Norfolk Power
IN BUSINESS TO SERVE.

August 26, 2011

Delivered by RESS and Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON
M4P 1E4

Dear Ms. Walli:

Re: EB-2011-0272 – Norfolk Power Distribution Inc.
Application to the Ontario Energy Board for Electricity Distribution Rates and Charges effective May 1, 2012

Please find accompany this letter an electronic version of Norfolk Power Distribution Inc.'s (Norfolk) Application for Electricity Distribution Rates and Charges effective May 1, 2012. Two hard copies of the Application will also be delivered to the Board. Those copies will be accompanied by a disk containing a copy of the Application in pdf format, together with Excel versions of the models that Norfolk is required to file.

Norfolk has made a limited number of redactions in the Application related to a number of smart meter-related agreements (this discussion can be found at Exhibit 9, Tab 5).

Norfolk is filing a redacted version of the Schedule 9 pursuant to the OEB's *Practice Direction on Confidential Filings* (the "Practice Direction"). Also pursuant to the Practice Direction, the agreements referred to are being filed in confidence in their entirety.

Norfolk is prepared to provide copies of the confidential material to parties' counsel and experts or consultants provided that they have executed the OEB's form of Declaration and Undertaking with respect to confidentiality and that they comply with the Practice Direction, subject to Norfolk's right to object to the OEB's acceptance of a Declaration and Undertaking from any person.

P.O. Box 588 ~ 70 Victoria Street ~ Simcoe, Ontario ~ N3Y 4N6
Tel 519 426-4440 ~ Fax 519 426-6509 ~ 1-800-465-0291

We ask that copies of all correspondence and orders pertaining to this proceeding be delivered to the following individuals:

Brad Randall
President & CEO
Norfolk Power Distribution Inc.
P.O. Box 588
70 Victoria Street
Simcoe, ON N3Y 4N6

Telephone	519-426-4440
Facsimile	519-426-9934
Email	brandall@norfolkpower.on.ca

James C. Sidlofsky
Partner
Borden Ladner Gervais LLP
Scotia Plaza
40 King Street West
Toronto, ON M5H 3Y4

Telephone	416-367-6277
Facsimile	416-361-2751
Email	jsidlofsky@blg.com

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

Sincerely,

B Randall

Brad Randall, P.Eng
President & CEO
Norfolk Power Distribution Inc.

cc Jody McEachran, Norfolk Power Distribution Inc.
James C. Sidlofsky, Borden Ladner Gervais LLP

NORFOLK POWER DISTRIBUTION INC

APPLICATION FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES EFFECTIVE MAY 1, 2012

INDEX

Exhibit	Tab	Schedule	Appendix	Contents
2 – Rate Base				
Appendices			A	Asset Management Plan
			B	Cost of Power Calculation
			C	Green Energy Plan
			D	OPA Letter of Comment

Exhibit	Tab	Schedule	Appendix	Contents
6 – Calculation of Revenue Deficiency or Surplus				
	1	1		Revenue Deficiency - Overview
		2		Cost Drivers for Revenue Deficiency

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by Norfolk Power Distribution Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2012.

Title of Proceeding: An application by Norfolk Power Distribution Inc. for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2012.

Applicant's Name: Norfolk Power Distribution Inc.

Applicant's Address for Service:
PO Box 588
70 Victoria St
Simcoe, ON
N3Y 4N6

Attention: Brad Randall
Telephone: 519-426-4440
Fax: 519-426-6509
E-mail: brandall@norfolkpower.on.ca

Applicant's Counsel:
Borden Ladner Gervais LLP
Suite 4100
40 King Street West
Toronto ON
M5H 3Y4

James C. Sidlofsky
Telephone: (416) 367-6277
Fax: (416) 361-2751
E-mail jsidlofsky@blgcanada.com

APPLICATION

1. Introduction

(a) The Applicant is Norfolk Power Distribution Inc. (referred to in this Application as the "Applicant" or "Norfolk"). The Applicant is a corporation incorporated pursuant to the Ontario *Business Corporations Act* with its head office in the Town of Simcoe. The Applicant carries on the business of distributing electricity within certain areas of the County of Norfolk.

(b) The Applicant hereby applies to the Ontario Energy Board (the "OEB") pursuant to Section 78 of the *Ontario Energy Board Act, 1998 (the "OEB Act")* for approval of its proposed distribution rates and other charges, effective May 1, 2011. A list of requested approvals is set out in Exhibit 1, Tab 1, and Schedule 4.

(c) Except where specifically identified in the Application, the Applicant followed Chapter 2 of the OEB's Filing Requirements for Transmission and Distribution Applications as revised June 22, 2011 (the "Filing Requirements") in order to prepare this Application.

2. Proposed Distribution Rates and Other Charges

(a) The Schedule of Rates and Charges proposed in this Application is identified in Appendix A attached to this Application and Exhibit 8, and the material being filed in support of this Application sets out Norfolk's approach to its distribution rates and charges.

3. Proposed Effective Date of Rate Order

(a) The Applicant requests that the OEB make its Rate Order effective May 1, 2011 in accordance with the Filing Requirements.

4. The Proposed Distribution Rates and Other Charges are Just and Reasonable

(a) The Applicant submits the proposed distribution rates contained in this Application are just and reasonable on the following grounds:

- (i) the proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements and reflect traditional rate making and cost of service principles;
- (ii) the proposed adjusted rates are necessary to meet the Applicant's Market Based Rate of Return ("MBRR") and Payments in Lieu of Taxes ("PILs") requirements;
- (iii) there are no impacts to any of the customer classes or consumption level subgroups that are so significant as to warrant the deferral of any adjustments being requested by the Applicant or the implementation of any other mitigation measures;
- (iv) the other service charges with exception of the temporary service charges proposed by the Applicant are the same as those previously approved by the OEB; and
- (v) such other grounds as may be set out in the material accompanying this Application Summary.

5. Relief Sought

(a) The Applicant applies for an Order or Orders approving the proposed distribution rates and other charges set out in Exhibit 1, Tab 1, and Schedule 2, Appendix A to this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2012, or as soon as possible thereafter.

6. Form of Hearing Requested

(a) The Applicant requests that this Application be disposed of by way of a written hearing.

DATED at Toronto, Ontario, this 26th day of August, 2011.

All of which is respectfully submitted,

B Randall

Brad Randall, P.Eng
President & CEO
Norfolk Power Distribution Inc.

APPENDIX A

SCHEDULE OF PROPOSED RATES AND CHARGES

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

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

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

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

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

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

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

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

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

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

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

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

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

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

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0272

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

CONTACT INFORMATION:

NORFOLK POWER DISTRIBUTION INC.

Brad Randall
President & CEO
PO Box 588
70 Victoria St
Simcoe ON N3Y 4N6

Telephone 519 426-4440
Facsimile 519 426-9934
Email brandall@norfolkpower.on.ca

APPLICANT’S COUNSEL:

Borden Ladner Gervais LLP
Suite 4100
40 King Street West
Toronto ON
M5H 3Y4

James C. Sidlofsky
Telephone 416 367-6277
Facsimile 416 361-2751
Email jsidlofsky@blgcanada.com

SPECIFIC APPROVALS REQUESTED:

In this proceeding, Norfolk is requesting the following approvals:

- Approval to charge rates effective May 1, 2012 to recover a revenue requirement of $12,686,869 which includes a revenue deficiency of $1,178,225 as set out in Exhibit 6, Schedule 1, Tab 1; the schedule of proposed rates is set out in Exhibit 8 Tab 6 Schedule 4;
- Approval of the proposed loss factor as set out in Exhibit 8, Tab 4, Schedule 1;
- Approval of revised low voltage rates as proposed and described in Exhibit 8, Tab 2, Schedule 1;
- Approval to charge a Retail Transmission Network Service rate and a Retail Transmission Connection Rate as proposed and described in Exhibit 8, Tab 3, Schedule 1;
- Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the OEB Decision and Order in the matter of Norfolk's 2011 Distribution Rates (EB-2011-0049);
- Approval to continue the Specific Service Charges and Transformer Allowance approved in the OEB Decision and Order in the matter of Norfolk's 2011 Distribution Rates (EB-2011-0049);
- Approval to dispose of the following Deferral and Variance Account balances as at December 31 2010 over a one year period using the method of recovery described in Exhibit 9, Tab 2, Schedule 2:
- Approval to recover amounts recorded in account 1562 Deferred Payments in Lieu of Taxes, using the method of recovery described in Exhibit 9, Tab 3;

- Approval to recover extraordinary event costs from storm damage incurred in April 2011, which Norfolk has recorded in account 1572 Extraordinary Event Costs. Explanation of the event, expenses and requested recovery method are described in Exhibit 9, Tab 4;

- Approval to discontinue the Smart Meter rate adder and through a rate rider recover amounts recorded in accounts 1555 and 1556, balances as at December 31 2010 as well as forecasted expenses for 2011, using the method of recovery described in Exhibit 9, Tab 5;

- Approval to recover the value of the stranded assets, using the method of recovery described in Exhibit 9, Tab 5;

- Approval to establish a funding adder for the purpose of renewable capital investment based on Norfolk's Green Energy Plan, using the method described in Exhibit 9, Tab 6;

- Approval for the creation of a PP&E deferral account to record the difference in 2011 Net Book Value of Property, Plant and Equipment, as a result of the transition from financial reporting under Canadian Generally Accepted Accounting Principles (CGAAP) to reporting under Modified International Financial Reporting Standards (MIFRS), and the disposition of this account using the method of recovery described in Exhibit 9, Tab7;

- Approval to recover amounts related to LRAM/SSM amounts related to activities in 2010 over a one year period, using the method of recovery described in Exhibit 9, Tab 8, Schedule 1;

- Approval to establish a "Group 1" Deferral and Variance account to track cost associated with Smart meter entity ("SME") charge from the IESO which relates to the recovery of costs from the IESO for expenses incurred in the development and operation of the provincial MDM/R. Norfolk anticipates that it (and all distributors) will have to start paying this charge to the IESO in the 2011 rate year. NPDI proposes the new deferral and variance be treated in a similar manner as account 1580 RSVA - Wholesale Market Service Charge;

- Approval to establish a new Embedded Distributor rate class consistent with the approach approved by the Board in EB-2009-0063. In that Decision the Board approved Brant County Power's request as an embedded distributor within Brantford Power Inc. to be separated as a customer from the General Service > 50 kW rate class and be classified as a member of a new Embedded Distributor rate class**;**

- In Norfolk's 2010 IRM Decision (EB-2009-0238) The Board directed NPDI to record in account 1592 the incremental Input Tax Credit (ITC) it receives on distribution revenue requirement items that were previously subject to PST and become subject to HST. Norfolk has complied with this directive and has been recording these amounts as of July 1, 2010. The application Norfolk is currently submitting is based on budgeted information net of any HST ITCs Norfolk will receive. As a result, Norfolk requests approval to discontinue recording these variances as of May 1, 2012.

PROPOSED ISSUES LIST:

The Applicant would expect, based on previous regulatory experience and other hearings, that the following matters pertaining to the 2012 Test Year may constitute issues in this Application:

- The amount of Norfolk's proposed revenue requirement and its basis including Norfolk's 2012 capital and operating budget; and
- The appropriateness of Norfolk's load forecast; and
- The appropriateness of Norfolk's proposed cost allocation-related adjustments to class-specific revenue requirements, reflected in the proposed distribution rates; and
- The appropriateness of Norfolk's proposed Retail Transmission Connection Rates; and
- The appropriateness of Norfolk's proposal to recover Smart Meter costs and include smart meter assets in rate base; and
- The appropriateness of Norfolk's proposal to recover expenses under Extraordinary Event Costs / Z Factor; and
- The appropriateness of Norfolk's proposed Green Energy Plan Funding Adder; and
- The appropriateness of Norfolk proposed LRAM recovery.

PROCEDURAL ORDERS/MOTIONS/NOTICES:

None.

ACCOUNTING ORDERS REQUESTED:

Norfolk is not requesting Accounting Orders in this proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS:

Norfolk has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the Uniform System of Accounts ("USoA") in the preparation of this Application.

DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM:

Description of Distributor:

COMMUNITY SERVED:	Urban and Rural areas of Norfolk County
URBAN AREAS:	Delhi, Port Dover, Port Rowan, Port Ryerse, Simcoe and Waterford
TOTAL SERVICE AREA:	693 sq km
RURAL SERVICE AREA:	549 sq km
DISTRIBUTION TYPE:	Electricity distribution
MUNICIPAL POPULATION:	62,563
POPULATION OF URBAN AREAS SERVED:	28,262

A map of Norfolk’s Distribution Service Territory accompanies this Schedule as Appendix B.

A schematic diagram of Norfolk’s distribution system is attached in Appendix C.

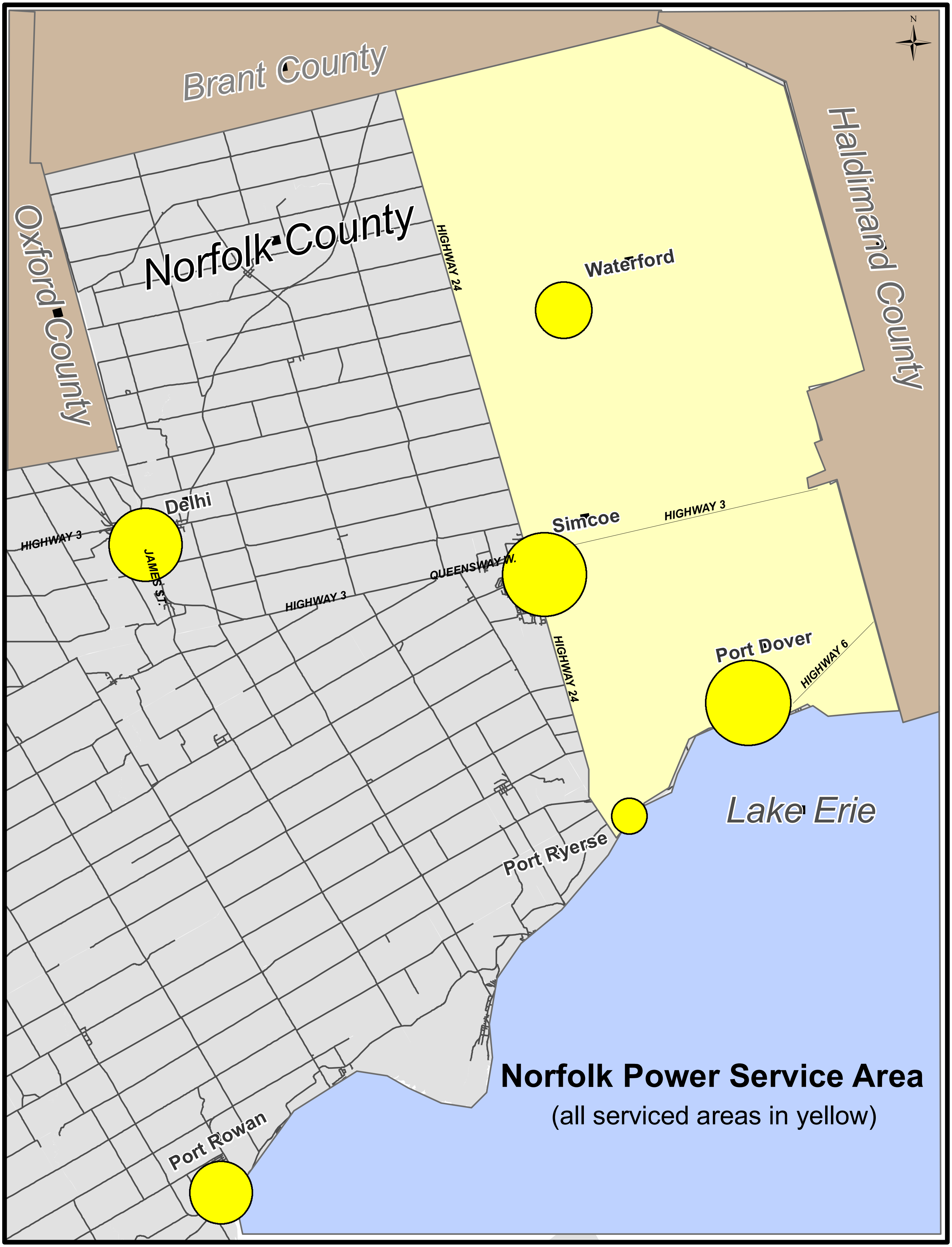
MAP OF DISTRIBUTION SERVICE TERRITORY:

The outlined area represents the County of Norfolk. The area highlighted in Yellow represents NPDI’s Distribution Service Territory.

Norfolk Power Distribution Inc
EB-2011-0272
Exhibit 1
Tab 1
Schedule 9
Appendix B
Filed: August 26, 2011

APPENDIX B

MAP OF DISTRIBUTION SERVICE TERRITORY



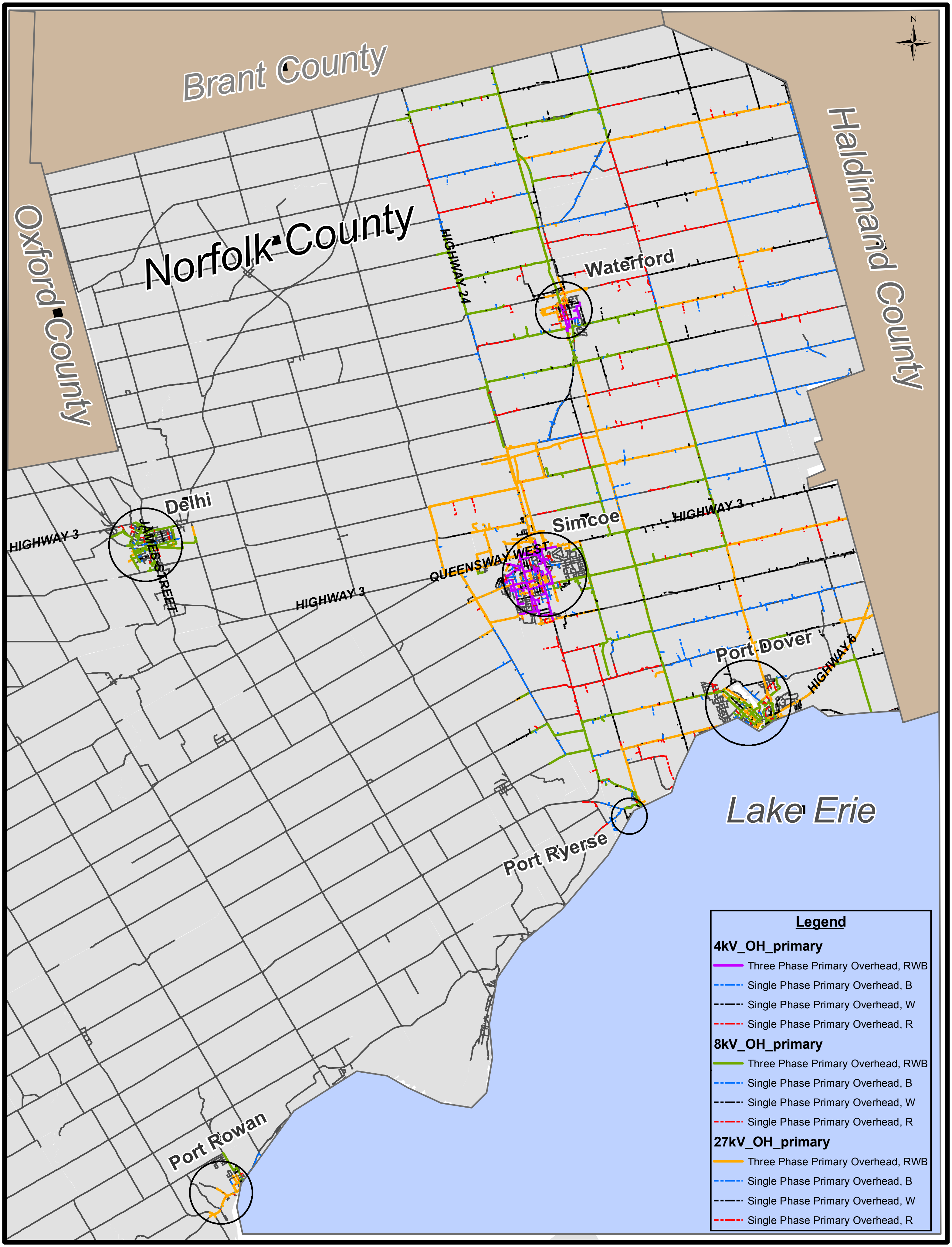
Norfolk Power Service Area

(all serviced areas in yellow)

Norfolk Power Distribution Inc
EB-2011-0272
Exhibit 1
Tab 1
Schedule 9
Appendix C
Filed: August 26, 2011

APPENDIX C

MAP OF DISTRIBUTION SYSTEM


N
Brant County
Oxford County
Norfolk County
Haldimand County
Waterford
Delhi
Simcoe
Port Dover
Port Ryerse
Port Rowan
Lake Erie
HIGHWAY 24
HIGHWAY 3
HIGHWAY 3
HIGHWAY 3
HIGHWAY 6
JAMES STREET
QUEENSWAY WEST
Legend
4kV_OH_primary
Three Phase Primary Overhead, RWB
Single Phase Primary Overhead, B
Single Phase Primary Overhead, W
Single Phase Primary Overhead, R
8kV_OH_primary
Three Phase Primary Overhead, RWB
Single Phase Primary Overhead, B
Single Phase Primary Overhead, W
Single Phase Primary Overhead, R
27kV_OH_primary
Three Phase Primary Overhead, RWB
Single Phase Primary Overhead, B
Single Phase Primary Overhead, W
Single Phase Primary Overhead, R

LIST OF NEIGHBOURING UTILITIES:

Norfolk is bounded by Hydro One, except the eastern border which is shared by Haldimand County Hydro.

EXPLANATION OF HOST AND EMBEDDED UTILITIES:

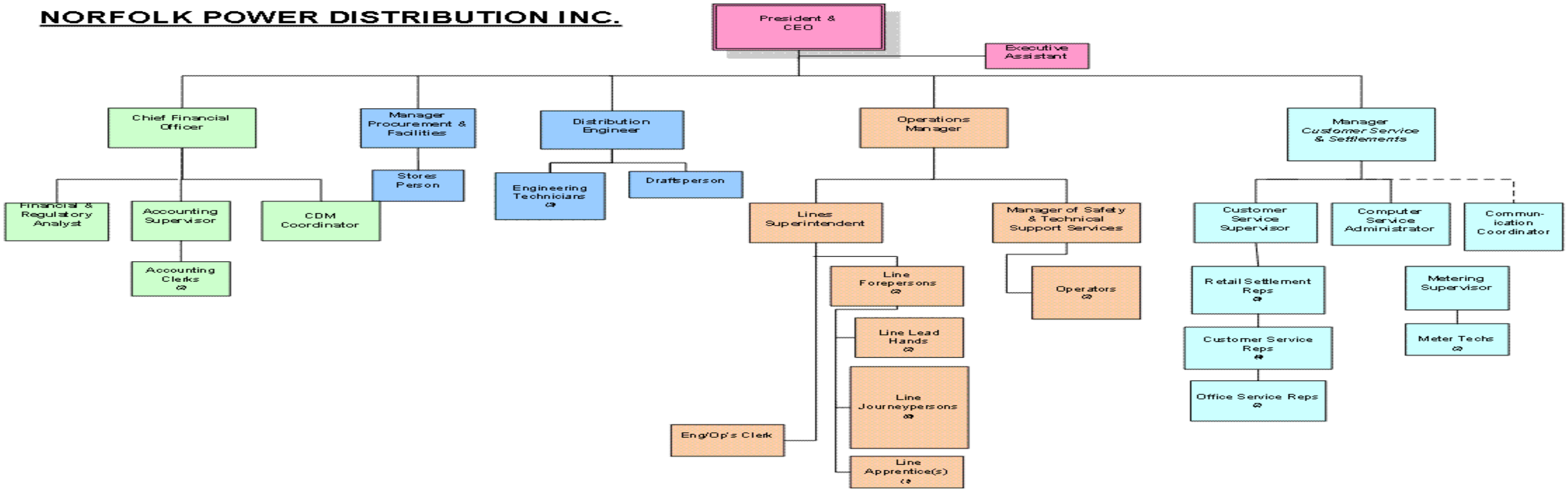
Norfolk is embedded to Hydro One. Norfolk was also previously embedded to Haldimand County Hydro, but as of August 2010 is no longer so.

Norfolk is a host utility to Hydro One and has requested an Embedded Distributor rate within this Application.

UTILITY ORGANIZATIONAL STRUCTURE:

Norfolk is 100% owned by its parent company Norfolk Power Inc. Norfolk Power Inc is 100% owned by the County of Norfolk. A chart illustrating Norfolk's corporate family is provided at Exhibit 1, Tab 1, Schedule 13.

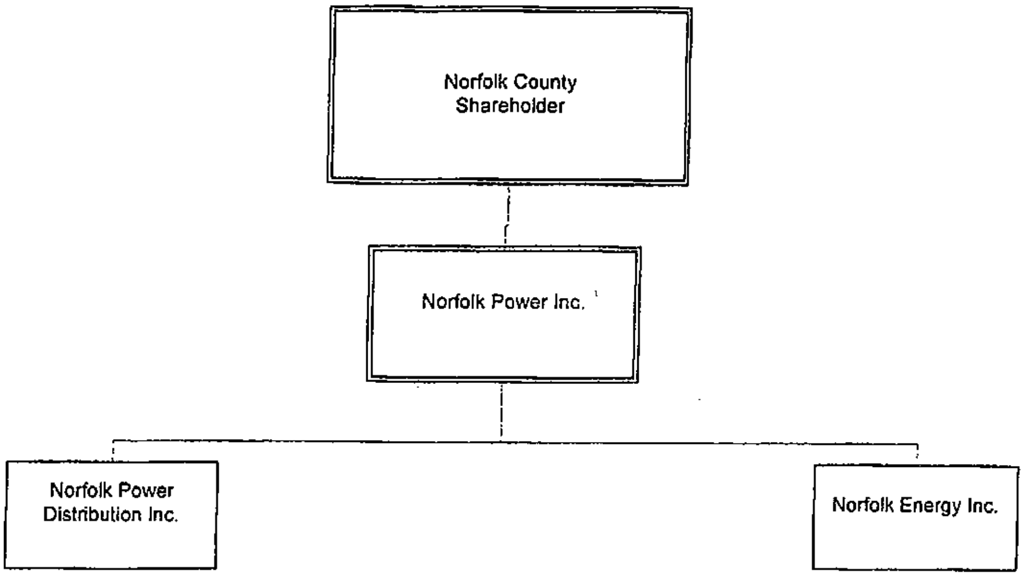
NORFOLK POWER DISTRIBUTION INC.



Total Employees: 48
Total Employees excluding CDM Coordinator: 47
Excludes part-time employees

CORPORATE ENTITIES RELATIONSHIP CHART:

A chart illustrating the Corporate Entities Relationships follows on the next page.


Norfolk County
Shareholder
Norfolk Power Inc.
Norfolk Power
Distribution Inc.
Norfolk Energy Inc.

PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE:

No changes to Norfolk’s corporate and operational structures are planned at the present time.

STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS:

Directive from 2008 Cost of Service Application (EB-2007-0753):

The Board prescribed a phase-in period to adjust its revenue-to-cost rates, moving the Sentinel Lighting and Street Lighting from their 2008 positions to the bottom of the Board's target ranges during 2009 and 2010. Norfolk has complied with this directive and as of its 2010 IRM application (EB-2009-0238), Sentinel Lighting and Street Lighting Revenue-to-Cost Ratios have been moved to within the Board's target ranges.

PRELIMINARY LIST OF WITNESSES:

While Norfolk requests that this Application be disposed of by way of a written hearing, should a technical conference or an oral hearing be necessary Norfolk will provide a list of potential witnesses as required.

SUMMARY OF THE APPLICATION:

Preamble

Norfolk has submitted this Application in order to meet its Corporate Mission and Corporate Goals as outlined below. Current rates will result in actual Return on Equity in 2011 and 2012 below levels currently approved by the OEB. The increased rates are required to:

1) Maintain current capital investment levels in infrastructure to ensure a safe, reliable distribution system.
2) Continue with operating expenses necessary to maintain and operate the distribution system, meet customer service expectations and ensure regulatory compliance.
3) Maintain current staffing requirements, including training and preparing for succession planning.
4) To provide a reasonable rate of return to the Shareholder.

Norfolk's Mission Statement is:

> *Norfolk Power Distribution Inc. is committed to provide a reliable supply of electricity at competitive distribution rates in an environment which focuses on safety, efficiency and increased economic development.*

Norfolk's priorities are defined in its Corporate Goals:

> *Provide a safe and reliable electricity distribution system with capacity to meet the expectations of our customers and support local economic growth.*
>
> *Promote and practice excellence in safety.*
>
> *Establish the lowest retail rates possible without compromising the financial integrity of the Corporation in compliance to our Shareholder's direction and Corporate Strategic Plan.*

Purpose and Need

Norfolk's requested revenue requirement for 2012 in the amount of $12,686,869 includes the recovery of its costs to provide distribution services, its permitted Return on Equity ["ROE"] and the funds necessary to service its debt.

When forecasted energy and demand levels for 2012 are considered, Norfolk estimates that its present rates will produce a deficiency in gross distribution revenue of $1,178,225 for the 2012 Test Year.

Therefore, Norfolk seeks the OEB's approval to revise its electricity distribution rates. The rates proposed to recover its projected revenue requirement and other relief sought are set out in Exhibit 1, Tab 1, Schedule 2, Appendix A and Exhibit 8, Tab 6, Schedule 4 to this Application.

The information presented in this Application represents Norfolk's forecasted results for its 2012 Test Year. Norfolk is also presenting the forecasted results for 2011 Bridge Year and audited financial information for fiscal 2008, 2009 and 2010.

Timing

The financial information supporting the Test Year for this Application will be Norfolk's fiscal year ending December 31, 2012 (the "2012 Test Year"). However, Norfolk is requesting rates effective May 1, 2012, continuing through April 30, 2013.

Customer Impact

In preparing this application, Norfolk has considered the impacts on its customers, with a goal of minimizing those impacts. With respect to cost allocation, Norfolk notes that only the Unmetered Scattered Load and Embedded Distributor classes fall outside the applicable threshold defined by the Board in the March 31, 2011 Report of the Board on Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219). In this application the Unmetered Scattered Load and Embedded Distributor classes have been brought within the Board's threshold with minimal impact to other classes.

Customer impacts including the percentage average Total Bill Impact and Average Dollar Impact, which include revised distribution rates [monthly service charge and volumetric rates], revised low voltage rates, revised retail transmission rates, revised loss factors, LRAM and SSM rate riders, and regulatory asset rate riders to dispose of the balances in the Deferral and Variance Accounts requested in this Application are set out in Table 1.1 below, for typical Residential (800 kWh per month) and Commercial (2000 kWh per month) customers. A complete listing of bill impacts for all customer classes is provided in Exhibit 8, Tab 8.

