in Wages: - $42,203

No new positions were created in the year, nor were any positions eliminated. The union FTEs will increase by +0.1 positions due to the carry-over of changes in 2010, offset by a temporary vacancy in the customer service department. Due to the vacated positions being filled by new people, the starting salaries for these positions are lower than the incumbents resulting in the decrease in wages. This combined with reduced overtime has created a decrease in wages.

<u>2012 Test vs. 2011 Bridge</u>

Management:
Change in FTE: +0.8
Change in Wages: +$139,001

In 2012 the Accounting Supervisor is returning from maternity leave (+0.8 FTE). The increase in wages reflects the increase in FTE staff plus general inflation at 3.0% and minor merit increases for some employees.

Non-Union:
Change in FTE: no change
Change in Wages: +$335

No change to the number of summer student employees is expected in 2012. The increase in wages represents a small increase in compensation for returning students.

Union:
Change in FTE: + 1.6
Change in Wages: + $151,772

One new line apprentice is budgeted to be hired by spring 2012 (0.8 FTE). Also budgeted is a new Control Room Operator to replace a contractor who currently fills this position by April 2012 (0.8FTE).

The increase in wages over 2011 is due to the hiring of these new positions plus collective bargaining increases.

Change in Benefits

In 2010 OMERS released a 3-year plan indicating approximately 1% per year increase in OMERS premiums beginning in 2011. The expected increase for 2012 was confirmed by email to Norfolk on July 07 2011. The following is an excerpt from that email:

OMERS 2012 Contribution Rates and Plan Changes Announced

On June 28, 2011, the OMERS Sponsors Corporation (SC) approved changes to the OMERS Primary Pension Plan (OMERS Plan) and Retirement Compensation

Arrangement (RCA).Contribution rate increases were set for 2012, the second increase as part of a three-year strategy announced in 2010; and

- The funding flexibility of the RCA was enhanced.
- The SC also made the decision to file the December 2010 OMERS Primary Plan valuation.

Contributions to the OMERS Plan are made by members and matched by employers. Along with investment earnings, contributions provide members with lifetime retirement income. Contribution rate changes are effective with the first full pay in 2012.

Contribution rates for normal retirement age 65 members

- On earnings up to CPP earnings limit*: 2011 is 7.4%; **2012 is 8.3%**
- On earnings over CPP earnings limit*: 2011 is 10.7%; **2012 is 12.8%**

Contribution rates for normal retirement age 60 members

- On earnings up to CPP earnings limit*: 2011 is 8.9%; **2012 is 9.4%**
- On earnings over CPP earnings limit*: 2011 is 14.1%; **2012 is 13.9%**

*CPP earnings limit (Year's Maximum Pensionable Earnings or YMPE) in 2011 is $48,300; the limit in 2012 will be higher. OMERS members pay a lower rate of contributions on earnings up to the YMPE because OMERS and the CPP are designed to work together to provide pension benefits.

This increase in OMERS pension costs has been included in the cost of current benefits in this application. The increases for 2011 and 2012 are compounded by general salary increases.

Table 2.20: Pension Premium Information

OMERS Premiums Paid	2008 - Actual	2009 - Actual	2010 - Actual	2011 - Bridge	2012 - Test
	$ 225,442	$ 222,058	$ 229,007	$ 259,445	$ 329,900

Post-Retirement Benefits - Liability:

Norfolk has provided post-retirement benefits accounting information as required and has included the change in Post-Retirement expense for 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year and 2012 Test Year, in Table 2.21 below.

Post-Retirement Benefits - Premiums:

Norfolk pays certain health, dental, and life insurance benefits on behalf of its retired employees. Actual premiums paid for 2008 Actual, 2009 Actual, 2010 Actual, 2010 Actual, 2011 Bridge Year, and 2012 Test Year, are shown in Table 2.21 below.

Table 2.21: Post-Retirement Benefit Information

Post Retirement Benefits	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Premiums & Expenses Paid *	$ 28,274	$ 28,337	$ 30,076	$ 30,979	$ 31,908
Change in Accrued Liability	$ 54,471	$ 68,163	$ 62,463	$ 77,400	$ 90,500
Total Post-Employement Benefit Expense	**$ 82,745**	**$ 96,500**	**$ 92,539**	**$ 108,379**	**$ 122,408**

** 2011 estimate based on 2010 plus 3%; 2012 based on 2011 estimate plus 3%*

The most recent (draft) actuarial report for 2011 is attached as Appendix C.

CHARGES TO AFFILIATES FOR SERVICES PROVIDED:

Introduction:

Norfolk provides and receives services from an affiliate company, Norfolk Energy Inc. Norfolk also performs and receives services from its shareholder Norfolk County. A summary of charges to affiliates for services provided for each year are shown in Table 2.22 below. A copy of the Affiliate Services Agreement is provided as Appendix A to this exhibit.

SERVICES PROVIDED BY NORFOLK to NORFOLK ENERGY

Management Related Services

Norfolk accounting staff provides accounting services to Norfolk Energy including accounts receivable and payable, payroll, as well as financial planning and reporting. Norfolk information technology (IT) staff provide computer and network related services. In addition the Chief Executive Officer, Chief Financial Officer and Executive Assistant provide certain management services to Norfolk Energy including strategic and financial planning, Board meeting preparation and attendance, and Human Resources. Norfolk Energy is billed monthly for these services based on actual costs. Actual costs are determined by the fully burdened hourly cost of each employee multiplied by the number of hours reported on each employee's respective timesheet for services to Norfolk Energy. All employees are required to submit timesheets weekly and are able to record time spent on activities in quarter hour increments. Billing of these services began in 2009.

Water & Sewer Billing Services

Norfolk Energy Inc (NEI) provides water and sewer billing and collecting services to Norfolk County. NEI purchases services and resources from Norfolk to assist it in providing these services to Norfolk County. These services include meter reading, billing, bill collection and payment, and other customer services as required. By providing these services, Norfolk has been able to combine and make more efficient use of its meter reading, billing, collections and customer service functions. Approximately 70% of the bills issued each month are shared electricity/water and sewer bills. A cost sharing arrangement was reached between Norfolk and NEI under the assumption that the number of bills shared (70%) was a fair representation of all Billing and Collecting services provided by Norfolk.

Norfolk has therefore allocated to NEI 35% (50% of 70%) of all Billing and Collecting expenses. This has been done through a cost re-allocation, with the appropriate amount of expense being reduced from Norfolk's expenses and re-allocated to NEI's expenses. This methodology has been used for several years and will continue until the end of 2011.

In 2010 Norfolk County staff responsible for water and sewer services informed Norfolk and NEI that they would soon either issue an RFP for water and sewer billing or provide their own services in-house. The primary reason for this change was price and County staff informed Norfolk they were being excessively overcharged.

Norfolk believes this shared service provides benefits to both itself and Norfolk County's customers. To provide this service Norfolk reviewed the expenses it incurs to provide these services, which are provided in Table 2.22 below. Norfolk believes it is better to keep part of this revenue to offset expenses than to lose it altogether. As a result Norfolk has reduced the price it will charge. Norfolk will begin billing at a rate of $2.34 per bill beginning January 1st 2012. As of the date of this application, a contract is being drafted as well as an amendment to the Affiliate Service Agreement to reflect this change.

With approximately 14,247 water and sewer bills issued each month, Norfolk will bill NEI approximately $400,000 per year. Table 2.22 contains the details of the estimated expenses of $190,000. This allows for an additional offset to expenses of $209,759 which reduces the amount of expense sought for recovery in rates.

Table 2.22: Costs for Water & Sewer Billing

Expense	$
2 Full time customer service staff	130,000
Meter Reading (14,247 @ 10 cents/read/month)	17,096
Stock and Postage of non shared bills	13,200
(1,100 bills @ $1.00/bill/month)	
IT Expenses: Incremental Daffron Maintenance Expense	20,000
Miscellaneous Expenses	10,000
Total Expenses	$190,296
Revenue Earned (14,247 x 2.34)	$400,056
Excess revenue for rate reduction	$209,759

Hot Water Heater Billing and Collecting Services

Norfolk previously provided NEI with billing, collecting and other customer services for Hot Water Heater rentals. This included issuing approximately 3,600 bills for hot water heaters and other rental units on a quarterly basis. Costs for this service were determined through employee time sheets with the appropriate amount charged to NEI at fully burdened employee rates. This service discontinued on September 1, 2010 when NEI began their own billing and collecting services. Norfolk will not perform any services related to hot water heaters in the future and has not budgeted any amount for this service in 2012.

Office Rental

Norfolk rents office space to NEI. The office space is a separate building located external to Norfolk's office building and is approximately 960 square feet. Rent includes property taxes and excludes utilities. Rent is based on $10 per square foot, which is comparable to the lease rates for other commercial properties in the area. Rental revenue is recorded in account 4210-3 Rental Revenue.

Joint Use Pole Rental

Norfolk rents cable space on its hydro poles to NEI based on the rate of $22.35 per pole, per year. In 2012, it is estimated that NEI will have attachments on approximately 715 poles, for a total revenue of $16,000.

Purchasing and Inventory Services

Norfolk previously provided purchasing and inventory services to NEI, primarily for the purchase and storage of hot water heaters. Norfolk charged NEI the full Stores/Materials burden for all items purchased. This service discontinued September 1, 2010 and no amount has been budgeted for 2012.

Fibre Rental

In 2010 Norfolk completed installation of fibre from its control room in Simcoe to the substation in Delhi, a total distance of 15,920 meters. Norfolk rents excess capacity to Norfolk Energy at a rate of $1.50 per meter per year. Norfolk receives related rental revenue of $23,880 which is included in the 2012 test year revenue.

Street Light and Sentinel Light Services

Norfolk provides maintenance services for street lights and sentinel lights to NEI. The charges for services provided are comprised of employee time at fully burdened rates, as well as truck and material expenses at fully burdened costs. These costs are summarized in Table 2.23 below.

SERVICES PROVIDED BY NORFOLK ENERGY INC to NORFOLK POWER DISTRIBUTION

CDM Program Services

Prior to July 1, 2011, NEI provided Conservation and Demand Management consulting services to administer OPA programs on behalf of Norfolk. The fee was billed based on an hourly rate for actual time spent consistent with market rates. Expenses for OPA programs are reported in account 4380 - Expenses of Non Utility Operations. Expenses for non-OPA programs are recorded in account 5415 - Energy Conservation. As of July 1, 2011, Norfolk now provides all CDM services internally will no longer purchase services from NEI.

Fibre Rental

NEI provides fibre rental service to Norfolk. Norfolk rents fibre to connect its control room with the Bloomsburg Transformer Station. Expense is based on $1.50/meter/year. This is the same rate that Norfolk charges to NEI for fibre rent. Expenses for fibre rental are reported in Norfolk account 5013 – TS Building and Fixtures expense (a sub-account of USoA account 5012).

SERVICES PROVIDED BY NORFOLK POWER DISTRIBUTION to NORFOLK COUNTY

Street Light and Sentinel Light Services

Until January 1, 2010 Norfolk provided maintenance services for street lights and sentinel lights to Norfolk County. Norfolk now provides these services to NEI.

SERVICES PROVIDED BY NORFOLK POWER INC to NORFOLK

Norfolk Power Inc (NPI) is the parent company of Norfolk and charges Norfolk a management fee for expenses based on the expenses related to its Board of Directors. Norfolk is not applying for recovery of these charges and has not included any amount for these fees in the 2012 Test Year expenses.

SERVICES PROVIDED BY NORFOLK COUNTY to NORFOLK

Norfolk County currently rents two towers to Norfolk at a cost of $14,000 per tower, per year. Norfolk uses the towers for its base stations to gather smart meter data. Norfolk has made arrangements to rent two additional towers at the same price of $14,000 per tower to improve the data collection efforts. The $14,000 annual rental fee is Norfolk County's standard fee for tower rental.

Table 2.23 – 2008 Actual Charges To and From Affiliates

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
NPDI	NEI	Water & Sewer Billing Services	Cost-Based	485,488	485,488	35% of Total B&C Costs
NPDI	NEI	Hot Water Heater Billing Services	Cost-Based	21,400	21,400	
NPDI	NEI	Office Rental	Market	9,600	9,600	
NPDI	NEI	Pole Rental	Market	11,579	11,579	
NPDI	NEI	Purchasing and Inventory Services	Cost-Based	33,533	33,533	
NEI	NPDI	CDM Consulting Services	Market	173,489	173,489	
NEI	NPDI	Fibre Rental	Market	10,800	10,800	
NPDI	Norfolk County	Street Light and Sentinel Light Services		78236	78,236	
NPI	NPDI	Management Fee	Cost-Based	0	0	

Table 2.24 – 2009 Actual Charges To and From Affiliates

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
NPDI	NEI	Management Related Services	Cost-Based	19,490	19,490	
NPDI	NEI	Water & Sewer Billing Services	Cost-Based	464,398	464,398	35% of Total B&C Costs
NPDI	NEI	Hot Water Heater Billing Services	Cost-Based	21,300	21,300	
NPDI	NEI	Office Rental	Market	9,600	9,600	
NPDI	NEI	Pole Rental	Market	15,053	15,053	
NPDI	NEI	Purchasing and Inventory Services	Cost-Based	7,297	7,297	
NPDI	NEI	Street Light & Sentinel Light Services	Cost-Based	5,372	5,372	
NEI	NPDI	CDM Consulting Services	Market	153,380	153,380	
NEI	NPDI	Fibre Rental	Market	14,400	14,400	
NPDI	Norfolk County	Street Light and Sentinel Light Services	Cost-Based	80,159	80,159	
NPI	NPDI	Management Fee	Cost-Based	48,993	48,993	

Table 2.25 – 2010 Actual Charges To and From Affiliates

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
NPDI	NEI	Management Related Services	Cost-Based	32,378	32,378	
NPDI	NEI	Water & Sewer Billing Services	Cost-Based	483,214	483,214	35% of Total B&C Costs
NPDI	NEI	Hot Water Heater Billing Services	Cost-Based	13,777	13,777	
NPDI	NEI	Office Rental	Market	9,600	9,600	
NPDI	NEI	Pole Rental	Market	15,600	15,600	
NPDI	NEI	Purchasing and Inventory Services				
NPDI	NEI	Street Light & Sentinel Light Services		87,517	87,517	
NEI	NPDI	CDM Consulting Services	Market	167,694	167,694	
NEI	NPDI	Fibre Rental	Market	14,400	14,400	
NPDI	Norfolk County	Street Light and Sentinel Light Services		0	0	
NPI	NPDI	Management Fee	Cost-Based	63,708	63,708	

Table 2.26 – 2011 Bridge Year Forecast Charges To and From Affiliates

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
NPDI	NEI	Management Related Services	Cost-Based	40,000	40,000	
NPDI	NEI	Water & Sewer Billing Services	Cost-Based	458,150	458,150	35% of Total B&C Costs
NPDI	NEI	Hot Water Heater Billing Services		0	0	
NPDI	NEI	Office Rental	Market	9,600	9,600	
NPDI	NEI	Pole Rental	Market	15,600	15,600	
NPDI	NEI	Purchasing and Inventory Services		0	0	
NPDI	NEI	Fibre Rental	Market	23,880	23,880	
NPDI	NEI	Street Light & Sentinel Light Services		91,000	91,000	
NEI	NPDI	CDM Consulting Services	Market	121,600	121,600	
NEI	NPDI	Fibre Rental	Market	14,400	14,400	
NPDI	Norfolk County	Street Light and Sentinel Light Services		0	0	
NPI	NPDI	Management Fee	Cost-Based	0	0	
Norfolk County	NPDI	Tower Rental	Market	28,000	28,000	

Table 2.27 – 2012 Test Year Budgeted Charges To and From Affiliates

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
NPDI	NEI	Management Related Services	Cost-Based	48,000	48,000	
NPDI	NEI	Water & Sewer Billing Services	Cost-Based	340,000	340,000	
NPDI	NEI	Hot Water Heater Billing Services	Cost-Based	N/A	N/A	
NPDI	NEI	Office Rental	Market	9,600	9,600	
NPDI	NEI	Pole Rental	Market	15,600	15,600	
NPDI	NEI	Purchasing and Inventory Services	Cost-Based	N/A	N/A	
NPDI	NEI	Fibre Rental	Market	23,880	23,880	
NPDI	NEI	Street Light & Sentinel Light Services			-	
NPDI	NEI	Labor	Cost-Plus	40,500	40,500	
NPDI	NEI	Truck	Cost-Plus	23,000	23,000	
NPDI	NEI	Material	Cost-Plus	28,000	28,000	
NPDI	NEI	Total Street Light & Sentinel Light Services	Cost-Plus	91,500	91,500	
					-	
NEI	NPDI	CDM Consulting Services	Market	N/A	N/A	
NEI	NPDI	Fibre Rental	Market	14,400	14,400	
NPDI	Norfolk County	Street Light and Sentinel Light Services				
NPI	NPDI	Management Fee	Cost-Based	N/A	N/A	
Norfolk County	NPDI	Tower Rental	Market	56,000	56,000	

PURCHASE OF PRODUCTS AND SERVICES FROM NON-AFFILIATES:

Norfolk purchases many services and products from third parties. Tables 2.28, 2.29 and 2.30 disclose the expenditures by vendor where the annual amount exceeded $50,000 per year, for the years 2008, 2009 and 2010, respectively.

A copy of Norfolk's procurement policy has been provided in Appendix B and Norfolk has followed this policy in the past and will continue to do so.

Tables 2.28 thru 2.30 contain the historical Non-Affiliate Supplier information including Vendor, total amount of goods or services purchased and the procurement method used.

Table 2.28: 2008 Non-Affiliate Suppliers

2008 Non-Affiliate Suppliers			
Vendor	**Amount**	**Product/Service**	**Procurement Method**
K-LINE MAINTENANCE & CONSTRUCTION	$641,139	Line Work	RFP
DAVEY TREE EXPERT CO. OF CANADA	546,566	Forestry	Tender
EQUITABLE LIFE INSURANCE COMPANY-THE	371,706	Employee Benefits	RFQ
STEIN INDUSTRIES INC.	223,710	Transformers	RFQ
HD SUPPLY UTILITIES	184,772	Materials	RFQ
MDMA,A DIVISION OF OZZ ENERGY	158,955	Meter Reading	RFP
MOLONEY ELECTRIC	157,874	Transformers	RFQ
WESTBURNE/RUDDY (SIMCOE)	156,046	Materials	RFQ
CANADA POST CORP./BILLING POSTAGE	138,169	Postage	Market Rate
CANADIAN ELECTRICAL SERVICES	116,140	Transformers	RFQ
MEARIE -THE MEARIE GROUP	91,969	Insurance	Sole Source
IBM CANADA LTD	89,790	AS 400 Server	Multi-year lease
UTILITY SCANNING SOLUTIONS LTD	74,743	Inspection Services	RFP
SIEMENS CANADA LIMITED	73,969	Transformer	RFP
GE CANADA	73,442	Meters	RFP
J.K.R. INC.	65,603	Professional Services - Operator	Market Rate
GUELPH UTILITY POLE	65,442	Poles	Sole Source
ENERCONNECT INC (FORMERLY ENERMAJICA)	63,240	Settlement Services	Sole Source
AMERCABLE INCORPORATED	62,943	Materials	RFQ
SECOND AVE PRINTING	54,848	Stationary	RFQ
TRILLIANT INC	51,392	Meter Reading	RFP
IRONWORKS	51,300	Materials	Tender

Table 2.29: 2009 Non-Affiliate Suppliers

2009 Non-Affiliate Suppliers			
Vendor	**Amount**	**Product/Service**	**Procurement Method**
SIEMENS CANADA LIMITED	$2,048,939	Transformer	RFP
B.G. HIGH VOLTAGE LTD.	1,943,425	TS Construction	Tender
SENSUS/KTI	1,808,834	Smart Meters & Towers	RFP
K-LINE MAINTENANCE & CONSTRUCTION	503,254	Line Work	Tender
EQUITABLE LIFE INSURANCE COMPANY	373,547	Employee Benefits	RFQ
NEDCO	330,657	OPA Retrofits for Customers	RFP
OLAMETER INC	294,347	Meter Reading	RFP
GE CANADA	237,836	Meters	RFP
TILTRAN SERVICES INC	235,195	Station Maintenance	Market Rate
HD SUPPLY UTILITIES	220,559	Materials	RFQ
DAVEY TREE EXPERT CO. OF CANADA	209,803	Forestry	Tender
DAFFRON ASSOCIATES INC.	188,801	Custom software & programming	Sole Source
GUELPH UTILITY POLE COMPANY LIMITED	165,501	Poles	Sole Source
A&W HIGH VOLTAGE CONTRACTING LTD.	145,600	Line Work	Tender
CANADA POST CORP./BILLING POSTAGE	143,977	Postage	Market Rate
FORCE FIELD SERVICES INC	115,642	Meter Reading / Collections	RFP
NORAMCO WIRE & CABLE	109,991	Materials	RFQ
TRENCH LIMITED	100,170	TS Equipment	RFP
IBM CANADA LTD	82,569	AS400 Server	Multi-year lease
WESTBURNE/RUDDY (SIMCOE)	76,160	Materials	RFQ
TOROMONT INDUSTRIES LTD	70,386	Equipment & Service	RFQ
WAJAX INDUSTRIES	69,487	Fleet Repairs	Market Rate
ENERCONNECT INC (FORMERLY ENERMAJICA)	64,200	Settlement Services	Sole Source
MOLONEY ELECTRIC INC	62,014	Transformers	RFQ
JESSTEC INDUSTRIES INC	57,274	Materials	RFQ
COOPER POWER SYSTEMS	53,846	Transformers	RFQ

Table 2.30: 2010 Non-Affiliate Suppliers

2010 Non-Affiliate Suppliers			
Vendor	**Amount**	**Product/Service**	**Procurement Method**
B.G. HIGH VOLTAGE LTD.	$ 410,403	TS Construction	Tender
A&W HIGH VOLTAGE CONTRACTING LTD.	395,125	Line Work	Tender
EQUITABLE LIFE INSURANCE COMPANY-THE	362,206	Employee Benefits	RFQ
KTI LIMITED	317,314	Meters & RTU	RFP
FORCE FIELD SERVICES INC	293,457	Meter Reading	RFP
HD SUPPLY UTILITIES	247,283	Materials	RFQ
DAVEY TREE EXPERT CO. OF CANADA	237,169	Forestry	Extension of previous year contract
DAFFRON & ASSOCIATES	197,606	Computer Programming	Sole Source
NEDCO	184,280	OPA Retrofits for Customers	Selected by OPA
TRINITY COMMUNICATIONS INC.	175,010	Fibre Supply & Installation	RFQ
NORFOLK ELECTRIC	161,523	OPA Retrofits for Customers	RFP
CANADA POST CORP./BILLING POSTAGE	141,809	Postage	Market Rate
GUELPH UTILITY POLE COMPANY LIMITED	134,706	Poles	Sole Source
WESTBURNE/RUDDY (SIMCOE)	131,387	Materials	RFQ
MEARIE -THE MEARIE GROUP	130,265	Insurance	Sole Source
MOLONEY ELECTRIC INC	125,763	Transformers	RFQ
TILTRAN SERVICES INC	119,953	Station Maintenance	Tender
K-LINE MAINTENANCE & CONSTRUCTION	114,062	Line Work	Tender
AESI-ACUMEN ENGINEERED SOLUTIONS INT	94,264	Professional Services	RFQ
NORAMCO WIRE & CABLE	84,726	Materials	RFQ
BORDEN LADNER GERVAIS	83,422	Professional Services	Sole Source
REID & DELEYE CONTRACTORS LTD	75,500	Building Renovations	Tender
AITKEN CHEV OLDS	67,810	Vehicles	RFQ
ENERCONNECT	64,200	Settlement Services	Sole Source
CARTE INTERNATIONAL INC.	60,013	Transformers	RFQ
IBM CANADA LTD	58,905	AS400	Multi-year lease (final year)
1445078 ONTARIO INC.	58,655	Professional Services	Extension of previous year contract
ARK CONSULTING	57,019	Professional Services	RFQ
SENSUS METERING	53,833	TGB Monthly Service Fee	RFP
WAJAX INDUSTRIES	54,579	Fleet Repairs	Market Rate
UTILITY SCANNING SOLUTIONS LTD.	49,303	Pole Testing & Inspections	RFQ

DEPRECIATION, AMORTIZATION AND DEPLETION:

Amortization on capital assets is calculated as follows:

- Norfolk uses the pooling of assets for all fixed assets with the exception of Computer Equipment/Software, Automotive Equipment, Furniture & Equipment, Communication Equipment, and Capital Tools. Amortization is calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year plus 50% of the current year capital additions.

- Norfolk's amortization policy has been to take a full year's amortization on capital additions during the current year. As per OEB guidelines, LDCs are required to use the half-year rule when accounting for amortization expense. For this rate application, Norfolk has applied the half year rule for calculating depreciation expense for the years 2007 to 2011 and has provided a reconciliation to its audited financial statements due to the discrepancy caused by the difference in accounting policies. Norfolk recognizes that it should have changed its accounting policy to the half year rule following the 2008 cost of service application. However due to a change in management staff this did not occur. Norfolk will change its accounting policy for amortization to reflect the half year rule for 2010.

- In 2001, four utilities were amalgamated to create Norfolk. At the time of amalgamation the closing net book value of fixed assets, for some assets, was used as the new opening balance of gross fixed assets. These assets were then depreciated over the number of years remaining in their depreciation life. Therefore a 10 year old asset, with a 25 year depreciation life according to the APH, was recorded at Net Book Value and depreciated over the remaining 15 years. While this method provides an annual depreciation expense that is correct, it does not allow proper completion of the OEB requested depreciation schedules. Norfolk has provided reconciliations for these differences where possible.

- Depreciation rates are in line with rates set out in the APH. These rates are reflected in the tables that follow.

Table 2.31 – Summary of Amortization Expense for 2008 to 2012

Account	Description	2008 Amortization Expense	2009 Amortization Expense	2010 Amortization Expense	2011 - Bridge Amortization Expense	2012 - Test Amortization Expense
1805	Land	$ -	$ -	$ -	$ -	$ -
1806	Land Rights	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ 30,499	$ 32,314	$ 32,358	$ 32,402	$ 32,402
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 80,426	$ 80,426	$ 151,636	$ 222,846	$ 222,846
1820	Distribution Station Equipment <50 kV	$ 82,146	$ 97,149	$ 87,303	$ 89,114	$ 94,948
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 791,096	$ 831,358	$ 848,278	$ 889,126	$ 942,314
1835	Overhead Conductors & Devices	$ 409,311	$ 438,613	$ 453,642	$ 485,670	$ 521,168
1840	Underground Conduit	$ 123,911	$ 136,410	$ 139,617	$ 147,224	$ 153,624
1845	Underground Conductors & Devices	$ 236,638	$ 257,244	$ 262,351	$ 275,217	$ 287,037
1850	Line Transformers	$ 510,519	$ 527,374	$ 542,264	$ 352,263	$ 317,405
1855	Services (Overhead and Underground)	$ 89,207	$ 100,292	$ 105,714	$ 116,498	$ 129,360
1860	Meters	$ 147,711	$ 153,056	$ 155,695	$ 159,775	$ 168,175
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ 214,267
1905	Land	$ -	$ -	$ -	$ -	$ -
1906	Land Rights	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 31,776	$ 32,299	$ 33,216	$ 34,232	$ 34,332
1910	Leasehold Improvements	$ 640	$ 640	$ 640	$ 640	$ 640
1915	Office Furniture & Equipment (10 Years)	$ 14,323	$ 14,730	$ 15,028	$ 14,517	$ 13,490
1915	Office Furniture & Equipment (5 Years)	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware (pre-2002)	$ 35,366	$ 35,366	$ 35,366	$ -	$ -
1920	Computer Equip. - Hardware (2002 & forward)	$ 95,713	$ 78,454	$ 67,928	$ 66,552	$ 73,552
1925	Computer Software	$ 48,256	$ 46,407	$ 44,571	$ 39,147	$ 56,097
1925	Computer Software (Smart Meters)	$ -	$ -	$ -	$ -	$ 83,500
1930	Transportation Equipment (Pooled - Pre 2006)	$ 87,082	$ 87,082	$ 99,481	$ 98,549	$ 73,020
1930-1	Transportation Equipment - Passenger Cars	$ 4,217	$ 4,217	$ 1,815	$ 9,348	$ 9,348
1930-2	Transportation Equipment - Light Trucks/Vans	$ 31,062	$ 31,062	$ 23,474	$ 26,900	$ 27,373
1930-3	Transportation Equipment - Heavy Trucks	$ 41,606	$ 41,606	$ 41,606	$ 60,356	$ 79,106
1930-4	Transportation Equipment - Trailers/Other	$ 2,916	$ 3,786	$ 3,837	$ 9,254	$ 13,629
1935	Stores Equipment	$ 3,889	$ 3,920	$ 3,938	$ 4,006	$ 3,223
1940	Tools, Shop & Garage Equipment	$ 29,263	$ 31,078	$ 31,425	$ 32,017	$ 29,706
1945	Measurement & Testing Equipment	$ 16,272	$ 17,897	$ 17,992	$ 18,387	$ 13,871
1950	Power Operated Equipment					
1955	Communications Equipment	$ 10,691	$ 10,691	$ 10,741	$ 11,193	$ 12,197
1955	Communication Equipment (Smart Meters)					
1960	Miscellaneous Equipment	$ 16,806	$ 41,233	$ 42,028	$ 43,072	$ 43,572
1975	Load Management Controls Utility Premises					
1980	System Supervisor Equipment	$ 40,805	$ 40,930	$ 58,953	$ 85,143	$ 96,643
1980	System Supervisor Equipment (Hardware/SW)	$ 1,991	$ 2,531	$ 3,478	$ 4,426	$ 4,426
1985	Miscellaneous Fixed Assets					
1995	Contributions & Grants	-$ 284,904	-$ 298,163	-$ 322,551	-$ 356,168	-$ 386,434
2005	Property Under Capital Lease	$ 1,004	$ 1,004	$ 1,004	$ 1,004	$ 1,004
2055	Work In Progress					
	Sub-Total Amortization Expense	**$ 2,730,238**	**$ 2,881,007**	**$ 2,992,830**	**$ 2,972,711**	**$ 3,365,842**
	Less: Fully Allocated Depreciation					
	Transportation Equipment	-$ 166,883	-$ 167,752	-$ 170,213	-$ 204,408	-$ 202,476
	Stores & Garage Equipment	-$ 34,156	-$ 36,002	-$ 33,317	-$ 33,977	-$ 30,884
	Computer Hardware & Software	-$ 179,336	-$ 160,227	-$ 147,866	-$ 105,699	-$ 129,649
	Other Adjustments (e.g. 1/2 Yr Rule)	$ -	$ -	-$ 289,866	$ -	$ -
NET AMORTIZATION EXPENSE TO INCOME STATEMENT		**$ 2,349,864**	**$ 2,517,025**	**$ 2,351,568**	**$ 2,628,627**	**$ 3,002,833**

The year-over-year fluctuations in amortization expense (as seen above) are natural based on capital additions, disposal of assets, and assets becoming fully depreciated. The $374,206 increase for 2012 over 2011 is mainly due to the inclusion of Smart Meters in Norfolk's rate base.

Norfolk has provided detailed amortization expense calculations using the OEB's methodology and provided a reconciliation to Norfolk's Audited Financial Statement amortization amounts (where applicable) in Tables 2.32 through 2.36 below:

Table 2.32 – Amortization Expense for 2008

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Depreciation Expense Per Financial Statements	Variance	Note to Explain Variance
1805	Land	$ 384,420.74	$ -	$ 384,420.74	$ 695.00	$ 384,768.24	-			$ -	$ -	
1806	Land Rights	$ 300,911.03	$ -	$ 300,911.03	$ -	$ 300,911.03	-			$ -	$ -	
1808	Buildings	$ 1,450,870.34	$ -	$ 1,450,870.34	$ 74,090.35	$ 1,487,915.52	50.00	2.0%	$ 29,758.31	$ 30,499.22	$ 740.91	1
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-			$ -		
1815	Transformer Station Equipment >50 kV	$ 3,083,382.07	$ -	$ 3,083,382.07	$ 132,213.80	$ 3,149,488.97	40.00	2.5%	$ 78,737.22	$ 80,426.45	$ 1,689.23	2
1820	Distribution Station Equipment <50 kV	$ 3,388,836.35	$ 1,376,349.09	$ 2,012,487.26	$ 495,817.63	$ 2,260,396.08	30.00	3.3%	$ 75,346.54	$ 82,146.14	$ 6,799.60	3
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -	-			$ -		
1830	Poles, Towers & Fixtures	$ 23,866,884.97	$ 5,686,689.59	$ 18,180,195.38	$ 824,598.96	$ 18,592,494.86	25.00	4.0%	$ 743,699.79	$ 791,096.44	$ 47,396.65	4
1835	Overhead Conductors & Devices	$ 12,116,999.23	$ 2,750,300.00	$ 9,366,699.23	$ 866,071.04	$ 9,799,734.75	25.00	4.0%	$ 391,989.39	$ 409,310.80	$ 17,321.41	5
1840	Underground Conduit	$ 3,478,269.97	$ 426,250.40	$ 3,052,019.57	$ 54,312.67	$ 3,079,175.91	25.00	4.0%	$ 123,167.04	$ 123,911.01	$ 743.97	6
1845	Underground Conductors & Devices	$ 6,944,195.44	$ 1,204,925.00	$ 5,739,270.44	$ 176,667.25	$ 5,827,604.07	25.00	4.0%	$ 233,104.16	$ 236,637.51	$ 3,533.35	7
1850	Line Transformers	$ 10,075,469.50		$ 10,075,469.50	$ 741,071.77	$ 10,446,005.39	25.00	4.0%	$ 417,840.22	$ 510,518.87	$ 92,678.65	8
1855	Services (Overhead and Underground)	$ 1,944,841.38		$ 1,944,841.38	$ 285,345.09	$ 2,087,513.93	25.00	4.0%	$ 83,500.56	$ 89,207.45	$ 5,706.89	9
1860	Meters	$ 3,703,687.66		$ 3,703,687.66	$ 187,841.83	$ 3,797,608.58	25.00	4.0%	$ 151,904.34	$ 147,710.64	-$ 4,193.70	10
1860	Meters (Smart Meters)	$ -		$ -	$ -	$ -	15.00	6.7%	$ -	$ -	$ -	
1905	Land	$ 242,867.44		$ 242,867.44	$ 768.00	$ 243,251.44	-			$ -		
1906	Land Rights	$ -		$ -	$ -	$ -	-			$ -		
1908	Buildings & Fixtures	$ 2,120,690.87		$ 2,120,690.87	$ 68,786.57	$ 2,155,084.16	50.00	2.0%	$ 43,101.68	$ 31,776.06	-$ 11,325.62	11
1910	Leasehold Improvements	$ 6,177.00		$ 6,177.00	$ -	$ 6,177.00	10.00	10.0%	$ 617.70	$ 639.70	$ 22.00	12
1915	Office Furniture & Equipment (10 Years)	$ 392,185.45	$ 264,715.08	$ 127,470.37	$ 15,427.18	$ 135,183.96	10.00	10.0%	$ 13,518.40	$ 14,322.75	$ 804.35	13
1915	Office Furniture & Equipment (5 Years)	$ -		$ -	$ -	$ -	5.00	20.0%	$ -	$ -	$ -	
1920	Computer Equipment - Hardware (pre-2002)	$ 682,997.22	$ 329,335.48	$ 353,661.74	$ -	$ 353,661.74	10.00	10.0%	$ 35,366.17	$ 35,366.17	-$ 0.00	
1920	Computer Equip. - Hardware (2002 & forward)	$ 393,436.96	$ 95,136.96	$ 298,300.00	$ 179,865.60	$ 388,232.80	5.00	20.0%	$ 77,646.56	$ 95,713.13	$ 18,066.57	14
1925	Computer Software	$ 316,587.61	$ 105,735.91	$ 210,851.70	$ 34,375.85	$ 228,039.63	5.00	20.0%	$ 45,607.93	$ 48,256.38	$ 2,648.46	15
1925	Computer Software (Smart Meters)	$ -	$ -	$ -	$ -	$ -	5.00	20.0%	$ -	$ -	$ -	
1930	Transportation Equipment (Pooled - Pre 2006)	$ 1,706,897.93	$ 697,166.67	$ 1,009,731.26	$ -	$ 1,009,731.26	10.00	10.0%	$ 100,973.13	$ 87,082.13	-$ 13,891.00	16
1930-1	Transportation Equipment - Passenger Cars	$ 16,866.11		$ 16,866.11	$ -	$ 16,866.11	4.00	25.0%	$ 4,216.53	$ 4,216.52	-$ 0.01	
1930-2	Transportation Equipment - Light Trucks/Vans	$ 218,911.88		$ 218,911.88	$ -	$ 218,911.88	5.00	20.0%	$ 43,782.38	$ 31,061.69	-$ 12,720.69	17
1930-3	Transportation Equipment - Heavy Trucks	$ 332,851.41		$ 332,851.41	$ -	$ 332,851.41	8.00	12.5%	$ 41,606.43	$ 41,606.43	$ 0.00	
1930-4	Transportation Equipment - Trailers/Other	$ 30,983.00		$ 30,983.00	$ 30,285.02	$ 46,125.51	8.00	12.5%	$ 5,765.69	$ 2,916.03	-$ 2,849.66	18
1935	Stores Equipment	$ 118,695.37	$ 81,131.77	$ 37,563.60	$ 1,325.67	$ 38,226.44	10.00	10.0%	$ 3,822.64	$ 3,888.95	$ 66.31	19
1940	Tools, Shop & Garage Equipment	$ 646,467.47	$ 417,155.33	$ 229,312.14	$ 63,320.00	$ 260,972.14	10.00	10.0%	$ 26,097.21	$ 29,262.91	$ 3,165.70	20
1945	Measurement & Testing Equipment	$ 150,141.73		$ 150,141.73	$ 12,575.51	$ 156,429.49	10.00	10.0%	$ 15,642.95	$ 16,271.73	$ 628.78	21
1950	Power Operated Equipment	$ -		$ -	$ -	$ -	-					
1955	Communications Equipment	$ 67,050.18		$ 67,050.18	$ 39,856.02	$ 86,978.19	10.00	10.0%	$ 8,697.82	$ 10,690.62	$ 1,992.80	22
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -	-					
1960	Miscellaneous Equipment	$ 103,274.00		$ 103,274.00	$ 64,787.00	$ 135,667.50	10.00	10.0%	$ 13,566.75	$ 16,806.08	$ 3,239.33	23
1975	Load Management Controls Utility Premises	$ 16,564.66		$ 16,564.66	$ -	$ 16,564.66	-					
1980	System Supervisor Equipment	$ 612,080.89		$ 612,080.89	$ -	$ 612,080.89	15.00	6.7%	$ 40,805.39	$ 40,805.39	-$ 0.00	
1980	System Supervisor Equipment (Hardware/SW)	$ -		$ -	$ 9,954.71	$ 4,977.36	5.00	20.0%	$ 995.47	$ 1,990.94	$ 995.47	24
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -	-					
1995	Contributions & Grants	-$ 6,791,146.00		-$ 6,791,146.00	-$ 331,460.71	-$ 6,956,876.36	25.00	4.0%	-$ 278,275.05	-$ 284,904.27	-$ 6,629.22	25
2005	Property Under Capital Lease	$ 10,038.60		$ 10,038.60	$ -	$ 10,038.60	10.00	10.0%	$ 1,003.86	$ 1,003.86	$ -	
2055	Work In Progress	$ -		$ -		$ -	-					
	Total	$ 72,133,388.46	$ 13,434,891.28	$ 58,698,497.18	$ 4,028,591.81	$ 60,712,793.09			$ 2,573,607.20	$ 2,730,237.73	$ 156,630.53	

Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs),

Notes to Explain Variances:

1 Half year rule not applied to financial statements ($74,090.35/50 = $1,481.81 * 1/2 = $740.71)
2 Half year rule not applied to financial statements ($132,213.80/40 = $3,305.35 * 1/2 = $1,652.67)
3 Half year rule not applied to financial statements and NPDI was using 35 year amortization period instead of 30 years ($495,817.63/35 = $14,166.22 * 1/2 = $7,083.10)
4 Half year rule not applied to financial statements ($824,598.96/25 = $32,983.96 * 1/2 = $16,491.98); assets acquired at amalgamation depreciated over REMAINING useful life, not total estimated useful life
5 Half year rule not applied to financial statements ($866,071.04/25 = $34,642.84 * 1/2 = $17,321.42)
6 Half year rule not applied to financial statements ($54,312.67/25 = $2,172.51 * 1/2 = $1,086.25); assets acquired at amalgamation depreciated over REMAINING useful life, not total useful life
7 Half year rule not applied to financial statements ($176,667.25/25 = $7,066.69 * 1/2 = $3,533.34)
8 Half year rule not applied to financial statements ($741,071.77/25 = $29,642.87 * 1/2 = $14,821.44); assets acquired at amalgamation depreciated over REMAINING useful life, not
9 Half year rule not applied to financial statements ($285,345.09/25 = $11,413.80 * 1/2 = $5,706.90)
10 Half year rule not applied to financial statements ($187,841.83/25 = $7,513.67 * 1/2 = $3,756.84); assets acquired at amalgamation depreciated over REMAINING useful life, not total
11 Half year rule not applied to financial statements ($68,786.57/50 = $1,375.73 * 1/2 = $687.87); in 2002, amortization period changed from 60 years to 50 years (per OEB direction)
12 Difference is immaterial
13 Half year rule not applied to financial statements ($15,427.18/10 = $1,542.72 * 1/2 = $771.36) ~ remaining difference due to amortization of asset that was not fully depreciated
14 Half year rule not applied to financial statements ($179,865.60/5 = $35,973.12 * 1/2 = $17,986.56) ~ remaining difference immaterial
15 Half year rule not applied to financial statements ($34,375.85/5 = $6,875.17 * 1/2 = $3,437.59) ~ remaining difference due to WIP assets added to this category but not depreciated
16 Asset not fully depreciated was disposed in 2005 (depreciation reduced by $13,900 for remaining 4 years of asset's life)
17 Half year rule not applied to financial statements (used # days available in year instead)
18 Half year rule not applied to financial statements (used # days available in year instead)
19 Half year rule not applied to financial statements ($1,325.67/10 = $132.57 * 1/2 = $66.29)
20 Assets with an 8-year estimated remaining useful life were acquired from an affiliate; Half year rule was not applied to financial statements ($63,320/10 = $6,332 * 0.5 = $3,316)
21 Half year rule not applied to financial statements ($12,575.51/10 = $1,257.55 * 1/2 = $628.78)
22 Half year rule not applied to financial statements ($39,856.02/10 = $3,985.60 * 1/2 = $1,992.80)
23 Half year rule was not applied to financial statements ($64,787/10 = $6,478.70 * 0.5 = $3,239.35)
24 Half year rule was not applied to financial statements ($9,954.71/5 = $1,990.94 * 0.5 = $995.47)
25 Half year rule was not applied to financial statements ($331,460.71/25 = $13,258.43 * 0.5 = $6,629.21)

Table 2.33 – Amortization Expense for 2009

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Depreciation Expense Per Financial Statements	Variance	Note to Explain Variance
1805	Land	$ 385,115.74	$ -	$ 385,115.74	$ 6,143.65	$ 388,187.57	-			$ -	$ -	
1806	Land Rights	$ 300,911.03	$ -	$ 300,911.03	$ 1,873.45	$ 301,847.76	-			$ -	$ -	
1808	Buildings	$ 1,524,960.69	$ -	$ 1,524,960.69	$ 90,756.64	$ 1,570,339.01	50.00	2.0%	$ 31,406.78	$ 32,314.35	$ 907.57	1
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-			$ -		
1815	Transformer Station Equipment >50 kV	$ 3,215,595.87	$ -	$ 3,215,595.87	$ -	$ 3,215,595.87	40.00	2.5%	$ 80,389.90	$ 80,426.45	$ 36.55	2
1820	Distribution Station Equipment <50 kV	$ 3,884,653.98	$ 1,376,349.09	$ 2,508,304.89	$ 236,273.70	$ 2,626,441.74	30.00	3.3%	$ 87,548.06	$ 97,148.76	$ 9,600.70	3
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -	-			$ -		
1830	Poles, Towers & Fixtures	$ 24,691,483.93	$ 5,686,689.59	$ 19,004,794.34	$ 1,006,528.47	$ 19,508,058.58	25.00	4.0%	$ 780,322.34	$ 831,357.54	$ 51,035.20	4
1835	Overhead Conductors & Devices	$ 12,983,070.27	$ 2,750,300.00	$ 10,232,770.27	$ 732,544.18	$ 10,599,042.36	25.00	4.0%	$ 423,961.69	$ 438,612.57	$ 14,650.88	5
1840	Underground Conduit	$ 3,532,582.64	$ 426,250.40	$ 3,106,332.24	$ 312,483.83	$ 3,262,574.16	25.00	4.0%	$ 130,502.97	$ 136,410.36	$ 5,907.39	6
1845	Underground Conductors & Devices	$ 7,120,862.69	$ 1,204,925.00	$ 5,915,937.69	$ 515,163.25	$ 6,173,519.32	25.00	4.0%	$ 246,940.77	$ 257,244.04	$ 10,303.27	7
1850	Line Transformers	$ 10,816,541.27		$ 10,816,541.27	$ 421,375.28	$ 11,027,228.91	25.00	4.0%	$ 441,089.16	$ 527,373.88	$ 86,284.72	8
1855	Services (Overhead and Underground)	$ 2,230,186.47		$ 2,230,186.47	$ 277,121.35	$ 2,368,747.15	25.00	4.0%	$ 94,749.89	$ 100,292.30	$ 5,542.41	9
1860	Meters	$ 3,891,529.49		$ 3,891,529.49	$ 133,635.55	$ 3,958,347.27	25.00	4.0%	$ 158,333.89	$ 153,056.06	-$ 5,277.83	10
1860	Meters (Smart Meters)	$ -		$ -	$ -	$ -	15.00	6.7%	$ -	$ -	$ -	
1905	Land	$ 243,635.44		$ 243,635.44	$ -	$ 243,635.44	-			$ -		
1906	Land Rights	$ -		$ -	$ -	$ -	-			$ -		
1908	Buildings & Fixtures	$ 2,189,477.44		$ 2,189,477.44	$ 26,160.50	$ 2,202,557.69	50.00	2.0%	$ 44,051.15	$ 32,299.27	-$ 11,751.88	11
1910	Leasehold Improvements	$ 6,177.00		$ 6,177.00	$ -	$ 6,177.00	10.00	10.0%	$ 617.70	$ 639.70	$ 22.00	12
1915	Office Furniture & Equipment (10 Years)	$ 407,612.63	$ 264,715.08	$ 142,897.55	$ 4,074.53	$ 144,934.82	10.00	10.0%	$ 14,493.48	$ 14,730.20	$ 236.72	13
1915	Office Furniture & Equipment (5 Years)	$ -		$ -	$ -	$ -	5.00	20.0%	$ -	$ -	$ -	
1920	Computer Equipment - Hardware (pre-2002)	$ 682,997.22	$ 329,335.48	$ 353,661.74	$ -	$ 353,661.74	10.00	10.0%	$ 35,366.17	$ 35,366.17	-$ 0.00	
1920	Computer Equip. - Hardware (2002 & forward)	$ 573,302.56	$ 205,431.03	$ 367,871.53	$ 23,999.32	$ 379,871.19	5.00	20.0%	$ 75,974.24	$ 78,453.96	$ 2,479.72	14
1925	Computer Software	$ 350,963.46	$ 105,735.91	$ 245,227.55	$ 56,033.86	$ 273,244.48	5.00	20.0%	$ 54,648.90	$ 46,406.89	-$ 8,242.01	15
1925	Computer Software (Smart Meters)	$ -	$ -	$ -	$ -	$ -	5.00	20.0%	$ -	$ -	$ -	
1930	Transportation Equipment (Pooled - Pre 2006)	$ 1,706,897.93	$ 697,166.67	$ 1,009,731.26	$ -	$ 1,009,731.26	10.00	10.0%	$ 100,973.13	$ 87,082.13	-$ 13,891.00	16
1930-1	Transportation Equipment - Passenger Cars	$ 16,866.11		$ 16,866.11	$ -	$ 16,866.11	4.00	25.0%	$ 4,216.53	$ 4,216.52	-$ 0.01	
1930-2	Transportation Equipment - Light Trucks/Vans	$ 218,911.88	$ 63,603.36	$ 155,308.52	$ -	$ 155,308.52	5.00	20.0%	$ 31,061.70	$ 31,061.69	-$ 0.01	
1930-3	Transportation Equipment - Heavy Trucks	$ 332,851.41		$ 332,851.41	$ -	$ 332,851.41	8.00	12.5%	$ 41,606.43	$ 41,606.43	$ 0.00	
1930-4	Transportation Equipment - Trailers/Other	$ 61,268.02	$ 30,983.00	$ 30,285.02	$ -	$ 30,285.02	8.00	12.5%	$ 3,785.63	$ 3,785.63	$ 0.00	
1935	Stores Equipment	$ 120,021.04	$ 81,131.77	$ 38,889.27	$ 314.28	$ 39,046.41	10.00	10.0%	$ 3,904.64	$ 3,920.37	$ 15.73	17
1940	Tools, Shop & Garage Equipment	$ 709,787.47	$ 417,155.33	$ 292,632.14	$ 18,145.61	$ 301,704.95	10.00	10.0%	$ 30,170.49	$ 31,077.81	$ 907.32	18
1945	Measurement & Testing Equipment	$ 162,717.24		$ 162,717.24	$ 16,256.04	$ 170,845.26	10.00	10.0%	$ 17,084.53	$ 17,897.33	$ 812.80	19
1950	Power Operated Equipment	$ -		$ -	$ -	$ -	-					
1955	Communications Equipment	$ 106,906.20		$ 106,906.20	$ -	$ 106,906.20	10.00	10.0%	$ 10,690.62	$ 10,690.62	$ 0.00	
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -	-					
1960	Miscellaneous Equipment	$ 168,061.00		$ 168,061.00	$ 244,273.40	$ 290,197.70	10.00	10.0%	$ 29,019.77	$ 41,233.42	$ 12,213.65	20
1975	Load Management Controls Utility Premises	$ 16,564.66		$ 16,564.66	$ -	$ 16,564.66	-					
1980	System Supervisor Equipment	$ 612,080.89		$ 612,080.89	$ 1,875.46	$ 613,018.62	15.00	6.7%	$ 40,867.91	$ 40,930.42	$ 62.51	21
1980	System Supervisor Equipment (Hardware/SW)	$ 9,954.71		$ 9,954.71	$ 2,698.31	$ 11,303.87	5.00	20.0%	$ 2,260.77	$ 2,530.60	$ 269.83	22
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -	-					
1995	Contributions & Grants	-$ 7,122,606.71		-$ 7,122,606.71	-$ 531,414.03	-$ 7,388,313.73	25.00	4.0%	-$ 295,532.55	-$ 298,162.70	-$ 2,630.15	23
2005	Property Under Capital Lease	$ 10,038.60		$ 10,038.60	$ -	$ 10,038.60	10.00	10.0%	$ 1,003.86	$ 1,003.86	$ -	
2055	Work In Progress	$ -		$ -	$ 5,472,038.35	$ 2,736,019.18	-					
	Total	$ 76,161,980.27	$ 13,639,771.71	$ 62,522,208.56	$ 9,068,354.98	$ 67,056,386.05			$ 2,721,510.54	$ 2,881,006.63	$ 159,496.09	

Notes to Explain Variances:

1 Half year rule not applied to financial statements ($90,756.64/50 = $1,815.13 * 1/2 = $907.57)
2 Difference is immaterial
3 Half year rule not applied to financial statements and NPDI was using 35 year amortization period instead of 30 years ($236,273.70/35 = $6,750.68 * 1/2 = $3,375.34)
4 Half year rule not applied to financial statements ($1,006,528.47/25 = $40,261.14 * 1/2 = $20,130.57); assets acquired at amalgamation depreciated over REMAINING useful life, not total estimated useful life
5 Half year rule not applied to financial statements ($732,544.18/25 = $29,301.77 * 1/2 = $14,650.88)
6 Half year rule not applied to financial statements ($312,483.83/25 = $12,499.35 * 1/2 = $6,249.68); assets acquired at amalgamation depreciated over REMAINING useful life, not total useful life
7 Half year rule not applied to financial statements ($515,163.25/25 = $20,606.53 * 1/2 = $10,303.27)
8 Half year rule not applied to financial statements ($421,375.28/25 = $16,855.01 * 1/2 = $8,427.51); assets acquired at amalgamation depreciated over REMAINING useful life, not total
9 Half year rule not applied to financial statements ($277,121.35/25 = $11,084.85 * 1/2 = $5,542.43)
10 Half year rule not applied to financial statements ($133,635.55/25 = $5,345.42 * 1/2 = $2,672.71); assets acquired at amalgamation depreciated over REMAINING useful life, not total useful
11 Half year rule not applied to financial statements ($26,160.50/50 = $523.21 * 1/2 = $261.61); in 2002, amortization period changed from 60 years to 50 years (per OEB direction)
12 Difference is immaterial
13 Half year rule not applied to financial statements ($4,074.53/10 = $407.45 * 1/2 = $203.73) ~ remaining difference due to amortization of asset that was not fully depreciated
14 Half year rule not applied to financial statements ($23,999.32/5 = $4,799.86 * 1/2 = $2,399.93) ~ remaining difference immaterial
15 Half year rule not applied to financial statements ($56,033.86/5 = $11,206.77 * 1/2 = $5,603.39) ~ remaining difference due to WIP assets added to this category but not depreciated
16 Asset not fully depreciated was disposed in 2005 (depreciation reduced by $13,900 for remaining 4 years of asset's life)
17 Half year rule not applied to financial statements ($314.28/10 = $31.43 * 1/2 = $15.74)
18 Half year rule was not applied to financial statements ($18,145.61/10 = $1,814.56 * 0.5 = $907.28)
19 Half year rule not applied to financial statements ($16,256.04/10 = $1,625.60 * 1/2 = $812.80)
20 Half year rule not applied to financial statements ($244,273.40/10 = $24,427.34 * 1/2 = $12,213.67)
21 Half year rule not applied to financial statements ($1,875.46/15 = $125.03 * 1/2 = $62.51)
22 Half year rule not applied to financial statements ($2,698.31/5 = $539.66 * 1/2 = $269.83)
23 Half year rule not applied to financial statements (-$531,414.03/25 = -$21,256.56 * 1/2 = $10,628.28) + $8,000 error in amortization expense for contributed capital

Table 2.34 – Amortization Expense for 2010

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Depreciation Expense Per Financial Statements	Variance	Note to Explain Variance
1805	Land	$ 391,259.39		$ 391,259.39	$ -	$ 391,259.39	-			$ -	$ -	
1806	Land Rights	$ 302,784.48		$ 302,784.48	$ -	$ 302,784.48	-			$ -	$ -	
1808	Buildings	$ 1,615,717.33		$ 1,615,717.33	$ 4,361.04	$ 1,617,897.85	50.00	2.0%	$ 32,357.96	$ 32,357.96	$ 0.00	
1810	Leasehold Improvements	$ -		$ -	$ -	$ -	-			$ -		
1815	Transformer Station Equipment >50 kV	$ 3,215,595.87		$ 3,215,595.87	$ 5,696,787.29	$ 6,063,989.52	40.00	2.5%	$ 151,599.74	$ 151,636.29	$ 36.55	1
1820	Distribution Station Equipment <50 kV	$ 4,120,927.68	$ 1,386,754.54	$ 2,734,173.14	$ 33,674.80	$ 2,751,010.54	30.00	3.3%	$ 91,700.35	$ 87,303.00	-$ 4,397.35	2
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -	-			$ -		
1830	Poles, Towers & Fixtures	$ 25,698,012.40	$ 5,686,689.59	$ 20,011,322.81	$ 846,035.50	$ 20,434,340.56	25.00	4.0%	$ 817,373.62	$ 848,278.29	$ 30,904.67	3
1835	Overhead Conductors & Devices	$ 13,715,614.45	$ 2,750,300.00	$ 10,965,314.45	$ 751,468.28	$ 11,341,048.59	25.00	4.0%	$ 453,641.94	$ 453,641.93	-$ 0.01	
1840	Underground Conduit	$ 3,845,066.47		$ 3,845,066.47	$ 160,329.06	$ 3,925,231.00	25.00	4.0%	$ 157,009.24	$ 139,616.94	-$ 17,392.30	4
1845	Underground Conductors & Devices	$ 7,636,025.94	$ 1,204,925.00	$ 6,431,100.94	$ 255,330.77	$ 6,558,766.33	25.00	4.0%	$ 262,350.65	$ 262,350.66	$ 0.01	
1850	Line Transformers	$ 11,237,916.55		$ 11,237,916.55	$ 744,525.11	$ 11,610,179.11	25.00	4.0%	$ 464,407.16	$ 542,264.38	$ 77,857.22	5
1855	Services (Overhead and Underground)	$ 2,507,307.82		$ 2,507,307.82	$ 271,077.13	$ 2,642,846.39	25.00	4.0%	$ 105,713.86	$ 105,713.85	-$ 0.01	
1860	Meters	$ 4,025,165.04		$ 4,025,165.04	$ 131,967.50	$ 4,091,148.79	25.00	4.0%	$ 163,645.95	$ 155,695.42	-$ 7,950.53	6
1860	Meters (Smart Meters)	$ -		$ -	$ -	$ -	15.00	6.7%	$ -	$ -	$ -	
1905	Land	$ 243,635.89		$ 243,635.89	$ -	$ 243,635.89	-			$ -		
1906	Land Rights	$ -		$ -	$ -	$ -	-			$ -		
1908	Buildings & Fixtures	$ 2,215,637.94		$ 2,215,637.94	$ 91,649.69	$ 2,261,462.79	50.00	2.0%	$ 45,229.26	$ 33,215.77	-$ 12,013.49	7
1910	Leasehold Improvements	$ 6,177.00		$ 6,177.00	$ -	$ 6,177.00	10.00	10.0%	$ 617.70	$ 639.70	$ 22.00	8
1915	Office Furniture & Equipment (10 Years)	$ 411,687.16	$ 264,715.08	$ 146,972.08	$ 5,957.59	$ 149,950.88	10.00	10.0%	$ 14,995.09	$ 15,028.11	$ 33.02	9
1915	Office Furniture & Equipment (5 Years)	$ -		$ -	$ -	$ -	5.00	20.0%	$ -	$ -	$ -	
1920	Computer Equipment - Hardware (pre-2002)	$ 682,997.22	$ 329,335.48	$ 353,661.74	$ -	$ 353,661.74	10.00	10.0%	$ 35,366.17	$ 35,366.17	-$ 0.00	
1920	Computer Equip. - Hardware (2002 & forward)	$ 597,301.88	$ 280,083.47	$ 317,218.41	$ 44,045.86	$ 339,241.34	5.00	20.0%	$ 67,848.27	$ 67,928.32	$ 80.05	10
1925	Computer Software	$ 406,997.32	$ 147,108.50	$ 259,888.82	$ 35,883.76	$ 277,830.70	5.00	20.0%	$ 55,566.14	$ 44,571.26	-$ 10,994.88	11
1925	Computer Software (Smart Meters)	$ -		$ -	$ -	$ -	5.00	20.0%	$ -	$ -	$ -	
1930	Transportation Equipment (Pooled - Pre 2006)	$ 1,492,706.00	$ 592,486.74	$ 900,219.26	$ -	$ 900,219.26	10.00	10.0%	$ 90,021.93	$ 99,480.60	$ 9,458.67	12
1930-1	Transportation Equipment - Passenger Cars	$ 16,866.11		$ 16,866.11	$ 37,391.79	$ 35,562.01	4.00	25.0%	$ 8,890.50	$ 1,815.26	-$ 7,075.24	13
1930-2	Transportation Equipment - Light Trucks/Vans	$ 218,911.88	$ 67,263.00	$ 151,648.88	$ 29,641.71	$ 166,469.74	5.00	20.0%	$ 33,293.95	$ 23,474.23	-$ 9,819.72	14
1930-3	Transportation Equipment - Heavy Trucks	$ 332,851.41		$ 332,851.41	$ -	$ 332,851.41	8.00	12.5%	$ 41,606.43	$ 41,606.43	$ -	
1930-4	Transportation Equipment - Trailers/Other	$ 61,268.02	$ 30,983.00	$ 30,285.02	$ 8,750.00	$ 34,660.02	8.00	12.5%	$ 4,332.50	$ 3,836.57	-$ 495.93	15
1935	Stores Equipment	$ 120,335.32	$ 81,131.77	$ 39,203.55	$ 358.49	$ 39,382.80	10.00	10.0%	$ 3,938.28	$ 3,938.30	$ 0.02	
1940	Tools, Shop & Garage Equipment	$ 727,933.08	$ 417,155.33	$ 310,777.75	$ 6,946.08	$ 314,250.79	10.00	10.0%	$ 31,425.08	$ 31,425.14	$ 0.06	
1945	Measurement & Testing Equipment	$ 178,973.28		$ 178,973.28	$ 1,895.00	$ 179,920.78	10.00	10.0%	$ 17,992.08	$ 17,992.08	$ 0.00	
1950	Power Operated Equipment	$ -		$ -	$ -	$ -	-					
1955	Communications Equipment	$ 106,906.20		$ 106,906.20	$ 1,021.02	$ 107,416.71	10.00	10.0%	$ 10,741.67	$ 10,741.17	-$ 0.50	
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -	-					
1960	Miscellaneous Equipment	$ 412,334.40		$ 412,334.40	$ 15,885.19	$ 420,277.00	10.00	10.0%	$ 42,027.70	$ 42,027.69	-$ 0.01	
1975	Load Management Controls Utility Premises	$ 16,564.66	$ 16,564.66	$ -	$ -	$ -	-					
1980	System Supervisor Equipment	$ 613,956.35		$ 613,956.35	$ 540,684.76	$ 884,298.73	15.00	6.7%	$ 58,953.25	$ 58,953.25	$ 0.00	
1980	System Supervisor Equipment (Hardware/SW)	$ 12,653.02		$ 12,653.02	$ 9,478.71	$ 17,392.38	5.00	20.0%	$ 3,478.48	$ 3,478.48	$ 0.01	
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -	-					
1995	Contributions & Grants	-$ 7,654,020.74		-$ 7,654,020.74	-$ 819,500.89	-$ 8,063,771.19	25.00	4.0%	-$ 322,550.85	-$ 322,550.85	-$ 0.00	
2005	Property Under Capital Lease	$ 10,038.60		$ 10,038.60	$ -	$ 10,038.60	10.00	10.0%	$ 1,003.86	$ 1,003.86	$ -	
2055	Work In Progress	$ 5,472,038.35		$ 5,472,038.35	-$ 5,472,038.00	$ 2,736,019.35	-					
	Total	$ 85,016,143.77	$ 13,255,496.16	$ 71,760,647.61	$ 3,433,607.24	$ 73,477,451.23			$ 2,944,577.95	$ 2,992,830.25	$ 48,252.30	

Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs),

Notes to Explain Variances:

1 Difference is immaterial
2 Asset life adjusted to 30 years as per OEB "Appendix B" of January 1, 2006 for asset acquisitions 2006 and later (any amounts in account 1820 prior to Jan 1/06 would be amortized at old rate of 35 years)
3 Assets at amalgamation were depreciated over estimated REMAINING useful life, not over TOTAL useful life
4 Assets at amalgamation were depreciated over estimated REMAINING useful life, not over TOTAL useful life
5 Assets at amalgamation were depreciated over estimated REMAINING useful life, not over TOTAL useful life
6 Assets at amalgamation were depreciated over estimated REMAINING useful life, not over TOTAL useful life
7 Amortization period changed from 60 years to 50 years (per OEB direction) as of January 1, 2002. Thus assets acquired prior to 2002 would be amortized over 60 years, and after 2002 would be 50 years.
8 Difference is immaterial
9 Difference is immaterial
10 Difference is immaterial
11 Computer software additions relating to new accounting software should have been added to Work-In-Progress (these assets not amortized until in-service as per auditors)
12 Vehicles disposed of were not fully depreciated - remaining depreciation spread over remaining useful life of the asset
13 Vehicles acquired late in the year. Method of depreciation used was pro-rated based on # days available (not 1/2 year rule)
14 Vehicles acquired late in the year. Method of depreciation used was pro-rated based on # days available (not 1/2 year rule)
15 Vehicles/Equipment acquired late in the year. Method of depreciation used was pro-rated based on # days available (not 1/2 year rule)

Table 2.35 – Amortization Expense for 2011 Bridge Year (GAAP)

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Depreciation Expense Per Continuity Schedule	Variance	Note to Explain Variance
1805	Land	$ 391,259.39		$ 391,259.39	$ -	$ 391,259.39	-			$ -	$ -	
1806	Land Rights	$ 302,784.48		$ 302,784.48	$ 1,000.00	$ 303,284.48	-			$ -	$ -	
1808	Buildings	$ 1,620,078.37		$ 1,620,078.37	$ -	$ 1,620,078.37	50.00	2.0%	$ 32,401.57	$ 32,402.00	$ 0.43	
1810	Leasehold Improvements	$ -		$ -	$ -	$ -	-			$ -		
1815	Transformer Station Equipment >50 kV	$ 8,912,383.16		$ 8,912,383.16	$ -	$ 8,912,383.16	40.00	2.5%	$ 222,809.58	$ 222,846.00	$ 36.42	1
1820	Distribution Station Equipment <50 kV	$ 2,767,847.94		$ 2,767,847.94	$ 75,000.00	$ 2,805,347.94	30.00	3.3%	$ 93,511.60	$ 89,114.00	-$ 4,397.60	2
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -	-			$ -		
1830	Poles, Towers & Fixtures	$ 20,857,358.31		$ 20,857,358.31	$ 1,196,375.00	$ 21,455,545.81	25.00	4.0%	$ 858,221.83	$ 889,126.00	$ 30,904.17	3
1835	Overhead Conductors & Devices	$ 11,716,782.73		$ 11,716,782.73	$ 849,912.00	$ 12,141,738.73	25.00	4.0%	$ 485,669.55	$ 485,670.00	$ 0.45	
1840	Underground Conduit	$ 4,005,395.53		$ 4,005,395.53	$ 220,000.00	$ 4,115,395.53	25.00	4.0%	$ 164,615.82	$ 147,224.00	-$ 17,391.82	4
1845	Underground Conductors & Devices	$ 6,686,431.71		$ 6,686,431.71	$ 388,000.00	$ 6,880,431.71	25.00	4.0%	$ 275,217.27	$ 275,217.00	-$ 0.27	
1850	Line Transformers	$ 11,982,441.66		$ 11,982,441.66	$ 902,945.00	$ 12,433,914.16	25.00	4.0%	$ 497,356.57	$ 352,263.00	-$ 145,093.57	5
1855	Services (Overhead and Underground)	$ 2,778,384.95		$ 2,778,384.95	$ 268,108.00	$ 2,912,438.95	25.00	4.0%	$ 116,497.56	$ 116,498.00	$ 0.44	
1860	Meters	$ 4,157,132.54		$ 4,157,132.54	$ 72,000.00	$ 4,193,132.54	25.00	4.0%	$ 167,725.30	$ 159,775.00	-$ 7,950.30	6
1860	Meters (Smart Meters)	$ -		$ -	$ -	$ -	15.00	6.7%	$ -	$ -	$ -	
1905	Land	$ 243,635.89		$ 243,635.89	$ -	$ 243,635.89	-			$ -		
1906	Land Rights	$ -		$ -	$ -	$ -	-			$ -		
1908	Buildings & Fixtures	$ 2,307,287.63		$ 2,307,287.63	$ 10,000.00	$ 2,312,287.63	50.00	2.0%	$ 46,245.75	$ 34,232.00	-$ 12,013.75	7
1910	Leasehold Improvements	$ 6,177.00		$ 6,177.00	$ -	$ 6,177.00	10.00	10.0%	$ 617.70	$ 640.00	$ 22.30	8
1915	Office Furniture & Equipment (10 Years)	$ 152,929.67	$ 15,585.03	$ 137,344.64	$ 15,000.00	$ 144,844.64	10.00	10.0%	$ 14,484.46	$ 14,517.00	$ 32.54	9
1915	Office Furniture & Equipment (5 Years)	$ -		$ -	$ -	$ -	5.00	20.0%	$ -	$ -	$ -	
1920	Computer Equipment - Hardware (pre-2002)	$ 353,661.74	$ 353,661.74	$ -	$ -	$ -	10.00	10.0%	$ -	$ -	$ -	
1920	Computer Equip. - Hardware (2002 & forward)	$ 361,264.27	$ 43,901.87	$ 317,362.40	$ 30,000.00	$ 332,362.40	5.00	20.0%	$ 66,472.48	$ 66,552.00	$ 79.52	10
1925	Computer Software	$ 295,772.58	$ 113,536.45	$ 182,236.13	$ 27,000.00	$ 195,736.13	5.00	20.0%	$ 39,147.23	$ 39,147.00	-$ 0.23	11
1925	Computer Software (Smart Meters)	$ -		$ -	$ -	$ -	5.00	20.0%	$ -	$ -	$ -	
1930	Transportation Equipment (Pooled - Pre 2006)	$ 900,219.26	$ 9,319.53	$ 890,899.73	$ -	$ 890,899.73	10.00	10.0%	$ 89,089.97	$ 98,548.61	$ 9,458.64	12
1930-1	Transportation Equipment - Passenger Cars	$ 54,257.90	$ 16,866.11	$ 37,391.79	$ -	$ 37,391.79	4.00	25.0%	$ 9,347.95	$ 9,347.95	$ 0.00	
1930-2	Transportation Equipment - Light Trucks/Vans	$ 181,290.59	$ 36,372.34	$ 144,918.25	$ 70,000.00	$ 179,918.25	5.00	20.0%	$ 35,983.65	$ 26,900.21	-$ 9,083.44	13
1930-3	Transportation Equipment - Heavy Trucks	$ 332,851.41		$ 332,851.41	$ 300,000.00	$ 482,851.41	8.00	12.5%	$ 60,356.43	$ 60,356.43	$ 0.00	
1930-4	Transportation Equipment - Trailers/Other	$ 70,018.02	$ 30,983.00	$ 39,035.02	$ 70,000.00	$ 74,035.02	8.00	12.5%	$ 9,254.38	$ 9,254.38	$ 0.00	
1935	Stores Equipment	$ 39,562.04		$ 39,562.04	$ 1,000.00	$ 40,062.04	10.00	10.0%	$ 4,006.20	$ 4,006.22	$ 0.02	
1940	Tools, Shop & Garage Equipment	$ 317,723.75	$ 9,053.72	$ 308,670.03	$ 23,000.00	$ 320,170.03	10.00	10.0%	$ 32,017.00	$ 32,017.03	$ 0.03	
1945	Measurement & Testing Equipment	$ 180,868.28		$ 180,868.28	$ 6,000.00	$ 183,868.28	10.00	10.0%	$ 18,386.83	$ 18,386.85	$ 0.02	
1950	Power Operated Equipment	$ -		$ -		$ -	-					
1955	Communications Equipment	$ 107,927.22		$ 107,927.22	$ 8,000.00	$ 111,927.22	10.00	10.0%	$ 11,192.72	$ 11,192.72	-$ 0.00	
1955	Communication Equipment (Smart Meters)	$ -		$ -		$ -	-					
1960	Miscellaneous Equipment	$ 428,219.50		$ 428,219.50	$ 5,000.00	$ 430,719.50	10.00	10.0%	$ 43,071.95	$ 43,071.94	-$ 0.01	
1975	Load Management Controls Utility Premises	$ -		$ -		$ -	-					
1980	System Supervisor Equipment	$ 1,154,641.11		$ 1,154,641.11	$ 245,000.00	$ 1,277,141.11	15.00	6.7%	$ 85,142.74	$ 85,142.74	-$ 0.00	
1980	System Supervisor Equipment (Hardware/SW)	$ 22,131.73		$ 22,131.73	$ -	$ 22,131.73	5.00	20.0%	$ 4,426.35	$ 4,426.35	$ 0.00	
1985	Miscellaneous Fixed Assets	$ -		$ -		$ -	-					
1995	Contributions & Grants	-$ 8,473,521.62		-$ 8,473,521.62	-$ 861,340.00	-$ 8,904,191.62	25.00	4.0%	-$ 356,167.66	-$ 356,167.67	-$ 0.01	
2005	Property Under Capital Lease	$ 10,038.60		$ 10,038.60	$ -	$ 10,038.60	10.00	10.0%	$ 1,003.86	$ 1,003.86	$ -	
2055	Work In Progress	$ -		$ -	$ -	$ -	-					
	Total	$ 75,225,237.34	$ 629,279.79	$ 74,595,957.55	$ 3,922,000.00	$ 76,556,957.55			$ 3,128,106.63	$ 2,972,710.62	-$ 155,396.01	

Notes:

[2] Applicable for the standard Board policy of the "half-year" rule, that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

[3] Applicants must indicate YES or NO as to whether the "Depreciation Rate" for the asset in column "g" has changed from the last rebasing year approved by the Board. Changes may arise due to the adoption of International Financial Reporting Standards (IFRS) requirements or other reasons.