Table 1.1: Bill Impact: Residential

Consumption 800 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	monthly	$ 20.7700	1	$ 20.77	$ 22.9900	1	$ 22.99	$ 2.22	10.69%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ -	1	$ -	-$ 1.00	-100.00%
Service Charge Rate Adder(s)	monthly		1	$ -	$ 0.0587	1	$ 0.06	$ 0.06	
Service Charge Rate Rider(s)	monthly		1	$ -	$ 1.7100	1	$ 1.71	$ 1.71	
Distribution Volumetric Rate	per kWh	$ 0.0190	800	$ 15.20	$ 0.0210	800	$ 16.80	$ 1.60	10.53%
Low Voltage Rate Adder	per kWh	$ 0.0007	800	$ 0.56	$ 0.0009	800	$ 0.72	$ 0.16	28.57%
Volumetric Rate Adder(s)			800	$ -		800	$ -	$ -	
Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
Smart Meter Disposition Rider	monthly		800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0023	800	$ 1.84	$ 0.0006	800	$ 0.48	-$ 1.36	-73.91%
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0044	800	-$ 3.52	$ 0.0003	800	$ 0.24	$ 3.76	-106.82%
Rate Rider for Tax Change	per kWh	-$ 0.0006	800	-$ 0.48		800	$ -	$ 0.48	-100.00%
Z Factor	per kWh			$ -	$ 0.0010	800	$ 0.80	$ 0.80	
RR&E Rider				$ -	-$ 0.0016	800	-$ 1.28	-$ 1.28	
PILS Rate Rider				$ -	$ 0.0006	800	$ 0.48	$ 0.48	
Sub-Total A - Distribution				**$ 35.37**			**$ 43.00**	**$ 7.63**	**21.57%**
RTSR - Network	per kWh	$ 0.0066	844.8	$ 5.58	$ 0.0064	845.12	$ 5.41	-$ 0.17	-2.99%
RTSR - Line and Transformation Connection		$ 0.0041	844.8	$ 3.46	$ 0.0035	845.12	$ 2.96	-$ 0.51	-14.60%
Sub-Total B - Delivery (including Sub-Total A)				**$ 44.41**			**$ 51.37**	**$ 6.96**	**15.66%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	844.8	$ 4.39	$ 0.0052	845.12	$ 4.39	$ 0.00	0.04%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	844.8	$ 1.10	$ 0.0013	845.12	$ 1.10	$ 0.00	0.04%
Special Purpose Charge		$ 0.0066000	844.8	$ 5.58	$ 0.0066000	845.12	$ 5.58	$ 0.00	0.04%
Standard Supply Service Charge	per kWh	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			800	$ -		800	$ -	$ -	
Energy	per kWh		844.8	$ -		845.12	$ -	$ -	
Energy	per kWh	$ 0.0790	244.8	$ 19.34	$ 0.0790	244.8	$ 19.34	$ -	0.00%
	per kWh	$ 0.0680	600	$ 40.80	$ 0.0680	600	$ 40.80	$ -	0.00%
Total Bill (before Taxes)				**$ 115.87**			**$ 122.83**	**$ 6.96**	**6.01%**
HST		13%		$ 15.06	13%		$ 15.97	$ 0.90	6.01%
Total Bill (including Sub-total B)				**$ 130.93**			**$ 138.79**	**$ 7.86**	**6.00%**
Ontario Clean Energy Benefit (OCEB)		-10%		**-$ 13.09**	-10%		**-$ 13.88**	**-$ 0.79**	**6.04%**
Total Bill (including OCEB)				**$ 117.84**			**$ 124.91**	**$ 7.07**	**6.00%**
Loss Factor (%)	**Note 1**	5.60%			5.64%				

Commercial: General Service < 50 kW

Consumption 2000 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	monthly	$ 49.7400	1	$ 49.74	$ 55.0200	1	$ 55.02	$ 5.28	10.62%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ -	1	$ -	-$ 1.00	-100.00%
Service Charge Rate Adder(s)	monthly		1	$ -	$ 0.0587	1	$ 0.06	$ 0.06	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0139	2000	$ 27.80	$ 0.0154	2000	$ 30.80	$ 3.00	10.79%
Low Voltage Rate Adder	per kWh	$ 0.0006	2000	$ 1.20	$ 0.0008	2000	$ 1.60	$ 0.40	33.33%
Volumetric Rate Adder(s)			2000	$ -		2000	$ -	$ -	
Volumetric Rate Rider(s)			2000	$ -		2000	$ -	$ -	
Smart Meter Disposition Rider	monthly		2000	$ -	$ 1.7100	1	$ 1.71	$ 1.71	
LRAM & SSM Rider	per kWh	$ 0.0007	2000	$ 1.40	$ 0.0012	2000	$ 2.32	$ 0.92	65.71%
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0045	2000	-$ 9.00	-$ 0.0002	2000	-$ 0.40	$ 8.60	-95.56%
Rate Rider for Tax Change	per kWh	-$ 0.0004	2000	-$ 0.80		2000	$ -	$ 0.80	-100.00%
Z Factor	per kWh			$ -	$ 0.0007	2000	$ 1.40	$ 1.40	
PP&E Rider				$ -	-$ 0.0011	2000	-$ 2.20	-$ 2.20	
PILS Rate Rider				$ -	$ 0.0004	2000	$ 0.80	$ 0.80	
Sub-Total A - Distribution				**$ 71.34**			**$ 91.11**	**$ 19.77**	**27.71%**
RTSR - Network	per kWh	$ 0.0060	2112	$ 12.67	$ 0.0058	2112.8	$ 12.25	-$ 0.42	-3.30%
RTSR - Line and Transformation Connection	per kWh	$ 0.0036	2112	$ 7.60	$ 0.0031	2112.8	$ 6.55	-$ 1.05	-13.86%
Sub-Total B - Delivery (including Sub-Total A)				**$ 91.62**			**$ 109.91**	**$ 18.30**	**19.97%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2112	$ 10.98	$ 0.0052	2112.8	$ 10.99	$ 0.00	0.04%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2112	$ 2.75	$ 0.0013	2112.8	$ 2.75	$ 0.00	0.04%
Special Purpose Charge			2112	$ -		2112.8	$ -	$ -	
Standard Supply Service Charge	per kWh	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0066	2112	$ 13.94	$ 0.0066	2112.8	$ 13.94	$ 0.01	0.04%
Energy	per kWh	$ 0.0680	600	$ 40.80	$ 0.0680	600	$ 40.80	$ -	0.00%
Energy	per kWh	$ 0.0790	1512	$ 119.45	$ 0.0790	1512	$ 119.45	$ -	0.00%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 279.78**			**$ 298.09**	**$ 18.31**	**6.54%**
HST		13%		$ 36.37	13%		$ 38.75	$ 2.38	6.54%
Total Bill (including Sub-total B)				**$ 316.15**			**$ 336.84**	**$ 20.69**	**6.54%**
Ontario Clean Energy Benefit (OCEB)		-10%		**-$ 31.62**	-10%		**-$ 33.68**	**-$ 2.06**	**6.51%**
Total Bill (including OCEB)				**$ 284.53**			**$ 303.16**	**$ 18.63**	**6.55%**

Loss Factor	**(1)**	5.60%		5.64%

Smart Meters:

Norfolk is requesting final disposition of its December 31, 2010 smart meter account balances, as well as 2011 forecasted expenses. Norfolk is also requesting the recovery of stranded meter amounts and the discontinuation of the smart meter funding adder, as outlined in Exhibit 9 of this Application.

Capital Structure

Norfolk is requesting the continuation of its current deemed capital structure of 40% Equity, 4% Short Term Debt, 56% Long Term Debt.

Return on Equity

Norfolk has assumed a return on equity of 9.58% consistent with the Cost of Capital Parameter Updates for 2011 Cost of Service Applications issued by the OEB on March 3, 2011. Norfolk understands the Board will be finalizing the cost of capital parameters for 2011 rates based on January 2011 market interest rate information, and that adjustments to the Application may be required as a result.

Capital Expenditures

Norfolk continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. Expenditures are also being made to meet regulations set out by both the OEB and IESO including load transfers and primary metering points.

Transition to Modified International Financial Reporting Standards (MIFRS)

Consistent with the Board’s letter issued March 15, 2011 entitled *Use of Modified IFRS as a Basis for Filing Cost of Service Applications in 2012 Rates*, this application has been prepared using modified IFRS (MIFRS). To allow transparent and useful comparisons to historical expenses, the expenses approved in Norfolk's 2008 Cost of Service application, and to clearly illustrate the impact of the conversion to MIFRS, the forecasted 2012 Test Year has been prepared using both Canadian Generally Accepted Accounting Principles (CGAAP) and MIFRS.

The transition to MIFRS has impacted the calculation of the cost of self constructed capital assets, depreciation rates, and operating expenses. These changes have impacted the 2012 rate base and the 2012 distribution revenue requirement. Norfolk has provided detailed explanations of these changes in the applicable section of the application.

Deemed Distribution Asset

As part of Norfolk's 2006 rate application (EB-2005-0396) its Transformer Station, which was put into service in 2004, was deemed to be a distribution asset. In the Decision and Order for that application it was stated "The Board deems the Norfolk Power TS asset to be a distribution asset. The costs associated with that asset are to be included in the revenue requirement for the Applicant." (EB-2005-0396 p5).

BUDGET OVERVIEW:

Norfolk compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budget forecast. This budget information is compiled for both the 2011 Bridge Year and the 2012 Test Year.

Revenue Forecast

Norfolk's energy sales and revenue forecast model were updated to reflect more recent information. This model was then used to prepare the revenues sales and throughput volume and revenue forecast at existing rates for fiscal 2011 and 2012. The forecast is weather normalized as outlined in Exhibit 3, Tab 2, Schedule 1 and considers such factors as average weather conditions and economic conditions in the area serviced by Norfolk.

Operating Maintenance and Administration ("OM&A") Expense Forecast

The OM&A expenses for the 2011 Bridge Year and the 2012 Test Year have been based on an in-depth review of operating priorities and requirements and is strongly influenced by prior year experience, year-to-date results and expected changes for the forecast periods. Each item is reviewed account by account for each of the forecast years with indirect costs allocated to direct costs for budget presentation.

Capital Budget

The capital budget forecast 2011 and 2012 is influenced by, among other factors, the highest priority capital requirements and Norfolk's capacity to finance capital projects. Indirect costs are allocated to direct costs in the capital budget. All proposed capital projects are assessed within the framework of the Asset Management Plan and resultant capital budget priority and are outlined in Exhibit 2, Tab 3.

CHANGES IN METHODOLOGY:

Norfolk is not requesting any changes in methodology in the current proceeding.

CALCULATION OF REVENUE DEFICIENCY:

Norfolk has provided detailed calculations supporting its 2012 revenue deficiency. Norfolk's net revenue deficiency is $913,129 and when grossed up for PILs Norfolk's revenue deficiency is $1,178,225. Table 1.2 on the following page provides the revenue deficiency calculations for the 2012 Test Year at Existing 2011 Board-approved rates and the 2012 Test Year Revenue Requirement.

Table 1.2: Calculation of Revenue Deficiency

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**

CAUSES OF REVENUE DEFICIENCY:

Norfolk's net revenue deficiency is calculated as $913,129 and when grossed up for PILs, the revenue deficiency is $1,178,225. Norfolk's calculation of its 2012 revenue deficiency is provided in Exhibit 1, Tab 2, Schedule 4 and Exhibit 6, Tab 1, Schedule 1.

The revenue deficiency is primarily the result of:

- Increases in OM&A costs since Norfolk's last cost of service in 2008. For the 2012 Test Year Norfolk is forecasting OM&A expenses increasing at a compound annual growth rate of 5.2% per year since 2008 Board Approved, under CGAAP (The compound annual growth rate is 0.1% from 2008 actual). The transition from CGAAP to MIFRS will increase operating expenses an additional $616,555. Norfolk has provided a detailed explanation of changes in operating expenses in Exhibit 4.

- Capital Expenditures have exceeded depreciation levels resulting in an increased rate base on which the rate of return is calculated. Norfolk is committed to ensuring the reliability of the distribution system and will continue to invest in capital infrastructure in 2010 and 2011 at a level exceeding depreciation. In particular this includes the completion of Norfolk's Transformer Station, a multi-year project. This station and other changes in the Rate Base are discussed further in Exhibit 2.

FINANCIAL STATEMENTS – 2008, 2009 and 2010:

Norfolk’s Audited Financial Statements accompany this Schedule as Appendix D.

APPENDIX D

COPIES OF NORFOLK POWER DISTRIBUTION INC. AUDITED FINANCIAL STATEMENTS FOR 2008, 2009 and 2010

Norfolk Power Distribution Inc.

Financial Statements

December 31, 2008

MILLARD, ROUSE & ROSEBRUGH LLP
Chartered Accountants

85 Robinson Street
Simcoe, Ontario

Auditors' Report

To the Shareholder of
Norfolk Power Distribution Inc.

We have audited the balance sheet of Norfolk Power Distribution Inc. as at December 31, 2008 and the statements of operations, retained earnings and cash flow for the year then ended. These financial statements are the responsibility of management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of Norfolk Power Distribution Inc. as at December 31, 2008 and the results of its operations and its cash flow for the year then ended in accordance with Canadian generally accepted accounting principles.

Millard Rouse & Rosebrugh LLP

March 27, 2009
Simcoe, Ontario

Chartered Accountants
Licensed Public Accountants

OUR REPORTS AND CERTIFICATES ARE ISSUED ON THE UNDERSTANDING THAT UNLESS THEY ARE REPRODUCED IN THEIR ENTIRETY, ANY SUMMARIES THEREOF, EXCERPTS THEREFROM OR REFERENCES THERETO SHALL BE SUBMITTED TO US FOR OUR APPROVAL.

Norfolk Power Distribution Inc.

Balance Sheet

As at December 31, 2008

	2008 $	2007 $
Assets		
Current assets		
Accounts receivable	**4,292,468**	4,330,698
Unbilled revenue	**4,634,444**	4,431,602
Loan to Norfolk Energy Inc.	**350,000**	350,000
Due from associated companies (note 6)	**402,384**	-
Corporate taxes receivable	**435,682**	233,915
Inventory (note 3)	**529,370**	613,210
Prepaid expenses	**354,605**	517,930
Total current assets	**10,998,953**	10,477,355
Property, plant and equipment (note 4)	**42,569,900**	41,302,982
Other assets		
Unamortized debenture discount	**-**	3,184
Total assets	**53,568,853**	51,783,521
Liabilities and Shareholder's Equity		
Current liabilities		
Bank overdraft (note 7a)	**3,726,158**	1,083,309
Accounts payable and accrued liabilities	**5,726,695**	6,734,295
Due to associated companies (note 6)	**-**	396,997
Current portion of long term liabilities	**637,628**	892,047
Total current liabilities	**10,090,481**	9,106,648
Long term liabilities		
Consumer deposits - net of current portion	**125,047**	84,008
Post employment benefits	**750,866**	681,905
Capital lease obligation - net of current portion (note 9)	**40,863**	-
Net regulatory liabilities (note 5)	**725,574**	87,930
Bank loans - net of current portion (note 7b)	**14,700,000**	15,185,000
Debentures - net of current portion (note 8)	**1,914,923**	1,958,514
Total long term liabilities	**18,257,273**	17,997,357
Total liabilities	**28,347,754**	27,104,005
Shareholder's equity		
Share capital (notes 1 and 10)	**22,768,898**	22,768,898
Contributed capital	**830,799**	830,799
Retained earnings	**1,621,402**	1,079,819
Total shareholder's equity	**25,221,099**	24,679,516
Total liabilities and shareholder's equity	**53,568,853**	51,783,521

The accompanying notes are an integral part of these financial statements

Norfolk Power Distribution Inc.

Statement of Operations

For the year ended December 31, 2008

	2008 $	2007 $
Revenue		
Energy sales and distribution services revenues	**37,082,980**	37,413,679
Other revenues	**428,348**	531,297
	37,511,328	37,944,976
Costs		
Purchase of power	**27,337,069**	28,439,699
Distribution system - operation and maintenance	**2,692,998**	2,205,508
Billing and collecting	**1,053,434**	1,017,402
Community relations	**95,043**	114,332
Administrative and general expense	**1,387,696**	1,367,077
Taxes other than amounts in lieu of corporate taxes	**112,717**	155,724
	32,678,957	33,299,742
Income before amortization, interest and payments in lieu of corporate taxes	**4,832,371**	4,645,234
Amortization (net of $380,375; 2007 - $325,610 charged to other accounts)	**2,349,864**	2,257,886
Interest	**1,319,911**	1,220,014
Income before provision for payments in lieu of corporate taxes	**1,162,596**	1,167,334
Provision for payments in lieu of corporate taxes (note 11)	**621,013**	357,823
Net income	**541,583**	809,511

Statement of Retained Earnings

For the year ended December 31, 2008

	2008 $	2007 $
Retained earnings - beginning of the year	**1,079,819**	570,308
Net income	**541,583**	809,511
Dividends	**-**	(300,000)
Retained earnings - end of the year	**1,621,402**	1,079,819

The accompanying notes are an integral part of these financial statements

Norfolk Power Distribution Inc.

Statement of Cash Flow

For the year ended December 31, 2008

	2008 **$**	2007 $
Cash provided by		
Operating activities		
Net income	**541,583**	809,511
Adjustment for non-cash items		
Amortization	**2,730,239**	2,583,496
Post employment benefits	**68,961**	41,784
Gain on disposal of property, plant and equipment	**(9,100)**	(111,422)
	3,331,683	3,323,369
Changes in non-cash working capital components:		
Decrease in accounts receivable	**38,230**	1,052,378
(Increase) in unbilled revenue	**(202,842)**	(98,349)
(Increase) in corporate taxes receivable	**(201,767)**	(283,053)
Decrease (increase) in inventory	**83,840**	(31,105)
Decrease (increase) in prepaid expenses	**163,325**	(68,925)
Decrease in unamortized debenture discount	**3,184**	3,183
(Increase) in miscellaneous deferred debits and other	**(68,798)**	(253,504)
(Decrease) in accounts payable and accrued liabilities	**(1,007,600)**	(161,102)
(Decrease) in amounts due to associated companies	**(799,381)**	(157,854)
	1,339,874	3,325,038
Investing activities		
Purchase of property, plant and equipment	**(4,276,639)**	(6,458,620)
Net change in regulatory liabilities	**706,442**	832,189
Contributions in aid of construction	**331,461**	994,216
Proceeds on disposition of property, plant and equipment	**(42,878)**	125,402
	(3,281,614)	(4,506,813)
Financing activities		
Receipt (repayment) of capital lease obligations	**88,339**	(3,211)
Receipt of customer deposits	**62,038**	13,915
Repayment of demand loan	**-**	(1,500,000)
Proceeds from bank loan	**-**	1,650,000
Proceeds from debentures	**-**	2,000,000
Repayment of bank loan	**(441,000)**	(382,000)
Repayment of debentures	**(410,486)**	(353,000)
Dividends declared	**-**	(300,000)
	(701,109)	1,125,704
Net decrease in cash and cash equivalents for the year	**(2,642,849)**	(56,071)
Bank (overdraft) - beginning of the year	**(1,083,309)**	(1,027,238)
Bank (overdraft) - end of the year	**(3,726,158)**	(1,083,309)

The accompanying notes are an integral part of these financial statements

1. Incorporation

On November 1, 2000, Norfolk Power Inc. was incorporated under the Ontario Business Corporations Act, along with its two wholly owned subsidiary companies, Norfolk Power Distribution Inc. and Norfolk Energy Inc. The incorporation was required in accordance with the Ontario Electricity Competition Act (Bill 35).

Effective January 1, 2001, Norfolk County was incorporated as a single tier municipality and assumed the assets, liabilities and operations of the former Townships of Norfolk and Delhi, the former Town of Simcoe and the western portions of the former City of Nanticoke and Regional Municipality of Haldimand-Norfolk.

Norfolk County, in conjunction with predecessor municipalities passed transfer by-laws to meet the requirements of Bill 35. Under the terms of the transfer by-law, Norfolk County became the sole shareholder of Norfolk Power Inc. and its wholly owned subsidiaries.

Under the transfer by-laws, the respective predecessor hydro-electric commissions transferred, at book values, the assets, liabilities and employees associated with the distribution and transmission of electricity and associated business activities to the new corporations. The transfer occurred on November 1, 2000, with the shares of the corporation held in trust until the incorporation of Norfolk County on January 1, 2001.

The values of the net assets transferred along with the share consideration are as follows:

Net assets as at November 1, 2000 were transferred from:	$
Delhi Hydro-Electric Commission	2,283,071
Nanticoke Hydro-Electric Commission	8,702,187
Norfolk Township Hydro-Electric Commission	588,723
Simcoe Hydro-Electric Commission	11,976,258
	23,550,239
Increase in net assets from November 1, 2000 to December 31, 2000	32,045
Net assets assumed by Norfolk County as at January 1, 2001	23,582,284
Retroactive adjustment for employee future benefits	(440,000)
Net assets converted to share capital	23,142,284

The net assets assumed by Norfolk Power Inc. and the share consideration were allocated to the wholly owned subsidiaries as follows:

	$
Norfolk Power Distribution Inc.	22,768,898
Norfolk Energy Inc.	373,386
	23,142,284

2. Accounting policies

The financial statements of Norfolk Power Distribution Inc. have been prepared in accordance with Canadian generally accepted accounting principles (GAAP), including accounting principles prescribed by the Ontario Energy Board (OEB) in the handbook "*Accounting Procedures Handbook for Electric Distribution Utilities*" and reflect the significant accounting policies summarized below:

a) Inventory

Effective January 1, 2008, the Company adopted CICA Handbook Section 3031 - "Inventories" which is based on the International Accounting Standards Board's International Accounting Standard 2 and replaced existing CICA Handbook Section 3030. Under this new standard, inventories are required to be measured at the lower of cost and net realizable value and any items considered to be major future components of property, plant and equipment are to be transferred to property, plant and equipment. The new standard also provides updated guidance on the appropriate methods of determining cost and the impact of any write-downs to net realizable value. The implementation of this standard did not have any impact on the Company's results of operations.

Inventory consists of repair parts, supplies and materials held for operating and maintenance activities and are valued at lower of cost and net realizable value. Cost is determined using the weighted average method.

b) Property, plant and equipment

Property, plant and equipment are valued at acquisition cost and include contracted services, materials, labour, engineering costs, interest and overheads. Property, plant and equipment acquired from predecessor commissions are recorded at their respective cost and accumulated amortization amounts. Gains or losses at retirement or disposition are credited or charged to other income in the year of acquisition or disposition.

Amortization is provided on a straight line basis for property, plant and equipment available for use over their estimated economic lives, at the following annual rates:

Buildings	50 Years	2%
Transformer equipment	40 Years	4%
Substation equipment	35 Years	4%
Distribution system	25 Years	4%
SCADA system	15 Years	6.7%
Meters	25 Years	4%
Office and warehouse equipment	10 Years	10%
Garage tools and equipment	10 Years	10%
Measurement and testing equipment	10 Years	10%
Vehicles	10 Years	10%
Computer hardware and software	5 Years	20%
Communication equipment	10 Years	10%
Miscellaneous equipment	10 Years	10%

Full amortization is recorded in the year of acquisition and none in the year of disposal.

2. Accounting policies - continued

c) Contributions in aid of construction

Contributions in aid of construction are required contributions received from outside sources used to finance additions to property, plant and equipment. Capital contributions are treated as a contra credit account included in the determination of property, plant and equipment. The amount is subsequently amortized by a charge to accumulated amortization and a credit to amortization expense, at an equivalent rate to that used for the amortization of the related property, plant and equipment.

d) Impairment of long-lived assets

The Company reviews long-lived assets for impairment whenever events or circumstances indicate that the carrying amount of the long-lived asset is not recoverable. Any resulting impairment loss is recorded in the period in which the impairment occurs.

e) Unamortized debenture discount

Unamortized debenture discount represents the discount and the cost of the issue of debentures. Amortization is provided on a straight-line basis over the term of the debenture.

f) Pension and other post-employment benefits

Norfolk Power Inc. and its subsidiary companies provide a pension plan for their employees through the Ontario Municipal Employees Retirement System (OMERS). OMERS is a multi-employer public sector contributory defined benefit pension plan. The pension fund is financed by equal contributions from participating employers and employees and by the investment earnings of the fund.

The Company actuarially determines the cost of other employment and post-employment benefits offered to employees using the projected benefit method prorated on service and based on management's best estimate assumptions. Under this method, the projected post-retirement benefit is deemed to be earned on a pro-rata basis over the years of service in the attribution period commencing at the date of hire, and ended at the earliest age the employee could retire and qualify for benefits. Compensated absences and termination benefits that do not vest or accumulate are recognized as an expense when the even occurs.

g) Customer deposits

Customer deposits are cash collections from customers to guarantee the payment of energy bills and fulfillment of contractual obligations. Deposits expected to be refunded to customers within the next fiscal period are classified as a current liability. Interest is accrued on customer deposit balances at rates established and reviewed by the Company on a quarterly basis.

2. Accounting policies - continued

h) Revenue recognition

Revenue from the sale and distribution of electricity is recorded on a basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed. The related cost of power is recorded on the basis of power used. Actual results could differ from estimates made of actual electricity usage.

Other revenues related to sales of other services are recognized as the services are rendered.

i) Financial instruments

All financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, other liabilities or available-for-sale. All financial instruments are carried at fair value on the balance sheet except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period in which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in other comprehensive income until the instrument is derecognized or impaired. The Company has classified its financial instruments as follows:

Accounts receivable	Loans and receivable
Bank overdraft	Other liabilities
Accounts payable and accrued liabilities	Other liabilities
Bank loans	Other liabilities
Debentures	Other liabilities

Effective January 1, 2008, the Company adopted CICA Handbook Sections 3862 - "Financial Instruments - Disclosures" and 3863 - "Financial Instruments - Presentation", which establish the requirement of disclosure of risk associated with both recognized and unrecognized financial instruments and the management of those risks. The adoption of these standards did not have any impact on the Company's results of operations or financial position.

j) Capital disclosures

Effective January 1, 2008, the Company adopted CICA Handbook Section 1535 - "Capital Disclosures" which requires disclosure of the Company's objectives, policies and processes for managing capital as well as its compliance with any external capital requirements. The implementation of this standard did not have any impact on the Company's results of operations or financial position.

2. Accounting policies - continued

k) Payments in lieu of corporate income taxes

The Company provides for payments in lieu of corporate income taxes using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Norfolk Power Distribution Inc. at that time.

l) Regulatory policies

Norfolk Power Distribution Inc. has adopted the following policies, as prescribed by the Ontario Energy Board (OEB) for rate-regulated enterprises. The policies have resulted in accounting treatments differing from Canadian generally accepted accounting principles for enterprises operating in a non-rate-regulated environment:

1. Various regulatory costs have been deferred in accordance with criteria set out in the OEB's Accounting Procedures Handbook. In the absence of such regulation, these costs would have been expensed when incurred under Canadian GAAP.
2. The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB's Accounting Procedures Handbook.
3. The Company provides payments in lieu of corporate income taxes using the taxes payable method.

m) Measurement uncertainty

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of revenue, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the financial statement date. Accounts receivable, unbilled revenue, inventory, regulatory assets/liabilities, and employee future benefits are reported based on amounts expected to be recovered/refunded and an appropriate allowance has been provided based on management's best estimate of unrecoverable amounts. Due to the inherent uncertainty involved in making such estimates, actual results could differ from amounts recorded in these financial statements, including changes as a result of future decisions made by the OEB or the Minister of Energy.

2. Accounting policies - continued

n) Rate setting and industry regulation

The Ontario Energy Board Act (1998) (the Act) gave the OEB increased powers and responsibilities to regulate the electricity industry in Ontario. These powers and responsibilities include the ability to approve or fix rates for the transmission and distribution of electricity, the ability to provide continued rate protection for rural and remote electricity consumers and the responsibility for ensuring the distribution companies fulfil obligations to connect and service customers.

The Act provides for a competitive market in the sale of electricity in addition to the regulation of the monopoly electricity delivery system in Ontario.

The OEB has regulatory authority over the electricity delivery sector. The Act sets out the Board's power to issue a distribution license, which must be obtained by any person owning or operating a distribution system under the Act. The Act allows the Board to prescribe license requirements and conditions to electricity distributors, which may include such considerations as specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing requirements for rate setting purposes.

With the commencement of the open market, the Company purchases electricity from the Independent Electricity System Operator (IESO), at the spot market rates and charges its customers unbundled rates. The unbundled rates include the actual cost of generation and transmission of electricity and an approved rate for electricity distribution. The cost of generation, transmission and other charges such as connection and debt retirement are collected by Norfolk Power Distribution Inc. and remitted to the IESO. The Company retains the distribution charge on the customer hydro invoices. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specified period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable in the future from customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts recovered for specific expenditures in excess of costs incurred by the Company. These liabilities are expected to be settled with future rate adjustments. Specific regulatory assets and liabilities are disclosed in Note 5.

2. Accounting policies - continued

o) Future accounting pronouncements

Income taxes

During 2007, the Accounting Standards Board (AcSB) issued an exposure draft proposing to remove all specific references to rate regulated accounting from the CICA Handbook. In August 2007, the AcSB decided to remove a temporary exemption in CICA Handbook Section 1100 "Generally Accepted Accounting Principles", retain existing references to rate regulated accounting in the CICA Handbook, amend CICA Handbook Section 3465 "Income Taxes" to require the recognition of future income tax liabilities and assets as well as a corresponding regulatory asset or liability, and retain existing requirements to disclose the effects of rate regulation per AcG-19. The new rules will apply prospectively to annual financial statements relating to fiscal years beginning on or after January 1, 2009. Future taxes are detailed in note 11 of these financial statements.

International Financial Reporting Standards ("IFRS")

On February 13, 2008, the AcSB confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP and annual reporting purposes for fiscal years beginning after January 1, 2011. A limited number of converged or IFRS-based standards will be incorporated into Canadian GAAP prior to 2011, with the remaining standards to be adopted at the change over date. The Company has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements. At this time, the impact on the Company's future financial position and results of operations is not reasonably determinable.

3. Inventory

Inventory consists of the following:

	2008 **$**	2007 $
Fuses, switches, LIS and arresters	**111,571**	131,247
Wire and cable	**119,899**	157,408
Poles	**40,311**	54,496
Recloser shop inventory	**33,260**	33,260
Other	**224,329**	236,799
	529,370	613,210

There was no reclassification out of inventory and into property, plant and equipment resulting from the adoption of CICA Handbook Section 3031 - "Inventories".

Norfolk Power Distribution Inc.

Notes to the Financial Statements

For the year ended December 31, 2008

4. Property, plant and equipment

	Cost $	Accumulated amortization $	2008 $	2007 $
Distribution plant				
Land, land rights and easements	686,027	-	686,027	685,332
Transformer station building	1,524,961	117,551	1,407,410	1,363,818
Transformer station equipment	3,215,595	297,500	2,918,095	2,866,309
Distribution station equipment	3,884,654	1,594,514	2,290,140	1,876,469
Poles, towers and fixtures	24,691,484	11,267,242	13,424,242	13,390,739
Overhead conductors and devices	12,983,070	4,966,692	8,016,378	7,559,618
Underground conduit	3,532,583	1,237,386	2,295,197	2,364,795
Underground conductors and devices	7,120,863	2,472,398	4,648,465	4,708,435
Transformers	10,816,541	5,684,971	5,131,570	4,901,018
Overhead and underground services	2,230,186	332,268	1,897,918	1,701,780
Meters	3,943,703	2,076,565	1,867,138	1,827,006
	74,629,667	30,047,087	44,582,580	43,245,319
General plant				
Land and easements	243,636	-	243,636	242,867
Buildings and fixtures	2,189,477	777,905	1,411,572	1,374,562
Leasehold improvements - Hunt St.	6,177	2,584	3,593	4,233
Office furniture and equipment	407,613	331,241	76,372	75,267
Computer equipment	1,607,263	1,213,715	393,548	366,816
Vehicles	2,267,042	1,480,243	786,799	923,397
Stores equipment	120,021	98,595	21,426	23,989
Equipment under capital lease	10,039	4,015	6,024	7,027
Garage tools and equipment	709,788	542,328	167,460	139,503
Measurement and testing equipment	162,717	76,096	86,621	90,317
Communication equipment	106,906	37,222	69,684	40,519
Miscellaneous equipment	168,061	59,406	108,655	77,838
Load management controls	16,565	16,565	-	-
SCADA system	622,036	227,770	394,266	427,108
	8,637,341	4,867,685	3,769,656	3,793,443
	83,267,008	34,914,772	48,352,236	47,038,762
Contributions in aid of construction	(7,122,607)	(1,340,271)	(5,782,336)	(5,735,780)
	76,144,401	33,574,501	42,569,900	41,302,982

5. Regulatory assets (liabilities)

	2008 **$**	2007 $
Settlement variances		
Wholesale market services	**(634,744)**	(526,496)
Transmission network services	**29,196**	190,209
Transmission connection services	**(1,639,773)**	(1,159,909)
Bloomsburg transformation connection charge	**492,840**	492,840
Power	**(125,778)**	(172,308)
Global adjustment	**280,329**	(24,655)
Total settlement variances	**(1,597,930)**	(1,200,319)
Recovery of regulatory assets		
Recovery of regulatory asset balances	**799,713**	1,018,370
Recovery of regulatory asset balances - carrying charges	**58,779**	23,766
Recovery of transition costs	**(236,091)**	174,596
Transition costs - carrying charges	**42,666**	46,125
Total recovery of regulatory assets	**665,067**	1,262,857
Smart meter funding	**(172,136)**	(82,484)
Other		
Hydro One charges	**(43,574)**	(422,186)
Retail services and service transaction requests variances	**1,646**	9,397
Low voltage variances	**48,096**	21,744
Other regulatory assets - OEB cost assets and other regular asset carrying charges	**163,582**	120,828
Extraordinary event costs and carrying charges	**202,607**	195,165
Conservation and demand management	**7,068**	7,068
Total other	**379,425**	(67,984)
Net regulatory assets (liabilities)	**(725,574)**	(87,930)

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operation in the period that the assessment is made.

Hydro One has been granted approval from the Ontario Energy Board to recover from embedded direct customers, its regulatory asset account balances of $23,155,642 over a three year period beginning on April 1, 2005. Amounts recovered from Hydro One by Norfolk Power Distribution Inc. have been charged to applicable regulatory asset accounts as per OEB direction.

5. Regulatory assets (liabilities) - continued

In 2007, the OEB mandated that all LDCs install Smart Meters for all residential and small commercial customers by December 31, 2010. The Smart Meter technology will allow for remote meter reads, time of use pricing, and will allow consumers to better manage their energy consumption. Data collected by the Smart Meters can be downloaded instantaneously and will provide outage notification. As part of the NEPA group (Niagara-Erie Power Alliance), Norfolk Power Distribution Inc. entered into a group purchase plan for the Smart Meter units. An American supplier called Sensus, with a distributor in Canada called KTI, was selected based on pricing, technology, and availability. As of December 31, 2008, Norfolk Power Distribution Inc. committed to purchase about 16,700 meters at a cost of approximately $1.5M US. The meters are expected to arrive in late April 2009 for installation beginning in May 2009.

Conservation and demand management expenditures include costs and investments outlined in the Company's conservation and demand management plan. This also includes amounts the Company collects in rates for its third tranche or final installment of MARR (Market Adjusted Revenue Requirement), over the approved collection period between March 1, 2005 and February 26, 2006.

	2008 **$**	2007 $
CDM expenditures	**194,466**	194,466
Revenue from 3rd tranche recovery	**(581,000)**	(581,000)
CDM contra account	**393,602**	393,602
	7,068	7,068

6. Related party transactions

Transactions with associated companies are conducted within the normal course of business at fair market value of the services provided.

As at December 31, 2008, the following transactions occurred between associated companies:

a) Norfolk Power Distribution Inc. paid operating expenses and income tax installments as follows:
   - $1,097,816 on behalf of Norfolk Energy Inc.
   - $103,288 on behalf of Norfolk Power Inc.

b) Norfolk Power Distribution Inc. financed capital asset additions on behalf of Norfolk Energy Inc. for a net amount of $942,012.

c) Norfolk Power Distribution Inc. received revenue accruing to Norfolk Energy Inc. amounting to $1,626,438.

Balances owing at December 31 have no set repayment terms.

	2008 **$**	2007 $
Amounts (owing to) due from Norfolk Power Inc.	**(92,098)**	102,473
Amounts (owing to) due from Norfolk Energy Inc.	**494,482**	(499,470)
	402,384	(396,997)

As the sole shareholder of Norfolk Power Distribution Inc.'s parent company (Norfolk Power Inc.), Norfolk County is considered a related party. All transactions with the County are conducted at prevailing market prices and normal trade terms.