General: Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes to Explain Variances:

1 Difference is immaterial
2 Asset life adjusted to 30 years as per OEB "Appendix B" of January 1, 2006 for asset acquisitions 2006 and later (any amounts in account 1820 prior to Jan 1/06 would be amortized at old rate of 35 years)
3 Assets at amalgamation were depreciated over estimated REMAINING useful life, not over TOTAL useful life
4 Assets at amalgamation were depreciated over estimated REMAINING useful life, not over TOTAL useful life
5 Assets at amalgamation were depreciated over estimated REMAINING useful life, not over TOTAL useful life
6 Assets at amalgamation were depreciated over estimated REMAINING useful life, not over TOTAL useful life
7 Amortization period changed from 60 years to 50 years (per OEB direction) as of January 1, 2002. Thus assets acquired prior to 2002 would be amortized over 60 years, and after 2002 would be 50 years.
8 Difference is immaterial
9 Difference is immaterial
10 Difference is immaterial
11 Difference is immaterial
12 Assets acquired in 2005 still amortized over 10 year useful life (2005 additions = $94,586.36/10 = $9,458.64)
13 Vehicles disposed of were not fully depreciated - remaining depreciation spread over remaining useful life of the asset

Table 2.36 – Amortization Expense for 2012 Test Year (GAAP)

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Depreciation Expense Per Continuity Schedule	Variance
1805	Land	$ 391,259.39		$ 391,259.39	$ -	$ 391,259.39	-			$ -	$ -
1806	Land Rights	$ 303,784.48		$ 303,784.48	$ -	$ 303,784.48	-			$ -	$ -
1808	Buildings	$ 1,620,078.37		$ 1,620,078.37	$ -	$ 1,620,078.37	50.00	2.0%	$ 32,401.57	$ 32,402.00	$ 0.43
1810	Leasehold Improvements	$ -		$ -	$ -	$ -	-			$ -	
1815	Transformer Station Equipment >50 kV	$ 8,912,383.16		$ 8,912,383.16	$ -	$ 8,912,383.16	40.00	2.5%	$ 222,809.58	$ 222,846.00	$ 36.42
1820	Distribution Station Equipment <50 kV	$ 2,842,847.94		$ 2,842,847.94	$ 275,000.00	$ 2,980,347.94	30.00	3.3%	$ 99,344.93	$ 94,948.00	-$ 4,396.93
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -	-			$ -	
1830	Poles, Towers & Fixtures	$ 22,053,733.31		$ 22,053,733.31	$ 1,463,000.00	$ 22,785,233.31	25.00	4.0%	$ 911,409.33	$ 942,314.00	$ 30,904.67
1835	Overhead Conductors & Devices	$ 12,566,694.73		$ 12,566,694.73	$ 925,000.00	$ 13,029,194.73	25.00	4.0%	$ 521,167.79	$ 521,168.00	$ 0.21
1840	Underground Conduit	$ 4,225,395.53		$ 4,225,395.53	$ 100,000.00	$ 4,275,395.53	25.00	4.0%	$ 171,015.82	$ 153,624.00	-$ 17,391.82
1845	Underground Conductors & Devices	$ 7,074,431.71		$ 7,074,431.71	$ 203,000.00	$ 7,175,931.71	25.00	4.0%	$ 287,037.27	$ 287,037.00	-$ 0.27
1850	Line Transformers	$ 12,885,386.66		$ 12,885,386.66	$ 952,000.00	$ 13,361,386.66	25.00	4.0%	$ 534,455.47	$ 317,405.00	-$ 217,050.47
1855	Services (Overhead and Underground)	$ 3,046,492.95		$ 3,046,492.95	$ 375,000.00	$ 3,233,992.95	25.00	4.0%	$ 129,359.72	$ 129,360.00	$ 0.28
1860	Meters	$ 2,048,301.54		$ 2,048,301.54	$ 348,000.00	$ 2,222,301.54	25.00	4.0%	$ 88,892.06	$ 168,175.00	$ 79,282.94
1860	Meters (Smart Meters)	$ 3,214,012.00		$ 3,214,012.00	$ -	$ 3,214,012.00	15.00	6.7%	$ 214,267.47	$ 214,267.47	$ -
1905	Land	$ 243,635.89		$ 243,635.89	$ -	$ 243,635.89	-			$ -	
1906	Land Rights	$ -		$ -	$ -	$ -	-			$ -	
1908	Buildings & Fixtures	$ 2,317,287.63		$ 2,317,287.63	$ -	$ 2,317,287.63	50.00	2.0%	$ 46,345.75	$ 34,332.00	-$ 12,013.75
1910	Leasehold Improvements	$ 6,177.00		$ 6,177.00	$ -	$ 6,177.00	10.00	10.0%	$ 617.70	$ 640.00	$ 22.30
1915	Office Furniture & Equipment (10 Years)	$ 167,929.67	$ 15,585.03	$ 152,344.64	$ 15,500.00	$ 160,094.64	10.00	10.0%	$ 16,009.46	$ 13,490.00	-$ 2,519.46
1915	Office Furniture & Equipment (5 Years)	$ -		$ -	$ -	$ -	5.00	20.0%	$ -	$ -	$ -
1920	Computer Equipment - Hardware (pre-2002)	$ 353,661.74	$ 353,661.74	$ -	$ -	$ -	10.00	10.0%	$ -	$ -	$ -
1920	Computer Equip. - Hardware (2002 & forward)	$ 391,264.27	$ 43,901.87	$ 347,362.40	$ 40,000.00	$ 367,362.40	5.00	20.0%	$ 73,472.48	$ 73,552.00	$ 79.52
1925	Computer Software	$ 322,772.58	$ 113,536.45	$ 209,236.13	$ 142,500.00	$ 280,486.13	5.00	20.0%	$ 56,097.23	$ 56,097.00	-$ 0.23
1925	Computer Software (Smart Meters)	$ 406,373.00		$ 406,373.00	$ -	$ 406,373.00	5.00	20.0%	$ 81,274.60	$ 83,499.58	$ 2,224.98
1930	Transportation Equipment (Pooled - Pre 2006)	$ 900,219.26	$ 9,319.53	$ 890,899.73	$ -	$ 890,899.73	10.00	10.0%	$ 89,089.97	$ 73,019.53	-$ 16,070.44
1930-1	Transportation Equipment - Passenger Cars	$ 54,257.90	$ 16,866.11	$ 37,391.79	$ -	$ 37,391.79	4.00	25.0%	$ 9,347.95	$ 9,347.95	$ 0.00
1930-2	Transportation Equipment - Light Trucks/Vans	$ 251,290.59	$ 36,372.34	$ 214,918.25	$ 40,000.00	$ 234,918.25	5.00	20.0%	$ 46,983.65	$ 27,373.18	-$ 19,610.47
1930-3	Transportation Equipment - Heavy Trucks	$ 632,851.41		$ 632,851.41	$ -	$ 632,851.41	8.00	12.5%	$ 79,106.43	$ 79,106.43	$ 0.00
1930-4	Transportation Equipment - Trailers/Other	$ 140,018.02	$ 30,983.00	$ 109,035.02	$ -	$ 109,035.02	8.00	12.5%	$ 13,629.38	$ 13,629.38	$ 0.00
1935	Stores Equipment	$ 40,562.04	$ 8,829.00	$ 31,733.04	$ 1,000.00	$ 32,233.04	10.00	10.0%	$ 3,223.30	$ 3,223.27	-$ 0.03
1940	Tools, Shop & Garage Equipment	$ 340,723.75	$ 53,655.10	$ 287,068.65	$ 20,000.00	$ 297,068.65	10.00	10.0%	$ 29,706.87	$ 29,706.38	-$ 0.48
1945	Measurement & Testing Equipment	$ 186,868.28	$ 49,157.82	$ 137,710.46	$ 2,000.00	$ 138,710.46	10.00	10.0%	$ 13,871.05	$ 13,871.01	-$ 0.04
1950	Power Operated Equipment	$ -		$ -	$ -	$ -	-				
1955	Communications Equipment	$ 115,927.22	$ 20,454.10	$ 95,473.12	$ 53,000.00	$ 121,973.12	10.00	10.0%	$ 12,197.31	$ 12,197.30	-$ 0.01
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -	-				
1960	Miscellaneous Equipment	$ 433,219.50		$ 433,219.50	$ 5,000.00	$ 435,719.50	10.00	10.0%	$ 43,571.95	$ 43,571.98	$ 0.03
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -	-				
1980	System Supervisor Equipment	$ 1,399,641.11		$ 1,399,641.11	$ 100,000.00	$ 1,449,641.11	15.00	6.7%	$ 96,642.74	$ 96,642.74	-$ 0.00
1980	System Supervisor Equipment (Hardware/SW)	$ 22,131.73		$ 22,131.73	$ -	$ 22,131.73	5.00	20.0%	$ 4,426.35	$ 4,426.35	$ 0.00
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -	-				
1995	Contributions & Grants	-$ 9,334,861.62		-$ 9,334,861.62	-$ 652,000.00	-$ 9,660,861.62	25.00	4.0%	-$ 386,434.46	-$ 386,434.47	-$ 0.00
2005	Property Under Capital Lease	$ 10,038.60		$ 10,038.60	$ -	$ 10,038.60	10.00	10.0%	$ 1,003.86	$ 1,003.86	$ -
2055	Work In Progress	$ -		$ -	$ -	$ -	-				
	Total	$ 80,586,791.34	$ 752,322.09	$ 79,834,469.25	$ 4,408,000.00	$ 82,038,469.25			$ 3,542,344.56	$ 3,365,841.94	-$ 176,502.62

Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs),

Notes to Explain Variances:

1 Difference is immaterial
2 Asset life adjusted to 30 years as per OEB "Appendix B" of January 1, 2006 for asset acquisitions 2006 and later (any amounts in account 1820 prior to Jan 1/06 would be amortized at old rate of 35 years)
3 Assets at amalgamation were depreciated over estimated REMAINING useful life, not over TOTAL useful life
4 Assets at amalgamation were depreciated over estimated REMAINING useful life, not over TOTAL useful life
5 Assets at amalgamation were depreciated over estimated REMAINING useful life, not over TOTAL useful life
6 Assets at amalgamation were depreciated over estimated REMAINING useful life, not over TOTAL useful life
7 Amortization period changed from 60 years to 50 years (per OEB direction) as of January 1, 2002. Thus assets acquired prior to 2002 would be amortized over 60 years, and after 2002 would be 50 years.
8 Difference is immaterial
9 Difference is immaterial
10 Difference is immaterial
11 Half Year's Depreciation taken on 2007 additions (additions of $55,942.66/5 = $11,188.53 * 50% = $5,594.27)
12 Fully depreciated assets not written off books
13 Assets acquired in 2005 still amortized over 10 year useful life (2005 additions = $94,586.36/10 = $9,458.64)
14 Vehicle acquired in 2007 was not subject to 1/2 year rule but rather amortization was pro-rated based on # days in the year the vehicle was owned; vehicle disposed in 2010 was not fully depreciated - remaining depreciation spread over remaining life

TAX CALCULATIONS:

Table 3.1 below provides a summary of 2008 Approved, the 2008, 2009, 2010 Actual, included in audited statements, and the 2011 Bridge Year (CGAAP) and 2012 Test Year (CGAAP) income tax estimate using rates prescribed by the OEB in Norfolk's 2010 IRM rate decision and order. A copy of Norfolk's annual federal and provincial tax return has been provided as Appendix D to this exhibit.

Table 3.1 – Summary of Income & Capital Taxes 2008 to 2012 (CGAAP)

Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 Test Year
Income Taxes - Current	909,447	621,013	912,000	531,000	389,279	563,708
Less: Prior Period Adjustments	0	0	0	0	0	0
Ontario Capital Tax	74,592	78,000	84,500	33,000	0	0
TOTAL TAXES	**984,039**	**699,013**	**996,500**	**564,000**	**389,279**	**563,708**

Norfolk's detailed tax calculations using the most recent tax rates are provided in Table 3.2.

Table 3.2 – Detailed Tax Calculations for 2008 to 2012 (CGAAP)

Item	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Accounting Net Income Before Taxes	**1,162,596**	**3,000,028**	**2,530,889**	**2,020,494**	**2,823,991**
Additions:					
Amortization of tangible assets	2,730,239	2,881,007	2,702,963	2,972,711	3,365,842
Reserves @ End of Year	1,476,440	1,874,160	1,820,375	1,897,775	1,988,275
Taxable Capital Gains	-	-	-	-	-
Regulatory Liabilities	-	-	-	-	-
Apprenticeship Training Tax Credit			10,000	10,000	10,000
Deductions:					
Capital cost allowance from Schedule 8	2,719,093	2,968,300	3,409,012	3,652,806	3,804,042
Reserves @ Beginning of Year	769,835	1,476,440	1,874,160	1,820,375	1,897,775
Gain (Loss) on Disposal of Assets	9,100	10,030	(3,138)	-	-
Cumulative Eligible Capital Deduction	17,478	16,676	15,508	14,423	13,413
Capital Tax in Provision	-	-	-	-	-
Prior Period Adjustment [1]	-	518,958	-	-	-
Total Tax Adjustments to Accounting Income	691,173	(235,237)	(762,204)	(607,118)	(351,113)
Income for Tax Purposes	**1,853,769**	**2,764,791**	**1,768,685**	**1,413,376**	**2,472,878**
Effective Tax Rate Reflecting Tax Credits (Federal + Provincial)	34%	33%	31%	28.25%	23.20%
Income Taxes Before Credits	**621,013**	**912,000**	**541,000**	**399,279**	**573,708**
Less: Apprenticeship Training Tax Credit	**-**	**-**	**10,000**	**10,000**	**10,000**
Income Taxes	**621,013**	**912,000**	**531,000**	**389,279**	**563,708**
Capital Tax Calculation:					
Total Rate Base	49,203,640	51,267,581	53,994,717	55,608,903	57,918,824
Reduction	(14,467,304)	(14,359,410)	(12,578,750)		
Rate	0.225%	0.225%	0.074%	0.000%	0.000%
Capital Tax - As Calculated	**78,157**	**83,043**	**30,807**	**-**	**-**
Capital Tax - As per Audited Statements	**78,000**	**84,500**	**33,000**	**N/A**	**N/A**

Notes:

1 - The prior period adjustment relates to net effect of the Regulatory Asset review (decrease in income for 2008 over what was previously reported)

CAPITAL COST ALLOWANCE:

Norfolk is providing Capital Cost Allowance continuity schedules for the 2011 Bridge Year (Tables 3.3 & 3.4) and the 2012 Test Year (Tables 3.5 & 3.6) as follows:

Table 3.3 – 2011 CCA / UCC Continuity Schedule (CGAAP)

CCA Continuity Schedule (2011)

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	25,442,024			25,442,024	0	0	25,442,024	0	25,442,024	0	1,017,681	24,424,343
2	Distribution System - pre 1988				0	0	0	0	0	0	0	0	0
6	Buildings (No footings below ground)				0	0	0	0	0	0	0	0	0
8	General Office/Stores Equip	1,150,803			1,150,803	58,000	0	1,208,803	29,000	1,179,803	0	235,961	972,842
10	Computer Hardware/ Vehicles	253,201			253,201	470,000	0	723,201	235,000	488,201	0	146,460	576,741
10.1	Certain Automobiles				0	0	0	0	0	0	0	0	0
12	Computer Software	0			0	27,000	0	27,000	13,500	13,500	1	13,500	13,500
3		2,684,222			2,684,222	0	0	2,684,222	0	2,684,222	0	134,211	2,550,011
					0	0	0	0	0	0		0	0
13 3	Lease # 3				0	0	0	0	0	0		0	0
13 4	Lease # 4				0	0	0	0	0	0		0	0
14	Franchise				0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				0	0	0	0	0	0	0	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment				0	0	0	0	0	0	0	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	16,219			16,219	0	0	16,219	0	16,219	0	7,299	8,920
50	Computers & Systems Hardware acq'd post Mar 19/07	25,207			25,207	0	0	25,207	0	25,207	1	13,864	11,343
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				0	0	0	0	0	0	0	0	0
47	Distribution System - post 22-Feb-2005	24,364,877			24,364,877	3,366,000	0	27,730,877	1,683,000	26,047,877	0	2,083,830	25,647,047
	SUB-TOTAL - UCC	**53,936,553**	**0**	**0**	**53,936,553**	**3,921,000**	**0**	**57,857,553**	**1,960,500**	**55,897,053**		**3,652,806**	**54,204,747**
CEC	Goodwill		0	0	0								
CEC	Land Rights		0	0	0								
CEC	FMV Bump-up		0	0	0								
	SUB-TOTAL - CEC	**0**	**0**	**0**	**0**								

Table 3.4 – 2011 CEC Continuity Schedule (CGAAP)

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				206,039
Additions:				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	206,039
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				206,039
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	206,039
Cumulative Eligible Capital Balance				206,039
CEC Deduction	7%			14,423
Cumulative Eligible Capital - Closing Balance				191,616

Table 3.5 – 2012 CCA / UCC Continuity Schedule (CGAAP)

CCA Continuity Schedule (2012)

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	24,424,343	0	0	24,424,343	0	0	24,424,343	0	24,424,343	4%	976,974	23,447,369
2	Distribution System - pre 1988	0	0	0	0	0	0	0	0	0	6%	0	0
6	Buildings (No footings below ground)	0	0	0	0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	972,842	0	0	972,842	96,500	0	1,069,342	48,250	1,021,092	20%	204,218	865,124
10	Computer Hardware/ Vehicles	576,741	0	0	576,741	80,000	0	656,741	40,000	616,741	30%	185,022	471,718
10.1	Certain Automobiles	0	0	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	13,500	0	0	13,500	142,500	0	156,000	71,250	84,750	100%	84,750	71,250
3		2,550,011	0	0	2,550,011	0	0	2,550,011	0	2,550,011	5%	127,501	2,422,510
		0	0	0	0	0	0	0	0	0		0	0
13 3	Lease # 3	0	0	0	0	0	0	0	0	0		0	0
13 4	Lease # 4	0	0	0	0	0	0	0	0	0		0	0
14	Franchise	0	0	0	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0	0	0	0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	8,920	0	0	8,920	0	0	8,920	0	8,920	45%	4,014	4,906
50	Computers & Systems Hardware acq'd post Mar 19/07	11,343	0	0	11,343	0	0	11,343	0	11,343	55%	6,239	5,104
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	25,647,047			25,647,047	4,089,000	0	29,736,047	2,044,500	27,691,547	8%	2,215,324	27,520,723
	SUB-TOTAL - UCC	**54,204,747**	**0**	**0**	**54,204,747**	**4,408,000**	**0**	**58,612,747**	**2,204,000**	**56,408,747**		**3,804,042**	**54,808,706**
						-486,000	0						
CEC	Goodwill	0	0	0	0								
CEC	Land Rights	0	0	0	0								
CEC	FMV Bump-up	0	0	0	0								
	SUB-TOTAL - CEC	**0**	**0**	**0**	**0**								

Table 3.6 - 2012 CEC Continuity Schedule (CGAAP)

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				191,616
Additions:				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	191,616
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				191,616
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	191,616
Cumulative Eligible Capital Balance				191,616
CEC Deduction	7%			13,413
Cumulative Eligible Capital - Closing Balance				178,203

MIFRS – IMPACT ON OM&A

Conversion to Modified International Financial Reporting Standards (MIFRS)

International Accounting Standard 16 (IAS 16) – Property, Plant and Equipment (PP&E), states the cost of an item of PP&E includes any costs that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. IAS 16 does not define the term "directly attributable". The specific facts and circumstances surrounding the nature of the costs and the activity associated with it must be considered to determine if it is directly attributable to an item of PP&E. Where Canadian GAAP allowed for the capitalization of general and administrative overhead, MIFRS does not.

In order to allocate costs between operating expenses and capital expenses, Norfolk utilizes the following burdens:

Payroll
Engineering
Fleet maintenance
Stores

In reviewing each of these burdens Norfolk has identified the following expenses that are not appropriate to capitalize under MIFRS.

Payroll

The payroll burden has included the full costs of all employees including, wages, benefits, safety, training and education expenses. The safety, training and education expenses are indirect expenses and cannot be capitalized under MIFRS. These expenses include the following:

In-house training (90910)
Miscellaneous Courses and Workshops (90918)
Safety Consulting (90920)
EUSA (90921)
Safety Meetings and training (90930)

The total reduction in payroll burden for these expenses to capital projects is $95,864.

Engineering

The engineering burden includes the engineering manager, engineering clerk, technicians, and drafting and design services.

In reviewing the work activities of the engineering manager and the technicians it was found that most of their time was directly attributable to capital projects and therefore appropriately included in the Engineering burden. However, the engineering clerk provides a support role to the technicians is not directly attributable to specific capital projects. Under MIFRS this expense will no longer be capitalized but reported under administration expense.

The engineering burden included supervisory services for capital projects. This included time charged from the Operations Manager, Lines Superintendent and the Manager of Safety & Technical Support Services. These expenses are not directly attributable to specific projects and will no longer be capitalized.

In addition the Engineering burden also included IT expenses and property charges. These expenses are considered to general expenses and not directly attributable to specific capital projects. Under MIFRS these expenses will no longer be capitalized.

The reduction in the engineering burden is summarized below:

Supervisory & Admin Labour:	$216,409
IT Charges	114,320
Property Charges	13,239
Total	$343,968

Fleet

Through the Fleet burden, the total cost of operating all vehicles is charged to specific jobs, based on an hourly rate for the time each vehicle is on a job. Timesheets are completed for each truck and therefore the costs are directly attributable to specific projects. However, included in the Fleet expense were the following expenses that are considered general or administrative and under IFRS will be expensed instead of capitalized.

Miscellaneous Tools	$ 9,000
Property Charges	$36,300
Total	$45,300

Stores

Included in this burden are purchasing expenses, labour hours, vehicle charges, IT expense and property charges. The labor hours include the purchasing manager, a stock keeper. Based on review of the purchasing manager’s time, it was determined that some time recorded under Stores was for purchasing activities and some for supervisory activities. The purchasing activities are directly attributable to the materials used in capital projects and therefore will continue to be capitalized as part of the Stores burden. However the supervisory activities are not directly attributable and under MIFRS should be expensed.

In addition to the supervisory expenses the expenses related to property charges and IT charges should also be expensed. The reduction in the stores burden is summarized below:

Supervisory Labour	$ 7,113
IT Charges	20,520
Property Charges	103,790
Total	$131,423

Table 4.1 Impact of MIFRS on Burdens and OM&A

Burdens		General & Administrative Labour	Labour Burden	IT Charges	Property Charge	Miscellaneous	Total
Engineering Burden		216,409		114,320	13,239		343,968
Stores Burden		7,113		20,520	103,790		131,423
Fleet Burden					36,300	9,000	45,300
Payroll Burden			95,864				95,864
Total		223,522	95,864	134,840	153,329	9,000	616,555
Burden amounts reallocated to OM&A	**2012 Test Year CGAAP**	**Amounts removed from Burdens aboved to be expensed in OM&A**					**2012 Test Year IFRS**
Operations	1,226,500	62,006					1,288,506
Maintenance	1,165,100	83,505					1,248,605
Billing & Collecting	1,228,062						1,228,062
Community Relations	37,000						37,000
Administration	1,544,400	78,011	95,864	134,840	153,329	9,000	2,015,444
Total	5,201,062	223,522	95,864	134,840	153,329	9,000	5,817,617

MIFRS – IMPACT ON DEPRECIATION

IAS 16 requires each part of an item of PP&E with a cost that is significant in relation to the total cost of the time to be depreciated separately. In addition IAS 16 requires that entities perform a review of assets' useful lives, depreciation methods and residual values on an annual basis.

The Board commissioned a depreciation study to assist electricity distributors in their transition to IFRS. In the Report of the Board, Transition to International Financial Reporting Standards, (EB-2008-0408) the Board stated:

> "While utilities remain solely responsible for complying with financial reporting requirements, the Board notes that a generic depreciation study could assist utilities with IFRS compliance in addition to providing considerable regulatory benefits. The study should provide a good starting point for the determination of service lives for distribution assets that may be both acceptable to the Board and useful for financial reporting purposes. Distributors will remain responsible for review and updates of the service lives for their particular assets for financial reporting and regulatory requirements."

Norfolk has reviewed the useful life of its assets with the aid of the Asset Depreciation Study by Kinetrics (Kinetrics Report). Table 4.2 contains the useful lives by Uniform System of Account, compared to the current useful lives used under CGAAP. Overall, the useful lives have been extended causing net depreciation (depreciation expense to the income statement after allocations to overhead accounts) to be reduced in the 2012 Test year by $675,310 ($3,002,833 under CGAAP to $2,327,523 under MIFRS). Table 4.2 also outlines the 2011 & 2012 Amortization Expense under IFRS by account number.

Table 4.2 MIFRS Amortization Periods & Amortization Expense for 2011 & 2012

USoA / Sub-Account	*Description*	*GAAP Amortization Period*	*IFRS Amortization Period*	*2011 IFRS Amortization Expense by USoA*	*2012 IFRS Amortization Expense by USoA*
1805	Land ~ Distribution Plant	N/A	N/A	0	0
1806	Land Rights ~ Distribution Plant	N/A	N/A	0	0
18082	Tranformer Station Building	50	50	33,112	33,112
18150	Station DC System	40	20	232,330	232,330
1820	Distribution Station Equipment	30	20	161,059	167,198
1830	POLES - Wood/Concrete	25	45	395,240	421,300
1835	O/H Conductors & Devices ~ OH Conductors - primary	25	60	191,773	199,428
1840	U/G Conduit ~ Ducts	25	50	60,211	63,015
1845	U/G Conductors & DevicesUG Primary Cables	25	30	219,158	227,795
1850 UG	Pad-Mounted Transformers	25	35	174,804	195,231
1855	Services ~ Secondary Cables - Direct Buried/Other (incl OH)	25	40	66,958	74,055
1860	Other Meters, PTs & CTs	25	30	97,707	50,876
1860	Smart Meters	15	10	0	321,401
1905	Land ~ General Plant	N/A	N/A	0	0
1908	Service Centre & Pond Street Storage Buildings	25	25	101,372	101,472
1910	Lease Improvements - Hunt St	10	10	654	654
1915	Office Equipment	10	10	15,568	13,790
1920	Computer Hardware	10	4	63,095	93,720
1925	Smart Meter - software	5	5	0	101,593
1925	Computer Software	5	5	37,574	47,211
1930	Transportation Equipment	10,8,4,5	15, 7	82,451	98,451
1935	Stores Equipment	10	10	3,990	3,107
1940	Tools & Garage Equipment	10	10	32,269	30,959
1945	Measurement & Testing Equipment	10	5	12,762	9,772
1955	Communication Equipment	10	5	23,866	22,088
1960	Miscellaneous Equipment	10	5	99,699	88,879
1980, 19810	SCADA	15, 5	20	58,081	65,632
1995	Contributed Capital	25	25	(193,817)	(205,507)
2005	Property under Capital Lease	10	10	1,004	1,004
SUBTOTAL AMORTIZATION EXPENSE				1,970,919	2,458,566
LESS: FULLY ALLOCATED AMORTIZATION					
	TRANSPORTATION EQUIPMENT			(82,451)	(98,451)
	STORES & GARAGE TOOLS/EQUIPMENT			(37,263)	(32,592)
NET AMORTIZATION EXPENSE TO INCOME STATEMENT				**1,851,204**	**2,327,523**

MIFRS – IMPACT ON TAXES

TAX CALCULATIONS:

Table 4.3 below provides a summary of 2008 Approved, 2008, 2009, and 2010 Actual income taxes included in audited statements, and the 2011 Bridge Year (IFRS) and 2012 Test Year (IFRS) income tax estimates using rates prescribed by the OEB in Norfolk's 2010 IRM rate decision and order. A copy of Norfolk's annual federal and provincial tax return has been provided as Appendix D to this exhibit.

Table 4.3 – Summary Income Taxes 2008 to 2012 Taxes Under MIFRS

Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year - IFRS	2012 Test Year - IFRS
Income Taxes - Current	909,447	621,013	912,000	531,000	318,326	321,256
Less: Prior Period Adjustments	0	0	0	0	0	0
Ontario Capital Tax	74,592	78,000	84,500	33,000	0	0
TOTAL TAXES	**984,039**	**699,013**	**996,500**	**564,000**	**318,326**	**321,256**

Norfolk has provided the Capital Cost Allowance continuity schedules for the 2011 Bridge Year (IFRS) under Tables 4.4 & 4.5, and the 2012 Test Year (IFRS) under Tables 4.6 & 4.7.

Table 4.4 – CCA Continuity Schedule 2011 (MIFRS)

CCA Continuity Schedule (2011)

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	25,442,024			25,442,024	0	0	25,442,024	0	25,442,024	4%	1,017,681	24,424,343
2	Distribution System - pre 1988				0	0	0	0	0	0	6%	0	0
6	Buildings (No footings below ground)				0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	1,150,803			1,150,803	58,000	89,504	1,119,299	(15,752)	1,135,051	20%	227,010	892,289
10	Computer Hardware/ Vehicles	253,201			253,201	470,000	0	723,201	235,000	488,201	30%	146,460	576,741
10.1	Certain Automobiles				0	0	0	0	0	0	30%	0	0
12	Computer Software	0			0	27,000	0	27,000	13,500	13,500	100%	13,500	13,500
3		2,684,222			2,684,222	0	0	2,684,222	0	2,684,222	5%	134,211	2,550,011
					0	0	0	0	0	0		0	0
13 3	Lease # 3				0	0	0	0	0	0		0	0
13 4	Lease # 4				0	0	0	0	0	0		0	0
14	Franchise				0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment				0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	16,219			16,219	0	0	16,219	0	16,219	45%	7,299	8,920
50	Computers & Systems Hardware acq'd post Mar 19/07	25,207			25,207	0	0	25,207	0	25,207	55%	13,864	11,343
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	24,364,877			24,364,877	2,811,043	0	27,175,920	1,405,522	25,770,399	8%	2,061,632	25,114,288
	SUB-TOTAL - UCC	**53,936,553**	**0**	**0**	**53,936,553**	**3,366,043**	**89,504**	**57,213,092**	**1,638,269**	**55,574,822**		**3,621,657**	**53,591,435**
CEC	Goodwill		0	0	0								
CEC	Land Rights		0	0	0								
CEC	FMV Bump-up		0	0	0								
	SUB-TOTAL - CEC	**0**	**0**	**0**	**0**								

Table 4.5 – CEC Continuity Schedule 2011 (MIFRS)

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				206,039
Additions:				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	206,039
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				206,039
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	206,039
Cumulative Eligible Capital Balance				206,039
CEC Deduction	7%			14,423
Cumulative Eligible Capital - Closing Balance				191,616

Table 4.6 – CCA Continuity Schedule 2012 (MIFRS)

CCA Continuity Schedule (2012)

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	24,424,343	0	0	24,424,343	0	0	24,424,343	0	24,424,343	4%	976,974	23,447,369
2	Distribution System - pre 1988	0	0	0	0	0	0	0	0	0	6%	0	0
6	Buildings (No footings below ground)	0	0	0	0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	892,289	0	0	892,289	96,500	0	988,789	48,250	940,539	20%	188,108	800,681
10	Computer Hardware/ Vehicles	576,741	0	0	576,741	80,000	0	656,741	40,000	616,741	30%	185,022	471,718
10.1	Certain Automobiles	0	0	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	13,500	0	0	13,500	142,500	0	156,000	71,250	84,750	100%	84,750	71,250
3		2,550,011	0	0	2,550,011	0	0	2,550,011	0	2,550,011	5%	127,501	2,422,510
		0	0	0	0	0	0	0	0	0		0	0
13 3	Lease # 3	0	0	0	0	0	0	0	0	0		0	0
13 4	Lease # 4	0	0	0	0	0	0	0	0	0		0	0
14	Franchise	0	0	0	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0	0	0	0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	8,920	0	0	8,920	0	0	8,920	0	8,920	45%	4,014	4,906
50	Computers & Systems Hardware acq'd post Mar 19/07	11,343	0	0	11,343	0	0	11,343	0	11,343	55%	6,239	5,104
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	25,114,288			25,114,288	3,581,520	0	28,695,808	1,790,760	26,905,048	8%	2,152,404	26,543,404
	SUB-TOTAL - UCC	**53,591,435**	**0**	**0**	**53,591,435**	**3,900,520**	**0**	**57,491,955**	**1,950,260**	**55,541,695**		**3,725,011**	**53,766,944**
						-533,477	0						
CEC	Goodwill	0	0	0	0								
CEC	Land Rights	0	0	0	0								
CEC	FMV Bump-up	0	0	0	0								
	SUB-TOTAL - CEC	**0**	**0**	**0**	**0**								

Table 4.7 – CEC Continuity Schedule 2012 (MIFRS)

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				191,616
Additions:				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	191,616
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				191,616
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	191,616
Cumulative Eligible Capital Balance				191,616
CEC Deduction	7%			13,413
Cumulative Eligible Capital - Closing Balance				178,203

1 Norfolk has provided detailed income tax calculations using MIFRS net income, MIFRS
2 amortization & MIFRS CCA as shown in Table 4.8 below.

Table 4.8 – Detailed Income Tax Calculations Under MIFRS

Item	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Accounting Net Income Before Taxes	**1,162,596**	**3,000,028**	**2,530,889**	**2,739,976**	**2,607,185**
Additions:					
Amortization of tangible assets	2,730,239	2,881,007	2,702,963	1,970,919	2,458,568
Reserves @ End of Year	1,476,440	1,874,160	1,820,375	1,897,775	1,988,275
Taxable Capital Gains	-	-	-	-	-
Regulatory Liabilities	-	-	-	-	-
Apprenticeship Training Tax Credit			10,000	10,000	10,000
Deductions:					
Capital cost allowance from Schedule 8	2,719,093	2,968,300	3,409,012	3,621,657	3,725,011
Reserves @ Beginning of Year	769,835	1,476,440	1,874,160	1,820,375	1,897,775
Gain on Disposal of Assets	9,100	10,030	(3,138)	-	-
Cumulative Eligible Capital Deduction	17,478	16,676	15,508	14,423	13,413
Capital Tax in Provision	-	-	-	-	-
Prior Period Adjustment 1	-	518,958	-	-	-
Total Tax Adjustments to Accounting Income	691,173	(235,237)	(762,204)	(1,577,761)	(1,179,356)
Income for Tax Purposes	**1,853,769**	**2,764,791**	**1,768,685**	**1,162,215**	**1,427,829**
Effective Tax Rate Reflecting Tax Credits (Federal + Provincial)	34%	33%	31%	28.25%	23.20%
Income Taxes Before Credits	**621,013**	**912,000**	**541,000**	**328,326**	**331,256**
Less: Apprenticeship Training Tax Credit	**-**	**-**	**10,000**	**10,000**	**10,000**
Income Taxes	**621,013**	**912,000**	**531,000**	**318,326**	**321,256**
Capital Tax Calculation:					
Total Rate Base	49,203,640	51,267,581	53,994,717	55,787,566	58,578,295
Reduction	(14,467,304)	(14,359,410)	(12,578,750)		
Rate	0.225%	0.225%	0.074%	0.000%	0.000%
Capital Tax - As Calculated	**78,157**	**83,043**	**30,807**	**-**	**-**
Capital Tax - As per Audited Statements	**78,000**	**84,500**	**33,000**	**N/A**	**N/A**

Notes:

1 - The prior period adjustment relates to net effect of the Regulatory Asset review (decrease in income for 2008 over what was previously reported)

EXHIBIT 4

APPENDIX A

Affiliate Services Agreement

NORFOLK ENERGY SERVICES INC.

- and -

NORFOLK POWER DISTRIBUTION INC.

- and -

NORFOLK POWER INC.

SERVICES AGREEMENT

October 26, 2010

SERVICES AGREEMENT

THIS SERVICES AGREEMENT is made as of the 26th day of, October 2010.

B E T W E E N:

NORFOLK POWER DISTRIBUTION INC., a corporation incorporated pursuant to the laws of the Province of Ontario

(hereinafter referred to as "**NPDI**")

- and -

NORFOLK POWER INC., a corporation incorporated pursuant to the laws of the Province of Ontario

(hereinafter referred to as "**NPI**")

- and -

NORFOLK ENERGY SERVICES INC., a corporation incorporated pursuant to the laws of the Province of Ontario

(hereinafter referred to as "**NEI**")

hereinafter referred to collectively as "the Parties" and individually as a "Party."