7. Bank indebtedness

a) Bank overdraft

The bank overdraft is on demand and bears interest at prime. The total overdraft facility limit is $3,000,000 and is secured by the Company's distribution assets. The Company subsequently secured temporary bank financing to cover the shortfall in the overdraft facility.

b) Bank loans

	2008	2007
	$	$
The original $2,000,000 ISDA swap for a 25-year term at 1.63% interest plus B/A stamping fees at 0.75%. Principal and interest payments are made on a quarterly basis. The loan is secured by certain distribution assets as per the General Security Agreement and is due December 2029.	**1,957,000**	2,000,000
The original $10,700,000 ISDA swap for a 25-year term at 1.63% interest plus B/A stamping fees at 0.75%. Principal and interest payments are made on a quarterly basis. The loan is secured by certain distribution assets as per the General Security Agreement and is due September 2029.	**9,971,000**	10,168,000
The original $4,000,000 ISDA swap for a 15-year term at 1.63% interest plus B/A stamping fees at 0.75%. Principal and interest payments are made on a quarterly basis. The loan is secured by certain distribution assets as per the General Security Agreement and is due September 2020.	**3,257,000**	3,458,000
	15,185,000	15,626,000
Less: current portion	**(485,000)**	(441,000)
	14,700,000	15,185,000

Future principal payments are as follows:	**$**	$
2008	**-**	441,000
2009	**485,000**	485,000
2010	**514,000**	514,000
2011	**547,000**	547,000
2012	**580,000**	580,000
2013	**623,000**	623,000
Additional future principal payments	**12,436,000**	12,436,000
	15,185,000	15,626,000

8. Debentures

	2008 **$**	2007 $
Debenture from former Region of Haldimand-Norfolk	-	369,000
Infrastructure Ontario debenture bearing an interest rate of 5.01% per annum over the term of the debenture and repayable in semi-annual installments of principal plus interest payments. The debenture is secured by certain distribution system assets.	**1,958,514**	2,000,000
	1,958,514	2,369,000
Less: current portion	**(43,591)**	(410,486)
	1,914,923	1,958,514

Future principal payments are as follows:	**$**	$
2008	-	410,486
2009	**43,591**	43,591
2010	**45,802**	45,802
2011	**48,125**	48,125
2012	**50,567**	50,567
2013	**53,132**	53,132
Additional future principal payments	**1,717,297**	1,717,297
	1,958,514	2,369,000

9. Capital lease obligation

	2008 **$**	2007 $
Capital vehicle lease	-	1,561
Capital lease is repayable in equal monthly installments of principal and interest and is due October 2010. The lease is secured by the leased computer hardware.	**89,900**	-
Less: current portion	**(49,037)**	(1,561)
	40,863	-

Future capital lease payments are as follows:	**$**	$
2008	-	1,561
2009	**49,037**	-
2010	**40,863**	-
	89,900	1,561

10. Share capital

As explained in note 1, share capital was issued as consideration for the net assets transferred from predecessor hydro-electric commissions as at January 1, 2001.

	2008		2007	
	#	$	#	$
Authorized				
Unlimited number of common shares				
Issued				
Common shares	**1,000**	**22,768,898**	1,000	22,768,898

11. Payments in lieu of corporate taxes

In accordance with the Ontario Electricity Competition Act (1998) (Bill 35), Norfolk Power Inc. and its subsidiary companies became responsible for payment in lieu of corporate taxes (PILS) effective October 31, 2001, using the taxes payable method.

The current provision for payments in lieu of corporate taxes is comprised of the following:

	2008 $	2007 $
Income tax	**602,318**	414,085
Prior year (over)/under provision	**18,695**	(56,262)
	621,013	357,823
Capital tax (classified as operating expense)	**78,000**	90,000

Future income taxes are not recognized by Norfolk Power Distribution Inc. because future income taxes are expected to be included in the approved rates charged to customers in the future and are expected to be recovered from customers.

Had future income taxes been recorded, their effect on these financial statements would have been as follows:

	2008 $	2007 $
Future benefit of taxable differences	**1,586,045**	1,346,802

12. Financial instruments

The Company's carrying value and fair value of financial instruments consist of the following:

	2008		2007	
	$		$	
	Carrying value	**Fair value**	Carrying value	Fair value
Accounts receivable	**4,292,468**	**4,292,468**	4,330,698	4,330,698
Accounts payable and accrued liabilities	**5,726,695**	**5,726,695**	6,734,295	6,734,295
Bank overdraft	**3,726,158**	**3,726,158**	1,083,309	1,083,309
Bank loans	**15,185,000**	**15,185,000**	15,626,000	15,626,000
Debentures	**1,958,514**	**2,119,068**	2,369,000	2,369,000

The fair value of bank loans approximate their carrying value as interest rates on these loans are adjusted quarterly. The fair value of debentures were determined using quoted market prices. The fair value of the other instruments are measured at amortized cost and approximate their carrying value because of the short term nature of the instruments.

Exposure to interest rate risk, credit risk, liquidity risk and foreign exchange risk arises in the normal course of the Company's business.

Interest rate risk

The Company is exposed to interest rate risk in holding certain financial instruments. The Company's objective is to minimize net interest expense. The Company attempts to minimize interest rate risk by issuing long term fixed rate debt, and by extending or shortening the term of its short term money market investments by assessing the monetary policy stance of the Bank of Canada, while ensuring that all payment obligations are met on an on-going basis.

Under the Company's bank agreements, the Company may obtain short term borrowing for working capital purposes. These borrowings expose the Company to fluctuations in short term interest rates (borrowings in the form of prime rate loans in Canadian dollars and bankers' acceptances and letters of credit). The fee payable for bankers' acceptances and letters of credit is based on a margin determined by reference to the Company's credit rating.

Credit risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2008, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, the Company did not earn a significant amount of revenue from any individual customer. As at December 31, 2008, there were no significant accounts receivable due from any single customer.

In the year, the Company's provision for bad debts remained relatively unchanged at $130,000 (2007 - $132,000). Minor adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at December 31, 2008, approximately 7% (2007 - 9%) of the Company's accounts receivable was aged more than 60 days.

12. Financial instruments - continued

Foreign exchange risk

The Company tries to limit its exposure to the changing values of foreign securities. As at December 31, 2008, the Company has committed to purchasing smart meters and computer software upgrades which are payable in U.S. funds. The Company is exposed to fluctuations in foreign exchange on these transactions. In the normal course of operation, the impact of foreign currency fluctuations is not material to the financial statements.

Liquidity risk

The Company monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Company's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest expense. The Company has access to credit facilities and monitors cash balances daily to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due. Liquidity risk associated with financial commitments are as follows:

	Due in 2009 $	**Due from 2010 to 2013 $**	**Due after 2013 $**
Accounts payable and accrued liabilities	5,726,695	-	-
Bank loans	485,000	2,264,000	12,436,000
Debentures	43,591	197,626	1,717,297
	6,255,286	2,461,626	14,153,297

13. Capital management

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long term basis at reasonable rates and to deliver appropriate financial returns.

The Company considers its capital structure to consist of shareholder's equity, bank loans and debentures. The Company's capital structure as at December 31, 2008 and December 31, 2007 was as follows:

	2008 $	2007 $
Bank loans	**15,185,000**	15,626,000
Debentures	**1,958,514**	2,369,000
	17,143,514	17,995,000
Contributed capital	**830,799**	830,799
Common shares	**22,768,898**	22,768,898
Retained earnings	**1,621,402**	1,079,819
	25,221,099	24,679,516
Total capital	**42,364,613**	42,674,516

13. Capital management - continued

The Company's capital structure as at December 31, 2008, is 39% debt and 61% equity (2007 - 41% debt and 59% equity). There have been no changes in the Company's approach to capital management during the year.

The OEB and shareholder restrict the permissible debt to 60% of the Company's total capitalization. As well, the Company has customary covenants typically associated with long term debt. Among other things, the Company's long term debt and credit facility covenants further limit the permissible debt to 50% of the Company's total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary expectations. At December 31, 2008, the Company is in compliance with all of these covenants and limitations.

14. Prudential support

Norfolk Power Distribution Inc. is required through the IESO, to provide security to mitigate the Company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if Norfolk Power Distribution Inc. fails to make payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2008 the Company provided prudential support in the form of bank letters of credit of $1,537,163.

15. Contingent liabilities

Griffith et al. v. Toronto Hydro-Electric Commission et al.

On April 22, 2004, in a decision in a class action commenced against The Consumers' Gas Company Limited (now Enbridge Gas Distribution Inc.), hereafter referred to as "Enbridge", the Supreme Court of Canada (the "Supreme Court") ruled that Enbridge was required to repay the portion of certain late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. Although the claim related to charges collected by Enbridge after the enactment of section 347 of the Criminal Code in 1981, the Supreme Court limited recovery to charges collected after the action was initiated in 1994. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for a determination of the plaintiffs' damages. The parties reached a settlement of this class action. The Ontario Superior Court of Justice has approved this settlement, however, the representative plaintiff, Mr. Garland, is appealing the settlement approval order in an attempt to increase the fees to which he is entitled for having acted as representative plaintiff, and to receive lawyer's fees in connection with that effort. Mr. Garland's appeal is pending.

On February 4, 2008, the OEB, in response to an application filed by Enbridge, ruled that all of Enbridge's costs related to settlements of the class action lawsuits, including legal cost, settlement costs and interest, are recoverable from ratepayers.

As a result of the above proceedings and settlements, Toronto Hydro is now subject to the two class actions described below in which the issues are analogous.

15. Contingent liabilities - continued

The first action commenced against a predecessor of Toronto Hydro and other Ontario municipal electric utilities under the Class Proceedings Act, 1992, seeking $500 million in restitution for late payment charges collected by them from their customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. This action is at a preliminary stage. Pleadings have closed but examinations for discovery have not been conducted and the classes have not been certified After the release by the Supreme Court of Canada of its 2004 decision in the Enbridge case, the plaintiffs in this proposed class action indicated their intention to proceed with the litigation, but no formal steps have been taken.

The second is an action commenced against a predecessor of Toronto Hydro under the Class Proceedings Act, 1992, seeking $64 million in restitution for late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. This action is also at the preliminary stage. Pleadings have closed and examinations for discovery have been conducted but, as in the first action, the classes have not been certified as the parties were awaiting the outcome of the Enbridge class action.

The claims made against Toronto Hydro and the definitions of the plaintiff classes are identical in both actions. As a result, any damages payable by Toronto Hydro in the first action would reduce the damages payable by Toronto Hydro in the second action, and vice versa.

It is anticipated that the first action will now proceed for determination in light of the reasons of the Supreme Court in the Enbridge class action.

Although Norfolk Power Distribution Inc. is not a party in any of the aforementioned legal proceedings, the legal proceedings brought against Toronto Hydro after the Enbridge Gas class action lawsuit demonstrate the ripple affect such decisions can have on other utilities.

The Electricity Distributor's Association is undertaking the defence of this class action. At this time, it is not possible to quantify the effect, if any, on these financial statements.

16. Supplemental cash flow information

	2008 **$**	2007 $
Interest expense	**1,319,911**	1,220,014
Interest revenue	**18,525**	42,435

17. Comparative figures

Certain amounts on the financial statements for the year ended December 31, 2007 have been reclassified to agree to the method of presentation adopted for the current year.

Norfolk Power Distribution Inc.

Financial Statements

December 31, 2009

MILLARD, ROUSE & ROSEBRUGH LLP
Chartered Accountants

85 Robinson Street
Simcoe, Ontario

Auditors' Report

To the Shareholder of
Norfolk Power Distribution Inc.

We have audited the balance sheet of Norfolk Power Distribution Inc. as at December 31, 2009 and the statements of operations, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of Norfolk Power Distribution Inc. as at December 31, 2009 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Millard Rouse & Rosebrugh LLP

April 14, 2010
Simcoe, Ontario

Chartered Accountants
Licensed Public Accountants

OUR REPORTS AND CERTIFICATES ARE ISSUED ON THE UNDERSTANDING THAT UNLESS THEY ARE REPRODUCED IN THEIR ENTIRETY, ANY SUMMARIES THEREOF, EXCERPTS THEREFROM OR REFERENCES THERETO SHALL BE SUBMITTED TO US FOR OUR APPROVAL.

Norfolk Power Distribution Inc.

Balance Sheet

As at December 31, 2009

	2009 **$**	2008 $ *As restated (note 3)*
Assets		
Current assets		
Cash	**288,243**	-
Accounts receivable	**4,666,697**	4,292,468
Unbilled revenue	**4,644,558**	4,634,444
Loan to Norfolk Energy Inc.	-	350,000
Due from associated companies (note 8)	**17,858**	402,384
Income taxes recoverable	-	435,682
Inventory (note 5)	**572,473**	529,370
Prepaid expenses	**255,981**	354,605
Total current assets	**10,445,810**	10,998,953
Property, plant and equipment (note 6)	**48,698,228**	42,517,728
Regulatory assets (note 7a)	**4,599,127**	1,436,442
Future tax asset	**1,618,588**	-
Total assets	**65,361,753**	54,953,123
Liabilities and Shareholder's Equity		
Current liabilities		
Bank overdraft (note 9a)	-	3,726,158
Demand loan (note 9b)	**2,000,000**	-
Accounts payable	**7,531,417**	5,915,687
Income taxes payable	**233,788**	-
Current portion of long term liabilities	**690,666**	637,627
Total current liabilities	**10,455,871**	10,279,472
Long term liabilities		
Customer deposits	**166,430**	125,047
Post employment benefits	**805,337**	750,866
Capital lease obligation (note 12)	-	40,864
Regulatory liabilities (note 7b)	**4,588,845**	2,439,810
Bank loans (note 9c)	**14,186,000**	14,700,000
Debentures (note 10)	**1,869,121**	1,914,923
Infrastructure Ontario financing (note 11)	**6,799,980**	-
Total long term liabilities	**28,415,713**	19,971,510
Total liabilities	**38,871,584**	30,250,982
Shareholder's equity		
Share capital (note 13)	**22,768,898**	22,768,898
Contributed capital	**830,799**	830,799
Retained earnings	**2,890,472**	1,102,444
Total shareholder's equity	**26,490,169**	24,702,141
Total liabilities and shareholder's equity	**65,361,753**	54,953,123

The accompanying notes are an integral part of these financial statements

Norfolk Power Distribution Inc.

Statement of Operations

For the year ended December 31, 2009

	2009 **$**	2008 $ *As restated (note 3)*
Revenue		
Energy sales	**28,763,186**	27,337,069
Distribution services	**11,015,769**	9,750,148
Other	**428,240**	428,348
	40,207,195	37,515,565
Costs		
Purchase of power	**28,763,186**	27,337,069
Distribution system - operation and maintenance	**2,086,375**	2,692,998
Billing and collecting	**1,037,686**	1,053,434
Community relations	**45,608**	95,043
Administrative and general expense	**1,402,169**	1,424,982
Taxes other than amounts in lieu of corporate taxes	**84,500**	112,717
	33,419,524	32,716,243
Income before amortization, interest and income taxes	**6,787,671**	4,799,322
Amortization (net of $363,982; 2008 - $380,375 charged to other accounts)	**2,517,025**	2,349,864
Interest	**1,270,618**	1,346,917
Income before income taxes	**3,000,028**	1,102,541
Income taxes - current (note 14)	**912,000**	621,013
Net income	**2,088,028**	481,528

Statement of Retained Earnings

For the year ended December 31, 2009

	2009 **$**	2008 $ *As restated (note 3)*
Retained earnings - beginning of the year	**1,102,444**	620,916
Net income	**2,088,028**	481,528
Dividends	**(300,000)**	-
Retained earnings - end of the year	**2,890,472**	1,102,444

The accompanying notes are an integral part of these financial statements

Norfolk Power Distribution Inc.

Statement of Cash Flows

For the year ended December 31, 2009

	2009 **$**	2008 $ *As restated (note 3)*
Cash provided by		
Operating activities		
Net income	**2,088,028**	481,528
Adjustment for non-cash items		
Amortization	**2,881,007**	2,730,239
Post employment benefits	**54,471**	68,961
Gain on disposal of property, plant and equipment	**(10,030)**	(9,100)
	5,013,476	3,271,628
Changes in non-cash working capital components:		
(Increase) decrease in accounts receivable	**(374,229)**	38,230
(Increase) in unbilled revenue	**(10,114)**	(202,842)
Decrease (increase) in income taxes recoverable / payable	**669,470**	(201,767)
Decrease in loan to Norfolk Energy Inc.	**350,000**	-
Decrease (increase) in inventory	**(43,103)**	83,840
Decrease in prepaid expenses	**98,624**	163,325
Decrease in unamortized debenture discount	-	3,184
Increase in future income taxes	**(1,618,588)**	-
Increase (decrease) in accounts payable	**1,615,730**	(818,608)
Increase (decrease) in amounts due to associated companies	**384,526**	(799,381)
	6,085,792	1,537,609
Investing activities		
Purchase of property, plant and equipment	**(9,599,769)**	(4,276,639)
Net change in regulatory liabilities	**(1,013,650)**	508,707
Contributions in aid of construction	**531,414**	331,461
Proceeds on disposition of property, plant and equipment	**16,878**	(42,878)
	(10,065,127)	(3,479,349)
Financing activities		
(Repayment) receipt of capital lease obligations	**(49,036)**	88,339
Receipt of customer deposits	**71,383**	62,038
Proceeds of demand loan	**2,000,000**	-
Infrastructure Ontario financing	**6,799,980**	-
Repayment of bank loan	**(485,000)**	(441,000)
Repayment of debentures	**(43,591)**	(410,486)
Dividends declared	**(300,000)**	-
	7,993,736	(701,109)
Net increase (decrease) in cash and cash equivalents for the year	**4,014,401**	(2,642,849)
Cash (deficiency) - beginning of the year	**(3,726,158)**	(1,083,309)
Cash (deficiency) - end of the year	**288,243**	(3,726,158)
Cash (deficiency) is comprised of:		
Cash	**288,243**	-
Bank overdraft	-	(3,726,158)
	288,243	(3,726,158)

The accompanying notes are an integral part of these financial statements

Norfolk Power Distribution Inc.

Notes to the Financial Statements

For the year ended December 31, 2009

1. Nature of activities

On November 1, 2000, Norfolk Power Inc. was incorporated under the Ontario Business Corporations Act, along with its two wholly owned subsidiary companies, Norfolk Power Distribution Inc. and Norfolk Energy Inc. Norfolk Power Distribution Inc. provides regulated electricity distribution services.

2. Summary of significant accounting policies

The financial statements of Norfolk Power Distribution Inc. have been prepared in accordance with Canadian generally accepted accounting principles (GAAP), including accounting principles prescribed by the Ontario Energy Board (OEB) in the handbook "*Accounting Procedures Handbook for Electric Distribution Utilities*" and reflect the significant accounting policies summarized below:

a) Inventory

Inventory consists of repair parts, supplies and materials held for operating and maintenance activities and are valued at lower of cost and net realizable value. Cost is determined using the weighted average method.

b) Property, plant and equipment

Property, plant and equipment are valued at acquisition cost and include contracted services, materials, labour, engineering costs, interest and overheads. Gains or losses at retirement or disposition are credited or charged to other income in the year of acquisition or disposition.

Amortization is provided on a straight line basis for property, plant and equipment available for use over their estimated economic lives, at the following annual rates:

Buildings	50 Years	2%
Transformer station equipment	40 Years	2.5%
Substation equipment	30 Years	3.3%
Distribution system	25 Years	4%
SCADA system	15 Years	6.7%
Meters	25 Years	4%
Office and warehouse equipment	10 Years	10%
Garage tools and equipment	10 Years	10%
Measurement and testing equipment	10 Years	10%
Vehicles	10 Years	10%
Computer hardware and software	5 Years	20%
Communication equipment	10 Years	10%
Miscellaneous equipment	10 Years	10%

Full amortization is recorded in the year of acquisition and none in the year of disposal.

2. Summary of significant accounting policies - continued

c) Contributions in aid of construction

Contributions in aid of construction are required contributions received from outside sources used to finance additions to property, plant and equipment. Capital contributions are treated as a contra credit account included in the determination of property, plant and equipment. The amount is subsequently amortized by a charge to accumulated amortization and a credit to amortization expense, at an equivalent rate to that used for the amortization of the related property, plant and equipment.

d) Impairment of long-lived assets

The Company reviews long-lived assets for impairment whenever events or circumstances indicate that the carrying amount of the long-lived asset is not recoverable. Any resulting impairment loss is recorded in the period in which the impairment occurs.

e) Pension and other post-employment benefits

Norfolk Power Inc. and its subsidiary companies provide a pension plan for their employees through the Ontario Municipal Employees Retirement System (OMERS). OMERS is a multi-employer public sector contributory defined benefit pension plan. The pension fund is financed by equal contributions from participating employers and employees and by the investment earnings of the fund.

The Company actuarially determines the cost of other employment and post-employment benefits offered to employees using the projected benefit method prorated on service and based on management's best estimate assumptions. Under this method, the projected post-retirement benefit is deemed to be earned on a pro-rata basis over the years of service in the attribution period commencing at the date of hire, and ended at the earliest age the employee could retire and qualify for benefits. Compensated absences and termination benefits that do not vest or accumulate are recognized as an expense when the event occurs.

f) Customer deposits

Customer deposits are cash collections from customers to guarantee the payment of energy bills and fulfillment of contractual obligations. Deposits expected to be refunded to customers within the next fiscal period are classified as a current liability. Interest is accrued on customer deposit balances at rates established and reviewed by the Company on a quarterly basis.

g) Revenue recognition

Distribution revenues are based on OEB approved distribution rates and are recognized on a basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed. The related cost of power is recorded on the basis of power used. Actual results could differ from estimates made of actual electricity usage.

Other revenues related to sales of other services are recognized as the services are rendered.

2. Summary of significant accounting policies - continued

h) Financial instruments

All financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, other liabilities or available-for-sale. All financial instruments are carried at fair value on the balance sheet except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period in which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in other comprehensive income until the instrument is derecognized or impaired. The Company has classified its financial instruments as follows:

Cash	Held-for-trading
Accounts receivable and unbilled revenue	Loans and receivable
Bank overdraft	Other liabilities
Accounts payable	Other liabilities
Bank loans	Other liabilities
Demand loan	Other liabilities
Customer deposits	Other liabilities
Debentures	Other liabilities
Infrastructure Ontario financing	Other liabilities

Effective January 1, 2008, the Company adopted CICA Handbook Sections 3862 - "Financial Instruments - Disclosures" and 3863 - "Financial Instruments - Presentation", which establish the requirement of disclosure of risk associated with both recognized and unrecognized financial instruments and the management of those risks. The adoption of these standards did not have any impact on the Company's results of operations or financial position.

In June 2009, the CICA amended Handbook Section 3862 to include additional disclosure requirements with respect to fair value measurements of financial instruments and to enhance liquidity risk disclosure requirements. The amendments require an entity to classify fair value measurements using a fair value hierarchy in levels ranging from 1 to 3 that reflect the significance of the inputs used in making these measurements. Upon application by the Company, the fair value hierarchy level used in the determination of the fair market value of debentures has been disclosed in Note 15.

i) Capital disclosures

Effective January 1, 2008, the Company adopted CICA Handbook Section 1535 - "Capital Disclosures" which requires disclosure of the Company's objectives, policies and processes for managing capital as well as its compliance with any external capital requirements. The implementation of this standard did not have any impact on the Company's results of operations or financial position.

2. Summary of significant accounting policies - continued

j) Payments in lieu of income taxes

Under the Electricity Act, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes.

The taxes payable method of accounting was applied until December 31, 2008. Effective January 1, 2009, the Company began using the liability method following the new recommendations from the CICA and the OEB. Under the liability method, future income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

k) Regulatory policies

Norfolk Power Distribution Inc. has adopted the following policies, as prescribed by the Ontario Energy Board (OEB) for rate-regulated enterprises. The policies have resulted in accounting treatments differing from Canadian generally accepted accounting principles for enterprises operating in a non-rate-regulated environment:

1. Various regulatory costs have been deferred in accordance with criteria set out in the OEB's Accounting Procedures Handbook. In the absence of such regulation, these costs would have been expensed when incurred under Canadian GAAP.
2. The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB's Accounting Procedures Handbook.

l) Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of revenue, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the financial statement date. Actual results could differ from amounts recorded in these financial statements, including changes as a result of future decisions made by the OEB or the Minister of Energy.

2. Summary of significant accounting policies - continued

m) Rate setting and industry regulation

The rates of the Company's electricity distribution business is subject to regulation by the OEB.

With the commencement of the open market, the Company purchases electricity from the Independent Electricity System Operator (IESO), at the spot market rates and charges its customers unbundled rates. The unbundled rates include the actual cost of generation and transmission of electricity and an approved rate for electricity distribution. The cost of generation, transmission and other charges such as connection and debt retirement are collected by Norfolk Power Distribution Inc. and remitted to the IESO. The Company retains the distribution charge on the customer hydro invoices.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specified period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable in the future from customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts recovered for specific expenditures in excess of costs incurred by the Company. These liabilities are expected to be settled with future rate adjustments. Specific regulatory assets and liabilities are disclosed in Note 7.

3. Restatement of 2008 comparative figures

In 2009, the Company had an independent assessment performed on the regulatory assets and liabilities that resulted in some adjustments made to those accounts. The restatement of the 2008 previously reported values are as follows:

Balance Sheet:

	2008 $ as reported	2008 $ as restated	change
Assets			
Property, plant and equipment	42,569,900	42,517,728	(52,172)
Regulatory assets	-	1,436,442	1,436,442
	42,569,900	43,954,170	1,384,270
Liabilities			
Accounts payable	5,726,695	5,915,687	188,992
Net regulatory liabilities	725,574	2,439,810	1,714,236
	6,452,269	8,355,497	1,903,228
Shareholder's equity			
Retained earnings	1,621,402	1,102,444	(518,958)

Statement of Operations:

	2008 $ as reported	2008 $ as restated	change
Revenue			
Energy sales and distribution service revenues	37,082,980	37,087,217	4,237
Costs			
Administrative and general expense	1,387,696	1,424,982	37,286
Interest	1,319,911	1,346,917	27,006
Net income	541,583	481,528	(60,055)

Statement of Retained Earnings:

	2008 $ as reported	2008 $ as restated	change
Retained earnings - beginning of the year	1,079,819	620,916	(458,903)
Net income	541,583	481,528	(60,055)
Retained earnings - end of the year	1,621,402	1,102,444	(518,958)

3. Restatement of 2008 comparative figures - continued

Statement of Cash Flows:

	2008 $ as reported	2008 $ as restated	change
Operating activities			
Net income	541,583	481,528	(60,055)
(Increase) in miscellaneous deferred debits and other	(68,798)	(26,934)	41,864
(Decrease) in accounts payable and accrued liabilities	(1,007,600)	(818,608)	188,992
	(534,815)	(364,014)	170,801
Investing activities			
Net change in regulatory liabilities	706,442	535,641	(170,801)

4. Emerging accounting changes

In 2008, the Accounting Standards Board (AcSB) confirmed that rate-regulated enterprises will be required to adopt International Financial Reporting Standards (IFRS) by January 1, 2011. Also, on October 14, 2009, the Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. As such the Company will apply IFRS to its financial statements ending December 31, 2011, with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2010, for comparative purposes.

The Company continues to assess the impact of conversion to IFRS on its results of operations. The International Accounting Standards Board (IASB) issued an exposure draft on rate-regulated activities in 2009. The Board is continuing its research related to rate-regulated entities and presently it is unclear what the outcome of the Board's deliberations will be and how that will impact on the Company's reporting under IFRS.

5. Inventory

Inventory consists of the following:

	2009 $	2008 $
Fuses, switches, LIS and arresters	**109,796**	111,571
Wire and cable	**122,600**	119,899
Poles	**65,183**	40,311
Recloser shop inventory	**29,583**	33,260
Other	**245,311**	224,329
	572,473	529,370

6. Property, plant and equipment

	Cost $	Accumulated amortization $	2009 $	2008 $ *As restated (note 3)*
Distribution plant				
Land, land rights and easements	694,044	-	694,044	686,027
Transformer station building	1,615,717	149,865	1,465,852	1,407,410
Transformer station equipment	3,215,595	377,926	2,837,669	2,918,095
Distribution station equipment	4,120,928	1,691,662	2,429,266	2,290,140
Poles, towers and fixtures	25,698,013	12,098,600	13,599,413	13,424,242
Overhead conductors and devices	13,715,614	5,405,305	8,310,309	8,016,378
Underground conduit	3,845,067	1,373,797	2,471,270	2,295,197
Underground conductors and devices	7,636,026	2,729,641	4,906,385	4,648,465
Transformers	11,237,917	6,212,345	5,025,572	5,131,570
Overhead and underground services	2,507,308	432,561	2,074,747	1,897,918
Meters	4,025,165	2,229,621	1,795,544	1,814,966
	78,311,394	32,701,323	45,610,071	44,530,408
General plant				
Land and easements	243,636	-	243,636	243,636
Buildings and fixtures	2,215,638	810,204	1,405,434	1,411,572
Leasehold improvements - Hunt St.	6,177	3,223	2,954	3,593
Office furniture and equipment	411,687	345,971	65,716	76,372
Computer equipment	1,687,297	1,373,942	313,355	393,548
Vehicles	2,122,603	1,510,404	612,199	786,799
Stores equipment	120,335	102,515	17,820	21,426
Equipment under capital lease	10,038	5,019	5,019	6,024
Garage tools and equipment	727,934	573,406	154,528	167,460
Measurement and testing equipment	178,973	93,994	84,979	86,621
Communication equipment	106,906	47,912	58,994	69,684
Miscellaneous equipment	412,335	100,640	311,695	108,655
Load management controls	16,565	16,565	-	-
SCADA system	626,609	271,231	355,378	394,266
	8,886,733	5,255,026	3,631,707	3,769,656
	87,198,127	37,956,349	49,241,778	48,300,064
Construction work in progress	5,472,038	-	5,472,038	-
Contributions in aid of construction	(7,654,021)	(1,638,433)	(6,015,588)	(5,782,336)
	85,016,144	36,317,916	48,698,228	42,517,728

7. Regulatory assets and liabilities

	2009 **$**	2008 $ *As restated (note 3)*
a) Regulatory assets		
Settlement variances		
Transmission network services	**229,565**	10,817
Bloomsburg transformation connection charge	**492,840**	492,840
Power	**383,487**	91,373
Total settlement variances	**1,105,892**	595,030
Recovery of regulatory assets	**206,426**	206,426
Retail services and service transaction requests variances	**22,484**	30,750
Extraordinary event costs and carrying charges	**178,422**	177,279
Smart meters	**2,786,858**	86,909
Other deferred charges	**299,045**	340,048
Total regulatory assets	**4,599,127**	1,436,442
b) Regulatory liabilities		
Settlement variances		
Wholesale market services	**(875,484)**	(771,480)
Transmission connection services	**(1,645,835)**	(1,457,880)
Total settlement variances	**(2,521,319)**	(2,229,360)
Smart meter funding	**(448,938)**	(210,450)
Future income taxes	**(1,618,588)**	-
Total regulatory liabilities	**(4,588,845)**	(2,439,810)

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operation in the period that the assessment is made.

7. Regulatory assets and liabilities - continued

In 2007, the OEB mandated that all LDCs install Smart Meters for all residential and small commercial customers by December 31, 2010. The Smart Meter technology will allow for remote meter reads, time of use pricing, and will allow consumers to better manage their energy consumption. Data collected by the Smart Meters can be downloaded instantaneously and will provide outage notification. At December 31, 2009, approximately 17,000 meters had been installed which accounted for 95% of the total meters to be installed.

8. Related party transactions

Transactions with associated companies are conducted within the normal course of business at fair market value of the services provided.

As at December 31, 2009, the following transactions occurred between associated companies:

a) Norfolk Power Distribution Inc. paid operating expenses and income tax installments as follows:
   - $685,392 on behalf of Norfolk Energy Inc.
   - $55,173 on behalf of Norfolk Power Inc.

b) Norfolk Power Distribution Inc. financed capital asset additions on behalf of Norfolk Energy Inc. for a net amount of $78,688.

c) Norfolk Power Distribution Inc. received revenue accruing to Norfolk Energy Inc. amounting to $1,172,354.

Balances owing at December 31 have no set repayment terms.

	2009 **$**	2008 $ *As restated (note 3)*
Amounts (owing to) due from Norfolk Power Inc.	**(35,918)**	436,868
Amounts (owing to) due from Norfolk Energy Inc.	**53,776**	(34,484)
	17,858	402,384

As the sole shareholder of Norfolk Power Distribution Inc.'s parent company (Norfolk Power Inc.), Norfolk County is considered a related party. All transactions with the County are conducted at prevailing market prices and normal trade terms.

9. Bank indebtedness

a) Bank overdraft

The bank overdraft is on demand and bears interest at prime plus 0.5%. The total overdraft facility limit is $3,000,000 and is secured by the Company's distribution assets.

b) Demand loan

	2009	2008
	$	$
The total is comprised of a 90-day $2,000,000 ISDA swap at 0.46% interest plus B/A stamping fees of 2%. The loan is secured by certain distribution assets as per the General Security Agreement and is due January 2010 and was subsequently renewed for similar terms.	**2,000,000**	-

c) Bank loans

The original $2,000,000 ISDA swap for a 25-year term at 5.42% interest plus B/A stamping fees at 0.75%. Principal and interest payments are made on a quarterly basis. The loan is secured by certain distribution assets as per the General Security Agreement and is due December 2029.	**1,909,000**	1,957,000
The original $10,700,000 ISDA swap for a 25-year term at 6.25% interest plus B/A stamping fees at 0.75%. Principal and interest payments are made on a quarterly basis. The loan is secured by certain distribution assets as per the General Security Agreement and is due September 2029.	**9,751,000**	9,971,000
The original $4,000,000 ISDA swap for a 15-year term at 5.27% interest plus B/A stamping fees at 0.75%. Principal and interest payments are made on a quarterly basis. The loan is secured by certain distribution assets as per the General Security Agreement and is due September 2020.	**3,040,000**	3,257,000
	14,700,000	15,185,000
Less: current portion	**(514,000)**	(485,000)
	14,186,000	14,700,000

Future principal payments are as follows:	$	$
2009	-	485,000
2010	**514,000**	514,000
2011	**547,000**	547,000
2012	**580,000**	580,000
2013	**623,000**	623,000
2014	**658,000**	658,000
Additional future principal payments	**11,778,000**	11,778,000
	14,700,000	15,185,000

10. Debentures

	2009 **$**	2008 $
Infrastructure Ontario debenture bearing an interest rate of 5.01% per annum over the term of the debenture and repayable in semi-annual installments of principal plus interest payments. The debenture is secured by certain distribution system assets.	**1,914,923**	1,958,514
Less: current portion	**(45,802)**	(43,591)
	1,869,121	1,914,923

Future principal payments are as follows:	**$**	$
2009	-	43,591
2010	**45,802**	45,802
2011	**48,126**	48,126
2012	**50,567**	50,567
2013	**53,132**	53,132
2014	**55,827**	55,827
Additional future principal payments	**1,661,469**	1,661,469
	1,914,923	1,958,514

11. Infrastructure Ontario financing

	2009 **$**	2008 $
Ontario Infrastructure Projects Corporation (OIPC) financing	**6,799,980**	-

During the year, the Company received funding for the construction of a transformer station and to purchase smart meters. Interest is payable monthly at OIPC advance interest rates. The Company has the option to repay the advance or convert to a debenture at the completion of the projects. It is anticipated that the Company will convert the financing into a debenture.

12. Capital lease obligation

	2009 **$**	2008 $
Capital lease is repayable in equal monthly installments of principal and interest and is due October 2010. The lease is secured by the leased computer hardware.	**40,864**	89,900
Less: current portion	**(40,864)**	(49,036)
	-	40,864

Future capital lease payments are as follows:	**$**	$
2009	-	49,036
2010	**40,864**	40,864
	40,864	89,900

13. Share capital

Share capital was issued as consideration for the net assets transferred from predecessor hydro-electric commissions as at January 1, 2001.

	2009		2008	
	#	$	#	$
Authorized				
Unlimited number of common shares				
Issued				
Common shares	1,000	22,768,898	1,000	22,768,898

14. Income taxes - current

The income tax provision was calculated based on taxable income. Taxable income is calculated as follows:	2009 $	2008 $
Income before income taxes	3,000,028	1,102,541
Capital cost allowance in excess of amortization	(103,968)	(6,332)
Net change in regulatory assets	(2,632,235)	706,605
Regulatory assets capitalized for tax purposes	2,697,693	-
Gain on disposal of assets	(10,030)	(9,100)
Other additions and deductions	(187,852)	60,055
	2,763,636	1,853,769
Tax at 33.00%,(2008 - 33.50%)	912,000	621,013

15. Financial instruments

The Company's carrying value and fair value of financial instruments consist of the following:

	2009 $		2008 $	
	Carrying value	Fair value	Carrying value	Fair value
Cash	288,243	288,243	-	-
Accounts receivable	4,666,697	4,666,697	4,292,468	4,292,468
Unbilled revenue	4,644,558	4,644,558	4,634,444	4,634,444
Accounts payable	7,531,417	7,531,417	5,915,687	5,915,687
Bank overdraft	-	-	3,726,158	3,726,158
Demand loan	2,000,000	2,000,000	-	-
Bank loans	14,700,000	14,700,000	15,185,000	15,185,000
Customer deposits	166,430	166,430	125,047	125,047
Debentures	1,914,923	1,909,538	1,958,514	2,119,068
Infrastructure Ontario financing	6,799,980	6,799,980	-	-

The fair value of bank loans approximate their carrying value as interest rates on these loans are adjusted quarterly. The fair value of debentures is based on unadjusted year-end market prices for the same or similar debt of the same remaining maturities. The fair value measurement of debentures is categorized as level 1 as the inputs used reflect quoted prices in an active market. The fair value of customer deposits approximate their carrying value based on the discounted amounts taking into account interest accrued on the outstanding balance.

15. Financial instruments - continued

The fair value of the other instruments are measured at amortized cost and approximate their carrying value because of the short term nature of the instruments.

Exposure to interest rate risk, credit risk, foreign exchange risk and liquidity risk arises in the normal course of the Company's business.

Interest rate risk

The Company is exposed to interest rate risk in holding certain financial instruments. The Company's objective is to minimize net interest expense. The Company attempts to minimize interest rate risk by issuing long term fixed rate debt, and by extending or shortening the term of its short term money market investments by assessing the monetary policy stance of the Bank of Canada, while ensuring that all payment obligations are met on an on-going basis.

Under the Company's bank agreements, the Company may obtain short term borrowing for working capital purposes. These borrowings expose the Company to fluctuations in short term interest rates (borrowings in the form of prime rate loans in Canadian dollars and bankers' acceptances and letters of credit). The fee payable for bankers' acceptances and letters of credit is based on a margin determined by reference to the Company's credit rating.

Credit risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2009, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, the Company did not earn a significant amount of revenue from any individual customer. As at December 31, 2009, there were no significant accounts receivable due from any single customer.

In the year, the Company's provision for bad debts increased to $160,000 (2008 - $130,000). Minor adjustments were determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at December 31, 2009, approximately 8% (2008 - 7%) of the Company's accounts receivable was aged more than 60 days.

Foreign exchange risk

The Company tries to limit its exposure to the changing values of foreign securities. As at December 31, 2009, the Company has committed to purchasing smart meters and computer software upgrades which are payable in U.S. funds. The Company is exposed to fluctuations in foreign exchange on these transactions. In the normal course of operation, the impact of foreign currency fluctuations is not material to the financial statements.

15. Financial instruments - continued

Liquidity risk

The Company monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Company's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest expense. The Company has access to credit facilities and monitors cash balances daily to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due. Liquidity risk associated with financial commitments are as follows:

	Due in 2010 $	**Due from 2011 to 2014 $**	**Due after 2014 $**
Accounts payable	7,531,417	-	-
Demand loan	2,000,000	-	-
Bank loans	514,000	2,408,000	11,778,000
Debentures	45,802	207,652	1,661,469
Infrastructure Ontario financing	6,799,980	-	-
	16,891,199	2,615,652	13,439,469

It is anticipated that the Company will convert the Infrastructure Ontario financing into a debenture.

16. Capital management

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long term basis at reasonable rates and to deliver appropriate financial returns.

The Company considers its capital structure to consist of shareholder's equity, bank loans, debentures and Infrastructure Ontario financing. The Company's capital structure as at December 31, 2009 and December 31, 2008 was as follows:

	2009 $	2008 $
Bank loans	**14,700,000**	15,185,000
Debentures	**1,914,923**	1,958,514
Infrastructure Ontario financing	**6,799,980**	-
	23,414,903	17,143,514
Contributed capital	**830,799**	830,799
Common shares	**22,768,898**	22,768,898
Retained earnings	**2,890,472**	1,102,444
	26,490,169	24,702,141
Total capital	**49,905,072**	41,845,655

16. Capital management - continued

The Company's capital structure as at December 31, 2009, is 47% debt and 53% equity (2008 - 39% debt and 61% equity). There have been no changes in the Company's approach to capital management during the year.

The OEB and shareholder restrict the permissible debt to 60% of the Company's total capitalization. As well, the Company has customary covenants typically associated with long term debt. The Company's long term debt and credit facility covenants further limit the Company's ability to sell assets and impose a negative pledge provision, subject to customary expectations. At December 31, 2009, the Company is in compliance with all of these covenants and limitations.

17. Prudential support

Norfolk Power Distribution Inc. is required through the IESO, to provide security to mitigate the Company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if Norfolk Power Distribution Inc. fails to make payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2009 the Company provided prudential support in the form of bank letters of credit of $1,537,163.

18. Contingent liabilities

Griffith et al. v. Toronto Hydro-Electric Commission et al.

This action has been brought under the Class Proceedings Act, 1992. The plaintiff class seeks $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities (LDCs) who received late payment penalties which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the Criminal Code. Pleadings have closed in this action. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of a similar proceedings brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas case rejecting all of the defences which had been raised by Enbridge, although the Court did not permit the Plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge and that settlement was approved by the Ontario Superior Court.

In 2007, Enbridge filed an application to the Ontario Energy Board (OEB) to recover the Court approved amount and related amounts from ratepayers. On February 4, 2008 the OEB approved recovery of the said amounts from ratepayers over a five year period.

After the release by the Supreme Court of Canada of its 2004 decision in the Consumers Gas case, the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with their litigation against the LDCs. The parties are in settlement discussions but no settlement has been reached. At this time, it is not possible to quantify the effect, if any, on the financial statements.

19. Supplemental cash flow information

	2009 **$**	2008 $ *As restated (note 3)*
Interest expense	**1,270,617**	1,346,917
Interest revenue	**17,544**	32,961

20. Comparative figures

Certain amounts on the financial statements for the year ended December 31, 2008 have been reclassified to conform with the method of presentation adopted for the current year.

Norfolk Power Distribution Inc.

Financial Statements

December 31, 2010

Norfolk Power Distribution Inc.

Index to Financial Statements

December 31, 2010

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Norfolk Power Distribution Inc.

We have audited the accompanying financial statements of Norfolk Power Distribution Inc., which comprise the balance sheet as at December 31, 2010, and the statements of operations, retained earnings and cash flow for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Norfolk Power Distribution Inc. as at December 31, 2010, and the results of its operations and its cash flow for the year then ended in accordance with Canadian generally accepted accounting principles.

April 6, 2011
Simcoe, Ontario

Chartered Accountants
Licensed Public Accountants

Management's Responsibility for Financial Reporting

The financial statements of Norfolk Power Distribution Inc. have been prepared in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. These statements include certain amounts based on management's estimates and judgments. Management has determined such amounts based on a reasonable basis in order to ensure that the financial statements are presented fairly in all material respects.

The integrity and reliability of Norfolk Power Distribution Inc. 's reporting systems are achieved through the use of formal policies and procedures, the careful selection of employees and an appropriate division of responsibilities. These systems are designed to provide reasonable assurance that the financial information is reliable and accurate.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board carries out this responsibility principally through its Audit and Finance Committee. The Committee is appointed by the Board and meets periodically with management and the shareholder's auditors to review significant accounting, reporting and internal control matters. Following its review of the financial statements and discussions with the auditors, the Audit and Finance Committee reports to the Board of Directors prior to its approval of the financial statements. The Committee also considers, for review by the Board and approval by the shareholder, the engagement or re-appointment of the external auditors.

The financial statements have been audited on behalf of the shareholder by Millard, Rouse & Rosebrugh LLP , in accordance with generally accepted auditing standards.

Brad Randall, President & CEO

Jody McEachran, CFO

John Dyck, Board of Directors Chair

Frank Casey, Audit and Finance Committee Chair

Norfolk Power Distribution Inc.

Balance Sheet

As at December 31, 2010

	2010	2009
ASSETS		
Current		
Cash	**$ 836,521**	$ 288,243
Accounts receivable	**4,191,422**	4,666,697
Unbilled revenue	**4,526,049**	4,644,558
Due from associated companies *(Note 5)*	**82,481**	17,858
Income taxes recoverable	**375,027**	-
Prepaid expenses	**319,822**	255,981
Inventory	**549,678**	572,473
	10,881,000	10,445,810
Property and equipment *(Note 6)*	**49,389,910**	48,698,228
Regulatory assets *(Note 7)*	**5,234,220**	4,599,127
Future tax asset	**1,215,250**	1,618,588
	$ 66,720,380	$ 65,361,753
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Demand loan *(Note 8)*	**$ 3,500,000**	$ 2,000,000
Accounts payable	**6,289,294**	7,531,417
Income taxes payable	**-**	233,788
Obligations under capital lease	**-**	40,864
Current portion of long term debt *(Note 9)*	**918,000**	559,802
Current portion of customer deposits *(Note 10)*	**130,000**	90,000
	10,837,294	10,455,871
Regulatory liabilities *(Note 7)*	**4,112,956**	4,588,845
Long term debt *(Note 9)*	**23,137,121**	22,855,101
Customer deposits *(Note 10)*	**110,363**	166,430
Post employment benefits *(Note 11)*	**867,800**	805,337
	39,065,534	38,871,584
Shareholder's equity		
Share capital *(Note 12)*	**22,768,898**	22,768,898
Retained earnings	**4,885,948**	3,721,271
	27,654,846	26,490,169
	$ 66,720,380	$ 65,361,753

See accompanying notes

Norfolk Power Distribution Inc.

Statement of Retained Earnings

Year ended December 31, 2010

	2010	2009
Retained earnings - beginning of year	**$ 3,721,271**	$ 1,933,243
Net income for the year	**1,999,888**	2,088,028
	5,721,159	4,021,271
Dividends	**(835,211)**	(300,000)
RETAINED EARNINGS - END OF YEAR	**$ 4,885,948**	$ 3,721,271

See accompanying notes

Norfolk Power Distribution Inc.

Statement of Operations

Year ended December 31, 2010

	2010	2009
REVENUE		
Energy sales	**$ 31,033,780**	$ 28,763,186
Distribution services	**10,802,100**	11,015,769
Other	**454,744**	428,240
	42,290,624	40,207,195
Cost of power	**31,033,780**	28,763,186
Distribution revenue	**11,256,844**	11,444,009
EXPENSES		
Distribution system - operation and maintenance	**2,222,251**	2,086,375
Billing and collecting	**971,841**	1,037,686
Community relations	**48,761**	45,608
Administrative and general expense	**1,682,502**	1,367,688
Taxes other than amounts in lieu of corporate taxes	**68,210**	118,981
	4,993,565	4,656,338
Income before amortization, interest and income taxes	**6,263,279**	6,787,671
Amortization (net of $350,720; 2009 - $363,982 charged to other accounts)	**2,351,567**	2,517,025
Interest	**1,380,824**	1,270,618
	3,732,391	3,787,643
Income before income taxes	**2,530,888**	3,000,028
Income taxes *(Note 13)*	**531,000**	912,000
NET INCOME FOR THE YEAR	**$ 1,999,888**	$ 2,088,028

See accompanying notes

Norfolk Power Distribution Inc.

Statement of Cash Flow

Year ended December 31, 2010

	2010	2009
OPERATING ACTIVITIES		
Net income for the year	$ 1,999,888	$ 2,088,028
Items not affecting cash:		
Amortization	2,702,287	2,881,007
Post employment benefits	62,463	54,471
Loss (gain) on disposal of property and equipment	3,138	(10,030)
	4,767,776	5,013,476
Changes in non-cash working capital:		
Accounts receivable	475,275	(374,229)
Unbilled revenue	118,509	(10,114)
Loan to Norfolk Energy Inc.	-	350,000
Amount due from associated companies	(64,623)	384,526
Prepaid expenses	(63,841)	98,624
Inventory	22,795	(43,103)
Accounts payable	(1,242,123)	1,615,730
Income taxes payable (recoverable)	(608,815)	669,470
	(1,362,823)	2,690,904
Cash flow from operating activities	3,404,953	7,704,380
INVESTING ACTIVITIES		
Purchase of property and equipment	(4,253,107)	(9,599,769)
Proceeds on disposal of property and equipment	36,500	16,878
Contributions in aid of construction	819,501	531,414
Future tax asset	403,338	(1,618,588)
Net change in regulatory assets and liabilities	(1,110,982)	(1,013,650)
Cash flow used by investing activities	(4,104,750)	(11,683,715)
FINANCING ACTIVITIES		
Demand loan financing	1,500,000	2,000,000
Loans and debentures financing received	1,200,020	6,799,980
Repayment of loans and debentures	(559,803)	(528,591)
(Repayment) receipt of customer deposits	(16,067)	71,383
Dividends declared	(835,211)	(300,000)
Repayment of capital lease obligations	(40,864)	(49,036)
Cash flow from financing activities	1,248,075	7,993,736
INCREASE IN CASH	548,278	4,014,401
Cash (deficiency) - beginning of year	288,243	(3,726,158)
CASH - END OF YEAR	$ 836,521	$ 288,243

See accompanying notes

1. NATURE OF ACTIVITIES

On November 1, 2000, Norfolk Power Inc. was incorporated under the Ontario Business Corporations Act, along with its two wholly owned subsidiary companies, Norfolk Power Distribution Inc. and Norfolk Energy Inc. Norfolk Power Distribution Inc. provides regulated electricity distribution services. Norfolk Energy Inc. provides home comfort rentals, conservation innovation, high-speed telecommunication fibre optics and other energy services.

As the sole shareholder of Norfolk Power Distribution Inc.'s parent company (Norfolk Power Inc.), Norfolk County is considered a related party. All transactions with Norfolk County are conducted within the normal course of operations and consideration paid is on similar terms as transactions with unrelated parties.

Norfolk Power Distribution Inc. is a rate-regulated enterprise and Norfolk Energy Inc. is a non-rate-regulated enterprise. The difference is rate-regulated enterprises have different policies that have accounting treatments differing from Canadian generally accepted accounting principles (GAAP) for enterprises operating in a non-rate-regulated environment, this is discussed in further detail below.

Norfolk Power Inc. consolidated financial statements have also been prepared separately that include the accounts of Norfolk Power Inc., Norfolk Power Distribution Inc. and Norfolk Energy Inc.

2. REGULATION

In April 1999, the government of Ontario began restructuring Ontario's electricity industry. Under regulations passed pursuant to the restructuring, the Company and other electricity distributors have been purchasing their electricity from the wholesale market administered by the Independent Electricity System Operator (IESO) and recovering the costs of electricity and certain other costs at a later date in accordance with procedures mandated by the Ontario Energy Board (OEB).

The OEB has regulatory oversight of electricity matters in the Province of Ontario. The *Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified account records, regulatory accounting principles, separation of accounts for separate businesses and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, and ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future.

(continues)

2. REGULATION *(continued)*

The Company is required to charge its customers for the following amounts (all of which, other than distribution charges, represent a pass through of amounts payable to third parties):

1. *Distribution Charges.* Distribution charges are designed to recover the costs incurred by the Company in delivering electricity to customers and the OEB-allowed rate of return. Distribution charges are regulated by the OEB and typically comprise of a fixed charge and a usage-based (consumption) charge.

   The volume of electricity consumed by the Company's customers during any period is governed by events largely outside the Company's control, principally sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity.

2. *Electricity Price and Related Regulated Adjustments.* The electricity price and related regulated adjustments represent a pass through of the commodity cost of electricity.

3. *Retail Transmission Rate.* The retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

4. *Wholesale Market Service Charge.* The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

The Company electricity distribution rates are typically effective from May 1 to April 30 of the following year. Accordingly, for the first four months of 2010, distribution revenue was based on the rates approved in 2009. Distribution revenue for the period from May 1, 2010 to December 31, 2010 was based on the distribution rates approved in 2010.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The financial statements of Norfolk Power Distribution Inc. have been prepared in accordance with GAAP, including accounting principles prescribed by the OEB in the handbook "Accounting Procedures Handbook for Electric Distribution Utilities" (AP Handbook) and reflect the significant accounting policies summarized below:

Regulation

The following three regulatory treatments have resulted in accounting treatments which differ from Canadian GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

The OEB has the general authority to include or exclude costs, revenues, losses or gains in the rates of a specified period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in the timing gives rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable in the future from customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts recovered for specific expenditures in excess of costs incurred by the Company. These liabilities are expected to be settled with future rate adjustments. Specific regulatory assets and liabilities are disclosed in Note 7.

Contributions in aid of construction

Capital contributions received from outside sources are used to finance additions to property and equipment of the Company. According to the AP Handbook, capital contributions received are treated as a reduction to property and equipment. The amount is subsequently amortized by a charge to accumulated amortization and a reduction to amortization expense at an equivalent rate to that used for the amortization of the related property and equipment.

Future income taxes

Income taxes are reported using the tax liability method, as follows: current income tax expense is the estimated income taxes payable for the current year after any refunds or the use of losses incurred in previous years, and future income taxes reflect:

- the temporary differences between the carrying amounts of assets and liabilities for accounting purposes and the amounts used for tax purposes;
- the benefit of unutilized tax losses that will more likely than not be realized and carried forward to future years to reduce income taxes.

Future income taxes are estimated using the rates enacted by tax law and those substantively enacted for the years in which future income taxes assets are likely to be realized, or future income tax liabilities settled. The effect of a change in tax rates on future income tax assets and liabilities is included in deferred costs or recoveries of regulatory assets and liabilities in the period when the change is substantively enacted.

(continues)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Revenue recognition

Energy sales and distribution services revenues are based on OEB approved rates and are recognized on a basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed.

Other revenues related to sales of other services are recognized as the services are rendered.

Inventory

Inventory consists of repair parts, supplies and materials held for operating and maintenance activities and are valued at lower of cost and net realizable value. Cost is determined using the weighted average method.

Property and equipment

Property and equipment are valued at acquisition cost and include contracted services, materials, labour, engineering costs, interest and overheads. Gains or losses at retirement or disposition are credited or charged to other income in the year of disposal.

Amortization is provided on a straight line basis for property and equipment available for use over their estimated economic lives, at the following annual rates:

Buildings and fixtures	50 years	2%
Transformer station equipment	40 years	2.5%
Distribution system	25 years	4%
Meters	25 years	4%
Vehicles	10 years	10%
SCADA system	15 years	6.7%
Computer equipment	5 years	20%
Office furniture and equipment	10 years	10%
Garage tools and equipment	10 years	10%
Measurement and testing equipment	10 years	10%
Communication equipment	10 years	10%
Miscellaneous equipment	10 years	10%

The Company reviews property and equipment for impairment whenever events or circumstances indicate that the carrying amount is not recoverable. Any resulting impairment loss is recorded in the period in which the impairment occurs.

Payments in lieu of income taxes

Under the Electricity Act, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

(continues)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Pension

Employees of the Company are members of the Ontario Municipal Employees Retirement System (OMERS) which is a multi-employer public sector contributory defined benefit pension plan. The pension fund is financed by equal contributions from participating employers and employees and by the investment earnings of the fund. Contributions made by the Company on behalf of the employees amounted to approximately $240,000 (2009 - $220,000).

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of revenue, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the financial statement date. Significant areas requiring the use of management estimates relate to regulatory assets and liabilities, employee future benefits and amortization. Actual results could differ from amounts recorded in these financial statements, including changes as a result of future decisions made by the OEB or the Minister of Energy.

Financial instruments

At inception, all financial instruments which meet the definition of a financial asset or financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Gains and losses related to the measurement of financial instruments are reported in the statement of operations. Subsequent measurement of each financial instrument will depend on the balance sheet classification elected by the Company. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties. Further discussion of financial instruments for the Company is included in note 14 of the financial statements.

4. INTERNATIONAL FINANCIAL REPORTING STANDARDS

In 2008, the Accounting Standards Board (AcSB) confirmed that rate-regulated enterprises will be required to adopt International Financial Reporting Standards (IFRS) by January 1, 2011. Also, on October 14, 2009, the Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011.

In 2010, the AcSB granted an optional one year deferral for IFRS adoption for entities subject to rate regulation. This decision came in light of the uncertainty created by the International Accounting Standards Board (IASB) in regard to the rate-regulated project which is assessing the potential recognition of regulatory assets and regulatory liabilities under IFRS. As such the Company will apply IFRS to its financial statements ending December 31, 2012, with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011 for comparative purposes.

Given the continued uncertainty around the timing, scope and eventual adoption of a rate-regulated accounting (RRA) standard under IFRS and the potential material impact of RRA on the Company's financial statements, the Company has decided to elect the optional one year deferral of its adoption of IFRS.

As a result of these developments related to RRA under IFRS and the uncertainty regarding the impact of IFRS on the OEB electricity distribution rates application process, the Company cannot reasonably quantify the full impact that adopting IFRS would have on its future financial position and results of operation. The Company will continue to assess and evaluate the impact of this adoption.

5. DUE FROM ASSOCIATED COMPANIES

The Company is wholly owned by Norfolk Power Inc. Norfolk Power Inc. also wholly owns Norfolk Energy Inc. Transactions with these associated companies are conducted within the normal course of operations and consideration paid is on similar terms as transactions with unrelated parties.

Balances owing at December 31 have no set repayment terms:

	2010	2009
Amounts (owing to) due from Norfolk Power Inc.	**$ (62,851)**	$ (35,918)
Amounts (owing to) due from Norfolk Energy Inc.	**145,332**	53,776
	$ 82,481	$ 17,858

6. PROPERTY AND EQUIPMENT

	Cost	Accumulated amortization	**2010**	2009
Distribution				
Land, land rights and easements	$ 694,044	$ -	**$ 694,044**	$ 694,044
Transformer station building	1,620,078	180,575	**1,439,503**	1,465,852
Transformer station equipment	8,912,383	524,387	**8,387,996**	8,309,707
Distribution station equipment	2,767,848	363,334	**2,404,514**	2,429,266
Poles, towers and fixtures	20,857,358	7,198,277	**13,659,081**	13,599,413
Overhead conductors and devices	11,716,783	3,056,012	**8,660,771**	8,310,309
Underground conduit	4,005,396	1,501,837	**2,503,559**	2,471,270
Underground conductors and devices	6,686,432	1,763,071	**4,923,361**	4,906,385
Transformers	11,982,442	6,710,564	**5,271,878**	5,025,572
Overhead and underground services	2,778,385	520,375	**2,258,010**	2,074,747
Meters	4,157,132	2,375,136	**1,781,996**	1,795,544
	76,178,281	24,193,568	**51,984,713**	51,082,109
General				
Land and easements	243,636	-	**243,636**	243,636
Buildings and fixtures	2,313,465	844,606	**1,468,859**	1,408,388
Vehicles	1,538,637	1,062,529	**476,108**	612,199
SCADA system	1,176,773	332,333	**844,440**	355,378
Computer equipment	1,010,699	728,771	**281,928**	313,355
Office furniture and equipment	202,530	125,659	**76,871**	88,555
Garage tools and equipment	317,724	184,305	**133,419**	154,528
Measurement and testing equipment	180,868	110,314	**70,554**	84,979
Communication equipment	107,927	56,055	**51,872**	58,994
Miscellaneous equipment	428,220	129,028	**299,192**	311,695
	7,520,479	3,573,600	**3,946,879**	3,631,707
	83,698,760	27,767,168	**55,931,592**	54,713,816
Contributions in aid of construction	(8,473,522)	(1,931,840)	**(6,541,682)**	(6,015,588)
	$ 75,225,238	$ 25,835,328	**$ 49,389,910**	$ 48,698,228

7. REGULATORY ASSETS AND LIABILITIES

	2010	2009
Regulatory assets		
Settlement variances		
Transmission network services	**$ 485,439**	$ 229,565
Bloomsburg transformation connection charge	**-**	492,840
Power	**847,636**	383,487
Total settlement variances	**1,333,075**	1,105,892
Recovery of regulatory assets	**-**	206,426
Retail services and service transaction requests variances	**17,997**	22,484
Extraordinary event costs and carrying charges	**-**	178,422
Smart meters	**3,547,622**	2,786,858
Special purpose charge	**58,780**	-
Other deferred charges	**276,746**	299,045
Total regulatory assets	**$ 5,234,220**	$ 4,599,127
Regulatory liabilities		
Settlement variances		
Wholesale market services	**$ 474,686**	$ 875,484
Transmission connection services	**613,141**	1,645,835
Total settlement variances	**1,087,827**	2,521,319
Smart meter funding	**674,911**	448,938
Recovery of regulatory assets	**1,134,968**	-
Future income taxes	**1,215,250**	1,618,588
Total regulatory liabilities	**$ 4,112,956**	$ 4,588,845

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operation in the period that the assessment is made.

(continues)

7. REGULATORY ASSETS AND LIABILITIES *(continued)*

The regulatory assets and liabilities of the Corporation are as follows:

Settlement variances

This account is comprised of the variances between amounts charged by the Company to customers, based on regulated rates, and the corresponding cost of non-competitive electricity service incurred by the Company after May 1, 2002. The settlement variances relate primarily to service charges, non-competitive electricity charges, imported power charges and the global adjustment. Accordingly, the Company has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB in the AP Handbook.

The balance for settlement variances continues to be calculated and attract carrying charges in accordance with the OEB's direction. In May 2010, settlement variances of $1,432,208 were approved for disposition (2009 - nil).

Recovery of regulatory assets

This account consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through rate riders. The account is subject to carrying charges following the OEB prescribed methodology and related rates.

Retail services and service transaction requests variances

This account is comprised of the variances between amounts charged by the Company to customers, based on regulated rates, and the corresponding cost for establishing, billing and maintaining service agreements. The account is subject to carrying charges in accordance with the OEB's direction.

Extraordinary event costs and carrying charges

This account is used to record extraordinary event costs that meet the qualifying criteria established in the AP Handbook. Amounts recorded in this account do not imply OEB acceptance. Consequently, amounts are subject to regulatory review and approval prior to disposition of amounts in rates. The account is subject to carrying charges following the OEB prescribed methodology and related rates. In May 2010, $178,422 was approved for disposition (2009 - nil). This amount related to damages caused by an ice storm experienced January 14, 2007.

Smart meters

The smart meters regulatory asset account relates to the Province of Ontario's decision to install smart meters throughout Ontario. The Company launched its smart meter project in 2008. As at December 31, 2010, all residential and small commercial customers have had smart meters installed. In 2008, the OEB ordered the Company to record all future expenditures and revenues related to smart meters to regulatory asset and liability accounts and allowed the Company to keep the net book value of the stranded meters related to the deployment of smart meters in its rate base.

(continues)

7. REGULATORY ASSETS AND LIABILITIES *(continued)*

Special purpose charge

On April 9, 2010, the OEB informed electricity distributors of a Special Purpose Charge (SPC) assessment under Section 26.1 of the *Ontario Energy Board Act, 1998*, for the Ministry of Energy and Infrastructure conservation and renewable energy program costs. The OEB assessed the Company the amount of $147,781 for its apportioned share of the total provincial amount of the SPC of $53,695,000 in accordance with the rules set out in the Ontario Regulation 66/10 (SPC Regulation). In accordance with Section 9 of the SPC Regulation, the Company is allowed to recover this amount. The recovery is being realized over a one-year period, which began on May 1, 2010.

Other deferred charges

This account is comprised primarily of the following amounts:

- OEB Cost Assessment - variances between OEB costs assessments invoiced to the Company for the OEB's 2004/05 and 2005/06 (up to April 30, 2006) fiscal years and OEB costs assessments previously included the Company's rates. The balance is subject to carrying charges following the OEB prescribed methodology and related rates.

- Pension Contributions - pension costs associated with the cash contributions paid to Ontario Municipal Employees Retirement Savings (OMERS) for the period from January 1, 2005 to April 30, 2006. The balance is subject to carrying charges following the OEB prescribed methodology and related rates.

- LV Variances - variances arising from low voltage transactions which are not part of the electricity wholesale market.

Future income taxes

This regulatory liability account relates to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of future tax assets.

8. DEMAND LOAN

	2010	2009
Loan is comprised of a 90-day $3,000,000 International Swaps and Derivatives Association (ISDA) swap at 1.32% interest plus Bankers Acceptance (BA) stamping fees of 2%. The loan is secured by certain distribution assets as per the General Security Agreement and is due January 2011 and was subsequently renewed for similar terms.	**$ 3,000,000**	$ 2,000,000
Loan is comprised of a 90-day $500,000 ISDA swap at 1.25% plus BA stamping fees of 2%. The loan is secured by certain distribution assets as per the General Security Agreement and is due January 2011 and was subsequently renewed for similar terms.	**500,000**	-
	$ 3,500,000	$ 2,000,000

The Company also has access to an overdraft facility limit of $3,000,000. The terms of this facility is that it is on demand, bears interest at prime plus 0.5% and is secured by distribution assets. The overdraft facility balance was nil at the year end.

9. LONG TERM DEBT

	2010	2009
Bank loans		
The original $2,000,000 ISDA swap for a 25-year term at 5.42% interest plus BA stamping fees at 0.75%. Principal and interest payments are made on a quarterly basis and approximate $13,500 plus interest. The loan is secured by certain distribution assets as per the General Security Agreement and is due December 2029.	**$ 1,859,000**	$ 1,909,000
The original $10,700,000 ISDA swap for a 25-year term at 6.25% interest plus BA stamping fees at 0.75%. Principal and interest payments are made on a quarterly basis and approximate $63,750 plus interest. The loan is secured by certain distribution assets as per the General Security Agreement and is due September 2029.	**9,516,000**	9,751,000
The original $4,000,000 ISDA swap for a 15-year term at 5.27% interest plus BA stamping fees at 0.75%. Principal and interest payments are made on a quarterly basis and approximate $61,500 plus interest. The loan is secured by certain distribution assets as per the General Security Agreement and is due September 2020.	**2,811,000**	3,040,000

(continues)

9. LONG TERM DEBT *(continued)*

Debentures

Infrastructure Ontario debenture bearing an interest rate of 5.01% per annum over the term of the debenture. The amount is repayable in semi-annual blended principal and interest payments of $70,587. The debenture is secured by certain distribution system assets and is due December 2032.	**1,869,121**	1,914,923
Infrastructure Ontario debenture bearing an interest rate of 4.73% per annum over the term of the debenture. The amount is repayable in semi-annual blended principal and interest payments of $192,154. The debenture is secured by certain distribution system assets and is due September 2035.	**5,600,000**	-
Infrastructure Ontario debenture bearing an interest rate of 3.72% per annum over the term of the debenture. The amount is repayable in semi-annual blended principal and interest payments of $144,801. The debenture is secured by certain distribution system assets and is due September 2020.	**2,400,000**	-
Ontario Infrastructure Projects Corporation (OIPC) financing for the construction of a transformer station and to purchase smart meters. This funding was converted to the above disclosed debentures during the year.	**-**	6,799,980
Subtotal	**24,055,121**	23,414,903
Less: current portion	**(918,000)**	(559,802)
	$ 23,137,121	$ 22,855,101

Future principal payments are approximately as follows:

2011	**$ 918,000**
2012	**967,000**
2013	**1,025,000**
2014	**1,079,000**
2015	**1,148,000**
Thereafter	**18,918,121**
	$ 24,055,121

10. CUSTOMER DEPOSITS

Customer deposits are cash collections from customers to guarantee the payment of energy bills and fulfillment of contractual obligations. Deposits expected to be refunded to customers within the next fiscal period are classified as a current liability. Interest is accrued on customer deposit balances at rates established and reviewed by the Company on a quarterly basis. The current portion and long term portion of customer deposits are:

	2010	2009
Customer deposits	**$ 240,363**	$ 256,430
Current portion	**(130,000)**	(90,000)
Long term portion	**$ 110,363**	$ 166,430

11. POST EMPLOYMENT BENEFITS

Post employment benefits other than pension provided by the Company include medical, dental and life insurance benefits. The Company actuarially determines the cost of other employment and post-employment benefits offered to employees using the projected benefit method prorated on service and based on management's best estimate assumptions. Under this method, the projected post-retirement benefit is deemed to be earned on a pro-rata basis over the years of service in the attribution period commencing at the date of hire, and ended at the earliest age the employee could retire and qualify for benefits. Compensated absences and termination benefits that do not vest or accumulate are recognized as an expense when the event occurs.