WHEREAS:

1. Each of the Parties to this Agreement is a corporation incorporated under the *Business Corporations Act* (Ontario);

2. NPDI carries on the business of distributing electricity within its service territory located in the County of Norfolk;

3. NEI is an energy services business which provides limited services to NPDI on the terms as set forth in this Agreement;

4. NPI and NPDI agree to provide certain services to NEI on the terms as set forth in this Agreement; and

5. NPI acts as the holding company parent to affiliates NPDI and NEI.

NOW THEREFORE in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

Unless the context otherwise specifies or requires, for the purposes of this Agreement all capitalized terms herein shall have the meanings set forth below

(a) **"Affiliate"** with respect to a corporation, shall have the same meaning as is ascribed to such term in the *Business Corporations Act* (Ontario);

(b) **"Agreement", "hereto", "hereof", "herein", "hereby", "hereunder"** and similar expressions mean this Services Agreement together with all Schedules attached hereto, as they may be amended from time to time;

(c) **"Business Day"** means any day other than a Saturday, Sunday, statutory or bank holiday in the Province of Ontario;

(d) **"Claim"** has the meaning ascribed to such term in **Section 4.4;**

(e) **"Confidential Information"** means information NPDI has obtained relating to a specific consumer, retailer or generator in the process of providing current or prospective distribution service;

(f) **"Default"** means in respect of Defaulting Party, an event set out in **Section 8.1**;

(g) **"Defaulting Party"** has the meaning ascribed to such term in **Section 8.1**;

(h) **"Direct Costs"** means costs incurred directly by a Party for its own operations including all income, property and land taxes, payments-in-lieu of taxes, fees and expenses in respect of directors of each Party, insurance, its assets, employees, directors and agents, including, where insurance is jointly held, a pro rata share of the premiums in respect of such insurance, regulatory, legal and accounting costs, fees and expenses;

(i) **"Effective Date"** means the date first written above;

(j) **"Event of Default"** means a Default, the notice and cure periods (if any) respecting which have expired;

(k) **"Force Majeure Event"** has the meaning ascribed to such term in **Section 11.1;**

(l) **"Law"** means any law, rule, regulation, code, order, writ, judgment, decree or other legal or regulatory determination by a court, regulatory agency, or governmental authority of competent jurisdiction;

(m) **"Other Parties"** means NPI and NPDI;

(n) **"Person"** means an individual, corporation, partnership, joint venture, association, trust, pension fund, union, governmental agency, official, board, tribunal, ministry, commission or department;

(o) **"Personnel"** means employees, agents, professional advisors, contractors and subcontractors;

(p) **"PoP"** means point of presence of associated telecom equipment;

(q) **"Prime Rate"** means, for any day, an annual rate of interest equal to the rate of interest which NPI's principal bank establishes at its principal office in Toronto as the reference rate of interest to determine interest rates that it will charge on such day for commercial loans in Canadian dollars made to its customers in Canada and which it refers to as its "prime rate of interest";

(r) **"Services"** are Services that are provided under **Section 3.1** of this Agreement;

(s) **"Term"** has the meaning ascribed thereto in **Section 2.1** of this Agreement; and

(t) **"Third Party Expenses"** means all fees, costs and charges paid to third parties by the Parties in connection with providing the Services under this Agreement.

1.2 Construction of Agreement

In this Agreement:

(a) words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

(b) all usage of the word "including" or the phrase "e.g.," in this Agreement shall mean "including, without limitation," throughout this Agreement;

(c) any reference to a statute shall mean the statute in force as at the date hereof, together with all regulations promulgated thereunder, as the same may be amended, re-enacted, consolidated and/or replaced, from time to time, and any successor statute thereto, unless otherwise expressly provided;

(d) any reference to a specific executive position or an internal division or department of a Party shall include any successor positions, divisions or departments having substantially the same responsibilities or performing substantially the same functions;

(e) when calculating the period of time within which or following which any act is to be done or step taken, the date which is the reference day in calculating such period shall be excluded, and if the last day of such period is not a Business Day, the period shall end on the next Business Day;

(f) all dollar amounts are expressed in Canadian dollars;

(g) the division of this Agreement into separate Articles, Sections, subsections and Schedules and the insertion of headings is for convenience of reference only and shall not affect the construction or interpretation of this Agreement;

(h) words or abbreviations which have well known or trade meanings are used herein in accordance with their recognized meanings; and

(i) the terms and conditions hereof are the result of negotiations between the Parties and the Parties therefore agree that this Agreement shall not be construed in favour of or against any Party by reason of the extent to which any Party or its professional advisors participated in the preparation of this Agreement.

ARTICLE 2
TERM

2.1 Term

Unless terminated in accordance with **Section 10.1** of this Agreement, this Agreement shall come into force on the Effective Date and shall continue in full force and effect for a period of five (5) years.

ARTICLE 3
SERVICES AND COVENANTS

3.1 Services

Subject to the terms, covenants and conditions contained in this Agreement; NPDI will provide, or cause to be provided, to NEI the services set out in **Schedule "A1"** and such other services as NEI shall request and NPDI shall agree to provide from time to time in writing; NEI will provide, or cause to be provided, to NPDI the services set out in **Schedule "A2"** and such other services as NPDI shall request and NEI shall agree to provide from time to time in writing; and NPI will provide, or cause to be provided to NPDI and NEI the services set out in **Schedule "A3"** and such other services as requested and agreed upon from time to time in writing (collectively the "**Services**"). NPI receives no services from NPDI or NEI.

Any additional shared service required by either affiliate shall be provided at mutually agreed upon terms and conditions, consistent with the requirements of the Affiliate Relationships Code.

3.2 Performance Standards

NPDI shall provide to NEI the services set out in **Schedule "A1"** at quality levels which are mutually acceptable to the parties. These levels shall be reviewed from time to time.

3.3 Changes

The Parties may, from time to time, agree to modifications to a service agreed to be provided hereunder by negotiating appropriate changes to the descriptions of the service and the consideration in connection with such changes and shall initial and attach amended schedules hereto.

3.4 General Covenants

(a) The Other Parties shall be responsible for obtaining all necessary licenses and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulations in connection with the provision of the Services and shall, when requested, provide NEI with adequate evidence of its compliance with this **Section 3.4**;

(b) The Other Parties shall pay for and maintain for their benefit, appropriate insurance concerning the operations and liabilities of NPI and NPDI relevant to this Agreement including, without limiting the generality of the foregoing, workers' compensation and employment insurance in conformity with applicable statutory requirements in respect of any remuneration payable by the Other Parties to any employees of NPI and NPDI and public liability and property damage insurance;

3.5 Regulatory Change

If any change of Law after the date of this Agreement renders this Agreement illegal or unenforceable, then the Parties shall renegotiate in good faith for thirty (30) days with a goal of developing a substitute agreement with such amendments as are necessary to comply with such change of Law.

ARTICLE 4
MUTUAL COVENANTS

4.1 Confidentiality of Confidential Information

NPDI shall not release to NEI or NPI any confidential information relating to a smart sub-metering provider, wholesaler, consumer, retailer or generator without the consent of that smart sub-metering provider, wholesaler, consumer, retailer or generator, in accordance with the Affiliate Relationship Code for Electricity Distributors and Transmitters prescribed by the Ontario Energy Board.

4.2 Maintain Records

The Parties will maintain such records as may be necessary in connection with this Agreement and as are agreed upon by the Parties acting reasonably.

4.3 Notification of Changes of Circumstances

The Other Parties shall promptly give written notice to NEI of any changes or prospective changes in circumstances that would materially affect the resources required for the performance of the Services, including any anticipated material change in the nature or level of business, the number of employees, or any efforts relating to the organization of or collective bargaining by employees, or any lease or service arrangements contemplated with any third parties.

4.4 Notice of Claims, Etc.

The Other Parties shall promptly give written notice to NEI, and NEI shall promptly give notice to the Other Parties, of all material claims, proceedings, notice of regulatory non-compliance from any regulatory authority, disputes (including labour disputes) or litigation (collectively, **"Claims"**) which it reasonably believes could have a material adverse effect on the fulfillment of any of the material terms hereof by the Other Parties or NEI (whether or not any such Claim is covered by insurance) in respect of its own operations of which any of them is aware. Each Party shall provide the other Parties with all information reasonably requested from time to time concerning the status of such Claims and any developments relating thereto.

ARTICLE 5
FEES AND COSTS

5.1 Fees

The payment of fees and charges between the Parties is set out in **Schedule "B"**. Where a reasonably competitive market exists for a service, NPDI shall charge no less than the greater of (i) the market price of the service and (ii) the utility's fully allocated cost to provide service when selling the service to an affiliate.

5.2 Taxes

In addition to the fees, NEI shall pay the Other Parties, as applicable, an amount equal to any and all goods and services taxes, sales taxes, value-added taxes or any other taxes (excluding income taxes) properly eligible on the supply of services provided by a third party under this Agreement.

5.3 Invoicing & Payment

(a) NPDI shall render to NEI on or before the 15th day of each month (or such other time as may be agreed), an invoice setting forth the total amount due to NPDI in respect of each of the services provided during the previous calendar month and the amount of any taxes which NEI has an obligation to pay.

(b) NEI shall, no later than forty-five days after receipt of a NPDI invoice, or if such day is not a business day, the immediately preceding business day, render to NPDI, by any acceptable method agreed to by the Parties, the amount due as set forth in the invoice. This Section 5.3 shall survive any termination of this Agreement or the expiry of the Term for a period of twelve (12) months from the date on which the last invoice is rendered to NEI pursuant to this Agreement.

5.4 Renegotiation

The Parties hereby agree and acknowledge that they shall renegotiate the Shared Services and pricing described in Schedules hereto at such times as necessary in order to ensure compliance with the requirements of the Affiliate Relationships Code.

ARTICLE 6
REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of NEI

NEI represents and warrants to NPDI as follows and acknowledges that NPDI is relying on such representations and warranties in connection herewith:

(a) NEI is a corporation, duly incorporated, validly existing and in good standing under the laws of the Province of Ontario and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate action;

(c) this Agreement constitutes a legal, valid and binding obligation of NEI, enforceable against NEI by NPDI in accordance with its terms; and

(d) NEI has the necessary resources and expertise to acquire or perform the Services.

6.2 Representations and Warranties of NPI

NPI represents and warrants to NEI and NPDI as follows and acknowledges that NEI and NPDI are relying on such representations and warranties in connection herewith:

(a) NPI is a corporation, duly incorporated, validly existing and in good standing under the laws of the Province of Ontario and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate action;

(c) this Agreement constitutes a legal, valid and binding obligation of NPI, enforceable against NPI by the Other Parties in accordance with its terms; and

(d) NPI has the necessary resources and expertise to acquire or perform the Services.

6.3 Representations and Warranties of NPDI

NPDI represents and warrants to NEI as follows and acknowledges that NEI is relying on such representations and warranties in connection herewith:

(a) NPDI is a company, duly organized, validly existing and in good standing under the laws of the Province of Ontario and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate actions; and

(c) this Agreement constitutes a legal, valid and binding obligation of NPDI, enforceable against NPDI by NEI in accordance with its terms; and

(d) NPDI has the necessary resources and expertise to acquire or perform the Services.

ARTICLE 7
INDEMNIFICATION

7.1 Indemnification

(a) NPDI shall indemnify, defend and hold harmless NEI, its officers, directors, and employees (each a "**NEI Indemnitee**") from and against any and all claims, demands, suits, losses, liabilities, damages, obligations, payments, costs and expenses and accrued interest thereon (including the costs and expenses of, and accrued interest in respect of, any and all actions, suits, proceedings, assessments, judgments, awards, settlements and compromises relating thereto and reasonable lawyers' fees and reasonable disbursements in connection therewith) (each an "**Indemnifiable Loss**"), asserted against or suffered by any NEI Indemnitee relating to, or in connection with, or resulting from or arising out of the provision of the Services under this Agreement.

(b) NPI shall indemnify, defend and hold harmless NEI and NPDI, their officers, directors, and employees (each a "**NEI or NPDI Indemnitee**") from and against any and all claims, demands, suits, losses, liabilities, damages, obligations, payments, costs and expenses and accrued interest thereon (including the costs and expenses of, and accrued interest in respect of, any and all actions, suits, proceedings, assessments, judgments, awards, settlements and compromises relating thereto and reasonable lawyers' fees and reasonable disbursements in connection therewith) (each an "**Indemnifiable Loss**"), asserted against or suffered by any NEI or NPDI Indemnitee relating to, or in connection with, or resulting from or arising out of the provision of the Services under this Agreement.

(c) NEI shall indemnify, defend and hold harmless NPI and NPDI, their officers, directors, and employees (each a "**NPI or NPDI Indemnitee**") from and against any and all claims, demands, suits, losses, liabilities, damages, obligations, payments, costs and expenses and accrued interest thereon (including the costs and expenses of, and accrued interest in respect of, any and all actions, suits, proceedings, assessments, judgments, awards, settlements and compromises relating thereto and reasonable lawyers' fees and reasonable disbursements in connection therewith) (each an "**Indemnifiable Loss**"), asserted against or suffered by any NPI or NPDI Indemnitee relating to, or in connection with, or resulting from or arising out of the provision of the Services under this Agreement.

(d) NEI shall be deemed to hold the provisions of **Sections 7.1(a)** and **7.1(b)** that are for the benefit of the NEI Indemnitees that are not party to this Agreement in trust for such persons as third party beneficiaries under this Agreement.

(e) NPDI shall be deemed to hold the provisions of **Section 7.1(b)** that are for the benefit of the NPDI Indemnitees that are not party to this Agreement in trust for such persons as third party beneficiaries under this Agreement.

7.2 Limit of Liability

(a) NPDI agrees that NEI's liability, if any, to NPDI or any third party in connection with or arising under this Agreement, including without limitation, any liability arising from any act or omission of NEI in the provision of the Services, whether arising in contract, tort, equity or otherwise, shall be limited to actions or liabilities resulting solely from the fraud or willful misconduct of NEI in the provision of the Services and shall not exceed an amount equal to the total amount paid by NPDI to NEI under this Agreement for Services over the twelve month period preceding the date that the cause of action or claim giving rise to the liability first arose.

(b) NEI agrees that the Other Parties' liability, if any, to NEI or any third party in connection with or arising under this Agreement, including without limitation, any liability arising from any act or omission of the Other Parties in the provision of the Services, whether arising in contract, tort, equity or otherwise, shall be limited to actions or liabilities resulting solely from the fraud or willful misconduct of the Other Parties in the provision of the Services and shall not exceed an amount equal to the total amount paid by NEI to the Other Parties under this Agreement for Services over the twelve month period preceding the date that the cause of action or claim giving rise to the liability first arose.

(c) The Parties shall not be liable for any damages caused by delay in delivering or furnishing any Services referred to in this Agreement.

7.3

a) Notwithstanding anything else to the contrary in this Agreement, the Parties agree that NPI shall not be responsible for any sanctions, fines, penalties, or similar obligations imposed on the Other Parties, and the Other Parties agree to indemnify and hold harmless NPI from any such sanctions fines, penalties or similar obligations.
b) Notwithstanding anything else to the contrary in this Agreement, the Parties agree that NPDI shall not be responsible for any sanctions, fines, penalties, or similar obligations imposed on the Other Parties, and the Other Parties agree to indemnify and hold harmless NPDI from any such sanctions fines, penalties or similar obligations.

c) Notwithstanding anything else to the contrary in this Agreement, the Parties agree that NEI shall not be responsible for any sanctions, fines, penalties, or similar obligations imposed on the Other Parties, and the Other Parties agree to indemnify and hold harmless NEI from any such sanctions fines, penalties or similar obligations.

ARTICLE 8
DEFAULT

8.1 Events of Default

The occurrence of any one or more of the following events shall constitute a Default by a Party (the **"Defaulting Party"**) under this Agreement and shall constitute an Event of Default if such Default is not remedied prior to the expiry of the relevant notice period (if any) and the relevant cure period (if any) applicable to such Default as hereinafter set out:

(a) if the Defaulting Party defaults in the payment of any amount due to the other Party under this Agreement and such default shall continue unremedied for sixty (60) days following notice in writing thereof to the Defaulting Party by the other Party; and/or

(b) if the Defaulting Party fails in any material respect to perform or observe any of its other material obligations under this Agreement and such failure shall continue unremedied for a period of sixty (60) days following notice in writing thereof (giving particulars of the failure in reasonable detail) from the other Party to the Defaulting Party or such longer period as may be reasonably necessary to cure such failure (if such failure is capable of being cured), provided that during such longer periods, the Defaulting Party;

(i) proceeds with all due diligence to cure or cause to be cured such failure; and

(ii) its proceedings can be reasonably expected to cure or cause to be cured such failure within a reasonable time frame acceptable to the other Party acting reasonably.

ARTICLE 9
REMEDIES

9.1 Default Remedies

Unless otherwise agreed to in writing, in the event of an Event of Default the non-defaulting Party may terminate this Agreement and all amounts payable by the defaulting Party hereunder shall become due and payable forthwith.

ARTICLE 10
TERMINATION

10.1 Termination

Where a non-defaulting Party wishes to terminate this agreement pursuant to, this Agreement shall terminate at the end of the fifth (5th) business day following any notice given pursuant to Section 10.2 below.

(a) in accordance with the provisions of **Section 9.1**;

10.2 Notice of Termination

Any termination hereof pursuant to **Section 10.1** shall be by written notice of the terminating Party.

ARTICLE 11
GENERAL

11.1 Force Majeure

No Party shall be liable for a failure or delay in the performance of its obligations pursuant to this Agreement:

(a) provided that such failure or delay could not have been prevented by reasonable precautions;

(b) provided that such failure or delay cannot reasonably be circumvented by the non-performing Party through the use of alternate sources, work around plans or other means; and

(c) if and to the extent such failure or delay is caused, directly or indirectly, by fire, flood, earthquake, elements of nature or acts of God, acts of war, terrorism, riots, civil disorders, rebellions, strikes, lock outs or labour disruptions or revolutions in Canada, or any other similar causes beyond the reasonable control of such Party, (each a "**Force Majeure Event**").

Upon the occurrence of a Force Majeure Event, the non-performing Party shall be excused from any further performance of those of its obligations pursuant to this Agreement affected by the Force Majeure Event only for so long as:

(a) such Force Majeure Event continues; and

(b) such Party continues to use commercially reasonable efforts to recommence performance whenever and to whatever extent possible without delay.

The Party delayed by a Force Majeure Event shall:

(a) immediately notify the other Parties by telephone (to be confirmed in writing within five (5) days of the inception of such delay) of the occurrence of a Force Majeure Event; and

(b) describe in reasonable detail the circumstances causing the Force Majeure Event.

11.2 Dispute Resolution

If any dispute arising in the performance of this agreement cannot be resolved by negotiation between the Parties involved in the dispute, then the dispute shall be referred to one arbitrator agreeable to and appointed by both of the Parties involved. If agreement on one arbitrator cannot be reached, the matter in dispute shall be referred to a panel of three arbitrators, one of which shall be appointed by each of the parties involved, and the third appointed by the two arbitrators selected by the two Parties. The arbitrator or arbitrators shall receive such oral and written evidence as may be required to investigate the matter in dispute and to render a decision. The arbitrators shall be guided by this Agreement and the intent of this Agreement. The decision of the arbitrator or arbitrators shall be provided in writing to the Parties involved no later than thirty (30) days after the sole arbitrator or the third arbitrator has been appointed. The decision of the arbitrator or arbitrators shall be final and binding on the Parties involved.

11.3 Assignment

No Party shall, without the written approval of the other Parties hereto, which may be arbitrarily withheld in the sole discretion of either of them, assign or transfer its interest in this Agreement. This Agreement shall be binding on the Parties and their respective successors and permitted assigns. Any purported assignment in contravention of this Agreement shall be void.

11.4 Notices

All notices, requests, approvals, consents and other communications required or permitted under this Agreement shall be in writing and addressed as follows:

(a) if to NEI,

Norfolk Energy Services Inc.
70 Victoria St., P.O. Box 207
Simcoe, Ontario
N3Y 4L1

Attn: Manager of Energy Services
Fax: (519) 426-6509

(b) if to NPI,

Norfolk Power Inc.
70 Victoria St., P.O. Box 588
Simcoe, Ontario
N3Y 4L1

Attn: CEO
Fax: (519) 426-6509

(c) if to NPDI,

Norfolk Power Distribution Inc.
70 Victoria St., P.O. Box 588
Simcoe, Ontario
N3Y 4L1

Attn: President
Fax: (905) 426-6509

and shall be sent by fax and the Party sending such notice shall telephone to confirm receipt. A copy of any such notice shall also be sent on the date such notice is transmitted by fax by registered express mail or courier with the capacity to verify receipt of delivery. Any Party may change its address or fax number for notification purposes by giving the other Party notice of the new address or fax number and the date upon which it will become effective in accordance with the terms of this Agreement. A notice shall be deemed to have been received as of the next Business Day following its transmission by fax.

11.5 Severability

If any provision of this Agreement is held by the Ontario Energy Board to be unenforceable or contrary to Law, then the remaining provisions of this Agreement, or the application of such provisions to persons or circumstances other than those as to which it is invalid or unenforceable shall not be affected thereby, and each such provision of this Agreement shall be valid and enforceable to the extent granted by Law. If any clause is deemed unenforceable or contrary to Law, the parties shall alter the said clause and this agreement to produce enforceability or compliance with Law such that the intent of the original clause is maintained and such change or alteration may be established through the dispute resolution clause in this Agreement.

11.6 Waiver

No delay or omission by a Party to exercise any right or power it has under this Agreement or to object to the failure of any covenant of any other Party to be performed in a timely and complete manner, shall impair any such right or power or be construed as a waiver of any succeeding breach or any other covenant. All waivers must be in writing and signed by the Party waiving its rights.

11.7 Entire Agreement

This Agreement constitutes the entire Agreement among the Parties with respect to the Services and there are no other representations, understandings or agreements, either oral or written, between the Parties other than as herein set forth.

11.8 Amendments

No amendment to, or change, waiver or discharge of, any provision of this Agreement shall be valid unless in writing and signed by authorized representatives of each Party.

11.9 Governing Law

This Agreement shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein. The Parties hereby agree that the courts of the Province of Ontario shall have exclusive jurisdiction over disputes under this Agreement, and the Parties agree that jurisdiction and venue in such courts is appropriate and irrevocably attorn to the jurisdiction of such courts.

11.10 Survival

The terms of **Article 7, Article 9** and **Article 11** shall survive the expiration of this Agreement or termination of this Agreement for any reason.

11.11 Third Party Beneficiaries

Each Party intends that this Agreement shall not benefit or create any right or cause of action in or on behalf of any person or entity other than the Parties.

11.12 Covenant of Further Assurances

The Parties agree that, subsequent to the execution and delivery of this Agreement and without any additional consideration, the Parties shall execute and deliver or cause to be executed and delivered any further legal instruments and perform any acts which are or may become necessary to effectuate the purposes of this Agreement and to complete the transactions contemplated hereunder.

IN WITNESS WHEREOF this Agreement has been executed by the duly authorized signatories of the parties hereto as of the date first written above.

NORFOLK POWER DISTRIBUTION INC.

Per: B Randall

Name: Brad Randall
Title: President & CEO

Per:

Name: John Dyck
Title: Chairman of the Board
Norfolk Power Distribution Inc

NORFOLK POWER INC.

Per: B Randall

Name: Brad Randall
Title: President & CEO

Per

Name: John Wells
Title: Chairman of the Board
Norfolk Power Inc.

NORFOLK ENERGY SERVICES INC.

Per:

Name: Tim Roberts
Title: Manager of Energy Services

Per

Name: Fred Ware
Title: Chairman of the Board
Norfolk Energy Services Inc

SCHEDULE A1

Description of Services

NPDI to NEI

Definition of Services

1. **"Management Related Services"**, if any, will include:

    (a) **Accounting Services:** Will include cash flow management, banking, payroll services, accounts payable/receivable services, management of customer deposits, taxation remittances, financial reporting, and other services as required.

    (b) **IT Services:** Will include maintaining plant records, updates and support, personal computer system support and communications support, as required.

    (c) **Management Services:** Will include strategic and financial planning, Board meeting preparation and attendance, human resources, and other services as required.

2. **"Water & Sewer Billing Services"**, if any, will include the provision and maintenance of all water & sewer billing, meter reading, customer interface, dispute resolution, bill payment and collections.

3. **"Street Light & Sentinel Light Services"**, if any, will include the installation and maintenance of sentinel and street lights in various locations as required by NEI.

4. **"Facilities Services"**, if any, will include all occupational services, PoP co-locate services and parking facilities.

    (a) Occupational services will include janitorial, mechanical including heating and ventilation and security service to maintain the agreed upon space which may be revised upon mutual consent from time to time.

    (b) Parking facilities will include sufficient space to allow for a single space for each NEI staff member and supplemental visitor accommodation. Ongoing access maintenance is also included.

    (c) Co-locate Service will include the rental of space, including associated utilities, to allow the occupation of PoP equipment within head office properties.

5. **"Purchasing & Inventory Services"**, if any, will include purchasing and of both stock and non-stock items including the issuing and handling of RFP's or RFQ's as well as storage support services (ie – stores management) for major materials.

6. **"Joint Use Pole Rental"**, if any, will include the rental of hydro poles for the attachment of fibre optic cable.

9. **"Dark Fibre Rental Services"**, if any, will include the provision of "dark" optical fibre to provide high speed communication links to remote equipment.

SCHEDULE A2

Description of Services

NEI to NPDI

Definition of Services

1. **"Conservation & Demand Management Consulting Services"**, if any, will include the administration, provision and regulatory reporting of all OPA programs across the NPDI service territory.

2. **"Dark Fibre Rental Services"**, if any, will include the provision of dark fibre pairs to provide high speed communication links to remote equipment and substations.

SCHEDULE A3

Description of Services

NPI to NPDI/NEI

Definition of Services

1. **"Management Oversight Services"**, if any, will include the general management, financial oversight and audit services of the affiliates to comply with regulatory and shareholder requirements.

SCHEDULE B

Description of Fees

	SERVICES	FEE METHODOLOGY	FEE FREQUENCY
A1-1	**Management Related Services**	Cost-Based Pricing	Costs allocated Monthly.
A1-2	**Water & Sewer Billing Services**	Cost-Based Pricing	Costs allocated Quarterly.
A1-4	**Street Light & Sentinel Light Services**	Cost-Plus Pricing	Billed Monthly
A1-6	**Facilities Services**	Market Price	Billed Monthly
A1-7	**Purchasing & Inventory Services**	Cost-Based Pricing	Costs allocated monthly.
A1-8	**Pole Rental**	Market Price	Billed Monthly
A1-9	**Dark Fibre Rental Services**	Market Price	Billed Monthly
A2-1	**Conservation & Demand Management Consulting Services**	Market Price	Billed Quarterly
A2-2	**Dark Fibre Rental Services**	Market Price	Billed Monthly
A3-1	**Management Oversight Services**	Cost-Based Pricing	Costs allocated Monthly

EXHIBIT 4

APPENDIX B

Norfolk Power Purchasing Policy

Norfolk Power Distribution Inc.
Policy & Procedures

SUBJECT: Purchasing Policy		
		No. Corporate Services #23
President & CEO: Fred Druyf Signature:		
Date: January 10, 2007	Revision#: 1	Page 1 of 4

General:

The Manager of Procurement & Facilities and Department Managers or designates are authorized to procure approved goods and services on behalf of the Corporation, subject to the following guidelines:

Details:

1. Law

   All procurement activity shall comply to applicable laws of the Province of Ontario and Dominion of Canada.

2. Conflict of Interest

   Only "arms length" transactions shall be permitted in the procurement of goods and services. For example, no purchases shall be made from any employee of the Corporation.

3. Co-operative Buying

   The Manager of Procurement & Facilities is authorized and encouraged to co-operate with Norfolk County and other LDCs in bulk buying in order to gain the benefits of volume purchasing.

4. Standardization

   The Manager of Procurement & Facilities is authorized and encouraged to simplify and standardize the various items used by different Departments subject to Engineering approval for materials subject to "Regulation 22/04" compliance. In addition, the Manager of Procurement & Facilities, along with Department Managers, shall strive to reduce the types of goods used to the smallest in number requiring the minimum investment in inventory.

5. Proposals

   Requests for proposals may be called when the requirement or services cannot be definitely or precisely specified.

6. Design and Development Services

Suppliers or potential suppliers shall not be requested to spend time, money or effort on design or in developing specifications or otherwise help define a requirement beyond the normal level of service expected from suppliers. Should such extraordinary services be required, then the company providing same, shall be compensated at a predetermined fee. The resulting specifications shall become the property of the Corporation for use in obtaining competitive bids.

7. Competitive Requirement

All purchases shall be made on a competitive basis whenever possible and be subject to the following guidelines:

Competitive Guidelines

- Purchases under $10,000 – Supported by published price lists or three (3) verbal quotes from competitive suppliers.
- Purchases from $10,000 to $50,000 - Supported by published price lists or three (3) written quotations from competitive suppliers.
- Purchases over $50,000 - At least three (3) written quotations from competitive suppliers.

8. Purchase by Negotiation

With the approval of the President & CEO, the Manager of Procurement and Facilities or Department Managers may negotiate purchases with suppliers and waive the requirements for written quotations under the circumstances noted below:

- When due to market conditions goods are in short supply.
- Where there is only one source of supply for the goods or services.
- Where two or more identical bids have been received.
- Where the lowest bid meeting specifications is excessive in total cost and/or substantially exceeds the estimated costs.
- When all bids received fail to meet the specifications.

9. Selection Criteria

The lowest ultimate cost shall be the key determining factor in selecting among competitive goods, services and suppliers. In cases where the competition is relatively equal, preference will be given to manufacturers and suppliers in the service area of Norfolk Power.

In determining the lowest ultimate cost, the following factors shall be considered along with the initial purchase price:

- Reliability and reputation of supplier
- Future operating cost and efficiency
- Standardization objectives
- Financing options
- Delivery times
- Repair service; availability and cost
- Other factors as appropriate

10. Approvals

All purchases must be approved in compliance to the following:

- Employees making miscellaneous small purchases shall be funded or reimbursed out of petty cash upon submission and proper approval of an expense voucher. Cash advances are allowed as required and controlled through the petty cash process. *(Purchases subject to regulation 22/04 are not allowed without Engineering approval.)*

- Employees authorized to use a Company credit card are required to provide detailed vouchers to support the monthly credit card invoice and obtain management approval before the credit card invoice is paid.

- The Manager of Procurement & Facilities shall approve all purchase orders related to replenishment of normal stock items.

- Department Managers shall approve all purchase requisitions or purchase orders related to budgeted non-stock items within their department. An approved purchase requisition is sufficient authority for the Manager of Procurement and Facilities to process and sign a related purchase order on behalf of the Department Manager who signed the related purchase requisition.

- **The President & CEO or designate shall approve all purchase orders related to:**
    - **Non-budget items (Budget transfer required)**
    - **Emergency purchases over $10,000 (i.e. storm repair)**
    - **Budget transfer items**
    - **Any purchase requiring special Board approval**

  The Board is to be informed about major non-budget or emergency purchases in a timely manner.

- Approval of Capital and Operating Budgets by the Board constitutes authorization for any purchase necessary to carry out such work. Selection of the product or supplier will be subject to the guidelines noted above.

11. Guidelines for Tendering *(if tendering considered necessary ie. for key components of a major capital project).*

All tenders shall be opened in the presence of three management employees of the Corporation.

Every tender received within the time specified in the tender documents shall be opened in full view of those attending and each Bidder's name and the tendered amounts(s) read aloud by the Manager of Procurement & Facilities, Department Manager or designate and subsequently recorded.

Request for tenders shall state that tenders will be received not later than 1200 hours on the specific day; and shall be opened at 1400 hours in the afternoon of the same day.

The Department Manager or designate shall analyze and evaluate all tenders and report the tender results to the President & CEO. Included in this report shall be a recommendation regarding tender acceptance and full disclosure regarding any tenders which did not comply with the Instruction to Bidders, specifications, terms or conditions.

12. Tender Award

The criteria to award a tender shall be as follows:

- Award will be to a bidder meeting specifications, terms and conditions of the tender and whose tender offers the lowest ultimate cost to the Corporation for the goods, equipment or services being tendered with due consideration of the importance of quality, delivery, service and price.

Note: For Capital Projects greater than $1,000,000: See Board Policy number 22 for special procedures and controls.

EXHIBIT 4

APPENDIX C

Draft Post-Retirement Benefit Report

Dion Durrell
Actuaries and Consultants

Dion, Durrell + Associates Inc.
250 Yonge Street, Suite 2900
Toronto, Ontario, Canada M5B 2L7
dion-durrell.com

T 416 408 2626
F 416 408 3721

MEMORANDUM

DATE: September 17, 2010
TO: Jody McEachran
FROM: Stanley Caravaggio
RE: Norfolk Power Distribution Inc. Post-Retirement Non-Pension Benefit Plan
Estimated FY 2011 Benefit Expense
COPY: Patrick Kavanagh

This memorandum provides you with our estimate of the FY 2011 benefit expense for the above noted benefit plan. This letter and attachment are intended solely for the use of Norfolk Power Distribution Inc. for the purpose of determining a benefit expense estimate for its 2011 rate application.

For the post-retirement non-pension plan, the FY 2011 benefit expense is estimated at approximately $110,000 with the supporting calculations summarized in the accounting worksheets hereby attached.

We have performed these calculations based on the following:

- **Plan provisions**: The plan provisions as summarized in our January 1, 2008 actuarial valuation report.
- **Data**: We have used the data as at January 1, 2008 which is summarized in the Report. You have confirmed that there has been no significant change in the membership data from the date of our Report to the current date. The roll forward of the Accrued Benefit Obligation ("ABO") has been calculated using the expected benefit payments for FY 2008, FY 2009, and FY 2010.
- **Assumptions**: A discount rate assumption of 5.50% per annum as at December 31, 2010 was used as management's best estimate assumption. All other assumptions as summarized in the Report were used to reflect management's best estimate assumptions at December 31, 2010.
- **Method**: We have done our calculations as at January 1, 2008 using the above information and the method described in the Report. The December 31, 2010 ABO is based on a roll forward of the January 1, 2008 results using management's best estimate assumptions as at December 31, 2010.
- **Accounting policy**: We have applied the same accounting policies described in the report, i.e. amortizing the amount of any gain or loss in excess of 10% of the accrued benefit obligation divided by the expected average remaining service lifetime of the active members of the group.

The calculations were performed in accordance with The Canadian Institute of Chartered Accountants (CICA) guidelines outlined in Employee Benefits, Section 3461 of the CICA Handbook – Accounting. As discussed, this estimate of the FY 2011 benefit expense is based on the assumptions and method described above and has been prepared for your rate filing purposes. We understand the actual benefit expense will be calculated as part of the next full triennial actuarial valuation scheduled for January 1, 2011.

If you have any questions regarding the above or the attached accounting schedules, please do not hesitate to call.

Norfolk Power Distribution Inc.
ESTIMATED BENEFIT EXPENSE (CICA 3461)
Draft

	Calendar Year 2010	Projected Calendar Year 2011
Discount Rate - January 1	6.00%	5.50%
Discount Rate - December 31	5.50%	5.50%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	8.00%

A. Determination of Benefit Expense

	Calendar Year 2010	Projected Calendar Year 2011
Current Service Cost	45,144	51,559
Interest on Benefits	46,281	48,812
Expected Interest on Assets	-	-
Past Service Cost	9,625	9,625
Transitional Obligation/(Asset)	-	-
Actuarial (Gain)/Loss	(8,361)	-
Benefit Expense	92,688	109,995

B. Reconciliation of Prepaid Benefit Asset (Liability)

	Calendar Year 2010		Projected Calendar Year 2011	
Accrued Benefit Obligation (ABO) as at December 31	852,247		919,975	
Assets as at December 31	-		-	
Unfunded ABO	(852,247)		(919,975)	
Unrecognized Loss/(Gain)	(82,926)		(82,926)	
Unrecognized Past Service Cost	67,372		57,747	
Unrecognized Transition	-		-	
Prepaid Benefit Asset (Liability)	(867,800)		(945,153)	
Prepaid Benefit/(Liability) as at January 1	(805,337)		(867,800)	
Benefit Income/(Expense)	(92,688)	62,463	(109,995)	77,352
Contributions/Benefit Payments by the Employer	30,225		32,643	
Prepaid Benefit Asset (Liability)	(867,800)		(945,153)	

* based on estimated employer benefit payments for those expected to be eligible for benefits.

Projected calendar year 2011 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2010.

Norfolk Power Distribution Inc.
ESTIMATED BENEFIT EXPENSE (CICA 3461)
Draft

	Calendar Year 2010	Projected Calendar Year 2011
Discount Rate - January 1	6.00%	5.50%
Discount Rate - December 31	5.50%	5.50%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	8.00%

C. Calculation of Component Items

	Calendar Year 2010	Projected Calendar Year 2011
Calculation of the Service Cost		
- Current service cost	45,144	51,559
Interest on Benefits		
- ABO at January 1	741,312	852,247
- Current service cost	45,144	51,559
- Benefit payments	(15,112)	(16,321)
- Accrued benefits	771,344	887,484
- Interest	46,281	48,812
Expected Interest on Assets		
- Assets at January 1	-	-
- Funding	15,112	16,321
- Benefit payments	(15,112)	(16,321)
- Expected assets	-	-
- Interest	-	-
Expected ABO as at December 31		
- ABO at January 1	741,312	852,247
- Current service cost	45,144	51,559
- Interest on benefits	46,281	48,812
- Benefit payments	(30,225)	(32,643)
- Expected ABO at December 31	802,512	919,975
Expected Assets as at December 31		
- Assets at January 1	-	-
- Funding	30,225	32,643
- Interest on assets	-	-
- Benefit payments	(30,225)	(32,643)
- Expected Assets at December 31	-	-

Projected calendar year 2011 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2010.