The Company measures its accrued benefits obligation for accounting purposes as at December 31 of each year. An actuarial valuation is completed every three years. The latest actuarial valuation was performed in September 2010 and no significant variance was found from the valuation.

12. SHARE CAPITAL

Authorized:

Unlimited Common shares

	2010	2009
Issued:		
1,000 Common shares	**$ 22,768,898**	$ 22,768,898

Share capital was issued as consideration for the net assets transferred from predecessor hydro-electric commissions at at January 1, 2001.

13. INCOME TAXES - CURRENT

The income tax provision was calculated based on taxable income. Taxable income is calculated as follows:

	2010	2009
Income before income taxes	**$ 2,530,888**	$ 3,000,028
Capital cost allowance in excess of amortization	**(721,557)**	(103,969)
Net change in regulatory assets and liabilities	**(116,248)**	343,249
Increase in post employment benefits reserve	**62,463**	54,471
Prior period adjustment	**-**	(518,958)
Other additions and deductions	**(42,643)**	(11,185)
	1,712,903	2,763,636
Tax at 31.00%, (2009 - 33.00%)	**531,000**	912,000

14. FINANCIAL INSTRUMENTS

Fair value

Financial instruments of the Company include cash, accounts receivable, unbilled revenues, due from associated companies, demand loan, accounts payable, customer deposits and long term debt. All financial instruments except customer deposits and long term debt represent their fair value due to their short term nature. The carrying value of customer deposits and long term debt approximate their fair value as the interest rates are consistent with rates offered for similar items.

Exposure to interest rate risk, credit risk, foreign exchange risk and liquidity risk arises in the normal course of the Company's business. These risks are considered as follows:

Interest rate risk

The Company is exposed to interest rate risk in holding certain financial instruments. The Company's objective is to minimize net interest expense. The Company attempts to minimize interest rate risk by issuing long term fixed rate debt and ensuring that all payment obligations are met on an on-going basis.

Under the Company's bank agreements, the Company may obtain short term borrowing for working capital purposes. These borrowings expose the Company to fluctuations in short term interest rates (borrowings in the form of prime rate loans in Canadian dollars and bankers' acceptances and letters of credit). The fee payable for bankers' acceptances and letters of credit is based on a margin determined by reference to the Company's credit rating.

(continues)

14. FINANCIAL INSTRUMENTS *(continued)*

Credit risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2010, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, the Company did not earn a significant amount of revenue from any individual customer. As at December 31, 2010, there were no significant accounts receivable due from any single customer. The company also collects security deposits from its customers as described in note 10.

At the year end, the Company's allowance for doubtful accounts was $130,000 (2009 - $130,000). The allowance is determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at December 31, 2010, approximately 5% (2009 - 8%) of the Company's accounts receivable was aged more than 60 days.

Foreign exchange risk

The Company tries to limit its exposure to the changing values of foreign securities. In the normal course of operation, the impact of foreign currency fluctuations is not material to the financial statements.

Liquidity risk

The Company monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Company's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest expense. The Company has access to credit facilities and monitors cash balances daily to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

15. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long term basis at reasonable rates and to deliver appropriate financial returns.

The Company considers its capital structure to consist of shareholder's equity, bank loans, debentures and Infrastructure Ontario financing. The Company's capital structure as at December 31, 2010 and December 31, 2009 was as follows:

	2010	2009
Bank loans	**$ 14,186,000**	$ 14,700,000
Debentures	**9,869,121**	1,914,923
Infrastructure Ontario financing	**-**	6,799,980
Subtotal	**24,055,121**	23,414,903
Share capital	**22,768,898**	22,768,898
Retained earnings	**4,885,948**	3,721,271
Subtotal	**27,654,846**	26,490,169
	$ 51,709,967	$ 49,905,072

The Company's capital structure as at December 31, 2010, is 47% debt and 53% equity (2009 - 47% debt and 53% equity). There have been no changes in the Company's approach to capital management during the year.

16. PRUDENTIAL SUPPORT

Norfolk Power Distribution Inc. is required through the IESO, to provide security to mitigate the Company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if Norfolk Power Distribution Inc. fails to make payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2010 the Company provided prudential support in the form of bank letters of credit of $1,537,163.

17. COMPARATIVE FIGURES

Some of the comparative figures have been reclassified to conform to the current year's presentation.

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND REGULATORY ACCOUNTING:

The only reconciliation required between financial statements and regulatory accounting relate to those expenses which the OEB has disallowed for rate application purposes. These have identified in the table below. These expenses have been removed from requested OM&A expenses for 2012 Test Year in Exhibit 4 of this application.

Table 1.3 – Reconciliation from Audited OM&A Expense to Regulatory OM&A Expense

	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

Norfolk would also like to note that for 2007, 2008, and 2009, it had not adopted the half year rule for depreciation in the year of acquisition in its audited financial statements. In 2010, Norfolk completed an adjusting entry that recorded the cumulative difference between actual depreciation expense for these three years and the amount that would have been recorded using the half year rule. This difference was booked to depreciation expense in 2010. As of 2010, Norfolk has adopted the half year rule for depreciation in the year of acquisition. This is reflected in 2011 & 2012 amortization expense and related continuity schedules as found in Exhibit 2 and Exhibit 4.

PRO FORMA FINANCIAL STATEMENTS - 2011 AND 2012:

The Pro Forma Statements for the 2011 Bridge Year and the 2012 Test Year accompany this Schedule as Appendix E and Appendix F respectively.

APPENDIX E

COPY OF NORFOLK POWER DISTRIBUTION INC.

2011 PRO FORMA FINANCIAL STATEMENTS - MIFRS

NORFOLK POWER DISTRIBUTION INC.

2011 PRO-FORMA BALANCE SHEET - MIFRS

Cash	$	706,900
A/R	$	4,589,100
Unbilled A/R	$	4,644,600
Prepaid Expenses	$	256,000
Inventory	$	575,000
Total Current Assets	**$**	**10,771,600**
Property, Plant & Equipment	$	50,696,531
Regulatory Assets	$	2,996,000
Other Long-Term Assets	$	1,200,000
TOTAL ASSETS	**$**	**65,664,131**
A/P	$	6,332,843
Current Portion of Long-Term Debt	$	1,057,000
Total Current Assets	**$**	**7,389,843**
Employee Future Benefits	$	950,900
Non-Current Liabilities	$	1,385,000
Long-Term Debt	$	25,833,000
Total Long-Term Liabilities	**$**	**28,168,900**
TOTAL LIABILITIES	**$**	**35,558,743**
Common Shares	$	22,768,900
Paid-In Capital	$	830,800
Retained Earnings	$	6,505,688
TOTAL SHAREHOLDER'S EQUITY	**$**	**30,105,388**
TOTAL LIABILITY & SHAREHOLDER'S EQUITY	**$**	**65,664,131**

NORFOLK POWER DISTRIBUTION INC.

2011 PRO-FORMA INCOME STATEMENT - MIFRS

Commodity Sales	$	33,304,179
Distribution Services Revenues	$	11,034,237
Other Income	$	522,825
TOTAL REVENUES	**$**	**44,861,242**
Cost of Power	$	33,304,179
Operating Expenses	$	1,144,900
Maintenance Expenses	$	1,151,200
Billing & Collecting Expenses	$	968,850
Community Relations Expenses	$	58,000
General & Administrative Expenses	$	1,633,500
Amortization & Depreciation Expense	$	1,851,204
Interest Expense	$	1,914,432
Taxes Other Than Income Tax	$	35,000
TOTAL EXPENSES	**$**	**42,061,266**
NET INCOME BEFORE TAX	**$**	**2,799,976**
Income Tax	$	318,326
NET INCOME	**$**	**2,481,650**

Norfolk Power Distribution Inc
EB-2011-0272
Exhibit 1
Tab 3
Schedule 3
Appendix F
Page 1 of 1
Filed: August 26, 2011

APPENDIX F

COPY OF NORFOLK POWER DISTRIBUTION INC.

2012 PRO FORMA STATEMENTS – MIFRS (Existing Rates)

NORFOLK POWER DISTRIBUTION INC.

2012 PRO-FORMA BALANCE SHEET - MIFRS (EXISTING RATES)

Cash	$	707,000
A/R	$	4,600,000
Unbilled A/R	$	4,500,000
Prepaid Expenses	$	250,000
Inventory	$	550,000
Total Current Assets	**$**	**10,607,000**
Property, Plant & Equipment	$	54,289,222
Regulatory Assets	$	1,746,600
Other Long-Term Assets	$	1,200,000
TOTAL ASSETS	**$**	**67,842,822**
A/P	$	5,707,032
Current Portion of Long-Term Debt	$	1,338,000
Total Current Assets	**$**	**7,045,032**
Employee Future Benefits	$	1,030,600
Non-Current Liabilities	$	1,350,000
Long-Term Debt	$	26,939,000
Total Long-Term Liabilities	**$**	**29,319,600**
TOTAL LIABILITIES	**$**	**36,364,632**
Common Shares	$	22,768,900
Paid-In Capital	$	830,800
Retained Earnings	$	7,878,490
TOTAL SHAREHOLDER'S EQUITY	**$**	**31,478,190**
TOTAL LIABILITY & SHAREHOLDER'S EQUITY	**$**	**67,842,822**

NORFOLK POWER DISTRIBUTION INC.

2012 PRO-FORMA INCOME STATEMENT - MIFRS (EXISTING RATES)

Commodity Sales	$	34,716,838
Distribution Services Revenues	$	11,031,355
Other Income	$	477,290
TOTAL REVENUES	**$**	**46,225,483**
Cost of Power	$	34,716,838
Operating Expenses	$	1,288,506
Maintenance Expenses	$	1,248,605
Billing & Collecting Expenses	$	1,228,062
Community Relations Expenses	$	37,000
General & Administrative Expenses	$	2,015,444
Amortization & Depreciation Expense	$	2,327,524
Interest Expense	$	1,899,543
Taxes Other Than Income Tax	$	35,000
TOTAL EXPENSES	**$**	**44,796,523**
NET INCOME BEFORE TAX	**$**	**1,428,960**
Income Tax	$	56,160
NET INCOME	**$**	**1,372,800**

RECONCILIATION BETWEEN PRO FORMA STATEMENTS AND REVENUE DEFICIENCY STATEMENTS

No reconciliation is required between the 2012 Pro Forma statement and the revenue deficiency statement.

INFORMATION ON AFFILIATES:

Norfolk Power Inc. (NPI) is the parent company of Norfolk. It is wholly owned by the County of Norfolk. Copies of NPI's consolidated and non-consolidated 2010 Audited financial statements accompany this Schedule as Appendix G. Neither NPI nor Norfolk produces an annual report.

Two other companies, Norfolk Telecommunications Inc., and Norfolk Power Generation Inc., are also wholly owned by NPI. These companies are dormant with no revenue or expenses.

Norfolk Power Distribution Inc
EB-2010-0139
Exhibit 1
Tab 3
Schedule 5
Appendix G
Filed: August 26, 2011

APPENDIX G

NPI CONSOLIDATED & NPI NON-CONSOLIDATED

AUDITED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2010

Norfolk Power Inc.

Consolidated Financial Statements

December 31, 2010

Norfolk Power Inc.

Index to the Consolidated Financial Statements

December 31, 2010

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Norfolk Power Inc.

We have audited the accompanying consolidated financial statements of Norfolk Power Inc., which comprise the consolidated balance sheet as at December 31, 2010, and the consolidated statements of operations, retained earnings and cash flow for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Norfolk Power Inc. as at December 31, 2010, and the results of its operations and its cash flow for the year then ended in accordance with Canadian generally accepted accounting principles.

April 6, 2011	Chartered Accountants
Simcoe, Ontario	Licensed Public Accountants

Management's Responsibility for Financial Reporting

The consolidated financial statements of Norfolk Power Inc. have been prepared in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. These statements include certain amounts based on management's estimates and judgments. Management has determined such amounts based on a reasonable basis in order to ensure that the financial statements are presented fairly in all material respects.

The integrity and reliability of Norfolk Power Inc.'s reporting systems are achieved through the use of formal policies and procedures, the careful selection of employees and an appropriate division of responsibilities. These systems are designed to provide reasonable assurance that the financial information is reliable and accurate.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and is ultimately responsible for reviewing and approving the consolidated financial statements. The Board carries out this responsibility principally through its Audit and Finance Committee. The Committee is appointed by the Board and meets periodically with management and the shareholder's auditors to review significant accounting, reporting and internal control matters. Following its review of the financial statements and discussions with the auditors, the Audit and Finance Committee reports to the Board of Directors prior to its approval of the financial statements. The Committee also considers, for review by the Board and approval by the shareholder, the engagement or re-appointment of the external auditors.

The consolidated financial statements have been audited on behalf of the shareholder by Millard, Rouse & Rosebrugh LLP , in accordance with generally accepted auditing standards.

Brad Randall, President & CEO	Jody McEachran, CFO
John Wells, Board of Directors Chair	Frank Casey, Audit and Finance Committee Chair

Norfolk Power Inc.

Consolidated Balance Sheet

As at December 31, 2010

	2010	2009
ASSETS		
Current		
Cash	**$ 1,058,828**	$ 526,465
Accounts receivable	**4,396,251**	4,848,922
Unbilled revenue	**4,526,049**	4,644,558
Income taxes recoverable	**385,223**	-
Prepaid expenses	**341,749**	259,355
Inventory	**550,097**	628,492
	11,258,197	10,907,792
Property and equipment *(Note 5)*	**51,718,531**	50,659,668
Regulatory assets *(Note 6)*	**5,234,220**	4,599,127
Future tax asset	**1,102,250**	1,519,588
	$ 69,313,198	$ 67,686,175
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Demand loan *(Note 7)*	**$ 3,500,000**	$ 2,000,000
Accounts payable	**6,405,547**	7,614,324
Income taxes payable	**-**	240,328
Obligations under capital lease	**-**	40,864
Current portion of long term debt *(Note 8)*	**976,000**	618,135
Current portion of customer deposits *(Note 9)*	**130,000**	90,000
Deferred income	**102,105**	113,362
	11,113,652	10,717,013
Regulatory liabilities *(Note 6)*	**4,112,956**	4,588,844
Long term debt *(Note 8)*	**23,696,482**	23,472,463
Customer deposits *(Note 9)*	**110,363**	166,430
Post employment benefits *(Note 10)*	**867,800**	805,337
	39,901,253	39,750,087
Shareholder's equity		
Share capital *(Note 11)*	**23,142,284**	23,142,284
Retained earnings	**6,269,661**	4,793,804
	29,411,945	27,936,088
	$ 69,313,198	$ 67,686,175

See accompanying notes

Norfolk Power Inc.

Consolidated Statement of Retained Earnings

Year ended December 31, 2010

	2010	2009
Retained earnings - beginning of year	**$ 4,793,804**	$ 2,797,716
Net income for the year	**2,275,857**	2,346,088
	7,069,661	5,143,804
Dividends	**(800,000)**	(350,000)
RETAINED EARNINGS - END OF YEAR	**$ 6,269,661**	$ 4,793,804

See accompanying notes

Norfolk Power Inc.

Consolidated Statement of Operations

Year ended December 31, 2010

	2010	2009
REVENUE		
Energy sales	**$ 31,033,780**	$ 28,763,186
Distribution services	**10,802,100**	11,015,769
Other	**454,744**	428,240
	42,290,624	40,207,195
Cost of power	**31,033,780**	28,763,186
Distribution revenue	**11,256,844**	11,444,009
Norfolk Energy Inc. program net revenue - page 23	**1,021,816**	969,246
Total net revenue	**12,278,660**	12,413,255
EXPENSES		
Distribution system - operation and maintenance	**2,222,252**	2,086,375
Billing and collecting	**971,841**	1,037,686
Community relations	**48,761**	45,608
Administrative and general expense	**2,022,382**	1,681,208
Taxes other than amounts in lieu of corporate taxes	**68,210**	118,981
	5,333,446	4,969,858
Income before amortization, interest and income taxes	**6,945,214**	7,443,397
Amortization (net of $350,720; 2009 - $363,982 charged to other accounts)	**2,624,645**	2,764,704
Interest	**1,410,712**	1,294,605
	4,035,357	4,059,309
Income before income taxes	**2,909,857**	3,384,088
Income taxes		
Current *(Note 12)*	**620,000**	1,008,000
Future	**14,000**	30,000
	634,000	1,038,000
NET INCOME FOR THE YEAR	**$ 2,275,857**	$ 2,346,088

See accompanying notes

Norfolk Power Inc.

Consolidated Statement of Cash Flow

Year ended December 31, 2010

	2010	2009
OPERATING ACTIVITIES		
Net income for the year	**$ 2,275,857**	$ 2,346,088
Items not affecting cash:		
Amortization	**2,975,365**	3,128,686
Future income taxes	**14,000**	30,000
Post employment benefits	**62,463**	54,471
Loss (gain) on disposal of property and equipment	**3,241**	(9,742)
	5,330,926	5,549,503
Changes in non-cash working capital:		
Accounts receivable	**452,671**	(428,574)
Unbilled revenue	**118,509**	(10,114)
Prepaid expenses	**(82,394)**	97,206
Inventory	**78,395**	(61,723)
Accounts payable	**(1,208,777)**	1,698,636
Income taxes payable (recoverable)	**(625,551)**	688,848
Deferred income	**(11,257)**	113,362
	(1,278,404)	2,097,641
Cash flow from operating activities	**4,052,522**	7,647,144
INVESTING ACTIVITIES		
Purchase of property and equipment	**(4,979,504)**	(10,037,739)
Proceeds on disposal of property and equipment	**122,535**	21,050
Contributions in aid of construction	**819,501**	531,414
Future tax asset	**403,338**	(1,618,588)
Net change in regulatory assets and liabilities	**(1,110,982)**	(1,013,650)
Cash flow used by investing activities	**(4,745,112)**	(12,117,513)
FINANCING ACTIVITIES		
Demand loan financing	**1,500,000**	2,000,000
Loans and debentures financing received	**1,200,020**	7,499,980
Repayment of loans and debentures	**(618,136)**	(552,897)
(Repayment) receipt of customer deposits	**(16,067)**	71,383
Dividends declared	**(800,000)**	(350,000)
Repayment of capital lease obligations	**(40,864)**	(49,036)
Cash flow from financing activities	**1,224,953**	8,619,430
INCREASE IN CASH	**532,363**	4,149,061
Cash (deficiency) - beginning of year	**526,465**	(3,622,596)
CASH - END OF YEAR	**$ 1,058,828**	$ 526,465

See accompanying notes

1. NATURE OF ACTIVITIES

On November 1, 2000, Norfolk Power Inc. was incorporated under the Ontario Business Corporations Act, along with its two wholly owned subsidiary companies, Norfolk Power Distribution Inc. and Norfolk Energy Inc. Norfolk Power Inc. supervises the operations of, and provides corporate, management services and strategic direction to its two subsidiaries. Norfolk Power Distribution Inc. provides regulated electricity distribution services. Norfolk Energy Inc. provides home comfort rentals, conservation innovation, high-speed telecommunication fibre optics and other energy services.

As the sole shareholder of Norfolk Power Inc., Norfolk County is considered a related party. All transactions with Norfolk County are conducted within the normal course of operations and consideration paid is on similar terms as transactions with unrelated parties.

Norfolk Power Distribution Inc. is a rate-regulated enterprise and Norfolk Energy Inc. is a non-rate-regulated enterprise. The difference is rate-regulated enterprises have different policies that have accounting treatments differing from Canadian generally accepted accounting principles (GAAP) for enterprises operating in a non-rate-regulated environment, this is discussed in further detail below.

2. REGULATION

In April 1999, the government of Ontario began restructuring Ontario's electricity industry. Under regulations passed pursuant to the restructuring, the Company and other electricity distributors have been purchasing their electricity from the wholesale market administered by the Independent Electricity System Operator (IESO) and recovering the costs of electricity and certain other costs at a later date in accordance with procedures mandated by the Ontario Energy Board (OEB).

The OEB has regulatory oversight of electricity matters in the Province of Ontario. The *Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified account records, regulatory accounting principles, separation of accounts for separate businesses and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, and ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future.

(continues)

2. REGULATION *(continued)*

The Company is required to charge its customers for the following amounts (all of which, other than distribution charges, represent a pass through of amounts payable to third parties):

1. *Distribution Charges.* Distribution charges are designed to recover the costs incurred by the Company in delivering electricity to customers and the OEB-allowed rate of return. Distribution charges are regulated by the OEB and typically comprise of a fixed charge and a usage-based (consumption) charge.

   The volume of electricity consumed by the Company's customers during any period is governed by events largely outside the Company's control, principally sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity.

2. *Electricity Price and Related Regulated Adjustments.* The electricity price and related regulated adjustments represent a pass through of the commodity cost of electricity.

3. *Retail Transmission Rate.* The retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

4. *Wholesale Market Service Charge.* The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

The Company electricity distribution rates are typically effective from May 1 to April 30 of the following year. Accordingly, for the first four months of 2010, distribution revenue was based on the rates approved in 2009. Distribution revenue for the period from May 1, 2010 to December 31, 2010 was based on the distribution rates approved in 2010.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The financial statements of Norfolk Power Inc. have been prepared in accordance with GAAP, including accounting principles prescribed by the OEB in the handbook "Accounting Procedures Handbook for Electric Distribution Utilities" (AP Handbook) and reflect the significant accounting policies summarized below:

Basis of consolidation

The consolidated financial statements include the accounts the Company and its wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated.

(continues)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Regulation

The following three regulatory treatments have resulted in accounting treatments which differ from Canadian GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

The OEB has the general authority to include or exclude costs, revenues, losses or gains in the rates of a specified period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in the timing gives rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable in the future from customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts recovered for specific expenditures in excess of costs incurred by the Company. These liabilities are expected to be settled with future rate adjustments. Specific regulatory assets and liabilities are disclosed in Note 6.

Contributions in aid of construction

Capital contributions received from outside sources are used to finance additions to property and equipment of the Company. According to the AP Handbook, capital contributions received are treated as a reduction to property and equipment. The amount is subsequently amortized by a charge to accumulated amortization and a reduction to amortization expense at an equivalent rate to that used for the amortization of the related property and equipment.

Future income taxes

Income taxes are reported using the tax liability method, as follows: current income tax expense is the estimated income taxes payable for the current year after any refunds or the use of losses incurred in previous years, and future income taxes reflect:

- the temporary differences between the carrying amounts of assets and liabilities for accounting purposes and the amounts used for tax purposes;
- the benefit of unutilized tax losses that will more likely than not be realized and carried forward to future years to reduce income taxes.

Future income taxes are estimated using the rates enacted by tax law and those substantively enacted for the years in which future income taxes assets are likely to be realized, or future income tax liabilities settled. The effect of a change in tax rates on future income tax assets and liabilities is included in deferred costs or recoveries of regulatory assets and liabilities in the period when the change is substantively enacted for the Company's regulated subsidiary. For the Company's unregulated subsidiary, the effect of a change in tax rates on future income tax assets and liabilities is included in earnings in the period when the change is substantively enacted.

(continues)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Revenue recognition

Energy sales and distribution services revenues are based on OEB approved rates and are recognized on a basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed.

Other revenues related to sales of other services are recognized as the services are rendered.

Inventory

Inventory consists of repair parts, supplies and materials held for operating and maintenance activities and are valued at lower of cost and net realizable value. Cost is determined using the weighted average method.

Property and equipment

Property and equipment are valued at acquisition cost and include contracted services, materials, labour, engineering costs, interest and overheads. Gains or losses at retirement or disposition are credited or charged to other income in the year of disposal.

Amortization is provided on a straight line basis for property and equipment available for use over their estimated economic lives, at the following annual rates:

Buildings and fixtures	50 years	2%
Transformer station equipment	40 years	2.5%
Distribution system	25 years	4%
Meters	25 years	4%
Vehicles	10 years	10%
SCADA system	15 years	6.7%
Computer equipment	5 years	20%
Water heaters	10 years	10%
Fibre optic network	25 years	4%
Water conditioners	10 years	10%
Tankless gas water heaters	10 years	10%
HVAC units	10 years	10%
Sentinel lights	10 years	10%
Office furniture and equipment	10 years	10%
Garage tools and equipment	10 years	10%
Measurement and testing equipment	10 years	10%
Communication equipment	10 years	10%
Miscellaneous equipment	10 years	10%

The Company reviews property and equipment for impairment whenever events or circumstances indicate that the carrying amount is not recoverable. Any resulting impairment loss is recorded in the period in which the impairment occurs.

(continues)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Payments in lieu of income taxes

Under the Electricity Act, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

Pension

Employees of the Company are members of the Ontario Municipal Employees Retirement System (OMERS) which is a multi-employer public sector contributory defined benefit pension plan. The pension fund is financed by equal contributions from participating employers and employees and by the investment earnings of the fund. Contributions made by the Company on behalf of the employees amounted to approximately $240,000 (2009 - $220,000).

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of revenue, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the financial statement date. Significant areas requiring the use of management estimates relate to regulatory assets and liabilities, employee future benefits and amortization. Actual results could differ from amounts recorded in these financial statements, including changes as a result of future decisions made by the OEB or the Minister of Energy.

Financial instruments

At inception, all financial instruments which meet the definition of a financial asset or financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Gains and losses related to the measurement of financial instruments are reported in the statement of operations. Subsequent measurement of each financial instrument will depend on the balance sheet classification elected by the Company. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties. Further discussion of financial instruments for the Company is included in note 13 of the financial statements.

4. INTERNATIONAL FINANCIAL REPORTING STANDARDS

In 2008, the Accounting Standards Board (AcSB) confirmed that rate-regulated enterprises will be required to adopt International Financial Reporting Standards (IFRS) by January 1, 2011. Also, on October 14, 2009, the Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011.

In 2010, the AcSB granted an optional one year deferral for IFRS adoption for entities subject to rate regulation. This decision came in light of the uncertainty created by the International Accounting Standards Board (IASB) in regard to the rate-regulated project which is assessing the potential recognition of regulatory assets and regulatory liabilities under IFRS. As such the Company will apply IFRS to its financial statements ending December 31, 2012, with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011 for comparative purposes.

Given the continued uncertainty around the timing, scope and eventual adoption of a rate-regulated accounting (RRA) standard under IFRS and the potential material impact of RRA on the Company's financial statements, the Company has decided to elect the optional one year deferral of its adoption of IFRS.

As a result of these developments related to RRA under IFRS and the uncertainty regarding the impact of IFRS on the OEB electricity distribution rates application process, the Company cannot reasonably quantify the full impact that adopting IFRS would have on its future financial position and results of operation. The Company will continue to assess and evaluate the impact of this adoption.

5. PROPERTY AND EQUIPMENT

	Cost	Accumulated amortization	**2010**	2009
Distribution				
Land, land rights and easements	$ 694,044	$ -	**$ 694,044**	$ 694,044
Transformer station building	1,620,078	180,575	**1,439,503**	1,465,852
Transformer station equipment	8,912,383	524,387	**8,387,996**	8,309,707
Distribution station equipment	2,767,848	363,334	**2,404,514**	2,429,266
Poles, towers and fixtures	20,857,358	7,198,277	**13,659,081**	13,599,413
Overhead conductors and devices	11,716,783	3,056,012	**8,660,771**	8,310,309
Underground conduit	4,005,396	1,501,837	**2,503,559**	2,471,270
Underground conductors and devices	6,686,432	1,763,071	**4,923,361**	4,906,385
Transformers	11,982,442	6,710,564	**5,271,878**	5,025,572
Overhead and underground services	2,778,385	520,375	**2,258,010**	2,074,747
Meters	4,157,132	2,375,136	**1,781,996**	1,795,544
	76,178,281	24,193,568	**51,984,713**	51,082,109
General				
Land and easements	243,636	-	**243,636**	243,636
Buildings and fixtures	2,313,465	844,606	**1,468,859**	1,408,388
Vehicles	1,538,637	1,062,529	**476,108**	612,199
SCADA system	1,176,773	332,333	**844,440**	355,378
Computer equipment	1,051,680	744,453	**307,227**	338,645
Water heaters	3,247,578	2,013,753	**1,233,825**	1,093,063
Fibre optic network	1,104,170	146,566	**957,604**	857,998
Water conditioners	213,881	67,419	**146,462**	119,217
Tankless gas water heaters	66,252	13,607	**52,645**	41,582
HVAC units	80,908	4,045	**76,863**	-
Sentinel lights	149,578	138,297	**11,281**	8,961
Office furniture and equipment	204,192	125,799	**78,393**	88,804
Garage tools and equipment	317,724	184,305	**133,419**	154,528
Measurement and testing equipment	180,868	110,314	**70,554**	84,979
Communication equipment	107,927	56,055	**51,872**	58,994
Miscellaneous equipment	428,220	129,028	**299,192**	311,695
	12,425,489	5,973,109	**6,452,380**	5,778,067
	88,603,770	30,166,677	**58,437,093**	56,860,176
Contributions in aid of construction	(8,674,522)	(1,955,960)	**(6,718,562)**	(6,200,508)
	$ 79,929,248	$ 28,210,717	**$ 51,718,531**	$ 50,659,668

6. REGULATORY ASSETS AND LIABILITIES

	2010	2009
Regulatory assets		
Settlement variances		
Transmission network services	**$ 485,439**	$ 229,565
Bloomsburg transformation connection charge	**-**	492,840
Power	**847,636**	383,487
Total settlement variances	**1,333,075**	1,105,892
Recovery of regulatory assets	**-**	206,426
Retail services and service transaction requests variances	**17,997**	22,484
Extraordinary event costs and carrying charges	**-**	178,422
Smart meters	**3,547,622**	2,786,858
Special purpose charge	**58,780**	-
Other deferred charges	**276,746**	299,045
Total regulatory assets	**$ 5,234,220**	$ 4,599,127
Regulatory liabilities		
Settlement variances		
Wholesale market services	**$ 474,686**	$ 875,483
Transmission connection services	**613,141**	1,645,835
Total settlement variances	**1,087,827**	2,521,318
Smart meter funding	**674,911**	448,938
Recovery of regulatory assets	**1,134,968**	-
Future income taxes	**1,215,250**	1,618,588
Total regulatory liabilities	**$ 4,112,956**	$ 4,588,844

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operation in the period that the assessment is made.

(continues)

6. REGULATORY ASSETS AND LIABILITIES *(continued)*

The regulatory assets and liabilities of the Corporation are as follows:

Settlement variances

This account is comprised of the variances between amounts charged by the Company to customers, based on regulated rates, and the corresponding cost of non-competitive electricity service incurred by the Company after May 1, 2002. The settlement variances relate primarily to service charges, non-competitive electricity charges, imported power charges and the global adjustment. Accordingly, the Company has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB in the AP Handbook.

The balance for settlement variances continues to be calculated and attract carrying charges in accordance with the OEB's direction. In May 2010, settlement variances of $1,432,208 were approved for disposition (2009 - nil).

Recovery of regulatory assets

This account consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through rate riders. The account is subject to carrying charges following the OEB prescribed methodology and related rates.

Retail services and service transaction requests variances

This account is comprised of the variances between amounts charged by the Company to customers, based on regulated rates, and the corresponding cost for establishing, billing and maintaining service agreements. The account is subject to carrying charges in accordance with the OEB's direction.

Extraordinary event costs and carrying charges

This account is used to record extraordinary event costs that meet the qualifying criteria established in the AP Handbook. Amounts recorded in this account do not imply OEB acceptance. Consequently, amounts are subject to regulatory review and approval prior to disposition of amounts in rates. The account is subject to carrying charges following the OEB prescribed methodology and related rates. In May 2010, $178,422 was approved for disposition (2009 - nil). This amount related to damages caused by an ice storm experienced January 14, 2007.

Smart meters

The smart meters regulatory asset account relates to the Province of Ontario's decision to install smart meters throughout Ontario. The Company launched its smart meter project in 2008. As at December 31, 2010, all residential and small commercial customers have had smart meters installed. In 2008, the OEB ordered the Company to record all future expenditures and revenues related to smart meters to regulatory asset and liability accounts and allowed the Company to keep the net book value of the stranded meters related to the deployment of smart meters in its rate base.

(continues)

6. REGULATORY ASSETS AND LIABILITIES *(continued)*

Special purpose charge

On April 9, 2010, the OEB informed electricity distributors of a Special Purpose Charge (SPC) assessment under Section 26.1 of the *Ontario Energy Board Act, 1998*, for the Ministry of Energy and Infrastructure conservation and renewable energy program costs. The OEB assessed the Company the amount of $147,781 for its apportioned share of the total provincial amount of the SPC of $53,695,000 in accordance with the rules set out in the Ontario Regulation 66/10 (SPC Regulation). In accordance with Section 9 of the SPC Regulation, the Company is allowed to recover this amount. The recovery is being realized over a one-year period, which began on May 1, 2010.

Other deferred charges

This account is comprised primarily of the following amounts:

- OEB Cost Assessment - variances between OEB costs assessments invoiced to the Company for the OEB's 2004/05 and 2005/06 (up to April 30, 2006) fiscal years and OEB costs assessments previously included the Company's rates. The balance is subject to carrying charges following the OEB prescribed methodology and related rates.
- Pension Contributions - pension costs associated with the cash contributions paid to Ontario Municipal Employees Retirement Savings (OMERS) for the period from January 1, 2005 to April 30, 2006. The balance is subject to carrying charges following the OEB prescribed methodology and related rates.
- LV Variances - variances arising from low voltage transactions which are not part of the electricity wholesale market.

Future income taxes

This regulatory liability account relates to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of future tax assets.

7. DEMAND LOAN

	2010	2009
Loan is comprised of a 90-day $3,000,000 International Swaps and Derivatives Association (ISDA) swap at 1.32% interest plus Bankers Acceptance (BA) stamping fees of 2%. The loan is secured by certain distribution assets as per the General Security Agreement and is due January 2011 and was subsequently renewed for similar terms.	**$ 3,000,000**	$ 2,000,000
Loan is comprised of a 90-day $500,000 ISDA swap at 1.25% plus BA stamping fees of 2%. The loan is secured by certain distribution assets as per the General Security Agreement and is due January 2011 and was subsequently renewed for similar terms.	**500,000**	-
	$ 3,500,000	$ 2,000,000

The Company also has access to an overdraft facility limit of $3,000,000. The terms of this facility is that it is on demand, bears interest at prime plus 0.5% and is secured by distribution assets. The overdraft facility balance was nil at the year end.

8. LONG TERM DEBT

	2010	2009
Bank loans		
The original $2,000,000 ISDA swap for a 25-year term at 5.42% interest plus BA stamping fees at 0.75%. Principal and interest payments are made on a quarterly basis and approximate $13,500 plus interest. The loan is secured by certain distribution assets as per the General Security Agreement and is due December 2029.	**$ 1,859,000**	$ 1,909,000
The original $10,700,000 ISDA swap for a 25-year term at 6.25% interest plus BA stamping fees at 0.75%. Principal and interest payments are made on a quarterly basis and approximate $63,750 plus interest. The loan is secured by certain distribution assets as per the General Security Agreement and is due September 2029.	**9,516,000**	9,751,000
The original $4,000,000 ISDA swap for a 15-year term at 5.27% interest plus BA stamping fees at 0.75%. Principal and interest payments are made on a quarterly basis and approximate $61,500 plus interest. The loan is secured by certain distribution assets as per the General Security Agreement and is due September 2020.	**2,811,000**	3,040,000

(continues)

8. LONG TERM DEBT *(continued)*

Comprised of a $700,000 bank loan bearing interest at prime plus 2%. Principal payments of $4,861 plus interest are made on a monthly basis. The loan is secured by a general security agreement and is due May 2021.	**617,361**	675,695
Debentures		
Infrastructure Ontario debenture bearing an interest rate of 5.01% per annum over the term of the debenture. The amount is repayable in semi-annual blended principal and interest payments of $70,587. The debenture is secured by certain distribution system assets and is due December 2032.	**1,869,121**	1,914,923
Infrastructure Ontario debenture bearing an interest rate of 4.73% per annum over the term of the debenture. The amount is repayable in semi-annual blended principal and interest payments of $192,154. The debenture is secured by certain distribution system assets and is due September 2035.	**5,600,000**	-
Infrastructure Ontario debenture bearing an interest rate of 3.72% per annum over the term of the debenture. The amount is repayable in semi-annual blended principal and interest payments of $144,801. The debenture is secured by certain distribution system assets and is due September 2020.	**2,400,000**	-
Ontario Infrastructure Projects Corporation (OIPC) financing for the construction of a transformer station and to purchase smart meters. This funding was converted to the above disclosed debentures during the year.	**-**	6,799,980
Subtotal	**24,672,482**	24,090,598
Less: current portion	**(976,000)**	(618,135)
	$ 23,696,482	$ 23,472,463

Future principal payments are approximately as follows:

2011	**$ 976,000**
2012	**1,025,000**
2013	**1,083,000**
2014	**1,137,000**
2015	**1,206,000**
Thereafter	**19,245,482**
	$ 24,672,482

9. CUSTOMER DEPOSITS

Customer deposits are cash collections from customers to guarantee the payment of energy bills and fulfillment of contractual obligations. Deposits expected to be refunded to customers within the next fiscal period are classified as a current liability. Interest is accrued on customer deposit balances at rates established and reviewed by the Company on a quarterly basis. The current portion and long term portion of customer deposits are:

	2010	2009
Customer deposits	**$ 240,363**	$ 256,430
Current portion	**(130,000)**	(90,000)
Long term portion	**$ 110,363**	$ 166,430

10. POST EMPLOYMENT BENEFITS

Post employment benefits other than pension provided by the Company include medical, dental and life insurance benefits. The Company actuarially determines the cost of other employment and post-employment benefits offered to employees using the projected benefit method prorated on service and based on management's best estimate assumptions. Under this method, the projected post-retirement benefit is deemed to be earned on a pro-rata basis over the years of service in the attribution period commencing at the date of hire, and ended at the earliest age the employee could retire and qualify for benefits. Compensated absences and termination benefits that do not vest or accumulate are recognized as an expense when the event occurs.

The Company measures its accrued benefits obligation for accounting purposes as at December 31 of each year. An actuarial valuation is completed every three years. The latest actuarial valuation was performed in September 2010 and no significant variance was found from the valuation.

11. SHARE CAPITAL

Authorized:
Unlimited Common shares

		2010	2009
Issued:			
1,000	Common shares	**$ 23,142,284**	$ 23,142,284

Share capital was issued as consideration for the net assets transferred from predecessor hydro-electric commissions at at January 1, 2001.

12. INCOME TAXES - CURRENT

The income tax provision was calculated based on taxable income. Taxable income is calculated as follows:

	2010	2009
Income before income taxes	**$ 2,909,857**	$ 3,384,088
Capital cost allowance in excess of amortization	**(813,323)**	(196,139)
Net change in regulatory assets and liabilities	**(116,248)**	343,249
Increase in post employment benefits reserve	**62,463**	54,471
Prior period adjustment	**-**	(518,958)
Other additions and deductions	**(42,750)**	(12,167)
	1,999,999	3,054,544
Tax at 31.00%, (2009 - 33.00%)	**620,000**	1,008,000

13. FINANCIAL INSTRUMENTS

Fair value

Financial instruments of the Company include cash, accounts receivable, unbilled revenues, demand loan, accounts payable, customer deposits and long term debt. All financial instruments except customer deposits and long term debt represent their fair value due to their short term nature. The carrying value of customer deposits and long term debt approximate their fair value as the interest rates are consistent with rates offered for similar items.

Exposure to interest rate risk, credit risk, foreign exchange risk and liquidity risk arises in the normal course of the Company's business. These risks are considered as follows:

Interest rate risk

The Company is exposed to interest rate risk in holding certain financial instruments. The Company's objective is to minimize net interest expense. The Company attempts to minimize interest rate risk by issuing long term fixed rate debt and ensuring that all payment obligations are met on an on-going basis.

Under the Company's bank agreements, the Company may obtain short term borrowing for working capital purposes. These borrowings expose the Company to fluctuations in short term interest rates (borrowings in the form of prime rate loans in Canadian dollars and bankers' acceptances and letters of credit). The fee payable for bankers' acceptances and letters of credit is based on a margin determined by reference to the Company's credit rating.

(continues)

13. FINANCIAL INSTRUMENTS *(continued)*

Credit risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2010, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, the Company did not earn a significant amount of revenue from any individual customer. As at December 31, 2010, there were no significant accounts receivable due from any single customer. The company also collects security deposits from its customers as described in note 9.

At the year end, the Company's allowance for doubtful accounts was $130,000 (2009 - $130,000). The allowance is determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at December 31, 2010, approximately 5% (2009 - 8%) of the Company's accounts receivable was aged more than 60 days.

Foreign exchange risk

The Company tries to limit its exposure to the changing values of foreign securities. In the normal course of operation, the impact of foreign currency fluctuations is not material to the financial statements.

Liquidity risk

The Company monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Company's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest expense. The Company has access to credit facilities and monitors cash balances daily to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

14. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long term basis at reasonable rates and to deliver appropriate financial returns.

The Company considers its capital structure to consist of shareholder's equity, bank loans, debentures and Infrastructure Ontario financing. The Company's capital structure as at December 31, 2010 and December 31, 2009 was as follows:

	2010	2009
Bank loans	**$ 14,803,361**	$ 15,375,695
Debentures	**9,869,121**	1,914,923
Infrastructure Ontario financing	**-**	6,799,980
Subtotal	**24,672,482**	24,090,598
Share capital	**23,142,284**	23,142,284
Retained earnings	**6,269,661**	4,793,804
Subtotal	**29,411,945**	27,936,088
	$ 54,084,427	$ 52,026,686

The Company's capital structure as at December 31, 2010, is 46% debt and 54% equity (2009 - 46% debt and 54% equity). There have been no changes in the Company's approach to capital management during the year.

The shareholder restricts the permissible debt to 60% of the Company's total capitalization. As well, the Company has customary covenants typically associated with long term debt. The Company's long term debt and credit facility covenants further limit the Company's ability to sell assets and impose a negative pledge provision, subject to customary expectations. At December 31, 2010, the Company is in compliance with all of these covenants and limitations.

15. PRUDENTIAL SUPPORT

Norfolk Power Inc. is required through the IESO, to provide security to mitigate the Company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if Norfolk Power Inc. fails to make payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2010 the Company provided prudential support in the form of bank letters of credit of $1,537,163.

16. COMPARATIVE FIGURES

Some of the comparative figures have been reclassified to conform to the current year's presentation.

Norfolk Power Inc.

Schedule of Norfolk Energy Inc. Program Revenue and Expenses

Year Ended December 31, 2010

	Revenue	Expenses	**Net Revenue 2010**	Net Revenue 2009
PROGRAMS				
Billing and collecting services	$ 646,419	$ 475,053	**$ 171,366**	$ 165,145
Home comfort division	541,783	70,227	**471,556**	449,101
Telecommunication services	250,733	20,931	**229,802**	221,147
OPA program consulting	161,329	78,535	**82,794**	89,142
SCADA services	47,865	3,655	**44,210**	42,273
Street light maintenance	108,193	89,917	**18,276**	-
Interest and sundry revenue	3,812	**-**	**3,812**	2,438
	$ 1,760,134	$ 738,318	**$ 1,021,816**	$ 969,246

See accompanying notes

Norfolk Power Inc.

(Non-Consolidated)
Financial Statements
For theTwelve Months Ended
December 31, 2010

NORFOLK POWER INC.
NON-CONSOLIDATED BALANCE SHEET
AS AT DECEMBER 31, 2010

- ASSETS -

	Dec 31 2010	Dec 31 2009
Current Assets		
Due from Subsidiary Companies	**$ 77,309**	$ 42,098
Corporate Taxes Receivable	**-**	-
Total Current Assets	**$ 77,309**	$ 42,098
Other Assets		
Investment in Subsidiary Companies	**$ 23,142,284**	$ 23,142,284
Total Assets	**$ 23,219,593**	$ 23,184,382

- LIABILITIES AND SHAREHOLDER'S EQUITY -

	Dec 31 2010	Dec 31 2009
Current Liabilities		
Dividend Payable	**$ -**	$ -
Shareholder's Equity		
Share Capital - Common Shares	**$ 23,142,284**	$ 23,142,284
Retained Earnings	**77,309**	42,098
Total Shareholder's Equity	**$ 23,219,593**	$ 23,184,382
Total Liabilities & Shareholder's Equity	**$ 23,219,593**	$ 23,184,382

NORFOLK POWER INC.
NON-CONSOLIDATED INCOME STATEMENT
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2010

	2010 YTD Actual	2010 Budget	
REVENUE			
Management Fees			
Norfolk Energy Inc.	**$ 8,278**	$ 12,000	69%
Norfolk Power Distribution Inc.	**63,708**	63,000	101%
	$ 71,987	$ 75,000	96%
Dividend Income			
Norfolk Energy Inc.	**$ -**	$ -	
Norfolk Power Distribution Inc.	**35,211**	-	
Total Revenue	**$ 107,198**	$ 75,000	143%
EXPENSES			
Board Remuneration and Expenses	**$ 71,987**	$ 70,000	103%
General Administration and Miscellaneous	**-**	5,000	0%
Total Operating Expense	**$ 71,987**	$ 75,000	96%
Earnings Before Income Tax	**$ 35,211**	$ -	
Income Tax	**-**	-	
Net Income	**$ 35,211**	$ -	

Note: Dividends will be determined after year end performance is reviewed.

MATERIALITY THRESHOLDS:

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, issued by the Board June 28, 2010 states the relevant default materiality threshold as:

"0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million."

As Table 1.4 indicates, the lowest materiality during the past 4 years for Norfolk is $57,345. To ensure a thorough analysis, all variances greater than $50,000 have been analyzed.

Table 1.4 Materiality Thresholds

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

OVERVIEW

RATE BASE OVERVIEW:

The rate base used for the purpose of calculating the revenue requirement used in this Application is the average of the balances at the beginning and the end of the 2012 Test Year, plus a working capital allowance, which is 15% of the sum of the cost of power and controllable expenses.

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

NPDI has provided its rate base calculations for the years 2008 Actual, 2008 OEB Approved, 2009 Actual, 2010 Actual, 2011 Bridge Year and 2012 Test Year in Table 1.1 below. NPDI has calculated its 2012 rate base as $59,653,664 under IFRS which will be used to determine the proposed revenue requirement.

Table 1.1 – Summary of Rate Base

	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test (CGAAP)	2012 Test (MIFRS)
Average Net Book Value of FA*	43,155,630	41,884,268	42,871,960	46,308,052	49,864,555	52,991,496	53,568,246
Working Capital Allowance (15%)	4,996,170	4,894,802	4,999,455	5,384,673	5,744,344	5,992,935	6,085,418
Rate Base	48,151,800	46,779,070	47,871,414	51,692,725	55,608,899	58,984,431	59,653,664

This exhibit will compare historical data with the 2011 Bridge Year and 2012 Test Year. In order to make the comparisons meaningful, all comparisons will be made under CGAAP. Changes to capital spending, working capital, fixed assets and rate base due to the conversion from CGAAP to MIFRS will be discussed in Tab 5 – Conversion to MIFRS, of this exhibit.

The Norfolk Power Distribution System:

Norfolk Power Distribution Inc. (NPDI) is a restructured utility amalgamated from 4 local predecessor Municipal Electric Utilities. NPDI owns and operates the electricity distribution system in its licensed service area in the Towns of Simcoe, Port Dover, Delhi, Waterford and the Village of Port Rowan plus Townsend and Woodhouse Townships (low density rural) serving approximately 19,000 Residential, General Service, Street Light, Sentinel Light and Unmetered Scattered Load customers/connections.

NPDI is comprised of 144 square kilometres of high density urban area plus 549 square kilometres of low density rural for a total of 693 square kilometres. NPDI's population density (customers per square kilometre) is 27.4 which makes it one of 8 LDCs in the province with a population density of less than 30 customers per square kilometre (as per the 2009 OEB Yearbook of Electricity Distributors). NPDI faces unique challenges inherent with this type of service area. Parts of NPDI are also embedded in Hydro One territory as they serve the balance of the rural area in Norfolk County.

With the amalgamation, NPDI acquired a diverse distribution system with a large number of poles (11,020) and transformers (4,469) consistent with low density and multiple distribution voltages (4.16 kV, 8.32 kV and 27.6 kV). These distribution voltages are supported by 12 Distribution Substations (DS).

NPDI also owns and operates a high voltage municipal transformer station (Bloomsburg MTS) that provides step down from 115 kV to 27.6 kV.

NPDI is supplied from several sources: two 115 kV transmission circuits traverse the 115 kV tower line originating at the north end of our territory from Vanessa Junction to Bloomsburg MTS (owned by NPDI) and Norfolk TS (which is owned by Hydro One). Other supply feeds originate from the Hydro One Tillsonburg TS located at the extreme west end of the NPDI service territory; and some rural supply off of the Hydro One 8.32 kV system in the Port Rowan area. Prior to August 31, 2010, NPDI also wheeled power from the Hydro One's Jarvis TS which is embedded in a neighbouring utility's territory (Haldimand County Hydro).

Some key system statistics follow:

Poles	11,020
Distribution Transformers	4,469
Distribution Stations	12
Transformer Station	1
km of Overhead Lines	657
km of Underground Lines	108

In managing its distribution system assets, NPDI's main objective is to optimize performance of assets at a reasonable cost with due regard for system reliability, public & worker safety and customer service expectations. This Application incorporates NPDI's 2012 Capital and Expense Budgets in determining the revenue requirement to bring these plans to fruition. Further information will be provided later in this Application.

NPDI considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, system configuration, line loss reduction, outage mitigation and procuring the lowest cost of commodity to determine investment needs in the system.

On an annual basis, NPDI reviews capital projects identified for potential implementation and prioritizes each project based on defined criteria basis. All members of the management team follow these criteria as they individually complete outlines of their recommendations, which are then discussed by the full management team. After examining all recommended projects, each are listed in order from high to low priority and then moved forward based on as an "as-needed" basis.

Various studies and assessments of NPDI assets are used to determine project priorities. For example NPDI has a pole testing and treatment program which reports the condition of poles with specific reference to "priority poles" which have been identified as poles reaching the end of their useful lives and require priority replacement. NPDI uses this database of pole location, type, age, and test results to provide a basis for long-range pole replacement plans. In addition, priorities may be affected by outside regulatory requirements as with an obligation to relocate a pole line to accommodate a municipal road widening.

Substation assets are similarly evaluated as to condition and priority upgrades are identified and scheduled to maintain substation reliability and safety.

In addition to the capital needs of the network, NPDI provides and plans for system maintenance of the network on a priority basis. The same preparation and consideration steps are undertaken before the final recommended budget amounts are established. Further information on NPDI's Capital and Operation, Maintenance & Administration amounts will follow later in this Application.

Capital Asset Categories

NPDI's assets fall into two broad categories – The first is ***distribution plant***, which includes assets such as high voltage transformation, MTS and substation buildings, poles, conductor, overhead and underground electricity distribution infrastructure, transformers, meters and substation equipment. The second is ***general plant*** which includes assets such as: office building and service centre; office furniture; transportation equipment; communications technology; computer equipment and software; general equipment; and tools. A more detailed list of distribution and general plant categories can be found in Table 2.6 (Gross Assets) in Exhibit 2, Tab 2, Schedule 2.

Distribution Plant Capital Projects:

NPDI’s capital budget items include:

- **Customer Demand:**

These are projects that NPDI undertakes to meet its customer service obligations in accordance with the OEB’s Distribution System Code (the “DSC”) and NPDI’s Conditions of Service. Activities include connecting new customers and building or overseeing construction of distribution systems for new subdivisions. Capital contributions toward the cost of these projects are collected by NPDI in accordance with the DSC and the provisions of its Conditions of Service. NPDI uses the economic evaluation methodology prescribed by the DSC to determine the level of capital contribution for each project and those levels are included in the annual capital budget.

- **Renewal:**

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

- **Security:**

The probability and impact of asset failure are considered at peak load to determine the risk the failure creates. In these cases, projects are developed to add switching devices or create a backup supply (ie. feeder or TS transformer etc.) to reduce the risk of power outages and to reduce restoration times.

- **Capacity:**

Load growth caused by new customer connections and increased demand of existing customers over time can result in a need for capacity improvements on the system. Projects can take the form of new or upgraded feeders, transformers or voltage conversion projects, substations or transformer stations additions or upgrades. These projects benefit many customers.

- **Reliability:**

The main driver for these investments is an analysis of what measures could be undertaken to improve NPDI reliability performance as measured by: System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI = SAIDI/SAIFI). These measures are indicators of the reliability of NPDI's distribution system. These activities will support maintenance of, or improvement to, the Service Quality Indices measured and submitted to the OEB each year by NPDI. The Asset Management Plan provided in Exhibit 2, Tab 3, Schedule 3 supports the capital and maintenance programs needed to maintain and enhance the reliability of NPDI's distribution system.

- **Regulatory Requirements:**

These projects are system capital investments which are being driven by regulatory requirements. These requirements may include, among others, directions from the OEB, the IESO, the Ministry of Energy or the Ministry of Environment and the County of Norfolk. Projects driven by the requirement for elimination of long term load transfers by June 30, 2014 as per section 6.5.3 of the DSC are included in this category. Regulatory requirement projects can also include relocating system plant for roadway reconstruction work. Where road widening projects are required as a result of municipal infrastructure development, NPDI follows the *Public Service Works on Highways Act, 1990* and related regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital for 50% of NPDI labour and vehicles.

- **Transformer Stations:**

Transformer Stations are used to transform power from the transmission system at 115 kV to the distribution system at 27.6 kV. Investments are undertaken to improve or maintain reliability to a large numbers of customers, maintain security and safety at the station, and to meet long range load growth. The Station facilities include power transformers, circuit breakers, switchgear, bus, insulators, power cables, support structures, disconnect switches and ancillary equipment such as protection and control relaying.

- **Substations:**

Distribution substations (DS) are used to transform power received from the transformer stations via primary distribution feeders to either 8.32 kV or 4.16 kV for further distribution. Investments are undertaken to improve or maintain reliability for a large number of customers and to maintain security and safety at the substations. The renewal or retirement of NPDI's 4.16 kV and 8.32 kV substations is the subject of an ongoing review being undertaken as part of the Asset Management Plan. NPDI has been expanding their 27.6 kV system for several years with the objective of eliminating much of the 4.16 kV network, which will eventually lead to a reduction in the number of distribution stations, a reduction in the number of distribution feeders, and improved electricity distribution efficiency.

- **Customer Connections and Metering:**

Capital expenditures in this pool include meter installations, meter upgrades, and the capital components of wholesale and retail meter verification activities. In 2009 NPDI began installation of smart meters and will complete the program in 2011. Smart meter activity and related expenses are discussed in full in Exhibit 9.

NPDI capital projects for the 2012 Test Year are discussed in further detail in Exhibit 2, Tab 3, Schedule 2. NPDI has provided project-specific justifications for 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year and 2012 Test Year.

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

The 2011 Bridge and 2012 Test Years' gross asset balances reflect the capital expenditure programs forecast for both years. Analyses of 2008 to 2012 capital programs are described in detail in NPDI's written evidence at Exhibit 2, Tab 3, Schedule 2.

Budget Process:

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

The budget is prepared annually by management and is reviewed and approved by the NPDI Board of Directors. The budget is prepared before the start of each fiscal year. Once approved, it typically does not change but provides a plan against which actual results may be evaluated.

The NPDI Board has on occasion directed Management to revise a Budget following consideration of year-end financial results or major changes in capital job priorities.

Responsibilities:

- It is the responsibility of the Finance department to co-ordinate the development of the operating budget, capital budget and forecast processes.
- Each department is responsible for preparing its respective operating budget, capital budget, and forecasts.
- The Manager of Engineering (or designate) is responsible for the capital budget.
- The CEO and CFO are responsible for presenting and recommending the budget to the Board of Directors for approval.

The budget is an important planning tool for NPDI. It puts capital and operational plans into a common financial plan. The final document provides a comprehensive package of departmental budgets that collectively ensure that appropriate resources are designated for the various capital and operational needs of the utility for the coming year.

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

VARIANCE ANALYSIS OF RATE BASE:

Table 1.2: 2008 Approved Rate Base vs. 2008 Actual

	2008 Board Approved	2008 Actual	Variance
Gross Fixed Assets	66,271,193	76,092,228	9,821,035
Accumulated Depreciation	21,488,308	33,574,501	12,086,193
Net Book Value	44,782,885	42,517,727	(2,265,158)
Average Net Book Value	43,155,630	41,884,268	(1,271,362)
Working Capital Expenses	33,307,800	32,632,012	(675,788)
Working Capital Allowance (15%)	4,996,170	4,894,802	(101,368)
Rate Base	48,151,800	46,779,070	(1,372,730)

The 2008 Approved Gross Fixed Assets and Accumulated Amortization amounts differ significantly from Norfolk's audited statements. Norfolk's 2008 Cost of Service application was made with the intention of removing fully depreciated assets from both the Gross Fixed Assets account and the Accumulated Amortization account, with the net amounts displayed in its application. This change did not occur on Norfolk's financial statements until 2010. This does not impact the net book value of the assets nor Rate Base. Norfolk has presented the assets and accumulated amortization as presented in the financial statements for clarity. Exhibit 2, Tab 2, Schedule 1 – Continuity Statements, contain more details.

The 2008 actual rate base was $1,372,730 lower than approved by the Board. $101,368 of this amount was due to lower working capital expenses than anticipated. The remaining $1,271,362 was the result of Norfolk not spending as much on capital as projected.

Norfolk notes that in the 2008 Cost of Service application it projected capital expenditures of $5,938,600. In actual fact Norfolk spent $4,276,639, or $1,661,961 less than planned. Norfolk notes that it spent more than planned in 2007 ($6,458,620 actual compared to $5,620,200 projected in the 2008 rate application). However in 2008 Norfolk encountered a number of problems including significantly increased expenses (2008 OM&A was $921,125 higher than the Board approved 2008 OM&A).

Table 1.3: 2008 Actual Rate Base vs. 2009 Actual

	2008 Actual	2009 Actual	Variance
Gross Fixed Assets*	76,092,228	79,544,106	3,451,878
Accumulated Depreciation	33,574,501	36,317,914	2,743,413
Net Book Value	42,517,727	43,226,192	708,465
Average Net Book Value	41,910,355	42,871,960	961,605
Working Capital Expenses	32,632,012	33,329,699	697,687
Working Capital Allowance (15%)	4,894,802	4,999,455	104,653
Rate Base	46,805,156	47,871,414	1,066,258

*2009 Actual Gross Assets: $85,016,144 less $5,472,038 WIP = $79,544,106

The rate base of $47,871,414 for 2009 was an increase of $1,066,258. This increase is primarily the result of an increase in average net fixed assets ($961,605) due to capital expenditures. Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2.

Table 1.4: 2009 Actual Rate Base vs. 2010 Actual

	2009 Actual	2010 Actual	Variance
Gross Fixed Assets	79,544,106	75,225,237	(4,318,869)
Accumulated Depreciation	36,317,914	25,835,324	(10,482,590)
Net Book Value	43,226,192	49,389,913	6,163,721
Average Net Book Value	42,871,960	46,308,053	3,436,093
Working Capital Expenses	33,329,699	35,897,823	2,568,124
Working Capital Allowance (15%)	4,999,455	5,384,673	385,219
Rate Base	47,871,414	51,692,726	3,821,312

Gross fixed assets declined in 2010 due to the removal of fully depreciated assets from Norfolk's accounting records. The same amount of accumulated amortization was also removed, resulting in no change in Net Book Value. Exhibit 2, Tab 2, Schedule 1 – Continuity Statements provides more details. The increase in rate base was the result of a large increase in net book value of assets, which was the result of the completion of Norfolk's Bloomsburg Transformer Station. Exhibit 2, Tab 3, Schedule 2 provides details of the capital projects in 2010.

Table 1.5: 2011 Bridge Year Rate Base vs. 2010 Actual

	2010 Actual	2011 Bridge	Variance
Gross Fixed Assets	75,225,237	79,147,237	3,922,000
Accumulated Depreciation	25,835,324	28,808,038	2,972,714
Net Book Value	49,389,913	50,339,199	949,286
Average Net Book Value	46,308,053	49,864,556	3,556,504
Working Capital Expenses	35,897,823	38,295,629	2,397,806
Working Capital Allowance (15%)	5,384,673	5,744,344	359,671
Rate Base	51,692,726	55,608,900	3,916,174

In 2011, rate base is forecast to increase by $3,916,174 from 2010. The average net book value of assets increased significantly due to a full year inclusion of the Bloomsburg station plus additional capital spending in 2011. The 2011 working capital allowance increased by $351,126 from the 2010 Bridge Year. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 4, Schedule 1.

Table 1.6: 2011 Bridge Year Rate Base vs. 2012 Test Year (CGAAP)

	2011 Bridge	2012 Test Opening Balance	2012 Test Closing Balance	Variance 2011 vs 2012
Gross Fixed Assets	79,147,237	80,586,792	84,994,791	5,847,554
Accumulated Depreciation	28,808,038	28,116,375	31,482,220	2,674,182
Net Book Value	50,339,199	52,470,417	53,512,571	3,173,372
Average Net Book Value	49,864,556		52,991,494	3,126,938
Working Capital Expenses	38,295,629		39,952,900	1,657,271
Working Capital Allowance (15%)	5,744,344		5,992,935	248,591
Rate Base	55,608,900		58,984,429	3,375,529

The 2012 Test year Opening Balances are shown above to illustrate the $3,620,385 addition of smart meters to fixed assets, less the removal of stranded assets (meters) totaling $2,180,831. Accumulated amortization increased $608,975 related to smart meters, offset by $1,300,635 with the removal of the stranded assets.   These changes impact the average balance of net fixed assets in 2012.

Overall rate base is projected to increase by $3,375,529. The net $746,894 of this is due to the addition of smart meters, less the stranded assets. The remainder is due to increased fixed assets from capital spending and increased working capital.

GROSS ASSETS – PROPERTY, PLANT & EQUIPMENT and ACCUMULATED AMORTIZATION

CONTINUITY STATEMENTS:

Table 2.1: Fixed Asset Continuity Schedule - 2008

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals / Adjustments**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals / Adjustments**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	N/A	$ 384,421	$ 695	$ -	$ 385,116	$ -	$ -		$ -	$ 385,116
CEC	1806	Land Rights	N/A	$ 300,911	$ -	$ -	$ 300,911	$ -	$ -		$ -	$ 300,911
47	1808	Buildings	2.00%	$ 1,450,870	$ 74,090	$ -	$ 1,524,961	-$ 87,052	-$ 30,499		-$ 117,551	$ 1,407,409
13	1810	Leasehold Improvements	N/A	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.00%	$ 3,083,382	$ 132,214	$ -	$ 3,215,596	-$ 217,074	-$ 80,426		-$ 297,500	$ 2,918,096
47	1820	Distribution Station Equipment <50 kV	3.30%	$ 3,388,836	$ 495,818	$ -	$ 3,884,654	-$ 1,512,367	-$ 82,146		-$ 1,594,513	$ 2,290,140
47	1825	Storage Battery Equipment	N/A	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 23,866,885	$ 824,599	$ -	$ 24,691,484	-$ 10,476,146	-$ 791,096		-$ 11,267,242	$ 13,424,242
47	1835	Overhead Conductors & Devices	4.00%	$ 12,116,999	$ 866,071	$ -	$ 12,983,070	-$ 4,557,381	-$ 409,311		-$ 4,966,692	$ 8,016,378
47	1840	Underground Conduit	4.00%	$ 3,478,270	$ 54,313	$ -	$ 3,532,583	-$ 1,113,475	-$ 123,911		-$ 1,237,386	$ 2,295,196
47	1845	Underground Conductors & Devices	4.00%	$ 6,944,195	$ 176,667	$ -	$ 7,120,863	-$ 2,235,760	-$ 236,638		-$ 2,472,397	$ 4,648,465
47	1850	Line Transformers	4.00%	$ 10,075,470	$ 741,072	$ -	$ 10,816,541	-$ 5,174,452	-$ 510,519		-$ 5,684,971	$ 5,131,571
47	1855	Services (Overhead & Underground)	4.00%	$ 1,944,841	$ 285,345	$ -	$ 2,230,186	-$ 243,061	-$ 89,207		-$ 332,268	$ 1,897,918
47	1860	Meters	4.00%	$ 3,703,688	$ 187,842		$ 3,891,529	-$ 1,928,855	-$ 147,711		-$ 2,076,565	$ 1,814,964
47	1860	Meters (Smart Meters)	N/A	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
N/A	1905	Land	N/A	$ 242,867	$ 768	$ -	$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 2,120,691	$ 68,787	$ -	$ 2,189,477	-$ 746,129	-$ 31,776		-$ 777,905	$ 1,411,572
13	1910	Leasehold Improvements	10.00%	$ 6,177	$ -	$ -	$ 6,177	-$ 1,944	-$ 640		-$ 2,584	$ 3,593
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 392,185	$ 15,427	$ -	$ 407,613	-$ 316,918	-$ 14,323		-$ 331,241	$ 76,372
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 1,076,434	$ 179,866	$ -	$ 1,256,300	-$ 836,193	-$ 131,079	-$ 8,173	-$ 975,445	$ 280,854
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	20.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	20.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 316,588	$ 34,376	$ -	$ 350,963	-$ 190,013	-$ 48,256		-$ 238,269	$ 112,694
12	1925	Computer Software (Smart Meters)	20.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
10	1930	Transportation Equipment	10% to 25%	$ 2,306,510	$ 30,285	-$ 69,753	$ 2,267,042	-$ 1,383,114	-$ 166,883	$ 69,753	-$ 1,480,243	$ 786,799
8	1935	Stores Equipment	10.00%	$ 118,695	$ 1,326	$ -	$ 120,021	-$ 94,706	-$ 3,889		-$ 98,595	$ 21,427
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 646,467	$ 32,817	$ 30,503	$ 709,787	-$ 506,964	-$ 29,263	-$ 6,101	-$ 542,328	$ 167,459
8	1945	Measurement & Testing Equipment	10.00%	$ 150,142	$ 12,576	$ -	$ 162,717	-$ 59,825	-$ 16,272		-$ 76,096	$ 86,621
8	1950	Power Operated Equipment	N/A	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	10.00%	$ 67,050	$ 39,856	$ -	$ 106,906	-$ 26,531	-$ 10,691		-$ 37,222	$ 69,684
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	10.00%	$ 103,274	$ 11,876	$ 52,911	$ 168,061	-$ 25,437	-$ 16,806	-$ 17,163	-$ 59,406	$ 108,655
47	1975	Load Management Controls Utility Premises	10.00%	$ 16,565	$ -	$ -	$ 16,565	-$ 16,565	$ -		-$ 16,565	$ -
47	1980	System Supervisor Equipment	6.70%	$ 612,081	$ -	$ -	$ 612,081	-$ 184,973	-$ 40,805		-$ 225,779	$ 386,302
45.1	1980	System Supervisor Equipment - Hardware	20.00%	$ -	$ 9,955	$ -	$ 9,955	$ -	-$ 1,991		-$ 1,991	$ 7,964
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 6,791,146	-$ 331,461	$ -	-$ 7,122,607	$ 1,055,366	$ 284,904		$ 1,340,271	-$ 5,782,336
8	2005	Property Under Capital Lease	10.00%	$ 10,039	$ -	$ -	$ 10,039	-$ 3,012	-$ 1,004		-$ 4,015	$ 6,023
N/A	2055	Work In Progress	N/A	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		Total		**$ 72,133,388**	**$ 3,945,178**	**$ 13,661**	**$ 76,092,228**	**-$ 30,882,579**	**-$ 2,730,238**	**$ 38,316**	**-$ 33,574,501**	**$ 42,517,726**

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation

Transportation	-$ 166,883
Stores & Garage Equipment	-$ 34,156
Computer HW & SW	-$ 179,336
Net Depreciation to Inc. Stmt	**-$ 2,349,864**