Norfolk Power Distribution Inc.
ESTIMATED BENEFIT EXPENSE (CICA 3461)
Draft

	Calendar Year 2010	Projected Calendar Year 2011
Discount Rate - January 1	6.00%	5.50%
Discount Rate - December 31	5.50%	5.50%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	8.00%

D. Actuarial (Gain)/Loss

	Calendar Year 2010	Projected Calendar Year 2011
(Gain)/Loss on ABO as at January 1		
- Prepaid Benefit/(Liability)	805,337	867,800
- Unamortized (Gain)/Loss From Prior Year	(141,021)	(82,926)
- Unamortized Past Service Costs	76,996	67,372
- Expected ABO	741,312	852,247
- Actual ABO	741,312	852,247
- (Gain)/Loss on ABO	-	-
(Gain)/Loss on assets as at January 1		
- Expected assets	-	-
- Actual assets	-	-
- (Gain)/Loss on assets	-	-
Total (Gain)/Loss as at January 1	(141,021)	(82,926)
10% of ABO as at January 1	74,131	85,225
Total (Gain)/Loss in excess of 10%	(66,890)	-
Expected average remaining service life (years)	8	7
Minimum Amortization for current year	(8,361)	-
Actual Amortization for current year	(8,361)	-
(Gain)/Loss on ABO at December 31		
- Expected ABO - December 31	802,512	
- Actual ABO - December 31	852,247	
- (Gain)/Loss on ABO	49,734	
Unamortized (Gain)/Loss at December 31	(82,926)	(82,926)

E. Amortization of Past Service Costs

	Calendar Year 2010	Projected Calendar Year 2011
Unamortized past service costs as at beginning of period	76,996	67,372
Period over which past service costs are to be amortized (years)	8	7
Actual Amortization for current period	9,625	9,625
Unamortized past service costs as at the end of period	67,372	57,747

Projected calendar year 2011 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2010.

EXHIBIT 4

APPENDIX D

2010 Federal & Ontario
Tax Return

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

EXEMPT FROM TAX

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Ontario (for tax years ending before 2009), Quebec, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, paragraphs, and subparagraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see www.cra.gc.ca or Guide T4012, *T2 Corporation – Income Tax Guide*.

055 Do not use this area

KEEP THIS COPY FOR YOUR RECORDS
MILLARD ROUSE AND ROSEBRUGH LLP
SIMCOE, ONTARIO

Identification

Business Number (BN) 001 86289 2593 RC0001

Corporation's name
002 NORFOLK POWER DISTRIBUTION INC

Address of head office
Has this address changed since the last time you filed your T2 return? . . . . 010 1 Yes [ ] 2 No [X]
(If yes, complete lines 011 to 018.)
011 PO BOX 588
012 70 VICTORIA ST
City 015 SIMCOE
Province, territory, or state 016 ON
Country (other than Canada) 017
Postal code/Zip code 018 N3Y 4N6

Mailing address (if different from head office address)
Has this address changed since the last time you filed your T2 return? . . . . 020 1 Yes [ ] 2 No [X]
(If yes, complete lines 021 to 028.)
021 c/o
022
023
City 025
Province, territory, or state 026
Country (other than Canada) 027
Postal code/Zip code 028

Location of books and records
Has the location of books and records changed since the last time you filed your T2 return? . . . . 030 1 Yes [ ] 2 No [X]
(If yes, complete lines 031 to 038.)
031 70 VICTORIA ST
032
City 035 SIMCOE
Province,territory, or state 036 ON
Country (other than Canada) 037
Postal code/Zip code 038 N3Y 4N6

040 Type of corporation at the end of the tax year
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 ______ YYYY MM DD

To which tax year does this return apply?
Tax year start 060 2010-01-01 YYYY MM DD
Tax year-end 061 2010-12-31 YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . 063 1 Yes [ ] 2 No [X]
If yes, provide the date control was acquired . . . . 065 ______ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? . . . . 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? . . . . 070 1 Yes [ ] 2 No [X]
Amalgamation? . . . . 071 1 Yes [ ] 2 No [X]
If yes, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . 072 1 Yes [ ] 2 No [X]
If yes, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used . . . . 079 ______

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If no, give the country of residence on line 081 and complete and attach Schedule 97.
081 ______

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . 082 1 Yes [ ] 2 No [X]
If yes, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [X] Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.

Schedules – Answer the following questions. For each **Yes** response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	———
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X
Has the major business activity changed since the last return was filed? (enter yes for first-time filers)	281		X

What is the corporation's major business activity? **282** ______
(Only complete if yes was entered at line 281)

If the major business activity involves the resale of goods, show whether it is wholesale or retail **283** 1 Wholesale ☐ 2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

			%
284	ELECTRICITY	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible **294** ______ YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? **295** 1 Yes ☐ 2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		1,768,685	A
Deduct: Charitable donations from Schedule 2	311			
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal				B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			1,768,685	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		1,768,685	
Income exempt under paragraph 149(1)(t)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				Z

* This amount is equal to 3.2 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . . **400** 1,768,685 A

Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 1/(.38 minus X**) 3.57143 times the amount on line 636***, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . . . **405** ______ B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

400,000	x	Number of days in the tax year before 2009 / Number of days in the tax year	/ 365	=		1
500,000	x	Number of days in the tax year after 2008 / Number of days in the tax year	365 / 365	=	500,000	2
			Add amounts at lines 1 and 2		500,000	4

Business limit (see notes 1 and 2 below) . . . . . **410** 500,000 C

Notes: 1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x **415** **** 97,761 D / 11,250 = ... 4,344,933 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . **425** ______ F

Small business deduction

Amount A, B, C, or F whichever is the least ______ x 17 % = ... **430** ______ G

Enter amount G on line 1.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** General rate reduction percentage for the tax year. This has to be pro-rated.

*** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

**** **Large corporations**

- If the corporation is not associated with any corporations in both the current and the previous tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360			A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		B	
Amount QQ from Part 13 of Schedule 27		C	
Amount used to calculate the credit union deduction from Schedule 17		D	
Amount from line 400, 405, 410, or 425, whichever is the least		E	
Aggregate investment income from line 440*		F	
Total of amounts B to F		▶	G
Amount A **minus** amount G (if negative, enter "0")			H

Amount H		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	I
Amount H		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	J
Amount H		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	365 / 365	x	10 %	=	K
Amount H		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	L
Amount H		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	L.1

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L.1 .... M
Enter amount M on line 638.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		O	
Amount QQ from Part 13 of Schedule 27		P	
Amount used to calculate the credit union deduction from Schedule 17		Q	
Total of amounts O to Q		▶	R
Amount N **minus** amount R (if negative, enter "0")			S

Amount S		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	T
Amount S		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	U
Amount S		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	365 / 365	x	10 %	=	V
Amount S		x	Number of days in the tax year after December 31, 2010, and before January 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	W
Amount S		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	W.1

General tax reduction – Total of amounts T to W.1 X
Enter amount X on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ____ x 26 2 / 3 % = ... ____ A

Foreign non-business income tax credit from line 632 . . . . ____

Deduct:

Foreign investment income from Schedule 7 . . . . **445** ____ x 9 1 / 3 % = ____

(if negative, enter "0") ____ ▶ ____ B

Amount A **minus** amount B (if negative, enter "0") . . . . ____ C

Taxable income from line 360 1,768,685

Deduct:

Amount from line 400, 405, 410, or 425, whichever is the least . . . . . ____

Foreign non-business income tax credit from line 632 . . . . ____ x 25 / 9 = ____

Foreign business income tax credit from line 636 . . . . ____ x 1(.38 - X*) 3.57143 = ____

____ ▶ ____

1,768,685

x 26 2 / 3 % = 471,649 D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) . . . . ____ E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least . . . . **450** ____ F

* General rate reduction percentage for the tax year. This has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . **460** ____

Deduct: Dividend refund for the previous tax year . . . . **465** ____

____ ▶ ____ G

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . ____

Total Part IV tax payable from Schedule 3 . . . . ____

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . **480** ____

____ ▶ ____ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H . . . . **485** ____

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3 . . . . 835,211 x 1 / 3 278,404 I

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . ____ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784) . . . . ____

Part I tax

Base amount of Part I tax – Taxable income (line 360 or amount Z, whichever applies) multiplied by 38.00 %			550	A
Recapture of investment tax credit from Schedule 31			602	B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income (if it was a CCPC throughout the tax year)

Aggregate investment income from line 440			i
Taxable income from line 360	1,768,685		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	1,768,685 ▶	1,768,685	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604	C
Subtotal (add lines A to C)		D

Deduct:

Small business deduction from line 430			1
Federal tax abatement	608		
Manufacturing and processing profits deduction from Schedule 27	616		
Investment corporation deduction	620		
Taxed capital gains 624			
Additional deduction – credit unions from Schedule 17	628		
Federal foreign non-business income tax credit from Schedule 21	632		
Federal foreign business income tax credit from Schedule 21	636		
General tax reduction for CCPCs from amount M	638		
General tax reduction from amount X	639		
Federal logging tax credit from Schedule 21	640		
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652		
Subtotal		▶	E

Part I tax payable – Line D minus line E	F

Enter amount F on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Ontario [for tax years ending before 2009], Quebec, and Alberta)	760	
Provincial tax on large corporations (New Brunswick* and Nova Scotia)	765	
Total tax payable	770	A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	B

Refund code 894 1 Overpayment

Balance (line A **minus** line B)

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

Certification

I, 950 BRAD (Last name in block letters) 951 RANDALL (First name in block letters) 954 PRESIDENT & CEO (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2011-04-26 Date (yyyy/mm/dd) — Signature of the authorized signing officer of the corporation — 956 (519) 426-4440 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☒ 2 No ☐

958 Name in block letters 959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
NORFOLK POWER DISTRIBUTION INC	86289 2593 RC0001	2010-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				1,999,889 A
Add:				
Provision for income taxes – current		101	531,000	
Amortization of tangible assets		104	2,702,963	
Loss on disposal of assets		111	3,138	
Reserves from financial statements – balance at the end of the year		126	1,820,375	
Subtotal of additions			5,057,476 ▶	5,057,476
Other additions:				
Miscellaneous other additions:				
OITC/ORDTC/BCRDTC/ABRDTC from prior year - 12(1)(x)	10,000			
Total	10,000	293	10,000	
604				
Subtotal of other additions		199	10,000 ▶	10,000
Total additions		500	5,067,476 ▶	5,067,476
Deduct:				
Capital cost allowance from Schedule 8		403	3,409,012	
Cumulative eligible capital deduction from Schedule 10		405	15,508	
Reserves from financial statements – balance at the beginning of the year		414	1,874,160	
Subtotal of deductions			5,298,680 ▶	5,298,680
Other deductions:				
Miscellaneous other deductions:				
704				
Total		394		
Subtotal of other deductions		499	0 ▶	0
Total deductions		510	5,298,680 ▶	5,298,680
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				1,768,685

* For reference purposes only

T2 SCH 1 E (09)

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
NORFOLK POWER DISTRIBUTION INC	86289 2593 RC0001	2010-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act*.
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return.*
- "X" under column A if dividend received from a foreign source (connected corporation only).
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

	Name of payer corporation (from which the corporation received the dividend) 200	A	B Enter 1 if payer corporation is connected 205 (Complete if payer corporation is connected)	C Business Number of connected corporation 210 (Complete if payer corporation is connected)	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD 220 (Complete if payer corporation is connected)	E Non-taxable dividend under section 83 230
1			2			
					Total (enter on line 402 of Schedule 1)	

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.

	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240	F1 Eligible dividends (included in column F)	F2	G Total taxable dividends paid by connected payer corporation (for tax year in column D) 250 (Complete if payer corporation is connected)	H Dividend refund of the connected payer corporation (for tax year in column D)** 260 (Complete if payer corporation is connected)	I Part IV tax before deductions F x 1 / 3 *** 270
1						
Total						J

Total (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)		
Deduct:		
Part IV.I tax payable on dividends subject to Part IV tax	320	
	Subtotal	
Deduct:		
Current-year non-capital loss claimed to reduce Part IV tax	330	
Non-capital losses from previous years claimed to reduce Part IV tax	335	
Current-year farm loss claimed to reduce Part IV tax	340	
Farm losses from previous years claimed to reduce Part IV tax	345	
Total losses applied against Part IV tax	x 1 / 3 =	
Part IV tax payable (enter amount on line 712 of the T2 return)	360	

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

	A	B	C	D	D1
	Name of connected recipient corporation 400	Business Number 410	Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	Taxable dividends paid to connected corporations 430	Eligible dividends (included in column D)
1	NORFOLK POWER INC	88974 1211 RC0001	2010-12-31	835,211	835,211
2					

Note

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation.

Total		835,211
Total taxable dividends paid in the tax year to other than connected corporations	450	
Eligible dividends (included in line 450)	450a	
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450)	460	835,211

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)			835,211
Other dividends paid in the tax year (total of 510 to 540)			
Total dividends paid in the tax year		500	835,211
Deduct:			
Dividends paid out of capital dividend account	510		
Capital gains dividends	520		
Dividends paid on shares described in subsection 129(1.2)	530		
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540		
Subtotal		▶	
Total taxable dividends paid in the tax year that qualify for a dividend refund			835,211

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
NORFOLK POWER DISTRIBUTION INC	86289 2593 RC0001	2010-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number (See Note)	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year)	3 Cost of acquisitions during the year (new property must be available for use)*	4 Net adjustments**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)***	7 Reduced undepreciated capital cost	8 CCA rate %	9 Recapture of capital cost allowance (line 107 of Schedule 1)	10 Terminal loss (line 404 of Schedule 1)	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)****	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11)
	200		201	203	205	207	211		212	213	215	217	220
1.	1	ELECTRIC DISTRIB.	26,502,108			0		26,502,108	4	0	0	1,060,084	25,442,024
2.	3	BUILDINGS	2,726,959	96,011		0	48,006	2,774,964	5	0	0	138,748	2,684,222
3.	8	GENERAL EQUIPMENT	783,499	582,226		0	291,113	1,074,612	20	0	0	214,922	1,150,803
4.	10	VEHICLES	213,125	75,784		41,663	17,061	230,185	30	0	0	69,056	178,190
5.	10	COMPUTER HARDWARE	107,158			0		107,158	30	0	0	32,147	75,011
6.	12	COMPUTER APPLICATION SOFT	28,017	35,884		0		63,901	100	0	0	63,901	
7.	45	COMPUTERS & SYSTEMS	29,490			0		29,490	45	0	0	13,271	16,219
8.	47	DISTRIBUTION SYSTEM POST 2	17,443,816	8,663,090		0	4,331,545	21,775,361	8	0	0	1,742,029	24,364,877
9.	50	SYSTEMS & SYSTEMS SOFTWAR	56,015			0		56,015	55	0	0	30,808	25,207
10.	52	SYSTEMS & SYSTEMS SOFTWAR		44,046		0		44,046	100	0	0	44,046	
		Total	47,890,187	9,497,041		41,663	4,687,725	52,657,840				3,409,012	53,936,553

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) plus or minus certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
N OLK POWER DISTRIBUTION INC	86289 2593 RC0001	2010-12-31

This schedule is to be completed by a corporation having one or more of the following:
- related corporation(s)
- associated corporations(s)

	Name 100	Country of residence (if other than Canada) 200	Business Number (Canadian corporation only) (see note 1) 300	Relationship code (see note 2) 400	Number of common shares owned 500	% of common shares owned 550	Number of preferred shares owned 600	% of preferred shares owned 650	Book value of capital stock 700
1.	NORFOLK POWER INC		88974 1211 RC0001	1	1,000	100.000			22,768,898
2.	NORFOLK ENERGY INC		86289 0399 RC0001	3					

Note 1: Enter "NR" if a corporation is not registered.

Note 2: Enter the code number of the relationship that applies from the following order: 1 – Parent 2 – Subsidiary 3 – Associated 4 – Related, but not associated.

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
NORFOLK POWER DISTRIBUTION INC	86289 2593 RC0001	2010-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") **200** 221,547 A

Add: Cost of eligible capital property acquired during the taxation year **222** ______

Other adjustments **226** ______

Subtotal (line 222 plus line 226) ______ x 3 / 4 = ______ B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 **228** ______ x 1 / 2 = ______ C

amount B minus amount C (if negative, enter "0") ______ ▶ ______ D

Amount transferred on amalgamation or wind-up of subsidiary **224** ______ E

Subtotal (add amounts A, D, and E) **230** 221,547 F

Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year **242** ______ G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) **244** ______ H

Other adjustments **246** ______ I

(add amounts G,H, and I) ______ x 3 / 4 = **248** ______ J

Cumulative eligible capital balance (amount F minus amount J) 221,547 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business **249** ______

amount K 221,547

less amount from line 249 ______

Current year deduction 221,547 x 7.00 % = **250** 15,508 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 15,508 ▶ 15,508 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") **300** 206,039 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400	1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401	2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402	3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408	4			
Line 3 minus line 4 (if negative, enter "0")		▶		5	
Total of lines 1, 2 and 5				6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8			
Subtotal (line 7 plus line 8)	409	▶		9	
Line 6 minus line 9 (if negative, enter "0")				▶	O
Line N minus line O (if negative, enter "0")					P
Line 5 ____ x 1 / 2 =					Q
Line P minus line Q (if negative, enter "0")					R
Amount R ____ x 2 / 3 =					S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				410	

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Add	Deduct	Balance at the end of the year
1	REGULATORY LIABILITIES	1,068,823		952,575	1,068,823	952,575
2	RETIREMENT BENEFITS	805,337		867,800	805,337	867,800
3						
	Reserves from Part 2 of Schedule 13					
	Totals	1,874,160		1,820,375	1,874,160	1,820,375

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- F[illegible]e by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated c[illegible]ation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

All[illegible]ating the business limit

Date filed (do not use this area) . . . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . . . **050** Year 2010

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . . **075** 1 Yes [ ] 2 No [X]

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**	
1	NORFOLK POWER DISTRIBUTION INC	86289 2593 RC0001	1	500,000	100.0000	500,000	
2	NORFOLK POWER INC	88974 1211 RC0001	1	500,000			
3	NORFOLK ENERGY INC	86289 0399 RC0001	1	500,000			
				Total	100.0000	500,000	A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* [illegible] corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, [illegible]e the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
NORFOLK POWER DISTRIBUTION INC	86289 2593 RC0001	2010-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	NORFOLK POWER INC	88974 1211 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
N OLK POWER DISTRIBUTION INC	86289 2593 RC0001	2010-12-31

On: 2010-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 — 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year			100	4,914,952 A
Taxable income for the year (DICs enter "0") *	110	B		
Income for the credit union deduction * (amount E in Part 3 of Schedule 17)	120			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less *	130			
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140			
Subtotal (add lines 120, 130, and 140)		C		
Income taxable at the general corporate rate (line B minus line C) (if negative enter "0")	150			
After-tax income (line 150 x general rate factor for the tax year ** 0.69)			190	D
Eligible dividends received in the tax year	200			
Dividends deductible under section 113 received in the tax year	210			
Subtotal (add lines 200 and 210)				E
GRIP addition:				
Becoming a CCPC (line PP from Part 4)	220			
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230			
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240			
Subtotal (add lines 220, 230, and 240)			290	F
Subtotal (add lines A, D, E, and F)				4,914,952 G
Eligible dividends paid in the previous tax year	300	300,000		
Excessive eligible dividend designations made in the previous tax year	310			

Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.

Subtotal (line 300 minus line 310)		300,000		300,000 H
GRIP before adjustment for specified future tax consequences (line G minus line H) (amount can be negative)			490	4,614,952
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)			560	
GRIP at the end of the tax year (line 490 **minus** line 560)			590	4,614,952

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2009-12-31

Taxable income before specified future tax consequences from the current tax year		2,764,791 J1	
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L1		
Aggregate investment income (line 440 of the T2 return)	M1		
Subtotal (add lines K1, L1, and M1)		N1	
Subtotal (line J1 minus line N1) (if negative, enter "0")		2,764,791	2,764,791 O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . ______ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R1

Aggregate investment income (line 440 of the T2 return) . . . . ______ S1

Subtotal (add lines Q1, R1, and S1) ______ ► ______ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ______ ► ______ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ______ V1

GRIP adjustment for specified future tax consequences to the first previous tax year

(line V1 **multiplied by** the general rate factor for the tax year 0.68) . . . . **500** ______

Second previous tax year 2008-12-31

Taxable income before specified future tax consequences from the current tax year 1,853,769 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L2

Aggregate investment income (line 440 of the T2 return) . . . . ______ M2

Subtotal (add lines K2, L2, and M2) ______ ► ______ N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 1,853,769 ► 1,853,769 O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . ______ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R2

Aggregate investment income (line 440 of the T2 return) . . . . ______ S2

Subtotal (add lines Q2, R2, and S2) ______ ► ______ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ______ ► ______ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ______ V2

GRIP adjustment for specified future tax consequences to the second previous tax year

(line V2 **multiplied by** the general rate factor for the tax year 0.68) . . . . **520** ______

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2007-12-31

Taxable income before specified future tax consequences from the current tax year . . . 1,187,526 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ________ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . ________ L3

Aggregate investment income (line 440 of the T2 return) . . . 37,566 M3

Subtotal (add lines K3, L3, and M3) 37,566 ▶ 37,566 N3

Subtotal (line J3 minus line N3) (if negative, enter "0") 1,149,960 ▶ 1,149,960 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . ________ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ________ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . ________ R3

Aggregate investment income (line 440 of the T2 return) . . . ________ S3

Subtotal (add lines Q3, R3, and S3) ________ ▶ ________ T3

Subtotal (line P3 minus line T3) (if negative, enter "0") ________ ▶ ________ U3

Subtotal (line O3 minus line U3) (if negative, enter "0") ________ V3

GRIP adjustment for specified future tax consequences to the third previous tax year
(line V3 **multiplied by** the general rate factor for the tax year 0.68) . . . **540** ________

Total GRIP adjustment for specified future tax consequences to previous tax years:
(add lines 500, 520, and 540) (if negative, enter "0") . . . ________ W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . ________ AA

Eligible dividends paid by the corporation in its last tax year . . . ________ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . ________ CC

Subtotal (line BB **minus** line CC) ________ ▶ ________ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)
(line AA **minus** line DD) . . . ________ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Co[illegible] this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and [illegible] predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . ________ FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . ________ GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses . . . . ________
Net capital losses . . . . ________
Farm losses . . . . ________
Restricted farm losses . . . . ________
Limited partnership losses . . . . ________

Subtotal ________ ▶ ________ HH

Subtotal (add lines FF, GG, and HH) ________ II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . ________ JJ

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . ________ KK

All the corporation's reserves deducted in its previous/last tax year . . . . ________ LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . ________ MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . ________ NN

Subtotal (add lines JJ, KK, LL, MM, and NN) ________ ▶ ________ OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (line II minus line OO) (if negative, enter "0") . . . . ________ PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year. Calculate your results to four decimal places.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	/ 365	=		QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	365 / 365	=	0.6900	RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	/ 365	=		SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	/ 365	=		TT

General rate factor for the tax year (total of lines QQ to TT) .... 0.6900 UU

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
NORFOLK POWER DISTRIBUTION INC	86289 2593 RC0001	2010-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation,* or Schedule 54, *Low Rate Income Pool Calculation (LRIP)*; whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- Parts, subsections, and paragraphs mentioned in this schedule refer to the *Income Tax Act.*
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3		835,211			
Total taxable dividends paid in the tax year	100	835,211			
Total eligible dividends paid in the tax year			150	835,211	
GRIP at the end of the year (line 590 on Schedule 53) (if negative, enter "0")			160	4,614,952	
Excessive eligible dividend designation (line 150 **minus** line 160)					A
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (line A **multiplied** by 20%)		x 20 %	190		

Enter the amount from line 190 at line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3					
Total taxable dividends paid in the tax year	200				
Total excessive eligible dividend designations in the tax year (line A of Schedule 54)					B
Part III.1 tax on excessive eligible dividend designations – Other corporations (line B **multiplied** by 20%)		x 20 %	290		

Enter the amount from line 290 at line 710 of the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
N..RFOLK POWER DISTRIBUTION INC	86289 2593 RC0001	2010-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
NORFOLK POWER DISTRIBUTION INC

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent — Year Month Day	**120** Ontario Corporation No.
Ontario	1999-11-03	1371939

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)
PO BOX 588

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
70	VICTORIA ST	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
SIMCOE	ON	CA	N3Y 4N6

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca.**

300 [1] If there have been no changes, enter 1 in this box and then go to "Part 4 – Certification."
If there are changes, enter 2 in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 BRAD — Last name
451 RANDALL — First name

454 ______________, Middle name(s)

460 [3] Please enter one of the following numbers in this box for the above-named person: 1 for director, 2 for officer, or 3 for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter 1 or 2.

No...ctions 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number **530** Street name/Rural route/Lot and Concession number **540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town) **570** Province/state **580** Country **590** Postal/zip code

Part 6 – Language of preference

600 Indicate your language of preference by entering 1 for English or 2 for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

OVERVIEW:

The purpose of this evidence is to summarize the method and cost of financing capital requirements for the 2012 test years.

Capital Structure:

Norfolk has a current deemed capital structure of 4% short term debt with a return of 2.07%, 56% long-term debt with a return of 5.81%, and 40% equity with a return of 8.57% as approved in the 2010 IRM rate decision (EB-2009-0238).

Norfolk has prepared this rate application with a deemed capital structure of 56% Long Term Debt with a return of 5.51%, 4% Short Term Debt with a return of 2.46%, and 40% Equity with a return of 9.58%.

Return on Equity:

Norfolk is requesting a return on equity ("ROE") for the 2012 Test year of 9.58% in accordance with the Cost of Capital Parameter Updates for 2011 Cost of Service Applications issued by the OEB on March 3, 2011. Norfolk understands that the OEB will be finalizing the ROE for 2012 rates based on January 2012 market interest rate information. Norfolk's use of an ROE of 9.58% is without prejudice to any revised ROE that may be adopted by the OEB in early 2012.

COST OF DEBT:

Long Term Debt

Norfolk is requesting a return on Long Term Debt for the 2011 Test Year of 5.51%. Norfolk is currently paying rates varying from 6.02 to 7.00% on existing Long Term Loans negotiated with TD Bank and rates varying from 3.72% to 5.01% for existing debentures negotiated with Infrastructure Ontario. On September 1, 2010, (2) new debentures were negotiated with Infrastructure Ontario. These debentures related to 2009 capital projects: a $5.6M debenture for the Bloomsburg MTS project and a $2.4M debenture for the Smart Meter project. During the later part of 2010 and to date Norfolk has borrowed $4.5M from the TD Bank via

Bankers Acceptances which revolve on a 30 to 90 day basis. Norfolk has recently concluded negotiations to borrow $6.0M from Infrastructure Ontario. Norfolk anticipates drawing $4.5M of the $6.0M by September 15, 2011 to repay the TD Bank loan. The remaining $1.5M will be used to fund various capital projects over the next 6 – 12 months. Norfolk plans to complete the new financing by June 30, 2012. This loan has been included in the weighted average cost of debt at a rate of 4.39%, which is the current indicative rate from Infrastructure Ontario for a 25 year loan.

Short Term Debt

Norfolk is requesting a return on Short Term Debt for the 2012 Test year of 2.46% in accordance with the Cost of Capital Parameter Updates for 2011 Cost of Service Applications issued by the OEB on March 3, 2011. Norfolk understands that the OEB will be finalizing the return on short term debt for 2012 rates based on January 2012 market interest rate information. Norfolk's use of a Return on Short Term Debt of 2.47% is without prejudice to any revised Short Term Debt rate that may be adopted by the OEB in early 2012.

Rate Base and Rate of Return

Table 1.1 of Exhibit 5, Tab 1, Schedule 2 details Norfolk's rate base, deemed debt/equity ratios, deemed rate of return, actual debt/equity ratios and actual rates of returns for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, and 2011 Bridge and 2012 Test Year Forecast.

CAPITAL STRUCTURE DEEMED & ACTUAL

Table 1.1 – Deemed Capital Structure 2008 to 2012

Deemed Capital Structure for 2008 - Board Approved

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	23,738,837	49.30%	6.10%	1,448,069
Unfunded Short Term Debt	1,926,072	4.00%	4.47%	86,095
Total Debt	25,664,909	53.30%		1,534,164
Common Share Equity	22,486,891	46.70%	8.57%	1,927,127
Total equity	22,486,891	46.70%		1,927,127
Total Rate Base	48,151,800	100.00%	7.19%	3,461,291

Deemed Capital Structure for 2009

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	25,228,235	52.70%	6.50%	1,638,819
Unfunded Short Term Debt	1,914,857	4.00%	4.47%	85,594
Total Debt	27,143,092	56.70%		1,724,413
Common Share Equity	20,728,322	43.30%	8.57%	1,776,417
Total equity	20,728,322	43.30%		1,776,417
Total Rate Base	47,871,414	100.00%	7.31%	3,500,831

Deemed Capital Structure for 2010

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	28,947,926	56.00%	5.81%	1,682,167
Unfunded Short Term Debt	2,067,709	4.00%	4.47%	92,427
Total Debt	31,015,635	60.00%		1,774,593
Common Share Equity	20,677,090	40.00%	8.57%	1,772,027
Total equity	20,677,090	40.00%		1,772,027
Total Rate Base	51,692,725	100.00%	6.86%	3,546,620

Deemed Capital Structure for 2011

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	31,241,037	56.00%	5.81%	1,814,684
Unfunded Short Term Debt	2,231,503	4.00%	4.47%	99,748
Total Debt	33,472,540	60.00%		1,914,432
Common Share Equity	22,315,026	40.00%	9.85%	2,198,030
Total equity	22,315,026	40.00%		2,198,030
Total Rate Base	55,787,566	100.00%	7.37%	4,112,462

Deemed Capital Structure for 2012

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	33,406,052	56.00%	5.51%	1,840,844
Unfunded Short Term Debt	2,386,147	4.00%	2.46%	58,699
Total Debt	35,792,199	60.00%		1,899,543
Common Share Equity	23,861,466	40.00%	9.58%	2,285,928
Total equity	23,861,466	40.00%		2,285,928
Total Rate Base	59,653,664	100.00%	7.02%	4,185,471

1 **Table 1.2 – Capital Structure Rate Base Calculations**

2007

Description	Deemed Portion	Effective Rate
Long-Term Debt	50.00%	6.49%
Short-Tern Debt		
Return On Equity	50.00%	8.57%
Weighted Debt Rate		6.49%
Regulated Rate of Return		7.53%

2008 BOARD APPROVED

Description	Deemed Portion	Effective Rate
Long-Term Debt	49.30%	6.10%
Short-Tern Debt	4.00%	4.47%
Return On Equity	46.70%	8.57%
Weighted Debt Rate		5.98%
Regulated Rate of Return		7.19%

WORKING CAPITAL ALLOWANCE FOR 2007

Distribution Expenses	
Distribution Expenses - Operation	1,262,270
Distribution Expenses - Maintenance	943,238
Billing and Collecting	1,017,402
Community Relations	114,332
Administrative and General Expenses	1,361,535
Taxes Other than Income Taxes	155,724
Less: Capital Taxes within 6105	90,000
Total Eligible Distribution Expenses	**4,764,500**
Power Supply Expenses	27,907,475
Total Working Capital Expenses	32,671,975
Working Capital Allowance rate of 15%	4,900,796

WORKING CAPITAL ALLOWANCE FOR 2008 (B.A.)

Distribution Expenses	
Distribution Expenses - Operation	1,201,788
Distribution Expenses - Maintenance	718,374
Billing and Collecting	982,644
Community Relations	27,069
Administrative and General Expenses	1,323,498
Taxes Other than Income Taxes	-
Less: Capital Taxes within 6105	0
Total Eligible Distribution Expenses	**4,253,373**
Power Supply Expenses	29,054,426
Total Working Capital Expenses	33,307,799
Working Capital Allowance rate of 15%	4,996,170

RATE BASE CALCULATION FOR 2007

Fixed Assets Opening Balance 2007	38,400,332
Fixed Assets Closing Balance 2007	41,040,572
Average Fixed Asset Balance for 2007	39,720,452
Working Capital Allowance	4,900,796
Rate Base	44,621,248
Regulated Rate of Return	7.53%
Regulated Return on Capital	3,359,479
Deemed Interest Expense	1,447,459
Deemed Return on Equity	1,912,020

RATE BASE CALCULATION FOR 2008 (B.A.)