Table 2.3: Fixed Asset Continuity Schedule - 2009

		Cost				Accumulated Depreciation				
Description	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals / Adjustments**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals / Adjustments**	**Closing Balance**	**Net Book Value**
Land	N/A	$ 385,116	$ 6,144		$ 391,259	$ -	$ -		$ -	$ 391,259
Land Rights		$ 300,911	$ 1,873		$ 302,784	$ -	$ -		$ -	$ 302,784
Buildings	2.00%	$ 1,524,961	$ 90,757		$ 1,615,717	-$ 117,551	-$ 32,314		-$ 149,866	$ 1,465,852
Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
Transformer Station Equipment >50 kV	2.00%	$ 3,215,596	$ -		$ 3,215,596	-$ 297,500	-$ 80,426		-$ 377,926	$ 2,837,669
Distribution Station Equipment <50 kV	3.30%	$ 3,884,654	$ 236,274		$ 4,120,928	-$ 1,594,513	-$ 97,149		-$ 1,691,662	$ 2,429,265
Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
Poles, Towers & Fixtures	4.00%	$ 24,691,484	$ 1,006,528		$ 25,698,012	-$ 11,267,242	-$ 831,358		-$ 12,098,600	$ 13,599,413
Overhead Conductors & Devices	4.00%	$ 12,983,070	$ 732,544		$ 13,715,614	-$ 4,966,692	-$ 438,613		-$ 5,405,305	$ 8,310,310
Underground Conduit	4.00%	$ 3,532,583	$ 312,484		$ 3,845,066	-$ 1,237,386	-$ 136,410		-$ 1,373,797	$ 2,471,270
Underground Conductors & Devices	4.00%	$ 7,120,863	$ 515,163		$ 7,636,026	-$ 2,472,397	-$ 257,244		-$ 2,729,642	$ 4,906,384
Line Transformers	4.00%	$ 10,816,541	$ 421,375		$ 11,237,917	-$ 5,684,971	-$ 527,374		-$ 6,212,344	$ 5,025,572
Services (Overhead & Underground)	4.00%	$ 2,230,186	$ 277,121		$ 2,507,308	-$ 332,268	-$ 100,292		-$ 432,561	$ 2,074,747
Meters	4.00%	$ 3,891,529	$ 133,636		$ 4,025,165	-$ 2,076,565	-$ 153,056		-$ 2,229,621	$ 1,795,544
Meters (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
Buildings & Fixtures	2.00%	$ 2,189,477	$ 26,161		$ 2,215,638	-$ 777,905	-$ 32,299		-$ 810,205	$ 1,405,433
Leasehold Improvements	10.00%	$ 6,177	$ -		$ 6,177	-$ 2,584	-$ 640		-$ 3,223	$ 2,954
Office Furniture & Equipment (10 years)	10.00%	$ 407,613	$ 4,075		$ 411,687	-$ 331,241	-$ 14,730		-$ 345,971	$ 65,716
Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
Computer Equipment - Hardware	20.00%	$ 1,256,300	$ 23,999		$ 1,280,299	-$ 975,445	-$ 113,820		-$ 1,089,266	$ 191,033
Computer Equip.-Hardware(Post Mar. 22/04)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
Computer Equip.-Hardware(Post Mar. 19/07)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
Computer Software	20.00%	$ 350,963	$ 56,034		$ 406,997	-$ 238,269	-$ 46,407		-$ 284,676	$ 122,321
Computer Software (Smart Meters)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
Transportation Equipment	10% to 25%	$ 2,267,042	$ -	-$ 144,439	$ 2,122,603	-$ 1,480,243	-$ 167,752	$ 137,592	-$ 1,510,404	$ 612,200
Stores Equipment	10.00%	$ 120,021	$ 314		$ 120,335	-$ 98,595	-$ 3,920		-$ 102,515	$ 17,820
Tools, Shop & Garage Equipment	10.00%	$ 709,787	$ 18,146		$ 727,933	-$ 542,328	-$ 31,078		-$ 573,406	$ 154,527
Measurement & Testing Equipment	10.00%	$ 162,717	$ 16,256		$ 178,973	-$ 76,096	-$ 17,897		-$ 93,994	$ 84,980
Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
Communications Equipment	10.00%	$ 106,906	$ -		$ 106,906	-$ 37,222	-$ 10,691		-$ 47,912	$ 58,994
Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
Miscellaneous Equipment	10.00%	$ 168,061	$ 244,273		$ 412,334	-$ 59,406	-$ 41,233		-$ 100,640	$ 311,695
Load Management Controls Utility Premises	N/A	$ 16,565	$ -		$ 16,565	-$ 16,565	$ -		-$ 16,565	$ -
System Supervisor Equipment	6.70%	$ 612,081	$ 1,875		$ 613,956	-$ 225,779	-$ 40,930		-$ 266,709	$ 347,247
System Supervisor Equipment - Hardware	20.00%	$ 9,955	$ 2,698		$ 12,653	-$ 1,991	-$ 2,531		-$ 4,522	$ 8,131
Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
Contributions & Grants	4.00%	-$ 7,122,607	-$ 531,414		-$ 7,654,021	$ 1,340,271	$ 298,163		$ 1,638,433	-$ 6,015,587
Property Under Capital Lease	10.00%	$ 10,039	$ -		$ 10,039	-$ 4,015	-$ 1,004		-$ 5,019	$ 5,019
Work In Progress	N/A	$ -	$ 5,472,038		$ 5,472,038	$ -	$ -		$ -	$ 5,472,038
Total		**$ 76,092,228**	**$ 9,068,355**	**-$ 144,439**	**$ 85,016,144**	**-$ 33,574,501**	**-$ 2,881,007**	**$ 137,592**	**-$ 36,317,916**	**$ 48,698,228**

Transportation
Stores Equipment & Garage Tools
Computer Hardware & Software

Less: Fully Allocated Depreciation	
Transportation	-$ 167,752
Stores & Garage Equipment	-$ 36,002
Computer HW & SW	-$ 160,227
Net Depreciation to Inc. Stmt	**-$ 2,517,025**

Table 2.4: Fixed Asset Continuity Schedule - 2010

				Cost				**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals / Adjustments**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals / Adjustments**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	N/A	$ 391,259	$ -		$ 391,259	$ -	$ -		$ -	$ 391,259
	1806	Land Rights		$ 302,784	$ -		$ 302,784	$ -	$ -		$ -	$ 302,784
47	1808	Buildings	2.00%	$ 1,615,717	$ 4,361		$ 1,620,078	-$ 149,866	-$ 32,358	$ 1,648	-$ 180,575	$ 1,439,503
13	1810	Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.00%	$ 3,215,596	$ 224,749	$ 5,472,038	$ 8,912,383	-$ 377,926	-$ 151,636	$ 5,176	-$ 524,387	$ 8,387,996
47	1820	Distribution Station Equipment <50 kV	3.30%	$ 4,120,928	$ 33,675	-$ 1,386,755	$ 2,767,848	-$ 1,691,662	-$ 87,303	$ 1,415,631	-$ 363,334	$ 2,404,514
47	1825	Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 25,698,012	$ 846,036	-$ 5,686,690	$ 20,857,358	-$ 12,098,600	-$ 848,278	$ 5,748,601	-$ 7,198,276	$ 13,659,082
47	1835	Overhead Conductors & Devices	4.00%	$ 13,715,614	$ 751,468	-$ 2,750,300	$ 11,716,783	-$ 5,405,305	-$ 453,642	$ 2,802,934	-$ 3,056,012	$ 8,660,771
47	1840	Underground Conduit	4.00%	$ 3,845,066	$ 160,329		$ 4,005,396	-$ 1,373,797	-$ 139,617	$ 11,576	-$ 1,501,837	$ 2,503,558
47	1845	Underground Conductors & Devices	4.00%	$ 7,636,026	$ 255,331	-$ 1,204,925	$ 6,686,432	-$ 2,729,642	-$ 262,351	$ 1,228,921	-$ 1,763,071	$ 4,923,361
47	1850	Line Transformers	4.00%	$ 11,237,917	$ 744,525		$ 11,982,442	-$ 6,212,344	-$ 542,264	$ 44,045	-$ 6,710,564	$ 5,271,877
47	1855	Services (Overhead & Underground)	4.00%	$ 2,507,308	$ 271,077		$ 2,778,385	-$ 432,561	-$ 105,714	$ 17,900	-$ 520,375	$ 2,258,010
47	1860	Meters	4.00%	$ 4,025,165	$ 131,968		$ 4,157,133	-$ 2,229,621	-$ 155,695	$ 10,181	-$ 2,375,136	$ 1,781,996
47	1860	Meters (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
N/A	1905	Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 2,215,638	$ 91,650		$ 2,307,288	-$ 810,205	-$ 33,216	$ 2,679	-$ 840,742	$ 1,466,546
13	1910	Leasehold Improvements	10.00%	$ 6,177	$ -		$ 6,177	-$ 3,223	-$ 640		-$ 3,863	$ 2,314
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 411,687	$ 5,958	-$ 264,715	$ 152,930	-$ 345,971	-$ 15,028	$ 266,478	-$ 94,521	$ 58,409
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 1,280,299	$ 44,046	-$ 609,419	$ 714,926	-$ 1,089,266	-$ 103,294	$ 636,791	-$ 555,770	$ 159,156
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 406,997	$ 35,884	-$ 147,109	$ 295,773	-$ 284,676	-$ 44,571	$ 156,246	-$ 173,001	$ 122,771
12	1925	Computer Software (Smart Meters)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1930	Transportation Equipment	10% to 25%	$ 2,122,603	$ 75,784	-$ 659,750	$ 1,538,637	-$ 1,510,404	-$ 170,213	$ 618,087	-$ 1,062,530	$ 476,107
8	1935	Stores Equipment	10.00%	$ 120,335	$ 358	-$ 81,132	$ 39,562	-$ 102,515	-$ 3,938	$ 81,339	-$ 25,115	$ 14,447
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 727,933	$ 6,946	-$ 417,155	$ 317,724	-$ 573,406	-$ 31,425	$ 420,526	-$ 184,305	$ 133,419
8	1945	Measurement & Testing Equipment	10.00%	$ 178,973	$ 1,895		$ 180,868	-$ 93,994	-$ 17,992	$ 1,672	-$ 110,314	$ 70,554
8	1950	Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	10.00%	$ 106,906	$ 1,021		$ 107,927	-$ 47,912	-$ 10,742	$ 2,599	-$ 56,055	$ 51,872
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	10.00%	$ 412,334	$ 15,885		$ 428,220	-$ 100,640	-$ 42,028	$ 13,640	-$ 129,028	$ 299,192
47	1975	Load Management Controls Utility Premises	N/A	$ 16,565	$ -	-$ 16,565	$ -	-$ 16,565	$ -	$ 16,565	$ -	$ -
47	1980	System Supervisor Equipment	6.70%	$ 613,956	$ 540,685		$ 1,154,641	-$ 266,709	-$ 58,953	$ 64	-$ 325,599	$ 829,042
45.1	1980	System Supervisor Equipment - Hardware	20.00%	$ 12,653	$ 9,479		$ 22,132	-$ 4,522	-$ 3,478	$ 1,265	-$ 6,735	$ 15,397
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 7,654,021	-$ 819,501		-$ 8,473,522	$ 1,638,433	$ 322,553	-$ 29,144	$ 1,931,842	-$ 6,541,679
8	2005	Property Under Capital Lease	10.00%	$ 10,039	$ -		$ 10,039	-$ 5,019	-$ 1,004		-$ 6,023	$ 4,015
N/A	2055	Work In Progress	N/A	$ 5,472,038	-$ 5,472,038		$ -	$ -	$ -		$ -	$ -
		Total		**$ 85,016,144**	**-$ 2,038,431**	**-$ 7,752,475**	**$ 75,225,237**	**-$ 36,317,916**	**-$ 2,992,829**	**$ 13,475,419**	**-$ 25,835,326**	**$ 49,389,911**

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation

Transportation	-$ 170,213
Stores & Garage Equipment	-$ 33,317
Computer HW & SW	-$ 147,866
Adjustment for 1/2 Year Rule	-$ 289,866
Net Depreciation to Inc. Stmt	**-$ 2,351,567**

Note: 2010 Amortization Expense adjusted for 2007 to 2009 cumulative effect of adopting half-year rule

Table 2.5: Fixed Asset Continuity Schedule – 2011 (CGAAP)

				Cost				**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	N/A	$ 391,259	$ -		$ 391,259	$ -	$ -		$ -	$ 391,259
	1806	Land Rights		$ 302,784	$ 1,000		$ 303,784	$ -	$ -		$ -	$ 303,784
47	1808	Buildings	2.00%	$ 1,620,078	$ -		$ 1,620,078	-$ 180,575	-$ 32,402		-$ 212,977	$ 1,407,101
13	1810	Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.00%	$ 8,912,383	$ -		$ 8,912,383	-$ 524,387	-$ 222,846		-$ 747,233	$ 8,165,150
47	1820	Distribution Station Equipment <50 kV	3.30%	$ 2,767,848	$ 75,000		$ 2,842,848	-$ 363,334	-$ 89,114		-$ 452,448	$ 2,390,400
47	1825	Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 20,857,358	$ 1,196,375		$ 22,053,733	-$ 7,198,276	-$ 889,126		-$ 8,087,402	$ 13,966,331
47	1835	Overhead Conductors & Devices	4.00%	$ 11,716,783	$ 849,912		$ 12,566,695	-$ 3,056,012	-$ 485,670		-$ 3,541,682	$ 9,025,013
47	1840	Underground Conduit	4.00%	$ 4,005,396	$ 220,000		$ 4,225,396	-$ 1,501,837	-$ 147,224		-$ 1,649,061	$ 2,576,334
47	1845	Underground Conductors & Devices	4.00%	$ 6,686,432	$ 388,000		$ 7,074,432	-$ 1,763,071	-$ 275,217		-$ 2,038,288	$ 5,036,144
47	1850	Line Transformers	4.00%	$ 11,982,442	$ 902,945		$ 12,885,387	-$ 6,710,564	-$ 352,263		-$ 7,062,827	$ 5,822,559
47	1855	Services (Overhead & Underground)	4.00%	$ 2,778,385	$ 268,108		$ 3,046,493	-$ 520,375	-$ 116,498		-$ 636,873	$ 2,409,620
47	1860	Meters	4.00%	$ 4,157,133	$ 72,000		$ 4,229,133	-$ 2,375,136	-$ 159,775		-$ 2,534,911	$ 1,694,221
47	1860	Meters (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
N/A	1905	Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 2,307,288	$ 10,000		$ 2,317,288	-$ 840,742	-$ 34,232		-$ 874,974	$ 1,442,314
13	1910	Leasehold Improvements	10.00%	$ 6,177	$ -		$ 6,177	-$ 3,863	-$ 640		-$ 4,503	$ 1,674
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 152,930	$ 15,000		$ 167,930	-$ 94,521	-$ 14,517		-$ 109,038	$ 58,892
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 714,926	$ 30,000		$ 744,926	-$ 555,770	-$ 66,552		-$ 622,322	$ 122,604
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 295,773	$ 27,000		$ 322,773	-$ 173,001	-$ 39,147		-$ 212,148	$ 110,624
12	1925	Computer Software (Smart Meters)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1930	Transportation Equipment	10% to 25%	$ 1,538,637	$ 440,000		$ 1,978,637	-$ 1,062,530	-$ 204,408		-$ 1,266,938	$ 711,699
8	1935	Stores Equipment	10.00%	$ 39,562	$ 1,000		$ 40,562	-$ 25,115	-$ 4,006		-$ 29,121	$ 11,441
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 317,724	$ 23,000		$ 340,724	-$ 184,305	-$ 32,017		-$ 216,322	$ 124,401
8	1945	Measurement & Testing Equipment	10.00%	$ 180,868	$ 6,000		$ 186,868	-$ 110,314	-$ 18,387		-$ 128,701	$ 58,167
8	1950	Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	10.00%	$ 107,927	$ 8,000		$ 115,927	-$ 56,055	-$ 11,193		-$ 67,248	$ 48,679
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	10.00%	$ 428,220	$ 5,000		$ 433,220	-$ 129,028	-$ 43,072		-$ 172,100	$ 261,120
47	1975	Load Management Controls Utility Premises	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	6.70%	$ 1,154,641	$ 245,000		$ 1,399,641	-$ 325,599	-$ 85,143		-$ 410,742	$ 988,899
45.1	1980	System Supervisor Equipment - Hardware	20.00%	$ 22,132			$ 22,132	-$ 6,735	-$ 4,426		-$ 11,161	$ 10,971
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 8,473,522	-$ 861,340		-$ 9,334,862	$ 1,931,842	$ 356,168		$ 2,288,010	-$ 7,046,851
8	2005	Property Under Capital Lease	10.00%	$ 10,039	$ -		$ 10,039	-$ 6,023	-$ 1,004		-$ 7,027	$ 3,011
N/A	2055	Work In Progress	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
		Total		**$ 75,225,237**	**$ 3,922,000**	**$ -**	**$ 79,147,237**	**-$ 25,835,326**	**-$ 2,972,711**	**$ -**	**-$ 28,808,038**	**$ 50,339,200**

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation	
Transportation	-$ 204,408
Stores & Garage Equipment	-$ 33,977
Computer HW & SW	-$ 105,699
Net Depreciation to Inc. Stmt	**-$ 2,628,627**

Table 2.6: Fixed Asset Continuity Statement – 2012 (CGAAP)

				Cost				**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	N/A	$ 391,259	$ -		$ 391,259	$ -	$ -		$ -	$ 391,259
CEC	1806	Land Rights	N/A	$ 303,784	$ -		$ 303,784	$ -	$ -		$ -	$ 303,784
47	1808	Buildings	2.00%	$ 1,620,078	$ -		$ 1,620,078	-$ 212,977	-$ 32,402		-$ 245,379	$ 1,374,699
13	1810	Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.00%	$ 8,912,383	$ -		$ 8,912,383	-$ 747,233	-$ 222,846		-$ 970,079	$ 7,942,304
47	1820	Distribution Station Equipment <50 kV	3.30%	$ 2,842,848	$ 275,000		$ 3,117,848	-$ 452,448	-$ 94,948		-$ 547,396	$ 2,570,452
47	1825	Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 22,053,733	$ 1,463,000		$ 23,516,733	-$ 8,087,402	-$ 942,314		-$ 9,029,716	$ 14,487,017
47	1835	Overhead Conductors & Devices	4.00%	$ 12,566,695	$ 925,000		$ 13,491,695	-$ 3,541,682	-$ 521,168		-$ 4,062,850	$ 9,428,845
47	1840	Underground Conduit	4.00%	$ 4,225,396	$ 100,000		$ 4,325,396	-$ 1,649,061	-$ 153,624		-$ 1,802,685	$ 2,522,710
47	1845	Underground Conductors & Devices	4.00%	$ 7,074,432	$ 203,000		$ 7,277,432	-$ 2,038,288	-$ 287,037		-$ 2,325,325	$ 4,952,107
47	1850	Line Transformers	4.00%	$ 12,885,387	$ 952,000		$ 13,837,387	-$ 7,062,827	-$ 317,405		-$ 7,380,232	$ 6,457,154
47	1855	Services (Overhead & Underground)	4.00%	$ 3,046,493	$ 375,000		$ 3,421,493	-$ 636,873	-$ 129,360		-$ 766,233	$ 2,655,260
47	1860	Meters	4.00%	$ 2,048,302	$ 348,000		$ 2,396,302	-$ 1,234,276	-$ 168,175		-$ 1,402,451	$ 993,850
47	1860	Meters (Smart Meters)	6.67%	$ 3,214,012	$ -		$ 3,214,012	-$ 479,090	-$ 214,267		-$ 693,357	$ 2,520,655
N/A	1905	Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 2,317,288	$ -		$ 2,317,288	-$ 874,974	-$ 34,332		-$ 909,306	$ 1,407,982
13	1910	Leasehold Improvements	10.00%	$ 6,177	$ -		$ 6,177	-$ 4,503	-$ 640		-$ 5,143	$ 1,034
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 167,930	$ 15,500		$ 183,430	-$ 109,038	-$ 13,490		-$ 122,528	$ 60,902
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 744,926	$ 40,000		$ 784,926	-$ 622,322	-$ 73,552		-$ 695,874	$ 89,052
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 322,773	$ 142,500		$ 465,273	-$ 212,148	-$ 56,097		-$ 268,245	$ 197,027
12	1925	Computer Software (Smart Meters)	20.00%	$ 406,373			$ 406,373	-$ 129,885	-$ 83,500		-$ 213,385	$ 192,988
10	1930	Transportation Equipment	10% to 25%	$ 1,978,637	$ 40,000		$ 2,018,637	-$ 1,266,938	-$ 202,476		-$ 1,469,414	$ 549,223
8	1935	Stores Equipment	10.00%	$ 40,562	$ 1,000		$ 41,562	-$ 29,121	-$ 3,223		-$ 32,344	$ 9,218
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 340,724	$ 20,000		$ 360,724	-$ 216,322	-$ 29,707		-$ 246,029	$ 114,694
8	1945	Measurement & Testing Equipment	10.00%	$ 186,868	$ 2,000		$ 188,868	-$ 128,701	-$ 13,871		-$ 142,572	$ 46,296
8	1950	Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	10.00%	$ 115,927	$ 53,000		$ 168,927	-$ 67,248	-$ 12,197		-$ 79,445	$ 89,482
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	10.00%	$ 433,220	$ 5,000		$ 438,220	-$ 172,100	-$ 43,572		-$ 215,672	$ 222,548
47	1975	Load Management Controls Utility Premises	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	6.70%	$ 1,399,641	$ 100,000		$ 1,499,641	-$ 410,742	-$ 96,643		-$ 507,385	$ 992,256
45.1	1980	System Supervisor Equipment - Hardware	20.00%	$ 22,132	$ -		$ 22,132	-$ 11,161	-$ 4,426		-$ 15,587	$ 6,545
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 9,334,862	-$ 652,000		-$ 9,986,862	$ 2,288,010	$ 386,434		$ 2,674,444	-$ 7,312,417
8	2005	Property Under Capital Lease	10.00%	$ 10,039	$ -		$ 10,039	-$ 7,027	-$ 1,004		-$ 8,031	$ 2,007
N/A	2055	Work In Progress	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
		Total		**$ 80,586,791**	**$ 4,408,000**	**$ -**	**$ 84,994,791**	**-$ 28,116,378**	**-$ 3,365,842**	**$ -**	**-$ 31,482,220**	**$ 53,512,571**

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation	
Transportation	-$ 202,476
Stores & Garage Equipment	-$ 30,884
Computer HW & SW	-$ 129,649
Net Depreciation to Inc. Stmt	**-$ 3,002,834**

GROSS ASSETS TABLE:

Table 2.6: Gross Assets (CGAAP)

Description	2008 Board Approved	2008 Actual	Variance - 2008 Approved to 2008 Actual	2009 Actual	Variance - 2008 Actual to 2009 Actual	2010 Actual	Variance - 2009 Actual to 2010 Actual	2011 Bridge	Variance - 2010 Actual to 2011 Bridge	2012 Test	Variance - 2011 Bridge to 2012 Test
Land & Buildings (Distribution Plant)											
1805 Land	380,064	385,116	5,052	391,259	6,144	391,259	(0)	391,259	0	391,259	-
1806 Land Rights	302,911	300,911	(2,000)	302,784	1,873	302,784	(0)	303,784	1,000	303,784	-
1808 Buildings and Fixtures	1,530,070	1,524,961	(5,109)	1,615,717	90,757	1,620,078	4,361	1,620,078	0	1,620,078	-
SUBTOTAL LAND & BUILDINGS	**2,213,045**	**2,210,987**	**(2,058)**	**2,309,761**	**98,774**	**2,314,121**	**4,360**	**2,315,122**	**1,001**	**2,315,122**	**-**
Distribution Stations											
1815 Transformer Station Equipment	3,199,994	3,215,596	15,602	3,215,596	-	8,912,383	5,696,787	8,912,383	-	8,912,383	-
1820 Distribution Station Equipment	2,990,092	3,884,654	894,562	4,120,928	236,274	2,767,848	(1,353,080)	2,842,848	75,000	3,117,848	275,000
SUBTOTAL DISTRIBUTION STATIONS	**6,190,086**	**7,100,250**	**910,164**	**7,336,524**	**236,274**	**11,680,231**	**4,343,708**	**11,755,231**	**75,000**	**12,030,231**	**275,000**
Poles & Wires											
1830 Poles, Towers and Fixtures	18,697,529	24,691,484	5,993,955	25,698,012	1,006,528	20,857,358	(4,840,654)	22,053,733	1,196,375	23,516,733	1,463,000
1835 Overhead Conductors & Devices	9,925,797	12,983,070	3,057,273	13,715,614	732,544	11,716,783	(1,998,832)	12,566,695	849,912	13,491,695	925,000
1840 Underground Conduit	3,828,245	3,532,583	(295,662)	3,845,066	312,484	4,005,396	160,329	4,225,396	220,000	4,325,396	100,000
1845 Underground Conductors & Devices	7,467,211	7,120,863	(346,348)	7,636,026	515,163	6,686,432	(949,594)	7,074,432	388,000	7,277,432	203,000
SUBTOTAL POLES & WIRES	**39,918,782**	**48,328,000**	**8,409,218**	**50,894,719**	**2,566,720**	**43,265,968**	**(7,628,751)**	**45,920,255**	**2,654,287**	**48,611,255**	**2,691,000**
Line Transformers											
1850 Line Transformers	10,656,687	10,816,541	159,854	11,237,917	421,375	11,982,442	744,525	12,885,387	902,945	13,837,387	952,000
SUBTOTAL TRANSFORMERS	**10,656,687**	**10,816,541**	**159,854**	**11,237,917**	**421,375**	**11,982,442**	**744,525**	**12,885,387**	**902,945**	**13,837,387**	**952,000**
Services & Meters											
1855 Services	2,245,317	2,230,186	(15,131)	2,507,308	277,121	2,778,384	271,076	3,046,493	268,109	3,421,493	375,000
1860 Meters	4,523,474	3,891,529	(631,945)	4,025,165	133,636	4,157,134	131,969	4,229,133	71,999	2,396,302	(1,832,831)
1860 Smart Meters	-	-	-	-	-	-	-	-	-	3,214,012	3,214,012
SUBTOTAL SERVICES & METERS	**6,768,791**	**6,121,716**	**(647,075)**	**6,532,473**	**410,757**	**6,935,518**	**403,045**	**7,275,625**	**340,107**	**9,031,806**	**1,756,181**
Land & Buildings (General Plant)											
1905 Land	236,830	243,636	6,806	243,636	-	243,636	0	243,636	(0)	243,636	-
1908 Buildings and Fixtures	2,209,188	2,189,477	(19,711)	2,215,638	26,161	2,307,289	91,651	2,317,288	9,999	2,317,288	-
1910 Leasehold Improvements	11,177	6,177	(5,000)	6,177	-	6,177	-	6,177	-	6,177	-
SUBTOTAL LAND & BUILDINGS (G.P.)	**2,457,195**	**2,439,290**	**(17,905)**	**2,465,451**	**26,161**	**2,557,102**	**91,651**	**2,567,101**	**9,998**	**2,567,101**	**-**
I/T Assets											
1920 Computer Equipment - Hardware	626,816	1,256,300	629,484	1,280,299	23,999	714,926	(565,373)	744,926	30,000	784,926	40,000
1925 Computer Software	356,656	350,963	(5,693)	406,997	56,034	295,773	(111,225)	322,773	27,000	465,273	142,500
1925 Computer Software - Smart Meters	-	-	-	-	-	-	-	-	-	406,373	406,373
SUBTOTAL I/T ASSETS	**983,472**	**1,607,263**	**623,791**	**1,687,296**	**80,033**	**1,010,699**	**(676,598)**	**1,067,699**	**57,000**	**1,656,572**	**588,873**
Equipment											
1915 Office Furniture and Equipment	163,706	407,613	243,907	411,687	4,075	152,930	(258,757)	167,930	15,000	183,430	15,500
1930 Transportation Equipment	1,490,157	2,267,042	776,885	2,122,603	(144,439)	1,538,637	(583,966)	1,978,637	440,000	2,018,637	40,000
1935 Stores Equipment	44,068	120,021	75,953	120,335	314	39,562	(80,773)	40,562	1,000	41,562	1,000
1940 Tools, Shop and Garage Equipment	277,866	709,787	431,921	727,933	18,146	317,724	(410,209)	340,724	23,000	360,724	20,000
1945 Measurement and Testing Equipment	193,041	162,717	(30,324)	178,973	16,256	180,868	1,895	186,868	6,000	188,868	2,000
1955 Communication Equipment	112,931	106,906	(6,025)	106,906	-	107,927	1,021	115,927	8,000	168,927	53,000
1960 Miscellaneous Equipment	151,827	168,061	16,234	412,334	244,273	428,220	15,885	433,220	5,000	438,220	5,000
1970 Load Mgmt Controls - Customer Premises	88,276	16,565	(71,711)	16,565	-	-	(16,565)	-	-	-	-
2005 Property under Capital Lease	10,039	10,039	-	10,039	-	10,039	-	10,039	-	10,039	-
SUBTOTAL EQUIPMENT	**2,531,911**	**3,968,751**	**1,436,840**	**4,107,376**	**138,625**	**2,775,906**	**(1,331,470)**	**3,273,906**	**498,000**	**3,410,406**	**136,500**
Other Distribution Assets											
1980 System Supervisory Equipment	748,152	622,036	(126,116)	626,609	4,573	1,176,773	550,164	1,421,773	245,000	1,521,773	100,000
1995 Contributions and Grants	(6,196,930)	(7,122,607)	(925,677)	(7,654,021)	(531,414)	(8,473,522)	(819,501)	(9,334,862)	(861,340)	(9,986,862)	(652,000)
2055 Work in Process	-	-	-	5,472,038	5,472,038	-	(5,472,038)	-	-	-	-
SUBTOTAL OTHER DISTRIBUTION ASSETS	**(5,448,778)**	**(6,500,571)**	**(1,051,793)**	**(1,555,373)**	**4,945,197**	**(7,296,749)**	**(5,741,376)**	**(7,913,089)**	**(616,340)**	**(8,465,089)**	**(552,000)**
TOTAL GROSS FIXED ASSETS	**66,271,191**	**76,092,228**	**9,821,037**	**85,016,143**	**8,923,915**	**75,225,238**	**(9,790,905)**	**79,147,238**	**3,921,999**	**84,994,792**	**5,847,554**

VARIANCE ANALYSIS ON GROSS ASSETS:

The Gross Asset Variance analysis for the variances highlighted in Table 2.6 of Exhibit 2, Tab 2, Schedule 2 is provided as follows.

2008 Board Approved vs. 2008 Actual

The 2008 Board Approved Fixed Asset value was based on the removal of $11,482,996 of fully depreciated assets which were removed by Norfolk for the 2008 rate application, but not removed from Norfolk's financial records. As a result of change in management subsequent to the last cost of service application this amount was not written off until 2010. The $11,482,996 was offset by lower capital spending than approved of $1,661,961.

2008 Actual vs. 2009 Actual

The variances in gross assets for 2008 Actual compared to 2009 Actual are the result of capital expenditures in 2009, and disposal of vehicles sold during the year (total gross book value of $144,439).

2009 Actual vs. 2010 Actual

The variances in gross assets for 2009 Actual compared to 2010 Actual are the result of writing off a back log of fully depreciated assets of $13,142,235 ($11,482,996 pre 2008, remainder 2008 thru 2010), offset by capital expenditures in 2010.

2010 Actual vs. 2011 Bridge Year

The increase of $3,921,999 for 2011 is a result of capital spending during the year.

2011 Bridge Year vs. 2012 Test Year

The variances in gross assets for the 2011 Bridge Year compared to the 2012 Test Year are the result of capital expenditures in 2012 (total capital expenditures in 2012 - $4,776,000), plus the addition of Smart Meters $3,620,385 to the opening balance, less stranded assets of $2,180,831.