Fixed Assets Opening Balance 2008 B.A.	41,528,375
Fixed Assets Closing Balance 2008 B.A	44,782,885
Average Fixed Asset Balance for 2008	43,155,630
Working Capital Allowance	4,996,170
Rate Base	48,151,800
Regulated Rate of Return	7.19%
Regulated Return on Capital	3,461,291
Deemed Interest Expense	1,534,164
Deemed Return on Equity	1,927,127

Table 1.2 - Capital Structure Rate Base Calculations (CONTINUED)

2008

Description	Deemed Portion	Effective Rate
Long-Term Debt	49.30%	6.49%
Short-Tern Debt	4.00%	4.47%
Return On Equity	46.70%	8.57%
Weighted Debt Rate		6.34%
Regulated Rate of Return		7.38%

2009

Description	Deemed Portion	Effective Rate
Long-Term Debt	52.70%	6.50%
Short-Tern Debt	4.00%	4.47%
Return On Equity	43.30%	8.57%
Weighted Debt Rate		6.35%
Regulated Rate of Return		7.31%

WORKING CAPITAL ALLOWANCE FOR 2008

Distribution Expenses	$
Distribution Expenses - Operation	1,185,564
Distribution Expenses - Maintenance	1,507,433
Billing and Collecting	1,053,434
Community Relations	95,043
Administrative and General Expenses	1,418,752
Taxes Other than Income Taxes	112,717
Less: Capital Taxes within 6105	78,000.00
Total Eligible Distribution Expenses	**5,294,943**
Power Supply Expenses	27,337,069
Total Working Capital Expenses	32,632,012
Working Capital Allowance rate of 15%	4,894,802

WORKING CAPITAL ALLOWANCE FOR 2009

Distribution Expenses	
Distribution Expenses - Operation	1,060,932
Distribution Expenses - Maintenance	1,025,443
Billing and Collecting	1,037,686
Community Relations	45,608
Administrative and General Expenses	1,362,364
Taxes Other than Income Taxes	118,981
Less: Capital Taxes within 6105	84,500.00
Total Eligible Distribution Expenses	**4,566,514**
Power Supply Expenses	28,763,185
Total Working Capital Expenses	33,329,699
Working Capital Allowance rate of 15%	4,999,455

RATE BASE CALCULATION FOR 2008

Fixed Assets Opening Balance 2008	41,250,812
Fixed Assets Closing Balance 2008	42,517,727
Average Fixed Asset Balance for 2008	41,884,269
Working Capital Allowance	4,894,802
Rate Base	46,779,071
Regulated Rate of Return	7.38%
Regulated Return on Capital	3,452,955
Deemed Interest Expense	1,580,768
Deemed Return on Equity	1,872,187

RATE BASE CALCULATION FOR 2009

Fixed Assets Opening Balance 2009	42,517,727
Fixed Assets Closing Balance 2009	43,226,191
Average Fixed Asset Balance for 2009	42,871,959
Working Capital Allowance	4,999,455
Rate Base	47,871,414
Regulated Rate of Return	7.31%
Regulated Return on Capital	3,500,831
Deemed Interest Expense	1,724,413
Deemed Return on Equity	1,776,417

1 **Table 1.2 – Capital Structure Rate Base Calculations (CONTINUED)**

2010			2011		
Description	**Deemed Portion**	**Effective Rate**	**Description**	**Deemed Portion**	**Effective Rate**
Long-Term Debt	56.00%	5.81%	Long-Term Debt	56.00%	5.81%
Short-Tern Debt	4.00%	4.47%	Short-Tern Debt	4.00%	4.47%
Return On Equity	40.00%	8.57%	Return On Equity	40.00%	8.57%
Weighted Debt Rate		5.72%	**Weighted Debt Rate**		5.72%
Regulated Rate of Return		6.86%	**Regulated Rate of Return**		6.86%

WORKING CAPITAL ALLOWANCE FOR 2010		WORKING CAPITAL ALLOWANCE FOR 2011	
Distribution Expenses		**Distribution Expenses**	
Distribution Expenses - Operation	1,106,741	Distribution Expenses - Operation	1,144,900
Distribution Expenses - Maintenance	1,115,511	Distribution Expenses - Maintenance	1,151,200
Billing and Collecting	971,841	Billing and Collecting	968,850
Community Relations	48,761	Community Relations	58,000
Administrative and General Expenses	1,586,708	Administrative and General Expenses	1,633,500
Taxes Other than Income Taxes	68,210	Taxes Other than Income Taxes	35,000
Less: Capital Taxes within 6105	33,729	**Less:** Capital Taxes within 6105	-
Total Eligible Distribution Expenses	**4,864,043**	**Total Eligible Distribution Expenses**	**4,991,450**
Power Supply Expenses	31,033,780	Power Supply Expenses	33,304,179
Total Working Capital Expenses	35,897,823	**Total Working Capital Expenses**	38,295,629
Working Capital Allowance rate of 15%	5,384,673	Working Capital Allowance rate of 15%	5,744,344

RATE BASE CALCULATION FOR 2010		RATE BASE CALCULATION FOR 2011	
Fixed Assets Opening Balance 2010	43,226,191	Fixed Assets Opening Balance 2011	49,389,912
Fixed Assets Closing Balance 2010	49,389,912	Fixed Assets Closing Balance 2011	50,696,531
Average Fixed Asset Balance for 2010	46,308,052	**Average Fixed Asset Balance for 2011**	50,043,222
Working Capital Allowance	5,384,673	Working Capital Allowance	5,744,344
Rate Base	51,692,725	**Rate Base**	55,787,566
Regulated Rate of Return	6.86%	Regulated Rate of Return	6.86%
Regulated Return on Capital	3,546,620	**Regulated Return on Capital**	3,826,830
Deemed Interest Expense	1,774,593	Deemed Interest Expense	1,914,432
Deemed Return on Equity	1,772,027	Deemed Return on Equity	1,912,398

1 **Table 1.2 – Capital Structure Rate Base Calculations (CONTINUED)**

2012		
Description	**Deemed Portion**	**Effective Rate**
Long-Term Debt	56.00%	5.51%
Short-Tern Debt	4.00%	2.46%
Return On Equity	40.00%	9.58%
Weighted Debt Rate		5.31%
Regulated Rate of Return		7.02%

WORKING CAPITAL ALLOWANCE FOR 2012	
Distribution Expenses	
Distribution Expenses - Operation	1,288,506
Distribution Expenses - Maintenance	1,188,605
Billing and Collecting	1,288,062
Community Relations	37,000
Administrative and General Expenses	2,015,444
Taxes Other than Income Taxes	35,000
Less: Capital Taxes within 6105	-
Total Eligible Distribution Expenses	**5,852,617**
Power Supply Expenses	34,716,838
Total Working Capital Expenses	40,569,455
Working Capital Allowance rate of 15%	6,085,418

RATE BASE CALCULATION FOR 2012	
Fixed Assets Opening Balance 2012	52,847,270
Fixed Assets Closing Balance 2012	54,289,222
Average Fixed Asset Balance for 2012	53,568,246
Working Capital Allowance	6,085,418
Rate Base	59,653,664
Regulated Rate of Return	7.02%
Regulated Return on Capital	4,185,471
Deemed Interest Expense	1,899,543
Deemed Return on Equity	2,285,928

Table 1.3 – Cost of Long-Term Debt

Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance	Principal	Term (Years)	Rate%	Year Applied to	Interest Cost
Bank Loan 758020T	TD Bank	No	September 20, 2007	1,957,000	25	6.17%	2008	120,747
Bank Loan 682491T	TD Bank	No	September 20, 2004	3,257,000	15	6.02%	2008	196,071
Bank Loan 682495T	TD Bank	No	September 20, 2004	9,971,000	25	7.00%	2008	697,970
Debenture	Infrastructure Ontario	No	December 3, 2007	1,958,514	25	5.01%	2008	98,122
Bank Loan 758020T	TD Bank	No	September 20, 2007	1,909,000	25	6.17%	2009	117,785
Bank Loan 682491T	TD Bank	No	September 20, 2004	3,040,000	15	6.02%	2009	183,008
Bank Loan 682495T	TD Bank	No	September 20, 2004	9,751,000	25	7.00%	2009	682,570
Debenture	Infrastructure Ontario	No	December 3, 2007	1,914,923	25	5.01%	2009	95,938
Bank Loan 758020T	TD Bank	No	September 20, 2007	1,859,000	25	6.17%	2010	114,700
Bank Loan 682491T	TD Bank	No	September 20, 2004	2,811,000	15	6.02%	2010	169,222
Bank Loan 682495T	TD Bank	No	September 20, 2004	9,516,000	25	7.00%	2010	666,120
Debenture	Infrastructure Ontario	No	December 3, 2007	1,869,121	25	5.01%	2010	93,643
Debenture 09-01-2010-2	Infrastructure Ontario	No	September 1, 2010	5,600,000	25	4.73%	2010	264,880
Debenture 09-01-2010-1	Infrastructure Ontario	No	September 1, 2010	2,400,000	15	3.72%	2010	89,280
Debenture 09-01-2010-2	Infrastructure Ontario	No	September 1, 2010	5,540,286	25	4.73%	2011	262,056
Debenture 09-01-2010-1	Infrastructure Ontario	No	September 1, 2010	2,299,839	15	3.72%	2011	85,554
Bank Loan 758020T	TD Bank	No	September 20, 2007	1,805,000	25	6.17%	2011	111,369
Bank Loan 682491T	TD Bank	No	September 20, 2004	2,568,000	15	6.02%	2011	154,594
Bank Loan 682495T	TD Bank	No	September 20, 2004	9,266,000	25	7.00%	2011	648,620
Debenture	Infrastructure Ontario	No	December 3, 2007	1,820,995	25	5.01%	2011	91,232
Debenture 09-01-2010-2	Infrastucture Ontario	No	September 1, 2010	5,416,589	25	4.73%	2012	256,205
Debenture 09-01-2010-1	Infrastucture Ontario	No	September 1, 2010	2,093,895	15	3.72%	2012	77,893
Bank Loan 758020T	TD Bank	No	September 20, 2007	1,734,000	25	6.17%	2012	106,988
Bank Loan 682491T	TD Bank	No	September 20, 2004	2,243,000	15	6.02%	2012	135,029
Bank Loan 682495T	TD Bank	No	September 20, 2004	8,929,000	25	7.00%	2012	625,030
Debenture	Infrastructure Ontario	No	December 3, 2007	1,770,428	25	5.01%	2012	88,698
New Debt	Infrastructure Ontario	No	June 30, 2012	6,000,000	25	4.39%	2012	263,400

2008 Total Long Term Debt	17,143,514	**Total Interest Cost for 2008**	1,112,910
		Weighted Debt Cost Rate for 2008	6.49%
2009 Total Long Term Debt	16,614,923	**Total Interest Cost for 2009**	1,079,301
		Weighted Debt Cost Rate for 2009	6.50%
2010 Total Long Term Debt	24,055,121	**Total Interest Cost for 2010**	1,397,845
		Weighted Debt Cost Rate for 2010	5.81%
2011 Total Long Term Debt	23,300,120	**Total Interest Cost for 2011**	1,353,423
		Weighted Debt Cost Rate for 2011	5.81%
2012 Total Long Term Debt	28,186,911	**Total Interest Cost for 2012**	1,553,242
		Weighted Debt Cost Rate for 2012	5.51%

REVENUE DEFICIENCY - OVERVIEW:

Under Modified International Financial Reporting Standards (MIFRS), Norfolk's net revenue deficiency is $913,129 and when grossed up for PILs Norfolk's revenue deficiency is $1,178,225. This deficiency is calculated as the difference between the 2012 Test Year Revenue Requirement of $12,686,869 and the Forecast 2012 Test Year Revenue, based on the 2011 approved rates, at $11,508,644. Table 1.1 on the following page provides the revenue deficiency calculations.

Revenue Requirement:

Norfolk's Revenue Requirement consists of the following:

- Administrative & General, Billing & Collecting Expense
- Operation & Maintenance Expense
- Depreciation Expense
- Property Taxes
- PILS'
- Deemed Interest & Return on Equity

Norfolk's revenue requirement is primarily received through electricity distribution rates and offset by revenue from OEB-approved specific service charges, late payment charges, interest, and other operating income.

Table 1.1 Revenue Deficiency

Norfolk Power Distribution Inc. Revenue Deficiency Determination		
Description	**2012 Test Existing Rates**	**2012 Test - Required Revenue**
Revenue		
Revenue Deficiency		**1,178,225**
Distribution Revenue	11,031,355	11,031,355
Other Operating Revenue (Net)	477,289	477,289
Total Revenue	**11,508,644**	**12,686,869**
Costs and Expenses		
Administrative & General, Billing & Collecting	3,280,506	3,280,506
Operation & Maintenance	2,537,111	2,537,111
Depreciation & Amortization	2,327,524	2,327,524
Property Taxes	35,000	35,000
Capital Taxes	0	0
Deemed Interest	1,899,543	1,899,543
Total Costs and Expenses	**10,079,684**	**10,079,684**
Less OCT Included Above	0	0
Total Costs and Expenses Net of OCT	**10,079,684**	**10,079,684**
Utility Income Before Income Taxes	**1,428,959**	**2,607,185**
Income Taxes:		
Corporate Income Taxes	56,160	321,256
Total Income Taxes	**56,160**	**321,256**
Utility Net Income	**1,372,800**	**2,285,928**
Capital Tax Expense Calculation:		
Total Rate Base	59,653,664	59,653,664
Exemption	15,000,000	15,000,000
Deemed Taxable Capital	**44,653,664**	**44,653,664**
Ontario Capital Tax	0	0
Income Tax Expense Calculation:		
Accounting Income	1,428,959	2,607,185
Tax Adjustments to Accounting Income	-1,179,356	-1,179,356
Taxable Income	**249,603**	**1,427,828**
Income Tax Expense	56,160	321,256
Tax Rate Refecting Tax Credits	22.50%	22.50%
Actual Return on Rate Base:		
Rate Base	59,653,664	59,653,664
Interest Expense	1,899,543	1,899,543
Net Income	1,372,800	2,285,928
Total Actual Return on Rate Base	**3,272,342**	**4,185,471**
Actual Return on Rate Base	5.49%	7.02%
Required Return on Rate Base:		
Rate Base	59,653,664	59,653,664
Return Rates:		
Return on Debt (Weighted)	5.31%	5.31%
Return on Equity	9.58%	9.58%
Deemed Interest Expense	1,899,543	1,899,543
Return On Equity	2,285,928	2,285,928
Total Return	**4,185,471**	**4,185,471**
Expected Return on Rate Base	7.02%	7.02%
Revenue Deficiency After Tax	**913,129**	**0**
Revenue Deficiency Before Tax	**1,178,225**	**0**

COST DRIVERS ON REVENUE DEFICIENCY

The Applicant notes there are several factors that contribute to the gross revenue deficiency of $1,178,225 for the 2012 Test Year. The following discussion highlights some significant items that contribute to this deficiency.

Operating Expenses

Norfolk's OM&A expenses have increased from the 2008 approved amount of $4,253,373 to $5,817,617 in the 2012 Test Year. Due to the transition in financial reporting from Canadian Generally Accepted Accounting Principles (CGAAP) to MIFRS, Norfolk has made changes to its capitalization policy in order to be compliant with the new standards. Under MIFRS $616,555 of expenses that Norfolk previously capitalized as part of its burden rates will no longer be capitalized. The full details of this change are outlined in Exhibit 4, Tab 4. The remaining cost increases of $947,689 over the 4 year period are discussed in Exhibit 4, Tab 2.

Rate Base

In this application Norfolk is applying for a rate base of $59,653,664 compared to a rate base of $48,151,800 which was approved during Norfolk's 2008 cost of service application. $669,000 of this increase is the result of the change in financial reporting from CGAAP to MIFRS. In addition the working capital allowance has increased by almost $1,000,000 from the 2008 Board Approved amount due to increases in the cost of power and increases in the applicant's operating expenses. The most significant increase however is the increase in the net book value of fixed assets which has risen by $9.9 million since the 2008 Board Approved amount. This increase has been primarily driven by the completion of Norfolk's Bloomsburg Transformer Station, the installation of smart meters, and capital improvements required to accommodate customer demand and to replace aging assets. The changes due to MIFRS, working capital and capital spending have been fully disclosed in Exhibit 2 of this application.

These changes have resulted in increased deemed interest expense of $365,379. Also the increased rate base, plus the increase in deemed return on equity from 8.57% to 9.58% has caused deemed return on equity to increase by $358,801.

COST ALLOCATION OVERVIEW:

Introduction:

On September 29, 2006, the OEB issued its directions on Cost Allocation Methodology for Electricity Distributors (the "Directions"). On November 15, 2006, the Board issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model. Norfolk Power prepared a cost allocation information filing consistent with Norfolk Power's understanding of the Directions, the Guidelines, the Model and the Instructions. Norfolk Power submitted this filing to the OEB on January 22, 2007.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization among a distributor's rate classifications. It was felt that this would give an indication of cross-subsidization from one class to another and this information would be useful as a tool in future rate applications.

In Norfolk Power's 2008EDR CoS Application (EB-2007-0753), the results of the original cost allocation study filed on January 22, 2007 was used as a basis for Norfolk Power to propose reallocations of distribution costs across customer classes to address the issue of cross-subsidization. The reallocations were based on the objective of moving the revenue to cost ratios to be within the Board's acceptable range as outlined in the "Report on Application of Cost Allocation for Electricity Distributors" (the Cost Allocation Report") issued by the OEB on November 28, 2007.

On September 2, 2010, the Board began a proceeding, EB-2010-0219, with the mandate to review and revise the existing Cost Allocation policy as needed. On March 31, 2011, the Report of the Board was released in relation to EB-2010-0219. In the letter accompanying report, the Board indicated that a Working Group would be formed to revise the original Cost Allocation Model to address the revision highlighted in the March 31st Board Report. On August 5, 2011, the Board released the new Cost Allocation model and instructed 2012 Cost of Service filers to use the revised model in their applications. In the March 31st Board Report, the Board stated that "default weighting factors should now be utilized only in exceptional circumstances". Distributors are therefore now expected to develop their own weighting factors.

For the purposes of this Application, Norfolk Power has submitted the revised cost allocation study to reflect 2012 test year costs, customer numbers and demand values. The 2012 demand values are based on the weather normalized load forecast used to design rates. Norfolk Power has developed weighting factors as outlined below based on discussions with staff experienced in the subject area.

Services (Account 1855)

Rate Class	Services Weighting Factor
Residential	1
General Service < 50kW	3
General Service ≥ 50 kW	10
All other classes	N/A

Billing and Collection (Accounts 5315 – 5340, except 5335)

Rate Class	Billing Weighting Factor
Residential	1
General Service < 50kW	1
General Service ≥ 50 kW	3
Street Light (per connection)	1
Sentinel Light	0.1
Unmetered Scattered Load	0.5
Embedded Distributor	1

Meter Capital (Sheet I7.1)

Meter Type	Installation Cost per Meter
Smart Meter	$200
Demand with IT and Interval Capability - Secondary	$2,300
Demand with IT and Interval Capability - Primary	$20,000

Meter Reading (Sheet I7.2)

Meter Type	Meter Reading Weighting Factor
Smart/Interval Meter	1

SUMMARY OF RESULTS AND PROPOSED CHANGES:

The data used in the updated cost allocation study is consistent with Norfolk Power's cost data that supports the proposed 2012 revenue requirement outlined in this application. Consistent with the Guidelines, Norfolk Power's assets were broken out into primary and secondary distribution functions using breakout percentages consistent with the original cost allocation informational filing. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to Norfolk Power, its engineering records, and its customer and financial information systems. The cost allocation study has been included in Appendix A.

Capital contributions, depreciation and accumulated depreciation by USoA is consistent with the information provided in the 2012 continuity statement shown in Exhibit 2. The rate class customer data used in the updated cost allocation study is consistent with the 2012 customer forecast outlined in Exhibit 3. The load profiles for all other rate class are the same as those used in the original information filing but have been scaled to match the load forecast. The following outlines the scaling factors used by rate class.

Table 7-1: Load Profile Scaling Percentages

Rate Class	2004 Weather Normal Values used in Informational Filing (kWh)	2012 Weather Normal Values (KWh)	Scaling Factor
Residential	148,551,834	148,067,203	99.7%
GS < 50	70,159,045	61,517,376	87.7%
General Service 50 to 4999 kW	148,099,993	131,521,846	88.8%
Streetlight	3,685,056	3,406,947	92.5%
Sentinel Lights	321,582	378,167	117.6%
Unmetered Scattered Load	177,341	467,056	263.4%
Total	**370,994,851**	**345,358,596**	**93.1%**

The allocated cost by rate class for the 2007 information filing and 2012 updated study are provided in the following Table 7-2. The results shown under the 2007 information filing column have be revised to exclude the "cost" and "revenues" of the transformation allowance as outlined in the June 28, 2010 filing requirements.

Table 7-2: Allocated Cost - (Consistent with Appendix 2-O: Allocated Costs)

Rate Class	Cost Allocated in Original Cost Allocation Information Filing Revised to Excluded Transformer Allowance	%	Cost Allocated in the 2012 Study	%
Residential	$5,635,197	60.7%	$7,963,674	62.8%
GS < 50	$1,848,174	19.9%	$2,060,191	16.2%
General Service 50 to 4999 kW	$1,534,125	16.5%	$2,347,607	18.5%
Sentinel Lights	$55,506	0.6%	$59,669	0.5%
Street Lighting	$185,907	2.0%	$205,061	1.6%
Unmetered Scattered Load	$21,614	0.2%	$16,681	0.1%
Embedded Distributor		0.0%	$33,986	0.3%
Total	$9,280,524	100.0%	$12,686,869	100.0%

As shown in the table above the Embedded Distributor class has been proposed as part of this application. Hydro One Networks Inc. (“Hydro One”) has been an embedded distributor of Norfolk Power since November 2005, when Hydro One deregistered five wholesale meters with the IESO that were within Norfolk Power's service area. Once these meters were deregistered they were classified as Norfolk Power retail meters that provided an embedded distributor service to Hydro One. Currently Norfolk Power charges Hydro One the monthly service charge of the GS> 50 kW class for the five meters. With this application Norfolk Power is proposing an Embedded Distribution class be establish to determine a distribution rate that will reflect the cost of providing service to Hydro One.

However, there are no Norfolk Power assets used to provide the embedded distributor service. Even thought there are assets within the Norfolk Power service area that provide the embedded distributor service, these assets are own by Hydro One. Essentially the only service that Norfolk Power provides to Hydro One is buying wholesale power, transmission and market services from the IESO and selling it to Hydro One. As a result, the only costs that should be assigned to Hydro One for the embedded distributor service are billing cost and the costs of the working capital allowance assumed in the 2012 rate base associated with the cost of power for Hydro One. The cost allocation model has determined that of the proposed 2012 rate base of $59,653,664, $445,424 is associated with the working capital allowance on the cost of power assigned to Hydro One. To determine the cost allocated to Hydro One, Norfolk Power determined the ratio of total PILs, deemed interest and deemed equity return to the total rate base and applied this ratio to the rate base of $445,424 to produce an amount of $33,639. Using the direct allocation method in the cost allocation model the $33,639 was directly assigned to Embedded Distributor class and when some billing costs were also allocated the total costs allocated to this class were $33,986 as shown in the above table.

The results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

In the Report of the Board on Cost Allocation released in relation to EB-2010-0219. dated March 31, 2011, the OEB established what it considered to be the appropriate ranges of revenue to cost ratios which are summarized in Table 7-3 below. In addition Table 7-3 provides Norfolk Power's revenue to cost ratios from the 2010 IRM application, the updated 2011 cost allocation study and the proposed 2011 to 2013 ratios. Information from the 2010 IRM application has been included as this was the last year of a three year program to move the revenue to cost ratios for Street Light and Sentinel Light rate classes to 70%.

Table 7-3 Revenue to Cost Ratios - (Consistent with Appendix 2-O: Revenue to Cost Ratios)

Class	2010 IRM Application	2012 Updated Cost Allocation Study	2012 Proposed Ratios	2013 Proposed Ratios	2014 Proposed Ratios	Board Targets Min to Max	
Residential	103.8%	102.6%	102.6%	102.6%	102.6%	85.0%	115.0%
GS < 50	101.2%	114.0%	114.0%	114.0%	114.0%	80.0%	120.0%
General Service 50 to 4999 kW	92.4%	80.2%	80.2%	80.2%	80.2%	80.0%	120.0%
Sentinel Lights	70.0%	92.3%	92.3%	92.3%	92.3%	80.0%	120.0%
Street Lighting	70.0%	86.9%	86.9%	86.9%	86.9%	70.0%	120.0%
Unmetered Scattered Load	100.7%	212.4%	114.0%	114.0%	114.0%	80.0%	120.0%
Embedded Distributor	n/a	47.8%	100.0%	100.0%	100.0%	80.0%	120.0%

Norfolk Power is proposing in this application to re-align its revenue to cost ratios by adjusting the allocations of revenue among rate classes in order to reduce some of the cross-subsidization that is occurring. It is proposed the Embedded Distributor class will be moved to 100% to ensure that Hydro One will pay the full cost of distribution service provided. In order maintain revenue neutrality, the additional revenue from the Embedded Distributor class with be used to reduce the revenue to cost ratio for the Unmetered Scattered Load class to be within the Board's range and to slightly reduce the revenue to cost ratio for the GS < 50 class to be consistent with the Unmetered Scattered Load class.

The following table 7-4 provides information on calculated class revenue. The resulting 2012 proposed base revenue will be the amount used in Exhibit 8 to design the proposed distribution charges in this application.

Table 7-4 Calculated Class Revenue - (Consistent with Appendix 2-O: Calculated Class Revenue)				
Class	2012 Base Revenue at Existing Rates	2012 Proposed Base Revenue Allocated at Existing Rates Proportion	2012 Proposed Base Revenue	Miscellaneous Revenue
Residential	$7,084,717	$7,841,414	$7,841,414	$327,906
GS < 50	$2,047,512	$2,266,201	$2,264,881	$82,997
General Service 50 to 4999 kW	$1,652,368	$1,828,853	$1,828,853	$54,449
Sentinel Lights	$47,347	$52,404	$52,404	$2,684
Street Lighting	$153,639	$170,049	$170,049	$8,237
Unmetered Scattered Load	$31,109	$34,432	$18,019	$992
Embedded Distributor	$14,663	$16,229	$33,961	$25
Total	$11,031,355	$12,209,580	$12,209,580	$477,289

Appendix A

2012 Updated Cost Allocation Study

2012 COST ALLOCATION

NORFOLK POWER DISTRIBUTION INC

EB-2011-0272

August 26, 2011

Sheet I6.1 Revenue Worksheet - Intial Application

Total kWhs from Load Forecast	377,257,928
Total kWs from Load Forecast	357,201
Deficiency from RRWF	- 1,178,225
Miscellaneous Revenue	477,289

	ID	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
Billing Data									
Forecast kWh	CEN	377,257,928	148,067,203	61,517,376	131,521,846	3,406,947	378,167	467,056	31,899,332
Forecast kW	CDEM	357,201			346,440	9,810	951		
Forecast kW, included in CDEM, of customers receiving line transformer allowance		159,363			159,363				
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-							
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	377,257,928	148,067,203	61,517,376	131,521,846	3,406,947	378,167	467,056	31,899,332
kWh - 30 year weather normalized amount	Click here to Enter Data	377,257,928	148,067,203	61,517,376	131,521,846	3,406,947	378,167	467,056	31,899,332
Existing Monthly Charge			$20.77	$49.74	$244.38	$1.85	$6.15	$26.55	$244.38
Existing Distribution kWh Rate			$0.0190	$0.0139				$0.0149	
Existing Distribution kW Rate					$3.6285	$6.9907	$18.2916		
Existing TFOA Rate					$0.60				
Additional Charges									
Distribution Revenue from Rates		$11,126,972	$7,084,717	$2,047,512	$1,747,986	$153,639	$47,347	$31,109	$14,663
Transformer Ownership Allowance		$95,618	$0	$0	$95,618	$0	$0	$0	$0
Net Class Revenue	CREV	$11,031,355	$7,084,717	$2,047,512	$1,652,368	$153,639	$47,347	$31,109	$14,663
Data Mismatch Analysis									
Revenue with 30 year weather normalized kWh		11,031,355	7,084,717	2,047,512	1,652,368	153,639	47,347	31,109	14,663
			7,084,717	2,047,512	1,652,368	153,639	47,347	31,109	14,663

Weather Normalized Data from Hydro One	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
kWh - 30 year weather normalized amount	377,257,928	148,067,203	61,517,376	131,521,846	3,406,947	378,167	467,056	31,899,332
Loss Factor		**1.0000**	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

2012 COST ALLOCATION
NORFOLK POWER DISTRIBUTION INC
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Sheet I6.2 Customer Data Worksheet - Intial Application

			1	2	3	7	8	9	10
	ID	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
Billing Data									
Bad Debt 3 Year Historical Average	BDHA	$72,230	$63,122	$9,108	$0	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$138,000	$98,136	$32,895	$6,580	$27		$362	
Number of Bills	CNB	237,488	205,654	23,973	2,009	12	4,870	910	60
Number of Devices						3,832	406	76	
Number of Connections (Unmetered)	CCON	1,624				1,142	406	76	
Total Number of Customers	CCA	19,308	17,138	1,998	167				5
Bulk Customer Base	CCB	-							
Primary Customer Base	CCP	19,303	17,138	1,998	167				
Line Transformer Customer Base	CCLT	19,272	17,138	1,994	140				
Secondary Customer Base	CCS	19,272	17,138	1,994	140				
Weighted - Services	CWCS	24,519	17,138	5,981	1,400	-	-	-	-
Weighted Meter -Capital	CWMC	3,922,323	3,427,572	399,551	95,200	-	-	-	-
Weighted Meter Reading	CWMR	231,636	205,654	23,973	2,009	-	-	-	-
Weighted Bills	CWNB	236,668	205,654	23,973	6,027	12	487	455	60

Bad Debt Data

Historic Year: 2009	72,230	63,122	9,108					
Historic Year: 2010	72,230	63,122	9,108					
Historic Year: 2011	72,230	63,122	9,108					
Three-year average	**72,230**	**63,122**	**9,108**	**-**	**-**	**-**	**-**	**-**

2012 COST ALLOCATION

NORFOLK POWER DISTRIBUTION INC

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Sheet I8 Demand Data Worksheet - Intial Application

This is an input sheet for demand

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	7	8	9	10
Customer Classes		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
CO-INCIDENT PEAK									
1 CP									
Transformation CP	TCP1	62,053	30,398	12,296	19,306	-	-	54	
Bulk Delivery CP	BCP1	62,053	30,398	12,296	19,306	-	-	54	
Total Sytem CP	DCP1	62,053	30,398	12,296	19,306	-	-	54	
4 CP									
Transformation CP	TCP4	235,296	116,250	42,934	75,174	646	79	213	
Bulk Delivery CP	BCP4	235,296	116,250	42,934	75,174	646	79	213	
Total Sytem CP	DCP4	235,296	116,250	42,934	75,174	646	79	213	
12 CP									
Transformation CP	TCP12	640,377	307,237	108,448	217,532	5,869	653	638	
Bulk Delivery CP	BCP12	640,377	307,237	108,448	217,532	5,869	653	638	
Total Sytem CP	DCP12	640,377	307,237	108,448	217,532	5,869	653	638	
NON CO_INCIDENT PEAK									
1 NCP									
Classification NCP from Load Data Provider	DNCP1	68,299	31,798	14,422	21,056	870	96	57	
Primary NCP	PNCP1	68,299	31,798	14,422	21,056	870	96	57	
Line Transformer NCP	LTNCP1	64,824	31,798	14,393	17,609	870	96	57	
Secondary NCP	SNCP1	64,824	31,798	14,393	17,609	870	96	57	
4 NCP									
Classification NCP from Load Data Provider	DNCP4	265,460	122,641	55,975	82,762	3,481	382	220	
Primary NCP	PNCP4	265,460	122,641	55,975	82,762	3,481	382	220	
Line Transformer NCP	LTNCP4	251,799	122,641	55,863	69,213	3,481	382	220	
Secondary NCP	SNCP4	251,799	122,641	55,863	69,213	3,481	382	220	
12 NCP									
Classification NCP from Load Data Provider	DNCP12	729,780	329,906	148,970	239,984	9,254	1,027	638	
Primary NCP	PNCP12	729,780	329,906	148,970	239,984	9,254	1,027	638	
Line Transformer NCP	LTNCP12	690,194	329,906	148,671	200,697	9,254	1,027	638	
Secondary NCP	SNCP12	690,194	329,906	148,671	200,697	9,254	1,027	638	

Rate Base Assets		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
crev	Distribution Revenue at Existing Rates	$11,031,355	$7,084,717	$2,047,512	$1,652,368	$153,639	$47,347	$31,109	$14,663
mi	Miscellaneous Revenue (mi)	$477,289	$327,906	$82,997	$54,449	$8,237	$2,684	$992	$25
		Miscellaneous Revenue Input equals Output							
	Total Revenue at Existing Rates	**$11,508,644**	**$7,412,623**	**$2,130,509**	**$1,706,817**	**$161,876**	**$50,030**	**$32,101**	**$14,688**
	Factor required to recover deficiency (1 + D)	1.1068							
	Distribution Revenue at Status Quo Rates	$12,209,580	$7,841,414	$2,266,201	$1,828,853	$170,049	$52,404	$34,432	$16,229
	Miscellaneous Revenue (mi)	$477,289	$327,906	$82,997	$54,449	$8,237	$2,684	$992	$25
	Total Revenue at Status Quo Rates	**$12,686,869**	**$8,169,320**	**$2,349,197**	**$1,883,301**	**$178,286**	**$55,087**	**$35,423**	**$16,254**
	Expenses								
di	Distribution Costs (di)	$2,297,811	$1,301,679	$411,535	$514,812	$51,578	$14,728	$3,480	$0
cu	Customer Related Costs (cu)	$1,467,362	$1,281,168	$151,768	$30,598	$45	$1,839	$1,717	$227
ad	General and Administration (ad)	$2,053,805	$1,402,516	$308,759	$302,025	$28,469	$9,084	$2,831	$120
dep	Depreciation and Amortization (dep)	$2,327,524	$1,380,637	$399,302	$493,116	$40,643	$11,037	$2,790	$0
INPUT	PILs (INPUT)	$321,256	$185,172	$56,230	$71,787	$6,011	$1,638	$418	$0
INT	Interest	$1,899,543	$1,094,895	$332,483	$424,465	$35,542	$9,686	$2,471	$0
	Total Expenses	**$10,367,301**	**$6,646,066**	**$1,660,078**	**$1,836,802**	**$162,289**	**$48,013**	**$13,707**	**$347**
	Direct Allocation	**$33,639**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$33,639**
NI	Allocated Net Income (NI)	$2,285,928	$1,317,607	$400,113	$510,805	$42,772	$11,656	$2,974	$0
	Revenue Requirement (includes NI)	$12,686,869	$7,963,674	$2,060,191	$2,347,607	$205,061	$59,669	$16,681	$33,986
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$59,807,293	$34,661,290	$10,467,080	$13,125,781	$1,154,610	$319,084	$79,448	$0
gp	General Plant - Gross	$5,245,657	$3,027,494	$921,000	$1,159,450	$102,358	$28,310	$7,045	$0
accum dep	Accumulated Depreciation	($3,755,685)	($2,310,031)	($624,822)	($741,446)	($59,297)	($15,999)	($4,089)	$0
co	Capital Contribution	($7,729,020)	($4,498,903)	($1,384,745)	($1,583,914)	($191,954)	($56,975)	($12,529)	$0
	Total Net Plant	**$53,568,246**	**$30,879,850**	**$9,378,514**	**$11,959,871**	**$1,005,717**	**$274,419**	**$69,875**	**$0**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$34,716,838	$13,625,758	$5,661,084	$12,103,186	$313,521	$34,801	$42,980	$2,935,509
	OM&A Expenses	$5,818,978	$3,985,363	$872,062	$847,435	$80,093	$25,651	$8,028	$347
	Directly Allocated Expenses	$33,639	$0	$0	$0	$0	$0	$0	$33,639
	Subtotal	***$40,569,456***	***$17,611,120***	***$6,533,146***	***$12,950,620***	***$393,614***	***$60,452***	***$51,008***	***$2,969,495***
	Working Capital	**$6,085,418**	**$2,641,668**	**$979,972**	**$1,942,593**	**$59,042**	**$9,068**	**$7,651**	**$445,424**
	Total Rate Base	**$59,653,664**	**$33,521,518**	**$10,358,486**	**$13,902,464**	**$1,064,759**	**$283,487**	**$77,526**	**$445,424**
		Rate Base Input equals Output							
	Equity Component of Rate Base	**$23,861,466**	**$13,408,607**	**$4,143,394**	**$5,560,985**	**$425,904**	**$113,395**	**$31,010**	**$178,170**
	Net Income on Allocated Assets	**$2,284,362**	**$1,523,254**	**$689,120**	**$46,499**	**$15,997**	**$7,075**	**$21,716**	**($19,298)**
	Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$2,284,362**	**$1,523,254**	**$689,120**	**$46,499**	**$15,997**	**$7,075**	**$21,716**	**($19,298)**
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**102.58%**	**114.03%**	**80.22%**	**86.94%**	**92.32%**	**212.35%**	47.83%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**($1,178,225)**	($551,051)	$70,318	($640,790)	($43,185)	($9,639)	$15,419	($19,298)
		Deficiency Input equals Output							
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	**($0)**	$205,646	$289,006	($464,306)	($26,775)	($4,582)	$18,742	($17,732)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.57%	11.36%	16.63%	0.84%	3.76%	6.24%	70.03%	-10.83%

2012 COST ALLOCATION

NORFOLK POWER DISTRIBUTION INC

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Intial Application

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	7	8	9	10
Summary	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
Customer Unit Cost per month - Avoided Cost	$7.04	$6.14	$16.61	$0.00	$0.30	$1.10	$3.00
Customer Unit Cost per month - Directly Related	$10.05	$9.18	$24.55	$0.00	$0.46	$1.92	$4.59
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$22.38	$24.71	$49.49	$8.95	$11.88	$11.43	$5.78
Existing Approved Fixed Charge	$20.77	$49.74	$244.38	$1.85	$6.15	$26.55	$244.38

Information to be Used to Allocate PILs, ROD, ROE and A&G	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
General Plant - Gross Assets	$5,245,657	$3,027,494	$921,000	$1,159,450	$102,358	$28,310	$7,045	$0
General Plant - Accumulated Depreciation	($1,001,437)	($577,972)	($175,826)	($221,348)	($19,541)	($5,405)	($1,345)	$0
General Plant - Net Fixed Assets	$4,244,220	$2,449,522	$745,174	$938,102	$82,817	$22,905	$5,700	$0
General Plant - Depreciation	$547,290	$315,865	$96,090	$120,968	$10,679	$2,954	$735	$0
Total Net Fixed Assets Excluding General Plant	$49,324,025	$28,430,328	$8,633,340	$11,021,769	$922,899	$251,514	$64,175	$0
Total Administration and General Expense	$2,053,805	$1,402,516	$308,759	$302,025	$28,469	$9,084	$2,831	$120
Total O&M	$3,765,173	$2,582,847	$563,303	$545,409	$51,624	$16,567	$5,197	$227

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
	Distribution Plant								
1860	Meters	$4,299,746	$3,757,388	$437,998	$104,361	$0	$0	$0	$0
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant - Meters only	($709,443)	($619,955)	($72,268)	($17,219)	$0	$0	$0	$0
	Meter Net Fixed Assets	**$3,590,304**	**$3,137,432**	**$365,730**	**$87,141**	**$0**	**$0**	**$0**	**$0**
	Misc Revenue								
4082	Retail Services Revenues	($800)	($549)	($120)	($116)	($11)	($4)	($1)	($0)
4084	Service Transaction Requests (STR) Revenues	($700)	($480)	($105)	($101)	($10)	($3)	($1)	($0)
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($138,000)	($98,136)	($32,895)	($6,580)	($27)	$0	($362)	$0
	Sub-total	*($139,500)*	*($99,165)*	*($33,120)*	*($6,797)*	*($47)*	*($7)*	*($364)*	*($0)*
	Operation								
5065	Meter Expense	$214,300	$187,269	$21,830	$5,201	$0	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$214,300*	*$187,269*	*$21,830*	*$5,201*	*$0*	*$0*	*$0*	*$0*
	Maintenance								
5175	Maintenance of Meters	$25,000	$21,847	$2,547	$607	$0	$0	$0	$0
	Billing and Collection								
5310	Meter Reading Expense	$234,395	$208,104	$24,259	$2,033	$0	$0	$0	$0
5315	Customer Billing	$586,501	$509,644	$59,409	$14,935	$30	$1,207	$1,127	$149
5320	Collecting	$256,895	$223,231	$26,022	$6,542	$13	$529	$494	$65
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	($132,877)	($115,464)	($13,460)	($3,384)	($7)	($273)	($255)	($34)
	Sub-total	$944,914	$825,514	$96,230	$20,126	$36	$1,462	$1,365	$180
	Total Operation, Maintenance and Billing	$1,184,214	$1,034,630	$120,607	$25,934	$36	$1,462	$1,365	$180
	Amortization Expense - Meters	$284,275	$248,417	$28,958	$6,900	$0	$0	$0	$0
	Allocated PILs	$21,530	$18,814	$2,193	$523	$0	$0	$0	$0
	Allocated Debt Return	$127,301	$111,243	$12,966	$3,093	$0	$0	$0	$0
	Allocated Equity Return	$153,195	$133,871	$15,603	$3,722	$0	$0	$0	$0
	Total	**$1,631,014**	**$1,447,809**	**$147,206**	**$33,374**	**($11)**	**$1,456**	**$1,001**	**$180**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
	Distribution Plant								
1860	Meters	$4,299,746	$3,757,388	$437,998	$104,361	$0	$0	$0	$0
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant - Meters only	($709,443)	($619,955)	($72,268)	($17,219)	$0	$0	$0	$0
	Meter Net Fixed Assets	$3,590,304	$3,137,432	$365,730	$87,141	$0	$0	$0	$0
	Allocated General Plant Net Fixed Assets	$309,302	$270,317	$31,567	$7,417	$0	$0	$0	$0
	Meter Net Fixed Assets Including General Plant	$3,899,605	$3,407,750	$397,297	$94,558	$0	$0	$0	$0
	Misc Revenue								
4082	Retail Services Revenues	($800)	($549)	($120)	($116)	($11)	($4)	($1)	($0)
4084	Service Transaction Requests (STR) Revenues	($700)	($480)	($105)	($101)	($10)	($3)	($1)	($0)
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($138,000)	($98,136)	($32,895)	($6,580)	($27)	$0	($362)	$0
	Sub-total	*($139,500)*	*($99,165)*	*($33,120)*	*($6,797)*	*($47)*	*($7)*	*($364)*	*($0)*
	Operation								
5065	Meter Expense	$214,300	$187,269	$21,830	$5,201	$0	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$214,300*	*$187,269*	*$21,830*	*$5,201*	*$0*	*$0*	*$0*	*$0*
	Maintenance								
5175	Maintenance of Meters	$25,000	$21,847	$2,547	$607	$0	$0	$0	$0
	Billing and Collection								
5310	Meter Reading Expense	$234,395	$208,104	$24,259	$2,033	$0	$0	$0	$0
5315	Customer Billing	$586,501	$509,644	$59,409	$14,935	$30	$1,207	$1,127	$149
5320	Collecting	$256,895	$223,231	$26,022	$6,542	$13	$529	$494	$65
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	($132,877)	($115,464)	($13,460)	($3,384)	($7)	($273)	($255)	($34)
	Sub-total	*$944,914*	*$825,514*	*$96,230*	*$20,126*	*$36*	*$1,462*	*$1,365*	*$180*
	Total Operation, Maintenance and Billing	$1,184,214	$1,034,630	$120,607	$25,934	$36	$1,462	$1,365	$180
	Amortization Expense - Meters	$284,275	$248,417	$28,958	$6,900	$0	$0	$0	$0
	Amortization Expense - General Plant assigned to Meters	*$39,884*	*$34,857*	*$4,071*	*$956*	*$0*	*$0*	*$0*	*$0*
	Admin and General	$643,945	$561,816	$66,107	$14,361	$20	$802	$744	$95
	Allocated PILs	$23,384	$20,435	$2,382	$568	$0	$0	$0	$0
	Allocated Debt Return	$138,268	$120,827	$14,085	$3,356	$0	$0	$0	$0
	Allocated Equity Return	$166,393	$145,405	$16,950	$4,039	$0	$0	$0	$0
	Total	**$2,340,863**	**$2,067,222**	**$220,039**	**$49,316**	**$9**	**$2,257**	**$1,745**	**$276**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

			1	2	3	7	8	9	10
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
	Distribution Plant								
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$5,796,563	$4,747,107	$553,369	$46,371	$316,297	$112,423	$20,996	$0
1830-5	Poles, Towers and Fixtures - Secondary	$343,927	$282,083	$32,817	$2,304	$18,795	$6,680	$1,248	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$3,704,911	$3,034,144	$353,689	$29,638	$202,164	$71,856	$13,420	$0
1835-5	Overhead Conductors and Devices - Secondary	$219,823	$180,295	$20,975	$1,473	$12,013	$4,270	$797	$0
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$933,029	$764,106	$89,072	$7,464	$50,912	$18,096	$3,380	$0
1840-5	Underground Conduit - Secondary	$162,674	$133,422	$15,522	$1,090	$8,890	$3,160	$590	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$1,822,605	$1,492,626	$173,995	$14,580	$99,453	$35,349	$6,602	$0
1845-5	Underground Conductors and Devices - Secondary	$317,771	$260,630	$30,321	$2,129	$17,366	$6,172	$1,153	$0
1850	Line Transformers	$2,592,421	$2,126,260	$247,361	$17,370	$141,672	$50,355	$9,404	$0
1855	Services	$2,658,269	$1,858,020	$648,466	$151,783	$0	$0	$0	$0
1860	Meters	$4,299,746	$3,757,388	$437,998	$104,361	$0	$0	$0	$0
1880	IFRS Placeholder Asset Account	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$22,851,738*	*$18,636,081*	*$2,603,584*	*$378,562*	*$867,561*	*$308,360*	*$57,590*	*$0*
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($4,647,209)	($3,788,434)	($518,777)	($71,326)	($188,964)	($67,164)	($12,544)	$0
	Customer Related Net Fixed Assets	$18,204,529	$14,847,648	$2,084,807	$307,236	$678,597	$241,196	$45,046	$0
	Allocated General Plant Net Fixed Assets	$1,572,213	$1,279,255	$179,947	$26,150	$60,895	$21,966	$4,001	$0
	Customer Related NFA Including General Plant	$19,776,742	$16,126,903	$2,264,754	$333,385	$739,491	$263,161	$49,047	$0
	Misc Revenue								
4082	Retail Services Revenues	($800)	($549)	($120)	($116)	($11)	($4)	($1)	($0)
4084	Service Transaction Requests (STR) Revenues	($700)	($480)	($105)	($101)	($10)	($3)	($1)	($0)
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($138,000)	($98,136)	($32,895)	($6,580)	($27)	$0	($362)	$0
4235	Miscellaneous Service Revenues	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*($139,500)*	*($99,165)*	*($33,120)*	*($6,797)*	*($47)*	*($7)*	*($364)*	*($0)*
	Operating and Maintenance								
5005	Operation Supervision and Engineering	$61,002	$48,924	$7,121	$902	$2,853	$1,014	$189	$0
5010	Load Dispatching	$122,880	$98,550	$14,344	$1,816	$5,746	$2,042	$381	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$34,760	$28,469	$3,318	$276	$1,897	$674	$126	$0
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$17,760	$14,546	$1,695	$141	$969	$344	$64	$0
5035	Overhead Distribution Transformers- Operation	$400	$328	$38	$3	$22	$8	$1	$0
5040	Underground Distribution Lines and Feeders - Operation Labour	$50,000	$40,957	$4,773	$390	$2,729	$970	$181	$0
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$400	$328	$38	$3	$22	$8	$1	$0
5055	Underground Distribution Transformers - Operation	$1,000	$820	$95	$7	$55	$19	$4	$0
5065	Meter Expense	$214,300	$187,269	$21,830	$5,201	$0	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0
5085	Miscellaneous Distribution Expense	$86,280	$69,197	$10,072	$1,275	$4,035	$1,434	$268	$0
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$10,800	$8,845	$1,031	$86	$589	$209	$39	$0
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$85,402	$68,492	$9,969	$1,262	$3,994	$1,420	$265	$0
5120	Maintenance of Poles, Towers and Fixtures	$28,160	$23,064	$2,688	$223	$1,537	$546	$102	$0
5125	Maintenance of Overhead Conductors and Devices	$151,040	$123,705	$14,419	$1,197	$8,242	$2,930	$547	$0
5130	Maintenance of Overhead Services	$10,500	$7,339	$2,561	$600	$0	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$105,320	$86,259	$10,054	$835	$5,747	$2,043	$382	$0
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
5150	Maintenance of Underground Conductors and Devices	$13,600	$11,140	$1,298	$106	$742	$264	$49	$0
5155	Maintenance of Underground Services	$45,000	$31,453	$10,977	$2,569	$0	$0	$0	$0
5160	Maintenance of Line Transformers	$26,200	$21,489	$2,500	$176	$1,432	$509	$95	$0
5175	Maintenance of Meters	$25,000	$21,847	$2,547	$607	$0	$0	$0	$0
	Sub-total	*$1,089,804*	*$893,020*	*$121,369*	*$17,674*	*$40,611*	*$14,434*	*$2,696*	*$0*
	Billing and Collection								
5305	Supervision	$172,740	$150,104	$17,498	$4,399	$9	$355	$332	$44
5310	Meter Reading Expense	$234,395	$208,104	$24,259	$2,033	$0	$0	$0	$0
5315	Customer Billing	$586,501	$509,644	$59,409	$14,935	$30	$1,207	$1,127	$149
5320	Collecting	$256,895	$223,231	$26,022	$6,542	$13	$529	$494	$65
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	($132,877)	($115,464)	($13,460)	($3,384)	($7)	($273)	($255)	($34)
5335	Bad Debt Expense	$100,000	$87,391	$12,609	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$10,409	$9,045	$1,054	$265	$1	$21	$20	$3
	Sub-total	*$1,228,062*	*$1,072,053*	*$127,391*	*$24,789*	*$45*	*$1,839*	*$1,717*	*$227*
	Sub Total Operating, Maintenance and Biling	*$2,317,867*	*$1,965,073*	*$248,760*	*$42,464*	*$40,656*	*$16,274*	*$4,413*	*$227*
	Amortization Expense - Customer Related	$743,532	$617,849	$81,193	$13,236	$21,982	$7,813	$1,459	$0
	Amortization Expense - General Plant assigned to Meters	$202,736	$164,959	$23,204	$3,372	$7,852	$2,832	$516	$0
	Admin and General	$1,260,792	$1,067,057	$136,351	$23,515	$22,421	$8,924	$2,404	$120
	Allocated PILs	$118,569	$96,705	$13,579	$2,001	$4,420	$1,571	$293	$0
	Allocated Debt Return	$701,084	$571,805	$80,289	$11,832	$26,134	$9,289	$1,735	$0
	Allocated Equity Return	$843,691	$688,116	$96,621	$14,239	$31,450	$11,178	$2,088	$0
	PLCC Adjustment for Line Transformer	$89,186	$74,579	$8,680	$609	$4,986	$0	$331	$0
	PLCC Adjustment for Primary Costs	$434,488	$362,743	$42,329	$3,550	$24,258	$0	$1,607	$0
	PLCC Adjustment for Secondary Costs	$40,214	$33,203	$3,471	$283	$3,047	$0	$210	$0
	Total	$5,484,884	**$4,601,876**	**$592,397**	**$99,420**	**$122,575**	**$57,874**	**$10,395**	**$347**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
	Distribution Plant								
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$5,796,563	$4,747,107	$553,369	$46,371	$316,297	$112,423	$20,996	$0
1830-5	Poles, Towers and Fixtures - Secondary	$343,927	$282,083	$32,817	$2,304	$18,795	$6,680	$1,248	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$3,704,911	$3,034,144	$353,689	$29,638	$202,164	$71,856	$13,420	$0
1835-5	Overhead Conductors and Devices - Secondary	$219,823	$180,295	$20,975	$1,473	$12,013	$4,270	$797	$0
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$933,029	$764,106	$89,072	$7,464	$50,912	$18,096	$3,380	$0
1840-5	Underground Conduit - Secondary	$162,674	$133,422	$15,522	$1,090	$8,890	$3,160	$590	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$1,822,605	$1,492,626	$173,995	$14,580	$99,453	$35,349	$6,602	$0
1845-5	Underground Conductors and Devices - Secondary	$317,771	$260,630	$30,321	$2,129	$17,366	$6,172	$1,153	$0
1850	Line Transformers	$2,592,421	$2,126,260	$247,361	$17,370	$141,672	$50,355	$9,404	$0
1855	Services	$2,658,269	$1,858,020	$648,466	$151,783	$0	$0	$0	$0
1860	Meters	$4,299,746	$3,757,388	$437,998	$104,361	$0	$0	$0	$0
1880	IFRS Placeholder Asset Account	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$22,851,738*	*$18,636,081*	*$2,603,584*	*$378,562*	*$867,561*	*$308,360*	*$57,590*	*$0*
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($4,647,209)	($3,788,434)	($518,777)	($71,326)	($188,964)	($67,164)	($12,544)	$0
	Customer Related Net Fixed Assets	$18,204,529	$14,847,648	$2,084,807	$307,236	$678,597	$241,196	$45,046	$0
	Allocated General Plant Net Fixed Assets	$1,572,213	$1,279,255	$179,947	$26,150	$60,895	$21,966	$4,001	$0
	Customer Related NFA Including General Plant	$19,776,742	$16,126,903	$2,264,754	$333,385	$739,491	$263,161	$49,047	$0
	Misc Revenue								
4082	Retail Services Revenues	($800)	($554)	($119)	($112)	($11)	($4)	($1)	($0)
4084	Service Transaction Requests (STR) Revenues	($700)	($485)	($104)	($98)	($9)	($3)	($1)	($0)
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($138,000)	($98,136)	($32,895)	($6,580)	($27)	$0	($362)	$0
4235	Miscellaneous Service Revenues	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*($139,500)*	*($99,174)*	*($33,118)*	*($6,790)*	*($47)*	*($7)*	*($364)*	*($0)*
	Operating and Maintenance								
5005	Operation Supervision and Engineering	$61,002	$48,924	$7,121	$902	$2,853	$1,014	$189	$0
5010	Load Dispatching	$122,880	$98,550	$14,344	$1,816	$5,746	$2,042	$381	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$34,760	$28,469	$3,318	$276	$1,897	$674	$126	$0
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$17,760	$14,546	$1,695	$141	$969	$344	$64	$0
5035	Overhead Distribution Transformers- Operation	$400	$328	$38	$3	$22	$8	$1	$0
5040	Underground Distribution Lines and Feeders - Operation Labour	$50,000	$40,957	$4,773	$390	$2,729	$970	$181	$0
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$400	$328	$38	$3	$22	$8	$1	$0
5055	Underground Distribution Transformers - Operation	$1,000	$820	$95	$7	$55	$19	$4	$0
5065	Meter Expense	$214,300	$187,269	$21,830	$5,201	$0	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0
5085	Miscellaneous Distribution Expense	$86,280	$69,197	$10,072	$1,275	$4,035	$1,434	$268	$0
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$10,800	$8,845	$1,031	$86	$589	$209	$39	$0
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$85,402	$68,492	$9,969	$1,262	$3,994	$1,420	$265	$0
5120	Maintenance of Poles, Towers and Fixtures	$28,160	$23,064	$2,688	$223	$1,537	$546	$102	$0
5125	Maintenance of Overhead Conductors and Devices	$151,040	$123,705	$14,419	$1,197	$8,242	$2,930	$547	$0
5130	Maintenance of Overhead Services	$10,500	$7,339	$2,561	$600	$0	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$105,320	$86,259	$10,054	$835	$5,747	$2,043	$382	$0
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
5150	Maintenance of Underground Conductors and Devices	$13,600	$11,140	$1,298	$106	$742	$264	$49	$0
5155	Maintenance of Underground Services	$45,000	$31,453	$10,977	$2,569	$0	$0	$0	$0
5160	Maintenance of Line Transformers	$26,200	$21,489	$2,500	$176	$1,432	$509	$95	$0
5175	Maintenance of Meters	$25,000	$21,847	$2,547	$607	$0	$0	$0	$0
	Sub-total	*$1,089,804*	*$893,020*	*$121,369*	*$17,674*	*$40,611*	*$14,434*	*$2,696*	*$0*
	Billing and Collection								
5305	Supervision	$181,908	$158,070	$18,426	$4,632	$9	$374	$350	$46
5310	Meter Reading Expense	$246,836	$219,149	$25,546	$2,141	$0	$0	$0	$0
5315	Customer Billing	$617,756	$536,804	$62,575	$15,731	$31	$1,271	$1,187	$157
5320	Collecting	$270,530	$235,079	$27,403	$6,889	$14	$557	$520	$69
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	($139,929)	($121,592)	($14,174)	($3,563)	($7)	($288)	($269)	($35)
5335	Bad Debt Expense	$100,000	$87,391	$12,609	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$10,961	$9,525	$1,110	$279	$1	$23	$21	$3
	Sub-total	*$1,288,062*	*$1,124,425*	*$133,496*	*$26,108*	*$48*	*$1,937*	*$1,809*	*$239*
	Sub Total Operating, Maintenance and Biling	*$2,377,866*	*$2,017,445*	*$254,865*	*$43,783*	*$40,659*	*$16,371*	*$4,505*	*$239*
	Amortization Expense - Customer Related	$743,532	$617,849	$81,193	$13,236	$21,982	$7,813	$1,459	$0
	Amortization Expense - General Plant assigned to Meters	$202,736	$164,959	$23,204	$3,372	$7,852	$2,832	$516	$0
	Admin and General	$1,292,979	$1,095,020	$139,701	$24,277	$22,427	$8,975	$2,453	$126
	Allocated PILs	$140,363	$114,481	$16,075	$2,369	$5,232	$1,860	$347	$0
	Allocated Debt Return	$701,084	$571,805	$80,289	$11,832	$26,134	$9,289	$1,735	$0
	Allocated Equity Return	$843,691	$688,116	$96,621	$14,239	$31,450	$11,178	$2,088	$0
	PLCC Adjustment for Line Transformer	$89,853	$75,137	$8,745	$614	$5,024	$0	$333	$0
	PLCC Adjustment for Primary Costs	$436,851	$364,714	$42,561	$3,570	$24,391	$0	$1,616	$0
	PLCC Adjustment for Secondary Costs	$40,369	$33,332	$3,486	$284	$3,056	$0	$211	$0
	Total	$5,595,679	**$4,697,319**	**$604,037**	**$101,851**	**$123,217**	**$58,312**	**$10,578**	**$365**

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
Distribution Plant								
CWMC	$ 4,299,746	$ 3,757,388	$ 437,998	$ 104,361	$ -	$ -	$ -	$ -
Accumulated Amortization								
Accum. Amortization of Electric Utility Plant - Meters only	$ (709,443)	$ (619,955)	$ (72,268)	$ (17,219)	$ -	$ -	$ -	$ -
Meter Net Fixed Assets	$ 3,590,304	$ 3,137,432	$ 365,730	$ 87,141	$ -	$ -	$ -	$ -
Misc Revenue								
CWNB	$ (1,500)	$ (1,038)	$ (223)	$ (210)	$ (20)	$ (7)	$ (2)	$ (0)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (138,000)	$ (98,136)	$ (32,895)	$ (6,580)	$ (27)	$ -	$ (362)	$ -
Sub-total	$ (139,500)	$ (99,174)	$ (33,118)	$ (6,790)	$ (47)	$ (7)	$ (364)	$ (0)
Operation								
CWMC	$ 214,300	$ 187,269	$ 21,830	$ 5,201	$ -	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	$ 214,300	$ 187,269	$ 21,830	$ 5,201	$ -	$ -	$ -	$ -
Maintenance								
1860	$ 25,000	$ 21,847	$ 2,547	$ 607	$ -	$ -	$ -	$ -
Billing and Collection								
CWMR	$ 246,836	$ 219,149	$ 25,546	$ 2,141	$ -	$ -	$ -	$ -
CWNB	$ 748,357	$ 650,291	$ 75,804	$ 19,056	$ 38	$ 1,540	$ 1,438	$ 190
Sub-total	$ 995,193	$ 869,440	$ 101,350	$ 21,197	$ 38	$ 1,540	$ 1,438	$ 190
Total Operation, Maintenance and Billing	$ 1,234,493	$ 1,078,555	$ 125,727	$ 27,005	$ 38	$ 1,540	$ 1,438	$ 190
Amortization Expense - Meters	$ 284,275	$ 248,417	$ 28,958	$ 6,900	$ -	$ -	$ -	$ -
Allocated PILs	$ 25,487	$ 22,272	$ 2,596	$ 619	$ -	$ -	$ -	$ -
Allocated Debt Return	$ 127,301	$ 111,243	$ 12,966	$ 3,093	$ -	$ -	$ -	$ -
Allocated Equity Return	$ 153,195	$ 133,871	$ 15,603	$ 3,722	$ -	$ -	$ -	$ -
Total	**$ 1,685,251**	**$ 1,495,183**	**$ 152,731**	**$ 34,549**	**$ (9)**	**$ 1,533**	**$ 1,074**	**$ 190**

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
Distribution Plant								
CWMC	$ 4,299,746	$ 3,757,388	$ 437,998	$ 104,361	$ -	$ -	$ -	$ -
Accumulated Amortization								
Accum. Amortization of Electric Utility Plant - Meters only	$ (709,443)	$ (619,955)	$ (72,268)	$ (17,219)	$ -	$ -	$ -	$ -
Meter Net Fixed Assets	$ 3,590,304	$ 3,137,432	$ 365,730	$ 87,141	$ -	$ -	$ -	$ -
Misc Revenue								
CWNB	$ (1,500)	$ (1,029)	$ (224)	$ (217)	$ (21)	$ (7)	$ (2)	$ (0)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (138,000)	$ (98,136)	$ (32,895)	$ (6,580)	$ (27)	$ -	$ (362)	$ -
Sub-total	$ (139,500)	$ (99,165)	$ (33,120)	$ (6,797)	$ (47)	$ (7)	$ (364)	$ (0)
Operation								
CWMC	$ 214,300	$ 187,269	$ 21,830	$ 5,201	$ -	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	$ 214,300	$ 187,269	$ 21,830	$ 5,201	$ -	$ -	$ -	$ -
Maintenance								
1860	$ 25,000	$ 21,847	$ 2,547	$ 607	$ -	$ -	$ -	$ -
Billing and Collection								
CWMR	$ 234,395	$ 208,104	$ 24,259	$ 2,033	$ -	$ -	$ -	$ -
CWNB	$ 710,519	$ 617,411	$ 71,971	$ 18,093	$ 36	$ 1,462	$ 1,365	$ 180
Sub-total	$ 944,914	$ 825,514	$ 96,230	$ 20,126	$ 36	$ 1,462	$ 1,365	$ 180
Total Operation, Maintenance and Billing	$ 1,184,214	$ 1,034,630	$ 120,607	$ 25,934	$ 36	$ 1,462	$ 1,365	$ 180
Amortization Expense - Meters	$ 284,275	$ 248,417	$ 28,958	$ 6,900	$ -	$ -	$ -	$ -
Allocated PILs	$ 21,530	$ 18,814	$ 2,193	$ 523	$ -	$ -	$ -	$ -
Allocated Debt Return	$ 127,301	$ 111,243	$ 12,966	$ 3,093	$ -	$ -	$ -	$ -
Allocated Equity Return	$ 153,195	$ 133,871	$ 15,603	$ 3,722	$ -	$ -	$ -	$ -
Total	**$ 1,631,014**	**$ 1,447,809**	**$ 147,206**	**$ 33,374**	**$ (11)**	**$ 1,456**	**$ 1,001**	**$ 180**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
Distribution Plant								
CWMC	$ 4,299,746	$ 3,757,388	$ 437,998	$ 104,361	$ -	$ -	$ -	$ -
Accumulated Amortization								
Accum. Amortization of Electric Utility Plant - Meters only	$ (709,443)	$ (619,955)	$ (72,268)	$ (17,219)	$ -	$ -	$ -	$ -
Meter Net Fixed Assets	$ 3,590,304	$ 3,137,432	$ 365,730	$ 87,141	$ -	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 309,302	$ 270,317	$ 31,567	$ 7,417	$ -	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 3,899,605	$ 3,407,750	$ 397,297	$ 94,558	$ -	$ -	$ -	$ -
Misc Revenue								
CWNB	$ (1,500)	$ (1,029)	$ (224)	$ (217)	$ (21)	$ (7)	$ (2)	$ (0)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (138,000)	$ (98,136)	$ (32,895)	$ (6,580)	$ (27)	$ -	$ (362)	$ -
Sub-total	*$ (139,500)*	*$ (99,165)*	*$ (33,120)*	*$ (6,797)*	*$ (47)*	*$ (7)*	*$ (364)*	*$ (0)*
Operation								
CWMC	$ 214,300	$ 187,269	$ 21,830	$ 5,201	$ -	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 214,300*	*$ 187,269*	*$ 21,830*	*$ 5,201*	*$ -*	*$ -*	*$ -*	*$ -*
Maintenance								
1860	$ 25,000	$ 21,847	$ 2,547	$ 607	$ -	$ -	$ -	$ -
Billing and Collection								
CWMR	$ 234,395	$ 208,104	$ 24,259	$ 2,033	$ -	$ -	$ -	$ -
CWNB	$ 710,519	$ 617,411	$ 71,971	$ 18,093	$ 36	$ 1,462	$ 1,365	$ 180
Sub-total	*$ 944,914*	*$ 825,514*	*$ 96,230*	*$ 20,126*	*$ 36*	*$ 1,462*	*$ 1,365*	*$ 180*
Total Operation, Maintenance and Billing	$ 1,184,214	$ 1,034,630	$ 120,607	$ 25,934	$ 36	$ 1,462	$ 1,365	$ 180
Amortization Expense - Meters	$ 284,275	$ 248,417	$ 28,958	$ 6,900	$ -	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 39,884	$ 34,857	$ 4,071	$ 956	$ -	$ -	$ -	$ -
Admin and General	$ 643,945	$ 561,816	$ 66,107	$ 14,361	$ 20	$ 802	$ 744	$ 95
Allocated PILs	$ 23,384	$ 20,435	$ 2,382	$ 568	$ -	$ -	$ -	$ -
Allocated Debt Return	$ 138,268	$ 120,827	$ 14,085	$ 3,356	$ -	$ -	$ -	$ -
Allocated Equity Return	$ 166,393	$ 145,405	$ 16,950	$ 4,039	$ -	$ -	$ -	$ -
Total	**$ 2,340,863**	**$ 2,067,222**	**$ 220,039**	**$ 49,316**	**$ 9**	**$ 2,257**	**$ 1,745**	**$ 276**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
	Distribution Plant								
	CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 12,257,107	$ 10,037,983	$ 1,170,125	$ 98,053	$ 668,826	$ 237,723	$ 44,398	$ -
	SNCP	$ 1,044,195	$ 856,431	$ 99,634	$ 6,996	$ 57,064	$ 20,282	$ 3,788	$ -
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 2,592,421	$ 2,126,260	$ 247,361	$ 17,370	$ 141,672	$ 50,355	$ 9,404	$ -
	CWCS	$ 2,658,269	$ 1,858,020	$ 648,466	$ 151,783	$ -	$ -	$ -	$ -
	CWMC	$ 4,299,746	$ 3,757,388	$ 437,998	$ 104,361	$ -	$ -	$ -	$ -
	Sub-total	*$ 22,851,738*	*$ 18,636,081*	*$ 2,603,584*	*$ 378,562*	*$ 867,561*	*$ 308,360*	*$ 57,590*	*$ -*
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (4,647,209)	$ (3,788,434)	$ (518,777)	$ (71,326)	$ (188,964)	$ (67,164)	$ (12,544)	$ -
	Customer Related Net Fixed Assets	$ 18,204,529	$ 14,847,648	$ 2,084,807	$ 307,236	$ 678,597	$ 241,196	$ 45,046	$ -
	Allocated General Plant Net Fixed Assets	$ 1,572,213	$ 1,279,255	$ 179,947	$ 26,150	$ 60,895	$ 21,966	$ 4,001	$ -
	Customer Related NFA Including General Plant	$ 19,776,742	$ 16,126,903	$ 2,264,754	$ 333,385	$ 739,491	$ 263,161	$ 49,047	$ -
	Misc Revenue								
	CWNB	$ (1,500)	$ (1,029)	$ (224)	$ (217)	$ (21)	$ (7)	$ (2)	$ (0)
	NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LPHA	$ (138,000)	$ (98,136)	$ (32,895)	$ (6,580)	$ (27)	$ -	$ (362)	$ -
	Sub-total	*$ (139,500)*	*$ (99,165)*	*$ (33,120)*	*$ (6,797)*	*$ (47)*	*$ (7)*	*$ (364)*	*$ (0)*
	Operating and Maintenance								
	1815-1855	$ 355,564	$ 285,163	$ 41,505	$ 5,255	$ 16,628	$ 5,910	$ 1,104	$ -
	1830 & 1835	$ 168,640	$ 138,120	$ 16,099	$ 1,337	$ 9,203	$ 3,271	$ 611	$ -
	1850	$ 27,600	$ 22,637	$ 2,634	$ 185	$ 1,508	$ 536	$ 100	$ -
	1840 & 1845	$ 50,400	$ 41,284	$ 4,811	$ 393	$ 2,751	$ 978	$ 183	$ -
	CWMC	$ 214,300	$ 187,269	$ 21,830	$ 5,201	$ -	$ -	$ -	$ -
	CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ 28,160	$ 23,064	$ 2,688	$ 223	$ 1,537	$ 546	$ 102	$ -
	1835	$ 151,040	$ 123,705	$ 14,419	$ 1,197	$ 8,242	$ 2,930	$ 547	$ -
	1855	$ 55,500	$ 38,792	$ 13,539	$ 3,169	$ -	$ -	$ -	$ -
	1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1845	$ 13,600	$ 11,140	$ 1,298	$ 106	$ 742	$ 264	$ 49	$ -
	1860	$ 25,000	$ 21,847	$ 2,547	$ 607	$ -	$ -	$ -	$ -
	Sub-total	*$ 1,089,804*	*$ 893,020*	*$ 121,369*	*$ 17,674*	*$ 40,611*	*$ 14,434*	*$ 2,696*	*$ -*
	Billing and Collection								
	CWNB	$ 893,667	$ 776,559	$ 90,523	$ 22,757	$ 45	$ 1,839	$ 1,717	$ 227
	CWMR	$ 234,395	$ 208,104	$ 24,259	$ 2,033	$ -	$ -	$ -	$ -
	BDHA	$ 100,000	$ 87,391	$ 12,609	$ -	$ -	$ -	$ -	$ -
	Sub-total	*$ 1,228,062*	*$ 1,072,053*	*$ 127,391*	*$ 24,789*	*$ 45*	*$ 1,839*	*$ 1,717*	*$ 227*
	Sub Total Operating, Maintenance and Biling	*$ 2,317,867*	*$ 1,965,073*	*$ 248,760*	*$ 42,464*	*$ 40,656*	*$ 16,274*	*$ 4,413*	*$ 227*
	Amortization Expense - Customer Related	$ 743,532	$ 617,849	$ 81,193	$ 13,236	$ 21,982	$ 7,813	$ 1,459	$ -
	Amortization Expense - General Plant assigned to Meters	$ 202,736	$ 164,959	$ 23,204	$ 3,372	$ 7,852	$ 2,832	$ 516	$ -
	Admin and General	$ 1,260,792	$ 1,067,057	$ 136,351	$ 23,515	$ 22,421	$ 8,924	$ 2,404	$ 120
	Allocated PILs	$ 118,569	$ 96,705	$ 13,579	$ 2,001	$ 4,420	$ 1,571	$ 293	$ -
	Allocated Debt Return	$ 701,084	$ 571,805	$ 80,289	$ 11,832	$ 26,134	$ 9,289	$ 1,735	$ -
	Allocated Equity Return	$ 843,691	$ 688,116	$ 96,621	$ 14,239	$ 31,450	$ 11,178	$ 2,088	$ -
	PLCC Adjustment for Line Transformer	$ 89,186	$ 74,579	$ 8,680	$ 609	$ 4,986	$ -	$ 331	$ -
	PLCC Adjustment for Primary Costs	$ 434,488	$ 362,743	$ 42,329	$ 3,550	$ 24,258	$ -	$ 1,607	$ -
	PLCC Adjustment for Secondary Costs	$ 40,214	$ 33,203	$ 3,471	$ 283	$ 3,047	$ -	$ 210	$ -
	Total	**$ 5,484,884**	**$ 4,601,876**	**$ 592,397**	**$ 99,420**	**$ 122,575**	**$ 57,874**	**$ 10,395**	**$ 347**

RATE DESIGN OVERVIEW:

This Exhibit documents the calculation of Norfolk Power's proposed distribution rates by rate class for the 2012 test year, based on the rate design as proposed in this Exhibit.

Norfolk has determined its total 2012 service revenue requirement to be $12,745,918. The total revenue offsets in the amount of $477,289 reduce Norfolk Power's total service revenue requirement to a base revenue requirement to $12,268,629 which is used to determine the proposed distribution rates. The base revenue requirement is derived from Norfolk's 2012 capital and operating forecasts, weather normalized usage, forecasted customer counts, and regulated return on rate base. The revenue requirement is summarized in the table below:

Table 8-1 Calculation of Base Revenue Requirement

Description	Amount
OM&A Expenses	$5,852,617
Amortization Expenses	$2,327,524
Regulated Return On Capital	$4,185,471
PILs	$321,256
Service Revenue Requirement	$12,686,869
Less: Revenue Offsets	$477,289
Base Revenue Requirement	**$12,209,580**

The outstanding base revenue requirement is allocated to the various rate classes using the proposed revenue to cost ratios outlined in Exhibit 7 – Cost Allocation. The following table shows how the base revenue requirement has been allocated to the rate classes.

TABLE 8-2 Rate Class Base Revenue Requirement

Rate Classification	2012 Base Revenue Requirement
Residential	$7,841,414
GS < 50	$2,264,881
General Service 50 to 4999 kW	$1,828,853
Sentinel Lights	$52,404
Street Lighting	$170,049
Unmetered Scattered Load	$18,019
Embedded Distributor	$33,961
Total	**$12,209,580**

Determination of Monthly Fixed Charges:

Based on apply the existing approved monthly service charges, excluding the smart meter adder, to the forecasted number of customers for 2012 and applying the existing approved distribution volumetric charge, excluding the adjustment for LV and transformation allowance, to 2012 forecasted volumes the following table outlines the Norfolk Power's current split between fixed and variable distribution revenue.

Table 8-3 Current Fixed Variable Split

Rate Classification	2012 Fixed Base Revenue with 2011 Approved Rates	2012 Variable Base Revenue with 2011 Approved Rates	2012 Total Base Revenue with 2011 Approved Rates	Fixed Revenue Proportion	Variable Revenue Proportion
Residential	$4,271,440	$2,813,277	$7,084,717	60.3%	39.7%
GS < 50	$1,192,421	$855,092	$2,047,512	58.2%	41.8%
General Service 50 to 4999 kW	$490,927	$1,161,442	$1,652,368	29.7%	70.3%
Sentinel Lights	$29,953	$17,394	$47,347	63.3%	36.7%
Street Lighting	$85,063	$68,576	$153,639	55.4%	44.6%
Unmetered Scattered Load	$24,150	$6,959	$31,109	77.6%	22.4%
Embedded Distributor	$14,663	$0	$14,663	100.0%	0.0%
Total	**$6,108,616**	**$4,922,739**	**$11,031,355**	**55.4%**	**44.6%**

Norfolk Power submits that it is appropriate for 2012 to maintain the same fixed/variable proportions assumed in the current rates to all customer classifications.

In its November 28, 2007 Report on Application of Cost Allocation for Electricity Distributors, the OEB addressed a number of "Other Rate Matters", including the treatment of the fixed rate component (the Monthly Service Charge, or 'MSC') of the bill. At page 12 of the Report, the OEB determined that the floor amount for the MSC should be the avoided costs, as that term is defined in the September 29, 2006 report of the OEB entitled "Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors". Norfolk Power's MSCs exceed that floor amount by rate class. With respect to the upper bound for the MSC, the OEB considered it to be inappropriate to make changes to the MSC ceiling at this time, given the number of issues that remain to be examined within the scope of the OEB's Rate Review proceeding (EB-2008-0031). The OEB indicated that for the time being, it does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC; and that distributors that are currently above that value are not required to make changes to their current MSC to bring it to or below that level at this time. In accordance with the filing requirements the following information has been provided with regards to the MSC.

Table 8-4 Monthly Service Charge Information from Cost Allocaiton Model

Rate Classification	2011 Approved Monthly Service Charge	Customer Unit Cost per month - Avoided Cost	Customer Unit Cost per month - Minimum System with PLCC Adjustment
Residential	$20.77	$7.04	$22.38
GS < 50	$49.74	$6.14	$24.71
General Service 50 to 4999 kW	$244.38	$16.61	$49.49
Sentinel Lights	$6.15	$0.30	$11.88
Street Lighting	$1.85	$0.00	$8.95
Unmetered Scattered Load	$26.55	$1.10	$11.43
Embedded Distributor	$244.38	$3.00	$5.78

Consistent with recent Board Decision on 2011 cost of service rate applications for Hydro One Brampton, Kenora Hydro and Horizon Utilities this Application proposes to maintain the current fixed/variable proportions for all rate classes as shown in the following table

Table 8-5 Proposed Monthly Service Charge

Rate Classification	Total Base Revenue Requirement	Fixed Revenue Proportion	Fixed Revenue	Annualized Customers / Connections	Proposed Fixed Distribution Charge
Residential	$7,841,414	60.3%	$4,727,659	205,654	$22.99
GS < 50	$2,264,881	58.2%	$1,319,011	23,973	$55.02
General Service 50 to 4999 kW	$1,828,853	29.7%	$543,361	2,009	$270.48
Sentinel Lights	$52,404	63.3%	$33,152	4,870	$6.81
Street Lighting	$170,049	55.4%	$94,148	45,980	$2.05
Unmetered Scattered Load	$18,019	77.6%	$13,988	910	$15.38
Embedded Distributor	$33,961	100.0%	$33,961	60	$566.02
Total	**$12,209,580**				

Proposed Volumetric Charges:

The variable distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2012 Test Year usage, kWh or kW, as the class charge determinant.

The following Table provides Norfolk Power's calculations of its proposed variable distribution charges for the 2012 Test Year which maintains the same fixed/variable split used in designing the current approved rates.

Table 8-6 Proposed Distribution Volumetric Charge

Rate Classification	Total Base Revenue Requirement	Fixed Revenue	Variable Revenue	Annualized kWh or kW as required	Unit of Measure	Proposed Variable Distribution Charge before Transformer Allowance
Residential	$7,841,414	$4,727,659	$3,113,754	148,067,203	kWh	$0.0210
GS < 50	$2,264,881	$1,319,011	$945,870	61,517,376	kWh	$0.0154
General Service 50 to 4999 kW	$1,828,853	$543,361	$1,285,492	346,440	kW	$3.7106
Sentinel Lights	$52,404	$33,152	$19,252	951	kW	$20.2453
Street Lighting	$170,049	$94,148	$75,900	9,810	kW	$7.7374
Unmetered Scattered Load	$18,019	$13,988	$4,031	467,056	kWh	$0.0086
Embedded Distributor	$33,961	$33,961	$0			
Total	**$12,209,580**	**$6,765,281**	**$5,444,299**			

Proposed Adjustment for Transformer Allowance:

Currently, Norfolk Power provides a Transformer Allowance to those customers that own their transformation facilities. Norfolk Power proposes to maintain the current approved transformer ownership allowance of $0.60 per kW. The Transformer Allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. Therefore, when a customer provides its own step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

The amount of the Transformer Allowance expected to be provided to those GS > 50 kW customers that own their transformers is included in the GS > 50 kW volumetric charge. As a result, the proposed volumetric charge of 3.7106 per kW for the GS > 50 kW customer class is increased by $0.2760 per kW to include the amount of the Transformer Allowance in the GS > 50 kW class distribution volumetric rate This means the total proposed distribution volumetric charge for the GS > 50 kW class will be $3.9866

Proposed Distribution Rates:

The following table sets out Norfolk Power's proposed 2011 electricity distribution rates based on the foregoing calculations.

Table 8-7 Proposed Distribution Rates

Rate Classification	Proposed Monthly Service Charge	Unit of Measure	Proposed Volumetric Distribution Charge incl Transformer Allowance Adjustment
Residential	$22.99	kWh	$0.0210
GS < 50	$55.02	kWh	$0.0154
General Service 50 to 4999 kW	$270.48	kW	$3.9866
Sentinel Lights	$6.81	kW	$20.2453
Street Lighting	$2.05	kW	$7.7374
Unmetered Scattered Load	$15.38	kWh	$0.0086
Embedded Distributor	$566.02		
Transformer Discount		kWh	($0.60)

Recovery of Low Voltage (LV) Costs:

Consistent with the approach in the Board's 2006 EDR model, LV costs of $296,427 have been allocated to each rate class based on the proportion of retail transmission connection revenue collected from each class. The amount of forecasted LV costs in 2012 is based on calculations shown in Table 8-8. These calculations are based on applying the appropriate Hydro One sub transmission charges to the forecasted units for 2012. The Hydro One sub transmission charges used in the calculations are from the Hydro One Approved Rate Schedule (EB-2009-0096). The forecasted units for 2012 is based on the trend in the level of sub transmission service (i.e kW) that Hydro One provided to Norfolk Power from 2008 to 2010.

Table 8-8 LV Costs					
2012 Data for ST/LV Charges					
Numer of Monthy Service Charges	6				
Number of Meter Points	2				
Common ST kW	189,580				
LVDS kW	70,749				
Hydro One Sub Tranmission Charges based on			Units	Months	
Service Charge (includes Smart Meter Funding Add	$292.56	per month	6	12	$21,064
Meter Charge (for Hydro One ownership)	$466.14	per meter per	2	12	$11,187
Facility charge for connection to Specific ST Lines	$0.668	per kW	189,580	12	$126,639
Facility charge for connection to low voltage (<	$1.944	per kW	70,749	12	$137,537
					$296,427
Source of Rates - Hydro One Approved Rate Order Filed: December 17, 2010; EB-2009-0096; Exhibit 3.0; Page 22 and 23 of 39					

The calculation of proposed LV charges to recover the 2012 LV amount is outlined in the following table:

Table 8-9 Proposed LV Charges

Rate Classification	Unit of Measure	Retail Transmission Connection Rate ($) Per kWh or kW	Basis for Allocation ($)	Allocation Percentages	Allocated $	Annualized kWh or kW as required	Proposed LV Charge
Residential	kWh	0.0041	641,072	46.4%	137,457	148,067,203	$0.0009
GS < 50	kWh	0.0036	233,864	16.9%	50,145	61,517,376	$0.0008
General Service 50 to 4999 kW	kW	1.4256	493,886	35.7%	105,898	346,440	$0.3057
Sentinel Lights	kW	1.1251	1,070	0.1%	229	951	$0.2412
Street Lighting	kW	1.1021	10,811	0.8%	2,318	9,810	$0.2363
Unmetered Scattered Load	kWh	0.0036	1,776	0.1%	381	467,056	$0.0008
Embedded Distributor			0	0.0%	0		
Total			**1,382,478**	**100%**	**296,427**		

RETAIL TRANSMISSION SERVICE RATES

Electricity distributors are charged the Ontario Uniform Transmission Rates (UTRs) at the wholesale level and subsequently pass these charges on to their distribution customers through Retail Transmission Service Rates (RTSRs). For each distribution rate class there are two RTSRs, one for network and one for connection. The RTSR network charge recovers the UTR wholesale network service charge, and the RTSR connection charge recovers the UTR wholesale line and transformation connection charges. Deferral accounts capture timing and rate differences between the UTR's paid at the wholesale level and RTSR's billed to distribution customers.

The Board has provided a Microsoft Excel workbook "2012_RTSR_Adjustment_Work_Form" and instructions for distributors to complete as part of their 2012 electricity rate applications. Norfolk has completed this workbook to determine the RTSR's and has filed the model as part of this application. Table 8.10 is reproduced from the Board model and indicates the new RTSR's**.**

Table 8.10

Final 2012 RTS Rates

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0064	$ 0.0035
General Service Less Than 50 kW	kWh	$ 0.0058	$ 0.0031
General Service 50 to 4,999 kW	kW	$ 2.3614	$ 1.2237
Unmetered Scattered Load	kWh	$ 0.0058	$ 0.0031
Sentinel Lighting	kW	$ 1.7900	$ 0.9658
Street Lighting	kW	$ 1.7810	$ 0.9460
Embedded Distributor	kWh	$ 0.0058	$ 0.0031

Previously Norfolk has been embedded to Haldimand Hydro (Haldimand) and as such was billed for transmission services from Haldimand, in addition to the IESO and Hydro One. As a result of changes to Norfolk's distribution system, effective August 2010, Norfolk is no longer embedded to Haldimand Hydro. Norfolk estimates that 65% of the load previously delivered via Haldimand Hydro will now be routed through Norfolk's own transformer station, incurring Network and Line Connection charges from the IESO, but not Transformation Connection charges. The remaining 35% of previous Haldimand load will flow through a Hydro One transformer station, incurring Network, Line Connection and Transformation Connection charges. In order to complete the Board Staff model, Norfolk has added 65% of the 2010 actual Haldimand volumes, to the IESO 2010 actual volumes (with the exception of Transformation) and has added the remaining 35% of Haldimand volumes to Hydro One 2010 actual data. The following tables illustrate the 2010 actual load data, followed by the redistributed data which was entered into the Board model. This method is similar to the method Norfolk proposed in its 2011 IRM application, which was accepted by the Board (EB-2011-0049).

Table 8.11 – 2010 Actual Transmission Charges to Norfolk

IESO						
Jan Rate	$2.97		$0.73		$1.71	
July Rate	$2.97		$0.73		$1.71	
	Network $	Network Volume (kW)	Line Connection ($)	Line Connection Volume (kW)	Transformation ($)	Transformation Volume (kW)
Jan	158,301.00	53,300.00	41,610.00	57,000.00	55,289.43	32,333.00
Feb	95,203.35	32,055.00	25,016.37	34,269.00	17,655.75	10,325.00
Mar	89,794.98	30,234.00	22,079.58	30,246.00	13,262.76	7,756.00
Apr	81,389.88	27,404.00	20,208.59	27,683.00	12,303.45	7,195.00
May	141,799.68	47,744.00	39,957.28	54,736.00	47,488.41	27,771.00
Jun	120,507.75	40,575.00	32,448.50	44,450.00	30,347.37	17,747.00
Jul	160,846.29	54,157.00	44,234.35	60,595.00	38,941.83	22,773.00
Aug	149,946.39	50,487.00	39,014.85	53,445.00	22,127.40	12,940.00
Sep	148,446.54	49,982.00	36,910.26	50,562.00	21,742.65	12,715.00
Oct	96,590.34	32,522.00	26,538.42	36,354.00	11,899.89	6,959.00
Nov	120,534.48	40,584.00	33,818.71	46,327.00	18,615.06	10,886.00
Dec	116,418.06	39,198.00	30,288.43	41,491.00	20,648.25	12,075.00
	$1,479,778.74	498,242.00	$392,125.34	537,158.00	$310,322.25	181,475.00

Hydro One						
Jan Rate	$2.24		$0.60		$1.39	
May Rate	$2.65		$0.64		$1.50	
	Network $	Network Volume (kW)	Line $	Line Volume (kW)	Transformation ($)	Tran Volume (kW)
Jan	35,360.64	15,786.00	9,471.60	15,786.00	21,942.54	15,786.00
Feb	34,590.08	15,442.00	9,265.20	15,442.00	21,464.38	15,442.00
Mar	28,779.52	12,848.00	7,836.60	13,061.00	18,154.79	13,061.00
Apr	27,471.58	11,831.00	7,229.12	11,890.00	16,788.68	11,890.00
May	46,284.90	17,466.00	11,178.24	17,466.00	24,277.74	17,466.00
Jun	51,380.55	19,389.00	12,408.96	19,389.00	29,083.50	19,389.00
Jul	53,182.85	20,069.00	12,844.16	20,069.00	30,103.50	20,069.00
Aug	53,331.25	20,125.00	12,880.00	20,125.00	30,187.50	20,125.00
Sep	36,373.90	13,726.00	8,784.64	13,726.00	20,589.00	13,726.00
Oct	34,807.75	13,135.00	8,460.80	13,220.00	19,830.00	13,220.00
Nov	40,778.20	14,747.00	9,848.32	15,388.00	23,082.00	15,388.00
Dec	43,346.05	16,357.00	10,468.48	16,357.00	24,535.50	16,357.00
	$485,687.27	190,921.00	$120,676.12	191,919.00	$280,039.13	191,919.00

Halidmand Hydro				
Jan Rate	$2.69		$2.53	
May Rate	$2.98		$2.72	
	Network $	Network Volume (kW)	Connection $	Connection Volume (kW)
Jan	23,045.71	8,567.18	21,674.97	8,567.18
Feb	20,892.42	7,766.70	19,649.75	7,766.70
Mar	18,562.86	6,900.69	17,458.75	6,900.69
Apr	16,668.02	6,196.29	15,676.61	6,196.29
May	22,918.51	7,690.26	20,888.28	7,690.26
Jun	24,838.77	8,334.60	22,638.44	8,334.60
Jul	3,565.99	1,196.56	3,250.10	1,196.56
Aug	0.00		0.00	
Sep	0.00		0.00	
Oct	0.00		0.00	
Nov	0.00		0.00	
Dec	0.00		0.00	
	$130,492.29	46,652.28	$121,236.90	46,652.28
Total kW		735,815		775,729

Table 8.12 - 2010 Transmission Volumes Reallocated

IESO with 65% of Haldimand Allocated to Network and Line Con Only	Network Volume (kW)	Line Connection Volume (kW)	Transformation Volume (kW)
Jan	58,869	62,569	32,333.00
Feb	37,103	39,317	10,325.00
Mar	34,719	34,731	7,756.00
Apr	31,432	31,711	7,195.00
May	52,743	59,735	27,771.00
Jun	45,992	49,867	17,747.00
Jul	54,935	61,373	22,773.00
Aug	50,487	53,445	12,940.00
Sep	49,982	50,562	12,715.00
Oct	32,522	36,354	6,959.00
Nov	40,584	46,327	10,886.00
Dec	39,198	41,491	12,075.00
Total	528,566	567,482	181,475

Hydro One with 35% of Haldimand Allocated All Categories	Network Volume (kW)	Line Connection Volume (kW)	Transformation Volume (kW)
Jan	18,785	18,785	18,785
Feb	18,160	18,160	18,160
Mar	15,263	15,476	15,476
Apr	14,000	14,059	14,059
May	20,158	20,158	20,158
Jun	22,306	22,306	22,306
Jul	20,488	20,488	20,488
Aug	20,125	20,125	20,125
Sep	13,726	13,726	13,726
Oct	13,135	13,220	13,220
Nov	14,747	15,388	15,388
Dec	16,357	16,357	16,357
Total	207,249	208,247	208,247

Total kW after Reallocation	735,815	775,729	389,722

LOSS FACTOR

DETERMINATION OF LOSS ADJUSTMENT FACTORS:

Total Loss Factor:

NPDI has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2004 to 2008. The calculations are summarized in Table 8-10 below.

Table 8-13 Line Loss Calculation

		Historical Years					5-Year Average
		2006	2007	2008	2009	2010	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	403,107,950	403,123,270	397,499,650	383,179,248	393,192,429	396,020,509
A(2)	"Wholesale" kWh delivered to distributor (lower value)	398,412,066	398,427,208	392,869,098	378,715,518	387,987,818	391,282,342
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						0
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	398,412,066	398,427,208	392,869,098	378,715,518	387,987,818	391,282,342
D	"Retail" kWh delivered by distributor	381,214,712	382,635,352	375,248,931	366,381,706	368,752,614	374,846,663
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = **D - E**	381,214,712	382,635,352	375,248,931	366,381,706	368,752,614	374,846,663
G	Loss Factor in Distributor's system = **C / F**	1.045111989	1.041271294	1.046955942	1.033663831	1.052162895	1.043846405
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0117865	1.011786499	1.011786501	1.011786499	1.013414367	1.012112073
	Total Losses						
I	Total Loss Factor = **G x H**	1.057430202	1.053544237	1.059295889	1.045847109	1.066276995	1.056489549

The supply facility loss factor (the "SFLF") shown in the above table represents the losses on supply to Norfolk. The SFLF is calculated on the measured quantities between the transformer stations and the wholesale meter points. The SFLF used in the calculations of the total loss factor above is based the weighted average of 2011 forecast of purchases from the IESO (1.0045) and Hydro One (1.0340).

Total Loss Factor by Class:

Table 8-11 sets out the class-specific Loss Factors used by Norfolk in the calculation of commodity and other non-distribution charges.

Table 8-14 Total Loss Factor by Class

Supply Facility Loss Factor	1.01211
Distribution Loss Factor	
Distribution Loss Factor - Secondary Metered Customer 5,000 kW	1.0565
Distribution Loss Factor - Primary Metered Customer < 5,000kW	1.0465
Total Loss Factor	
Total Loss Factor - Seconday Metered Customer < 5,000kW	1.0565
Total Loss Factor - Primary Metered Customer < 5,000kW	1.0465

Materiality Analysis on Distribution Losses:

Norfolk's Distribution Loss Adjustment factor is 4.43%. Pursuant to the Filing Requirements, as the Distribution Loss Adjustment factor is less than 5%, Norfolk is not required to provide a explanation of, or justification for, its loss adjustment factor.

RATE MITIGATION:

Norfolk has applied for disposition of the PP&E deferral account (credit to customers) over a one year period instead of over multiple years to provide a greater offset to increasing rates.

Norfolk has requested the smart meter revenue requirement and the stranded meter costs be recovered over a four year period to reduce the increase in rates.

EXISTING RATE CLASSES:

Residential:

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less Than 50kW:

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. This class includes small commercial services such as small stores, small service stations, restaurants, churches, small offices and other establishments with similar loads.

General Service Greater Than 50 kW:

This classification refers to a non-residential account whose monthly average peak demand is greater than, or is forecast to be greater than, 50 kW but less than 5,000 kW. This class includes medium and large-size commercial buildings, apartment buildings, condominiums, trailer courts, industrial plants, as well as large stores, shopping centers, hospitals, manufacturing or processing plants, garages, storage buildings, restaurants, office buildings, hotels, motels, schools, colleges, arenas and other comparable premises.

Unmetered Scattered Load:

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, private sentinel lighting, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/ consumption of the proposed unmetered load.

Sentinel Lighting:

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting:

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photocells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

EXISTING RATE SCHEDULE

Norfolk has attached the Board's Decision and Order from its 2011 Rate Application (EB-2011-0049) which contains a complete schedule of existing rates.

Appendix A

To Decision and Order

Draft Tariff of Rates and Charges

Board File No: EB-2011-0049

DATED: May 6, 2011

Norfolk Power Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0049

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex, or quadruplex house, with residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	20.77
Smart Meter Funding Adder – effective until April 30, 2012	$	1.00
Distribution Volumetric Rate	$/kWh	0.0190
Low Voltage Service Rate	$/kWh	0.0007
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kWh	0.0034
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kWh	(0.0044)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery (2011) – effective until April 30, 2012	$/kWh	0.0023
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0006)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0066
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0049

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	49.74
Smart Meter Funding Adder – effective until April 30, 2012	$	1.00
Distribution Volumetric Rate	$/kWh	0.0139
Low Voltage Service Rate	$/kWh	0.0006
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kWh	0.0034
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kWh	(0.0045)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery (2011) – effective until April 30, 2012	$/kWh	0.0007
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0004)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0060
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0036

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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EB-2011-0049

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	244.38
Smart Meter Funding Adder – effective until April 30, 2012	$	1.00
Distribution Volumetric Rate	$/kW	3.6285
Low Voltage Service Rate	$/kW	0.2622
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kW	1.5716
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kW	(2.1576)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery (2011) – effective until April 30, 2012	$/kW	0.1090
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.0589)
Retail Transmission Rate – Network Service Rate	$/kW	2.4432
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4256

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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EB-2011-0049

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per customer)	$	26.55
Distribution Volumetric Rate	$/kWh	0.0149
Low Voltage Service Rate	$/kWh	0.0006
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kWh	(0.0050)
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0007)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0060
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0036

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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EB-2011-0049

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	6.15
Distribution Volumetric Rate	$/kW	18.2916
Low Voltage Service Rate	$/kW	0.2024
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kW	1.3797
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kW	(1.2486)
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(1.2663)
Retail Transmission Rate – Network Service Rate	$/kW	1.8520
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1251

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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EB-2011-0049

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to a account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	1.85
Distribution Volumetric Rate	$/kW	6.9907
Low Voltage Service Rate	$/kW	0.1999
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kW	(1.5276)
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.1736)
Retail Transmission Rate – Network Service Rate	$/kW	1.8427
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1021

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
TARIFF OF RATES AND CHARGES
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0049

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

Norfolk Power Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0049

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Notification Charge	$	15.00
Account History	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer-owned equipment	$	30.00
Service call – after regular hours	$	165.00
Specific Charge for Access to the Power Poles ($/pole/year)	$	22.35

Norfolk Power Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0049

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0560
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0454
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

PROPOSED RATE CLASSES:

Norfolk is proposing the creation of an Embedded Distributor rate class, with the rates and line loss as proposed within this application. This classification applies to Hydro One Networks Inc., an electricity distributor licensed by the Board, and provided electricity by means of Norfolk Power Distribution Inc.'s distribution facilities. Further servicing details are available in the Norfolk's Conditions of Service.

PROPOSED RATES AND CHARGES

Norfolk has attached a schedule of the proposed rates and charges effective May 1, 2012.

Norfolk Power Distribution Inc.
Proposed TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0272

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	22.99
GEA Funding Adder	$	0.06
Smart Meter / Stranded Assets Rate Rider	$	1.71
Distribution Volumetric Rate	$/kWh	0.0210
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	0.0033
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	0.0003
Rate Rider for PILS Recovery (2012) – effective until December 31, 2013	$/kWh	0.0006
Rate Rider for Extraordinary Event / Z Factor Storm Expense – effective until April 30, 2013	$/kwh	0.0010
Rate Rider for PP&E Deferral Account Disposition – effective until April 30, 2013	$/kwh	(0.0016)
Rate Rider for LRAM Recovery – effective until April 30, 2013	$/kwh	0.0006
Retail Transmission Rate – Network Service Rate	$/kWh	0.0064
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0035

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
Proposed TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0272

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

Service Charge	$	55.02
GEA Funding Adder	$	0.06
Smart Meter / Stranded Assets Rate Rider	$	1.71
Distribution Volumetric Rate	$/kWh	0.0154
Low Voltage Service Rate	$/kWh	0.0008
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0033
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0002)
Rate Rider for PILS Recovery (2012) – effective until December 31, 2013	$/kWh	0.0004
Rate Rider for Extraordinary Event / Z Factor Storm Expense – effective until April 30, 2013	$/kwh	0.0007
Rate Rider for PP&E Deferral Account Disposition – effective until April 30, 2013	$/kwh	(0.0011)
Rate Rider for LRAM Recovery – effective until April 30, 2013	$/kwh	0.0012
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0031

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
Proposed TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0272

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	270.48
GEA Funding Adder	$	0.06
Smart Meter / Stranded Assets Rate Rider	$	1.71
Distribution Volumetric Rate	$/kW	3.9866
Low Voltage Service Rate	$/kW	0.3057
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kW	0.0033
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(0.3294)
Rate Rider for PILS Recovery (2012) – effective until December 31, 2013	$/kW	0.0621
Rate Rider for Extraordinary Event / Z Factor Storm Expense – effective until April 30, 2013	$/kw	0.1016
Rate Rider for PP&E Deferral Account Disposition – effective until April 30, 2013	$/kw	(0.1599)
Rate Rider for LRAM Recovery – effective until April 30, 2013	$/kw	0.0605
Retail Transmission Rate – Network Service Rate	$/kW	2.3614
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2237

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
Proposed TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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EB-2011-0272

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per Customer)	$	15.38
Distribution Volumetric Rate	$/kWh	0.0086
Low Voltage Service Rate	$/kWh	0.0008
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	0.0001
Rate Rider for PILS Recovery (2012) – effective until December 31, 2013	$/kWh	0.0005
Rate Rider for Extraordinary Event / Z Factor Storm Expense – effective until April 30, 2013	$/kwh	0.0007
Rate Rider for PP&E Deferral Account Disposition – effective until April 30, 2013	$/kwh	(0.0012)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0031

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
Proposed TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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EB-2011-0272

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	6.81
Distribution Volumetric Rate	$/kW	20.2453
Low Voltage Service Rate	$/kW	0.2412
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kW	0.0033
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	0.9961
Rate Rider for PILS Recovery (2012) – effective until December 31, 2013	$/kW	0.6480
Rate Rider for Extraordinary Event / Z Factor Storm Expense – effective until April 30, 2013	$/kw	1.0610
Rate Rider for PP&E Deferral Account Disposition – effective until April 30, 2013	$/kw	(1.6693)
Retail Transmission Rate – Network Service Rate	$/kW	1.7900
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9658

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
Proposed TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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EB-2011-0272

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.05
Distribution Volumetric Rate	$/kW	7.7374
Low Voltage Service Rate	$/kW	0.2363
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	0.0636
Rate Rider for PILS Recovery (2012) – effective until December 31, 2013	$/kW	0.2038
Rate Rider for Extraordinary Event / Z Factor Storm Expense – effective until April 30, 2013	$/kw	0.3337
Rate Rider for PP&E Deferral Account Disposition – effective until April 30, 2013	$/kw	(0.5251)
Retail Transmission Rate – Network Service Rate	$/kW	1.7810
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9460

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
Proposed TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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EB-2011-0272

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Board, and provided electricity by means of Norfolk Power Distribution Inc.'s distribution facilities. Further servicing details are available in the distributor's Conditions of Service

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	566..02
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0012)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0031

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
Proposed TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0272

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

Norfolk Power Distribution Inc.
Proposed TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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EB-2011-0272

ALLOWANCES

Transformer Allowance for Ownership - General Service 50 to 4,999 kW customers - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Norfolk Power Distribution Inc.
Proposed TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Customer Administration		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Pulling post-dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income tax letter	$	15.00
Notification Charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge / change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special Meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install / remove load control device – during regular hours	$	65.00
Install / remove load control device – after regular hours	$	185.00
Service call – customer-owned equipment	$	30.00
Service call – after regular hours	$	165.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Norfolk Power Distribution Inc.
Proposed TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0272

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0564
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0564
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0464
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0464

RECONCILIATION OF RATE CLASS REVENUE

The following table provides a reconciliation between the 2012 distribution rate calculations based on the 2012 Proposed Rates and the total base revenue required.

Rate Classification	Customers/ Connections	Annualized Average Number of Customer Connections	Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Service Revenue Requirement	Transformer Allowance Credit	Total	Difference
			kWh	kW	Monthly Service Charge	Volumetric kWh	Volumetric kW					
Residential	Customers	205,654	148,067,203		$22.99	$0.0210		$7,841,414	$7,841,414		$7,841,414	$ -
GS < 50	Customers	23,973	61,517,376		$55.02	$0.0154		$2,264,881	$2,264,881		$2,264,881	$ -
General Service 50 to 4999 kW	Customers	2,009		346,440	$270.48		$3.9866	$1,924,470	$1,828,853	$ 95,618	$1,924,470	$ -
Sentinel Lights	Connections	4,870		951	$6.81		$20.2453	$52,404	$52,404		$52,404	$ -
Street Lighting	Connections	45,980		9,810	$2.05		$7.7374	$170,049	$170,049		$170,049	$ -
Unmetered Scattered Load	Connections	910	467,056		$15.38	$0.0086		$18,019	$18,019		$18,019	$ -
Embedded Distributor	Customers	60	0		$566.02	$0.0000		$33,961	$33,961		$33,961	$ -
Total								$12,305,198	$12,209,580	$ 95,618	$ 12,305,198	$ -

RATE AND BILL IMPACTS:

This Exhibit presents the results of the assessment of customer total bill impacts by level of consumption by customer per rate class and per the total customer class.

Impacts are shown using the applicable current approved rates and the proposed 2012 distribution rates, including rate riders for the disposition of Deferral and Variance Accounts, as discussed in Exhibit 9.

The total bill impacts are calculated for each rate class at various levels of consumption. The rate impacts are assessed on the basis of moving to the proposed distribution rates.

RESIDENTIAL

Consumption: 800 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE	CHARGE	Volume	RATE	CHARGE		%	% of Total Bill
Monthly Service Charge			20.77			22.99	2.22	10.69%	16.60%
Distribution (kWh)	800	0.0190	15.20	800	0.0210	16.80	1.60	10.53%	12.13%
Tax Change Rider	800	(0.0006)	(0.48)	800	0.0000	0.00	0.48	(100.00%)	0.00%
Low Voltage Rider (kWh)	800	0.0007	0.56	800	0.0009	0.72	0.16	28.57%	0.52%
Smart Meter Adder/Rider (per month)			1.00			1.71	0.71	71.00%	1.23%
LRAM & SSM Rider (kWh)	800	0.0023	1.84	800	0.0006	0.47	(1.37)	(74.49%)	0.34%
GEA Plan (per month) Adder						0.06	0.06	#DIV/0!	0.04%
Deferrral & Variance Acct (kWh)	800	(0.0044)	(3.52)	800	0.0003	0.24	3.76	(106.82%)	0.17%
Distribution Sub-Total			**35.37**			**42.99**	**7.62**	**21.54%**	**31.03%**
Retail Transmisssion (kWh)	845	0.0107	9.04	845	0.0099	8.36	(0.68)	(7.48%)	6.04%
Delivery Sub-Total			**44.41**			**51.35**	**6.94**	**15.63%**	**37.07%**
Other Charges (kWh)	845	0.0131	11.09	845	0.0131	11.09	(0.00)	(0.02%)	8.01%
Cost of Power Commodity (kWh)	600	0.0680	40.80	600	0.0680	40.80	0.00	0.00%	29.46%
Cost of Power Commodity (kWh)	245	0.0790	19.34	245	0.0790	19.34	0.00	0.00%	13.96%
Total Bill Before Taxes			**115.64**			**122.58**	**6.94**	**6.00%**	**88.50%**
GST		13.00%	15.03		13.00%	15.94	0.90	6.00%	11.50%
Total Bill			**130.67**			**138.52**	**7.84**	**6.00%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption: 2,000 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			49.74			55.02	5.28	10.62%	16.34%
Distribution (kWh)	2,000	0.0139	27.80	2,000	0.0154	30.80	3.00	10.79%	9.15%
Tax Change Rider	2,000	(0.0004)	(0.80)	2,000	0.0000	0.00	0.80	(100.00%)	0.00%
Low Voltage Rider (kWh)	2,000	0.0006	1.20	2,000	0.0008	1.63	0.43	35.85%	0.48%
Smart Meter Adder/Rider (per month)			1.00			1.71	0.71	71.00%	0.51%
LRAM & SSM Rider (kWh)	2,000	0.0007	1.40	2,000	0.0012	2.32	0.92	66.06%	0.69%
GEA Plan (per month) Adder						0.06	0.06	#DIV/0!	0.02%
Deferrral & Variance Acct (kWh)	2,000	(0.0045)	(9.00)	2,000	(0.0002)	(0.40)	8.60	(95.56%)	(0.12%)
Distribution Sub-Total			**71.34**			**91.14**	**19.80**	**27.76%**	**27.07%**
Retail Transmisssion (kWh)	2,112	0.0096	20.28	2,112	0.0089	18.80	(1.48)	(7.29%)	5.58%
Delivery Sub-Total			**91.62**			**109.94**	**18.33**	**20.00%**	**32.66%**
Other Charges (kWh)	2,112	0.0131	27.73	2,112	0.0131	27.72	(0.01)	(0.02%)	8.24%
Cost of Power Commodity (kWh)	600	0.0680	40.80	600	0.0680	40.80	0.00	0.00%	12.12%
Cost of Power Commodity (kWh)	1,512	0.0790	119.45	1,512	0.0790	119.45	0.00	0.00%	35.48%
Total Bill Before Taxes			**279.59**			**297.91**	**$18.32**	**6.55%**	**88.50%**
GST		13.00%	36.35		13.00%	38.73	2.38	6.55%	11.50%
Total Bill			**315.94**			**336.64**	**$20.70**	**6.55%**	**100.00%**

GENERAL SERVICE > 50 kW

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			244.38			270.48	26.10	10.68%	6.62%
30,000 kWh	Distribution (kW)	100	3.6285	362.85	100	3.9866	398.66	35.81	9.87%	9.76%
100 kW	Tax Change Rider	100	(0.0589)	(5.89)	100	0.0000	0.00	5.89	(100.00%)	0.00%
	Low Voltage Rider (kW)	100	0.2622	26.22	100	0.3057	30.57	4.35	16.58%	0.75%
	Smart Meter Adder/Rider (per month)			1.00			1.71			
	LRAM & SSM Rider (kW)	100	0.1090	10.90	100	0.0605	6.05	(4.85)	(44.45%)	0.15%
	GEA Plan (per month) Adder						0.06	0.06	#DIV/0!	0.00%
	Deferral & Variance Acct (kW)	100	(2.1576)	(215.76)	100	(0.3256)	(32.56)	183.20	(84.91%)	(0.80%)
	Distribution Sub-Total			**423.70**			**674.97**	**250.56**	**59.14%**	**16.48%**
	Retail Transmisssion (kW)	100	3.8688	386.88	100	3.5851	358.51	(28.37)	(7.33%)	8.78%
	Delivery Sub-Total			**810.58**			**1,033.48**	**222.19**	**27.41%**	**25.30%**
	Other Charges (kWh)	31,680	0.0131	415.92	31,680	0.0131	415.84	(0.08)	(0.02%)	10.18%
	Cost of Power Commodity (kWh)	31,680	0.0684	2,165.96	31,680	0.0684	2,165.96	0.00	0.00%	53.02%
	Total Bill Before Taxes			**3,392.46**			**3,615.28**	**222.11**	**6.55%**	**88.50%**
	GST		13.00%	441.02		13.00%	469.99	28.97	6.57%	11.50%
	Total Bill			**3,833.48**			**4,085.27**	**251.08**	**6.55%**	**100.00%**

Sentinel Lighting

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Billing Determinants	Monthly Service Charge			6.15			6.81	0.66	10.68%	23.43%
1 Connections	Distribution (kW)	0.3	18.2916	5.49	0.3	20.2453	6.07	0.59	10.68%	23.43%
135.00 kWh	Tax Change Rider	0.3	(1.2663)	(0.38)	0.3	0.0000	0.00	0.38	(100.00%)	20.91%
0.30 kW	Low Voltage Rider (kW)	0.3	0.2024	0.06	0.3	0.2412	0.07	0.01	19.19%	0.25%
	LRAM & SSM Rider (kW)	0.3	0.0000	0.00	0.3	0.0000	0.00	0.00	#DIV/0!	0.00%
	GEA Plan (per month) Adder			0.00			0.00	0.00	#DIV/0!	0.00%
	Deferral & Variance Acct (kW)	0.3	(1.2486)	(0.37)	0	1.0358	0.31	0.69	(182.96%)	1.07%
	Distribution Sub-Total			**10.94**			**13.26**	**2.32**	**21.20%**	**69.09%**
	Retail Transmisssion (kW)	0.3	2.9771	0.89	0.3	2.7558	0.83	(0.07)	(7.43%)	2.85%
	Delivery Sub-Total			**11.84**			**14.09**	**2.25**	**19.04%**	**48.50%**
	Other Charges (kWh)	143	0.0131	1.87	143	0.0131	1.87	(0.00)	(0.02%)	6.44%
	Cost of Power Commodity (kWh)	143	0.0684	9.75	143	0.0684	9.75	0.00	0.00%	33.55%
	Total Bill Before Taxes			**23.46**			**25.71**	**2.25**	**9.61%**	**88.50%**
	GST		13.00%	3.05		13.00%	3.34	0.29	9.61%	11.50%
	Total Bill			**26.50**			**29.05**	**2.55**	**9.61%**	**100.00%**

Street Lighting

Billing Determinants		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
1 Connections	Monthly Service Charge			1.85			2.05	0.20	10.68%	18.50%
65.00 kWh	Distribution (kW)	0.2	6.9907	1.40	0.2	7.7374	1.55	0.15	10.68%	13.98%
0.20 kW	Tax Change Rider	0.2	(1.2663)	(0.25)	0.2	0.0000	0.00			
	Low Voltage Rider (kW)	0.2	0.1999	0.04	0.2	0.2363	0.05	0.01	18.21%	0.43%
	LRAM & SSM Rider (kW)	0.2	0.0000	0.00	0.2	0.0000	0.00	0.00	#DIV/0!	0.00%
	GEA Plan (per month) Adder			0.00			0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW)	0.2	(1.5276)	-0.31	0.2	0.0760	0.02	0.32	(104.98%)	0.14%
	Distribution Sub-Total			**2.73**			**3.66**	**0.67**	**24.73%**	**33.04%**
	Retail Transmisssion (kW)	0.2	2.9448	0.59	0.2	2.727	0.55	(0.04)	(7.40%)	4.93%
	Delivery Sub-Total			**3.32**			**4.20**	**0.63**	**19.03%**	**37.97%**
	Other Charges (kWh)	69	0.0131	0.90	69	0.0131	0.90	(0.00)	(0.02%)	8.14%
	Cost of Power Commodity (kWh)	69	0.0684	4.69	69	0.0684	4.69	0.00	0.00%	42.39%
	Total Bill Before Taxes			**8.91**			**9.80**	**0.63**	**7.08%**	**88.50%**
	GST		13.00%	1.16		13.00%	1.27	0.11	9.92%	11.50%
	Total Bill			**10.07**			**11.07**	**0.75**	**7.41%**	**100.00%**

Unmetered Scattered

Consumption		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
500 kWh	Monthly Service Charge			26.55			15.38	(11.17)	(42.08%)	20.05%
	Distribution (kW)	500	0.0149	7.45	500	0.0086	4.30	(3.15)	(42.28%)	5.61%
	Tax Change Rider	500	(0.0007)	-0.35	500	0.0000	0.00	0.35	(100.00%)	0.00%
	Low Voltage Rider (kW)	500	0.0006	0.30	500	0.0008	0.41	0.11	35.85%	#DIV/0!
	LRAM & SSM Rider (kW)	500	0.0000	0.00	500	0.0000	0.00	0.00	#DIV/0!	0.00%
	GEA Plan (per month) Adder			0.00			0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW)	500	(0.0050)	(2.50)	500	0.0001	0.05	2.55	(102.00%)	0.07%
	Distribution Sub-Total			**31.45**			**20.14**	**(11.31)**	**(35.97%)**	**26.26%**
	Retail Transmisssion (kWh)	528	0.0096	5.07	528	0.0089	4.70	(0.37)	(7.29%)	6.13%
	Delivery Sub-Total			**36.52**			**24.84**	**-11.68**	**(31.99%)**	**32.38%**
	Other Charges (kWh)	528	0.0131	6.93	528	0.0131	6.93	(0.00)	(0.02%)	9.04%
	Cost of Power Commodity (kWh)	528	0.0684	36.10	528	0.0684	36.10	0.00	0.00%	47.07%
	Total Bill Before Taxes			**79.55**			**67.87**	**-11.32**	**(14.22%)**	**88.50%**
	GST		13.00%	10.34		13.00%	8.82	(1.52)	(14.69%)	11.50%
	Total Bill			**89.89**			**76.69**	**-12.83**	**(14.28%)**	**100.00%**