ACCUMULATED AMORTIZATION TABLE:

Table 2.7 - Accumulated Amortization

Description	2008 Board Approved	2008 Actual	Variance - 2008 Approved to 2008 Actual	2009 Actual	Variance - 2008 Actual to 2009 Actual	2010 Actual	Variance - 2009 Actual to 2010 Actual	2011 Bridge	Variance - 2010 Actual to 2011 Bridge	2012 Test	Variance - 2011 Bridge to 2012 Test
Land & Buildings (Distribution Plant)											
1805 Land	-	-	-	-	-	-	-	-	-	-	-
1806 Land Rights	24,153	-	(24,153)	-	-	-	-	-	-	-	-
1808 Buildings and Fixtures	116,962	117,551	589	149,865	32,314	180,575	30,709	212,976	32,402	245,378	32,402
SUBTOTAL LAND & BUILDINGS	**141,115**	**117,551**	**(23,564)**	**149,865**	**32,314**	**180,575**	**30,709**	**212,976**	**32,402**	**245,378**	**32,402**
Distribution Stations											
1815 Transformer Station Equipment NB1	289,976	297,500	7,524	377,926	80,426	524,386	146,460	747,233	222,846	970,079	222,846
1820 Distribution Station Equipment	225,653	1,594,513	1,368,860	1,691,662	97,149	363,334	(1,328,328)	452,449	89,115	547,397	94,948
SUBTOTAL DISTRIBUTION STATIONS	**515,629**	**1,892,013**	**1,376,384**	**2,069,588**	**177,575**	**887,721**	**(1,181,867)**	**1,199,682**	**311,961**	**1,517,476**	**317,794**
Poles & Wires											
1830 Poles, Towers and Fixtures	5,445,345	11,267,242	5,821,897	12,098,600	831,358	7,198,277	(4,900,323)	8,087,403	889,126	9,029,718	942,314
1835 Overhead Conductors & Devices	2,165,105	4,966,692	2,801,587	5,405,305	438,613	3,056,013	(2,349,292)	3,541,683	485,670	4,062,851	521,168
1840 Underground Conduit	1,275,476	1,237,386	(38,090)	1,373,796	136,410	1,501,837	128,041	1,649,060	147,224	1,802,684	153,624
1845 Underground Conductors & Devices	2,558,946	2,472,397	(86,549)	2,729,641	257,244	1,763,070	(966,571)	2,038,288	275,217	2,325,325	287,037
SUBTOTAL POLES & WIRES	**11,444,872**	**19,943,718**	**8,498,846**	**21,607,343**	**1,663,625**	**13,519,197**	**(8,088,146)**	**15,316,434**	**1,797,237**	**17,220,577**	**1,904,143**
Line Transformers											
1850 Line Transformers	5,478,651	5,684,971	206,320	6,212,345	527,374	6,710,564	498,220	7,062,828	352,263	7,380,233	317,405
SUBTOTAL TRANSFORMERS	**5,478,651**	**5,684,971**	**206,320**	**6,212,345**	**527,374**	**6,710,564**	**498,220**	**7,062,828**	**352,263**	**7,380,233**	**317,405**
Services & Meters											
1855 Services	319,353	332,268	12,915	432,560	100,292	520,374	87,814	636,872	116,498	766,231	129,360
1860 Meters NB2	2,056,221	2,076,566	20,344	2,229,622	153,056	2,375,136	145,515	2,534,911	159,775	1,402,451	(1,132,460)
1860 Meters ~ Smart Meters	-	-	-	-	-	-	-	-	-	693,357	693,357
SUBTOTAL SERVICES & METERS	**2,375,574**	**2,408,834**	**33,259**	**2,662,182**	**253,348**	**2,895,511**	**233,329**	**3,171,783**	**276,272**	**2,862,040**	**(309,743)**
Land & Buildings (General Plant)											
1905 Land	-	-	-	-	-	-	-	-	-	-	-
1908 Buildings and Fixtures	800,619	777,904	(22,715)	810,203	32,299	840,741	30,537	874,973	34,232	909,305	34,332
1910 Leasehold Improvements	1,304	2,585	1,281	3,225	640	3,865	640	4,504	640	5,144	640
SUBTOTAL LAND & BUILDINGS (G.P.)	**801,923**	**780,489**	**(21,434)**	**813,428**	**32,939**	**844,605**	**31,177**	**879,477**	**34,872**	**914,449**	**34,972**
I/T Assets											
1920 Computer Equipment - Hardware	458,691	975,445	516,754	1,089,265	113,820	555,769	(533,496)	622,321	66,552	695,873	73,552
1925 Computer Software	123,039	238,269	115,230	284,676	46,407	173,001	(111,675)	212,148	39,147	268,245	56,097
1925 Computer Software ~ Smart Meters	-	-	-	-	-	-	-	-	-	213,385	213,385
SUBTOTAL I/T ASSETS	**581,730**	**1,213,715**	**631,985**	**1,373,942**	**160,227**	**728,770**	**(645,171)**	**834,469**	**105,699**	**1,177,503**	**343,034**
Equipment											
1915 Office Furniture and Equipment	66,862	331,241	264,379	345,971	14,730	94,521	(251,450)	109,038	14,517	122,528	13,490
1930 Transportation Equipment	737,873	1,480,244	742,371	1,510,404	30,160	1,062,530	(447,874)	1,266,937	204,408	1,469,414	202,476
1935 Stores Equipment	17,681	98,595	80,914	102,515	3,920	25,114	(77,400)	29,121	4,006	32,344	3,223
1940 Tools, Shop and Garage Equipment	116,001	542,328	426,327	573,406	31,078	184,305	(389,101)	216,322	32,017	246,029	29,707
1945 Measurement and Testing Equipment	78,494	76,097	(2,397)	93,994	17,897	110,314	16,320	128,701	18,387	142,572	13,871
1955 Communication Equipment	53,399	37,222	(16,177)	47,913	10,691	56,055	8,143	67,248	11,193	79,445	12,197
1960 Miscellaneous Equipment	38,680	59,406	20,726	100,639	41,233	129,027	28,388	172,099	43,072	215,671	43,572
1970 Load Mgmt Controls - Customer Premises	13,855	16,565	2,710	16,565	-	-	(16,565)	-	-	-	-
2005 Property under Capital Lease	2,008	4,015	2,007	5,019	1,004	6,023	1,004	7,027	1,004	8,031	1,004
SUBTOTAL EQUIPMENT	**1,124,853**	**2,645,712**	**1,520,859**	**2,796,424**	**150,713**	**1,667,890**	**(1,128,534)**	**1,996,493**	**328,603**	**2,316,034**	**319,540**
Other Distribution Assets											
1980 System Supervisory Equipment	233,289	227,770	(5,519)	271,231	43,461	332,334	61,103	421,902	89,568	522,971	101,069
1995 Contributions and Grants	(1,263,475)	(1,340,270)	(76,795)	(1,638,433)	(298,163)	(1,931,842)	(293,409)	(2,288,010)	(356,168)	(2,674,444)	(386,434)
2055 Work in Process	-	-	-	-	-	-	-	-	-	-	-
SUBTOTAL OTHER DISTRIBUTION ASSETS	**(1,030,186)**	**(1,112,500)**	**(82,314)**	**(1,367,202)**	**(254,702)**	**(1,599,508)**	**(232,306)**	**(1,866,108)**	**(266,600)**	**(2,151,473)**	**(285,365)**
TOTAL ACCUMULATED AMORTIZATION	**21,434,161**	**33,574,501**	**12,140,340**	**36,317,914**	**2,743,413**	**25,835,324**	**(10,482,590)**	**28,808,034**	**2,972,710**	**31,482,217**	**2,674,182**

VARIANCE ANALYSIS ON ACCUMULATED AMORTIZATION:

Changes in accumulated amortization are directly affected by changes in fixed assets due to additions, the removal of fully depreciated assets from the grouped asset classes, and the disposition of identified assets.

Table 2.7 shows the changes in accumulated amortization from 2008 Actual to the 2012 Test Year. The change in accumulated amortization is a result of capital expenditures, amortization expense each year, and write-offs of fully-amortized assets as appropriate over the four year period. From 2011 to 2012, the accumulated amortization relating to Smart Meter assets transferred to rate base as of January 1, 2012 (representing $479,090 of the variance from 2011 for account 1860 Smart Meters and $129,885 for account 1925 Smart Meter Software) is considered in addition to the current year’s amortization expense. Another significant anomaly in the year-over-year variances relates to 2008 Actual vs. 2008 Board Approved. In the 2008 Cost of Service Application, NPDI indicated that it would be writing off some fully depreciated assets in various accounts. Due to a Management change, these amounts were not written off as indicated in the fixed asset continuity statements and hence the 2008 Board Approved figure does not reconcile to 2008 Actual after considering capital additions and disposals. NPDI wrote off these fully-depreciated amounts in 2010. The total amount of fully-depreciated assets written off in the year 2010 (relating to assets that were fully-depreciated assets as of December 31, 2009) was $13,142,235. These adjusted balances of gross fixed assets and accumulated amortization are reflected in the tables provided in this Exhibit). Please refer to Exhibit 4, Tab 2, Schedule 7 for details of annual amortization expense for each asset account.

CAPITAL BUDGET

Norfolk's Asset Management Plan identifies the capital projects required over a 3 year period based on the best available information for each year. The capital budget forecast is influenced significantly by condition data that is collected each year on aging infrastructure and as such, Norfolk may be required to adjust the capital project forecast as the knowledge of its system needs increases. As provided in Exhibit 2, Tab 3, Schedule 2, a significant portion of Norfolk's capital investments are customer or municipal driven. All proposed capital projects for the 2011 Bridge Year and 2012 Test Year will be completed and in service in that year. Details of Norfolk's capital budget for these periods are provided in Tables 3.2 to 3.6.

Provincial Sales Tax Impact

As a result of the implementation of HST in the province of Ontario on July 1, 2010, NPDI has considered the reduction in capital expenditures relating to the purchase of products and services due to the increased input tax credit (ITC). Neither the 2011 Bridge Year forecast nor the 2012 Test Year budget for capital expenditures includes tax on purchases of products or services made after July 1, 2010.

INTRODUCTION:

NPDI has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital spending. The capital spending for the 2011 Bridge Year and the 2012 Test year is broken down by account and by project in Exhibit 2, Tab 3, Schedule 2. Below is an analysis of NPDI's capital spending from 2008 to 2012.

Table 3.1 – Capital Spending Summary 2006 to 2012

Year	Total Distribution Plant ($)	Capital Contributions	Net Distribution Plant	General Plant	Total Capital net of Contributions	$ Increase / (Decrease)	% Increase / (Decrease)
2006	4,343,309	(886,512)	3,456,797	706,447	4,163,244	1,585,115	61%
2007	5,883,106	(994,216)	4,888,890	575,515	5,464,405	1,301,161	31%
2008	3,838,726	(331,461)	3,507,265	437,917	3,945,182	(1,519,223)	-28%
2009	9,205,936	(531,414)	8,674,522	393,832	9,068,354	5,123,172	130%
2010	3,423,518	(819,501)	2,604,017	829,591	3,433,608	(5,634,746)	-62%
2011	3,973,340	(861,340)	3,112,000	810,000	3,922,000	488,392	14%
2012	4,641,000	(652,000)	3,989,000	419,000	4,408,000	486,000	12%

* 2009 includes $5,562,793 of spending for the Bloomsburg TS which was considered Work-In-Progress at the end of 2009

The updated filing requirements for Exhibit 2 (Rate Base) request actual historical summary information for the last 5 years. Note that 2006 and 2007 expenditures are presented for informational purposes only and will not be discussed in detail in this application.

In 2008, the main driver of the decrease of 28% was a decrease in expenditures relating to the distribution system (poles, conductors, and conduit) in the amount of $1,096,000. In correlation with distribution system expenditures, there was a decrease in expenditures on transformers ($299,000 decrease over 2007 spending levels), and a decrease in expenditures on services ($47,000 decrease over 2007 spending levels).

In 2009, the main driver of the increase of 130% over 2008 spending levels was the Transformer Station T2 project. This project is discussed in further detail in Exhibit 2, Tab 3, Schedule 2 on page 32. The spending in 2009 was allocated to Work-In-Progress because T2 (the second transformer at Bloomsburg) did not go on-line until February 2010. This represents $5,472,000 of the variance over 2008. This is offset by $349,000 which is attributable to a reduction in the expenditures on various distribution system components (poles, conductors, conduit, transformers & services) as compared to 2008.

In 2010 Norfolk's capital expenditures reduced significantly with the completion of the second transformer at the Bloomsburg Transformer Station. This represents a reduction of approximately $5.2M over 2009 spending levels.

For 2011 and 2012 Norfolk is planning a number of projects to update its aging infrastructure. Variances are due to the timing of scheduled projects. Tab 3, Schedule 2 provides details of all projects for both years.

The capital spending numbers reported above in Table 3.1 are excluding all amounts of smart meter spending. These expenditures are discussed in Exhibit 9. The expenses in Table 3.1 are also exclusive of spending required to meet the needs of the Green Energy Act. These expenses are discussed as part of Norfolk's Green Energy Plan which can be found in Exhibit 2, Appendix C.

CAPITAL PROJECTS BY YEAR AND USoA:

The tables below summarize NPDI’s actual investment in construction projects for the years 2008, 2009, 2010 plus projects for the 2011 Bridge Year and 2012 Test Year. Project descriptions are also provided.

Table 3.2 - 2008 Capital Projects

DISTRIBUTION PLANT												
Category	**Reference Number**	**Total**	**Land Rights (1806)**	**TS Equip. (1815) & Building (1808)**	**DS Equip. (1820)**	**Poles (1830)**	**OH Cond. (1835)**	**Conduit (1840)**	**UG Cond. (1845)**	**Trans. (1850)**	**Services (1855)**	**Meters (1860) (1555)**
Trans Station	1	206,304		206,304								
Substations	2	125,572			125,572							
Substations	3	312,423			312,423							
Substations	4	53,681			53,681							
Renewal	5	564,847				212,947	272,821		8,473	70,606		
Renewal	6	81,080				18,973	26,270	2,108	33,729			
Renewal	7	152,333				68,550	83,783					
Renewal	8	84,396				14,769	51,904			17,723		
Renewal	9	67,309				14,135	53,174					
Renewal	10	56,182				2,472	52,699			1,011		
Renewal	11	223,826				223,826						
Renewal	12	677,476	695		4,142	244,171	216,640	21,639	76,888	93,907	19,068	326
Regulatory	13	60,936				18,281	42,655					
Cust. Demand	14	87,509				6,476	63,619			9,626	7,788	
Cust. Demand	15	257,491									257,491	
Cust. Demand	16	104,883					2,507	30,565	57,578	13,239	994	
Transformers	17	534,960								534,960		
Meters	18	187,518										187,518
Subtotal		3,838,726	695	206,304	495,818	824,600	866,072	54,312	176,668	741,072	285,341	187,844
Contributed Capital (1995)		**(331,461)**										
Total Dist.Plant Capital Expend		**3,507,265**	**695**	**206,304**	**495,818**	**824,600**	**866,072**	**54,312**	**176,668**	**741,072**	**285,341**	**187,844**

GENERAL PLANT											
Category	**Reference Number**	**Total**	**Land (1905)**	**Serv. Ctre. Bldg. (1908)**	**Office Equip. (1915)**	**Comp. Hardware (1920)**	**Comp Software (1925)**	**Trucks (1930)**	**Tools and Equipment (1935) (1940) (1945) (1955) (1960)**	**SCADA Equip (1980) (1981)**	**Commun. Equip. (1955)**
Land	19	769	769								
Facilities	20	68,786		68,786							
Office Equip	21	15,427			15,427						
Computer HW	22	179,865				179,865					
Computer SW	23	20,104					20,104				
Computer SW	24	14,272					14,272				
Trucks	25	21,419						21,419			
Trucks	26	8,866						8,866			
Tools & Equip.	27	74,638							74,638		
Communication Equip	28	23,816									23,816
SCADA	29	9,955								9,955	
Total		**437,917**	**769**	**68,786**	**15,427**	**179,865**	**34,376**	**30,285**	**74,638**	**9,955**	**23,816**
Total Capital Expenditures		**3,945,181**									

DISTRIBUTION PLANT PROJECTS

TRANSFORMER STATION

2008 Project #1 – Upgrade Building at Bloomsburg MTS and Design for 2nd Transformer

Cost: $206,304 (Account 1808 - $74,090; 1815 - $132,214)

Need: With the planned 2009 expansion of Bloomsburg MTS there was a need in 2008 to upgrade the station building to provide washrooms and proper task lighting as well as upgrade heating and air conditioning. In addition, it was necessary to complete the design specifications for the additional transformer, complete engineering studies and drafting as required and issue the purchase order in a timely manner taking into account manufacturing time and delivery.

Scope: Consultants were hired for project management, engineering and drafting etc. The project was planned and purchase orders issued as required. A security deposit of $74,980 was required by the manufacturer and included with the purchase order.

The building upgrades included construction of washroom facilities ($24,795) security cameras ($12,897) and HVAC upgrades ($19,434). Project management ($39,692).

SUBSTATIONS

2008 Project # 2 – Miscellaneous Substation Equipment Projects

Cost: $125,572 (Account 1820)

Need: This expenditure includes urgent and necessary substation projects. Grounding at NP10 DS required replacement for safety. Switchgear at NP3 DS was in poor condition, unreliable and in need of refurbishment. Other minor miscellaneous capital substation projects are also included. All individual projects are under materiality.

Scope: Complete projects as required.

2008 Project # 3 – Complete Mobile Substation Transformer

Cost: $312,423 (Account 1820)

Need: Due to the age of Norfolk's substations and the lack of available resources to provide back-up transformation in the event of an unforseen failure, a mobile DS transformer was designed and procured.

Scope: Complete construction and commissioning of the mobile DS transformer.

2008 Project # 4 – Complete New Customer-Specific Substation

Cost: $53,681 (Account 1820)

Need: This expenditure was necessary to complete a new customer-specific substation constructed in 2007 to meet new industrial growth on the outskirts of Simcoe.

Scope: Provide and install miscellaneous equipment as required to complete the station.

RENEWAL

2008 Project #5 - Rebuild Line on Hillcrest Road in Simcoe

Cost: $564,847 (Accounts 1830 - $212,947; 1835 - $272,821; 1845 - $8,473; 1850 - $70,606)

Need: Pole line was deteriorated and in poor condition. Priority rebuild based on results of pole test program and visual inspection. In addition, the 8 kV distribution was upgraded to 27.6 kV to accommodate load growth.

Scope: The replacement of approximately 45 poles, 3 km of conductor including transformer installation costs. A step-down transformer was eliminated as it was limiting growth due to inadequate capacity. The 8 kV circuit was upgraded to 27.6 kV.

2008 Project #6 - Rebuild Egress of NP4 DS

Cost: $81,080 (Accounts 1830 - $18,973; 1835 - $26,270; 1840 - $2,108; 1845 - $33,729)

Need: Priority rebuild required based on results of pole test program and visual inspection. Norfolk expects improvement in system reliability and performance indices plus reduction in maintenance costs, consistent with having new plant in use.

Scope: Convert overhead egress to underground in compliance with current standards and replace small section of triple circuit overhead pole line adjacent to station. Egress includes 2 UG circuits (8 conductors) plus 5 poles from station boundary to adjacent feeder lines.

2008 Project #7 – Rebuild Lynn Park Drive to Norfolk Street

Cost: $152,333 (Accounts 1830 - $68,550; 1835 - $83,783)

Need: Priority rebuild required as per results of pole test program and visual inspection. Expect improvement in system reliability and performance indices plus reduction in maintenance costs, consistent with having new plant in use.

Scope: Replacement of 5 poles, 5 transformers and related conductors.

2008 Project #8 – Rebuild Auty Street – Waterford

Cost: $84,396 (Accounts 1830 - $14,769; 1835 - $51,904; 1850 - $17,723)

Need: Priority rebuild required as per results of pole test program and visual inspection. Expect improvement in system reliability and performance indices plus reduction in maintenance costs, consistent with having new plant in use. Consideration was given to constructing line in conjunction with County initiative to rebuild the road and to convert to 27.6 kV.

Scope: Replace and upgrade 6 poles and 400 meters of primary and secondary conductor plus related transformation costs.

2008 Project #9 – Extend M5/M6 Feeder at Norfolk TS Concession 13 to Accommodate Supply to Port Dover

Cost: $67,309 (Accounts 1830 - $14,135; 1835 - $53,174)

Need: Norfolk recognized low voltage and inadequate capacity problems in the Port Dover area and was obliged to improve supply to comply with current standards and meet customer expectations, demand and load growth. This work was completed in coordination with the acquisition of redundant Hydro One feeder circuits in 2007 to enable a backup to the Port Dover area.

Scope: Constructed new overhead feeder line (approx. 3 pole spans) to tie from existing feeder line on right of way, south of Concession 13 to existing pole line on Concession 13. This work resulted in extending the 22M5 feeder from Norfolk TS to the east side of Port Dover.

2008 Project #10 – Rebuild Evergreen Hill Road – Simcoe

Cost: $56,182 (Accounts 1830 - $2,472; 1835 - $52,699; 1850 - $1,011)

Need: Completion of Evergreen Hill road rebuild and removal of old line which was a safety concern. Removing the surplus circuit also alleviated the need to replace 2 poles to accommodate new riser pole standards.

Scope: Remove redundant 3 phase conductor.

2008 Project #11 - Pole Replacement Program

Cost: $223,826 (Account 1830)

Need: Deteriorated poles at the end of their useful life in need of replacement before becoming a safety hazard to the public and/or plant failure resulting in related power outages and high cost of emergency repair or replacement. Poles were identified as high priority through test and treatment program.

Scope: In 2008 approximately 45 priority poles were replaced.

2008 Project #12 – Miscellaneous Projects (Each Under Materiality)

Cost: $677,476 (Accounts: 1806 - $695; 1820 - $4,142; 1830 - $244,171; 1835 - $216,640; 1840 - $21,639; 1845 $76,888; 1850 $93,907; 1855 $19,068; 1860 - $326)

Need: Provision for urgent and necessary equipment replacement identified as a result of routine system inspections and customer service calls. Reactive renewal of assets with a “run to failure” replacement strategy are included in this category (eg.

distribution transformers, underground cable). This category also includes replacement or adjustment to distribution system plant as required to accommodate customer demand work.

Scope: Multiple small construction jobs completed throughout the year. Expenditure represents many small construction jobs under $50,000 materiality.

REGULATORY

2008 Project #13 – Plant Relocation for Road Widening – Brant Hill

Cost: $60,936 (Accounts 1830 - $18,281; 1835 - $42,655)

Need: Where road widening projects are required as a result of municipal infrastructure development, Norfolk follows the *Public Service Works on Highways Act, 1990* and related regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital from the municipality for 50% of labour and vehicle cost.

Scope: Relocate poles and related conductors as required.

CUSTOMER DEMAND

2008 Project # 14 - Service Upgrade to Our Lady Queen of Martyrs Church

Cost: $87,509 (Accounts 1830 - $6,476; 1835 - $63,619; 1850 - $9,626; 1855 - $7,788)

Need: Norfolk is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Related contributed capital is determined using the Economic Evaluation Calculation as required by the DSC.

Scope: Upgrade 1 phase line to 3 phase to accommodate upgraded service at the Church. (Replace 6 poles plus conductor and transformer bank).

2008 Project #15 - New Services and Service Upgrades

Cost: $257,491 (Account 1855)

Need: Norfolk is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions for connection assets are charged for commercial / industrial services in accordance with NPDI’s Conditions of Service.

Scope: During 2008, 183 new customers were connected.

2008 Project #16 - Subdivision Development

Cost: $104,883 (Accounts 1835 - $2,507; 1840 - $30,565; 1845 - $57,578; 1850 - $13,239; 1855 - $994)

Need: Norfolk is obligated under the DSC to provide and connect distribution systems for new subdivisions that are funded through contributed capital. If the distribution system is constructed by the Developer (to specified standards) the account represents the cost of line extensions and plant alterations to connect new subdivisions. (Related contributed capital is recorded separately in compliance with NPDI Conditions of Service and Economic Valuation Calculation.)

Scope: Miscellaneous line construction to connect new subdivisions.

TRANSFORMERS

2008 Project # 17 - Transformers for Installation and Inventory

Cost: $534,960 (Account 1850)

Need: In compliance with OEB accounting guidelines, capitalizes transformers at the time they are purchased rather than when installed. As a result prior to 2011 transformers were not recorded to a specific project. This expenditure represents the purchased cost of transformers for installation or inventory.

Scope: Transformers are purchased throughout the year in anticipation of timing of future expected use to service new subdivisions and renewal projects including PCB transformer replacement and prudent backup requirements.

METERS

2008 Project # 18 - Meter Installations

Cost: $187,518 (Accounts 1860)

Need: Supply and installation of meters is required to meet customer demand for new services in compliance with Norfolk's Conditions of Service and regulatory requirements.

Scope: Purchase and install meters as required to meet customer demand.

CAPITAL CONTRIBUTIONS

Source of Funds: $ 331,461 (Account 1995)

Need: Norfolk must have a sufficient source of funds to finance capital expenditures.

Scope: Capital contributions from Developers and others is a significant source of funds for Norfolk. Capital contributions are charged in compliance with the Conditions of Service using the Economic Evaluation Calculation as required by the DSC. Where a Developer constructs a new underground distribution system for a subdivision, Norfolk calculates and pays a rebate to the Developer as new customer services are connected.

GENERAL PLANT

2008 Project #19 – Land Upgrade Employee Parking

Cost $ 769 (Account 1905)

Need Additional modifications to land to accommodate extended employee parking.

Scope As required (under materiality).

2008 Project #20 – Facilities

Cost:	$68,786	(Account 1908)

Need: Air quality in stock room was found to be poor and in need of priority improvement for health and safety reasons. Security at the service centre was also found to be inadequate and in need of improvement. The doorway to some office areas were open to the public area of the office. This was considered a safety and security risk.

Scope: Add air handling equipment to stock room to improve air quality as required. Add a key pad security system to the service centre to limit and control access to the building and various internal departments. Renovate access to the Administrative Assistant's office to move the door from the public area to the executive foyer adjacent to the CEO office. Other small projects as required.

2008 Project #21 - Office Furniture and Equipment

Cost:	$15,427	(Account 1915)

Need: Miscellaneous office equipment and furniture found to be obsolete and in need of replacement.

Scope: Miscellaneous purchases in compliance with Norfolk purchasing policy including a work station for the control room and filing cabinets for the Accounting Department.

2008 Project #22 – Computer Hardware

Cost: $179,865 (Account 1920)

Need: NPDI recognizes the need to keep current with computer technology to meet operating and regulatory requirements and to replace existing equipment that is obsolete and inadequate for required applications.

Computer hardware is used by all departments and is essential to the business of NPDI. Upgrades are based on business software applications approved by management or required by software vendors. Every reasonable effort is made to extend the life of computer hardware through prudent deployment practices.

Scope: This includes $147,109 to capitalize the lease of a main frame computer (AS 400) in compliance with OEB accounting guide and external Auditors. The balance of $32,756 is for laptop replacements ($12,286) iXP hardware ($7,230) projection equipment for Board Room ($6,236) and miscellaneous.

2008 Project #23 – Computer Software - Miscellaneous

Cost: $20,104 (Account 1925)

Need: Upgrade and replace obsolete software to keep current with the applications needed to retain operating efficiency. It is also necessary to pay for user licenses as required.

Scope: Purchase and install programs as required including $9,300 for Data Base program for asset management and $6,858 for GIS software, as well as other miscellaneous.

2008 Project #24 – Computer Software re: Disaster Recovery

Cost: $14,272 (Account 1925)

Need: Norfolk recognized a due diligence obligation to provide capability to recover from "disasters" such as fire, flood or vandalism etc. that would risk computerized business information and operating capabilities including customer records and billing, etc.

Scope: Acquire and install disaster recovery programs and related hot site requirements. Document as required and train staff.

2008 Project #25 – Pole Trailer

Cost: **$** 21,419 (Account 1930)

Need: New pole trailer required to improve operating efficiency.

Scope: Purchase pole trailer as required.

2008 Project #26 – Upgrade Pole Trailer

Cost: $8,866 (Accounts 1930)

Need: Pole trailer needed to carry longer poles.

Scope: Upgrade existing pole trailer #80 to accommodate need to transport longer poles.

2008 Project #27 – Tools and Equipment

Cost: $74,638 (Accounts 1935 - $1,325; 1940 - $32,817; 1945 - $12,576; 1955 - $16,041; 1960 - $11,879)

Need: On a regular basis it is necessary to replace tools and equipment consumed or worn out during daily use. In addition, miscellaneous testing equipment is added as required.

Scope: Miscellaneous tools and equipment are acquired as needed subject to management approval and Norfolk purchasing policy. Specifics include a line and load adapter, ground cables, 35 kVA jumpers, P&C test equipment, lineman tools for new apprentices, primary voltage recorders, meter warm up board, karabiners for pole top rescue etc.

2008 Project #28 – Geographical Positioning System (GPS) for Fleet

Cost: $ 23,816 (Account 1955)

Need: A GPS was required to provide information on location of fleet vehicles for informational, tracking, and outage support purposes.

Scope: Purchase GPS software and provide user training.

2008 Project #29 – SCADA Upgrades

Cost: $9,955 (Account 1981)

Need:	SCADA base station did not have a dedicated backup power supply needed to keep SCADA operating during power outages affecting the control room. SCADA information and remote control capability is essential during power outages to expedite restoration.
Scope:	Purchase and installation of backup power supply for dedicated use by the SCADA base station in Norfolk's control room.

1 Table 3.3 - 2009 Capital Projects

DISTRIBUTION PLANT												
Category	**Reference Number**	**Total**	**Land & Land Rights (1805 &**	**TS Equip. (1815/2055 & Building 1808)**	**DS Equipment (1820)**	**Poles (1830)**	**OH Cond. (1835)**	**Conduit (1840)**	**UG Cond. (1845)**	**Trans. (1850)**	**Services (1855)**	**Meters (1860) (1555)**
Trans Station	1	5,562,793		5,562,793								
Substations	2	197,935			197,935							
Security	3	456,549				166,184	269,364			21,001		
Security	4	395,655						158,262	237,393			
Renewal	5	168,176				64,075	82,113		687	21,301		
Renewal	6	441,799				438,133	803			2,863		
Renewal	7	837,854	8,015		38,339	251,397	195,714	90,558	129,616	94,851	29,364	
Regulatory	8	285,440				61,010	137,713			59,025	27,692	
Cust. Dem.	9	358,166				25,730	46,838	63,665	147,467	64,146	10,320	
Cust. Dem.	10	209,747									209,747	
Transformers	11	158,190								158,190		
Meters	12	133,632										133,632
Subtotal		**9,205,936**	**8,015**	**5,562,793**	**236,274**	**1,006,529**	**732,545**	**312,485**	**515,163**	**421,377**	**277,123**	**133,632**
Contributed Capital (1995)		**(531,414)**										
Total Dist.Plant Capital Expend		**8,674,522**	**8,015**	**5,562,793**	**236,274**	**1,006,529**	**732,545**	**312,485**	**515,163**	**421,377**	**277,123**	**133,632**

GENERAL PLANT											
Category	**Reference Number**	**Total**	**Land (1905)**	**Serv. Ctre. Bldg. (1908)**	**Office Equip. (1915)**	**Comp. Hardware (1920)**	**Comp Software (1925)**	**Trucks (1930)**	**Tools and Equipment (1935) (1940) (1945) (1955) (1960)**	**SCADA Equip (1980) (1981)**	**Commun. Equip. (1955)**
Land	n/a										
Facilities	13	6,315		6,315							
Facilities	14	19,846		19,846							
Office Equip	15	4,075			4,075						
Computer HW	16	24,000				24,000					
Computer SW	17	51,029					51,029				
Computer SW	18	5,005					5,005				
Trucks	n/a										
Tools & Equip.	19	44,415							44,415		
Tools & Equip	20	192,875							192,875		
Tools & Equip	21	41,700							41,700		
Commun Equip	n/a										
SCADA	22	4,572								4,572	
Total General Plant Capital Expenditures		**393,832**		**26,161**	**4,075**	**24,000**	**56,034**		**278,990**	**4,572**	

Total Capital Expenditures **9,068,354**

DISTRIBUTION PLANT PROJECTS

TRANSFORMER STATION

2009 Project #1 – Add 2nd Transformer at Bloomsburg MTS

Cost: $5,562,793 (Accounts 2055 - $5,472,037; 1808 - $90,756)

Need: Completion of the Bloomsburg MTS which began in 2004. The first transformer was completed in 2005 and added to Rate Base in 2006. The addition of the 2nd transformer was necessary for the following reasons:

- Provide backup to the original transformer and complete the station as designed to provide the standard dual element spot network (DESN) capability for system security.
- Provide capacity for long term growth in Norfolk’s service territory and accommodate need to add and extend feeders to meet customer demand.
- Specifically, the second transformer was required to provide voltage support to Port Dover and surrounding area that was experiencing considerable low voltage problems and limited supply from the Jarvis TS (owned by Hydro One and embedded in Haldimand Hydro territory).

Scope: This is a major construction project which was contracted out in compliance with Norfolk purchasing policy. Some planning and ordering of major components took place in 2008 with the bulk of the construction completed in 2009 and residual commissioning and in service checks carried forward to 2010.

SUBSTATIONS

2009 Project # 2 – Replace Obsolete Transformers at NP4 DS

Cost: $197,935 (Account 1820)

Need: The transformers at NP4 DS were in poor condition at 59 years of age and in need of replacement. The 3 single phase transformers in service were leaking and in poor condition. Priority replacement was required and the design upgraded to current standards.

Scope: A single three phase transformer which was surplus to NP7 DS was refurbished and installed at the NP4 DS. The existing steel structure was also refurbished. This action provided a needed upgrade at minimal cost and took advantage of surplus equipment.

SECURITY

2009 Project # 3 – Add Feeder Bloomsburg MTS Cloet Rd. to Regional Rd. 24

Cost: $456,549 (Accounts 1830 - $166,184; 1835 - $269,364; 1850 - $21,001)

Need: A new feeder was required to facilitate efficient utilization and access to the increased capacity of the Bloomsburg MTS.

Scope: This project included the construction of a new 2.5 km feeder extension with 45 new poles. Conductor configuration included 1 km of 27.6 kV double circuit with provision for a third circuit plus a 1.5 km single circuit with provision for a second circuit. This project also included the installation cost associated with 5 distribution transformers.

2009 Project # 4 – Add New Egress at Bloomsburg MTS

Cost: $395,655 (Accounts 1840 - $158,262; 1845 - $237,393)

Need: A new underground egress was required to facilitate efficient utilization and access to the increased capacity of the Bloomsburg MTS. See Project #1 above for related narrative.

Scope: This project facilitates new underground egress construction including new duct structure for two 27.6 kV feeder circuits plus five 65 foot class 1 riser poles and associated hardware with provision for 3 circuits. This project also included terminations both inside and outside the station.

RENEWAL

2009 Project #5 - Rebuild Area of Owen St., Woodhouse and Patterson St. (Simcoe)

Cost: $168,176 (Accounts 1830 - $64,075; 1835 - $82,113; 1845 - $687; 1850 - $21,301)

Need: Pole line was deteriorated and in poor condition. Priority rebuild required per results of pole test program and visual inspection. Removal of PCB contaminated transformers also included.

Scope: The replacement of 19 poles and elimination of 12 poles plus installation of new primary and secondary conductor and installation of 9 distribution transformers.

2009 Project #6 - Pole Replacement Program

Cost: $441,798 (Accounts 1830 - $438,133; 1835 - $803; 1850 - $2,863)

Need: Deteriorated poles at the end of their useful lives in need of replacement before becoming a safety hazard to the public and/or plant failure resulting in related power outages and high cost of emergency repair or replacement. Poles were identified as high priority through test and treatment program and field inspections.

Scope: For 2009 approximately 90 priority poles were replaced.

2009 Project #7 – Miscellaneous Projects (Each under Materiality)

Cost: $837,854 (Accounts 1805/1806 - $8,015; 1820 - $38,339; 1830 - $251,397; 1835 - $195,714; 1840 $90,558; 1845 $129,616; 1850 $94,851; 1855 - $29,364)

Need: Provision for urgent and necessary equipment replacement identified as a result of routine system inspections and customer service calls. Reactive renewal of assets with a “run to failure” replacement strategy are included in this category (eg. distribution transformers, underground cable). This category also includes replacement or adjustment to distribution system plant as required to accommodate customer demand work.

Scope: Multiple small construction jobs completed throughout the year. Expenditure represents many small construction jobs under $50,000 materiality.

REGULATORY

2009 Project #8 – Rebuild Ann & Main Streets Delhi (Joint Use)

Cost: $285,440 (Accounts 1830 - $61,010; 1835 - $137,713; 1850 - $59,025; 1855 - $27,692)

Need: Priority rebuild required to comply with joint use obligation to accommodate Hydro One initiative to relocate line from back lot to street.

Scope: Relocate or upgrade 23 poles as required and relocate 8 kV feeder and 11 distribution transformers.

CUSTOMER DEMAND

2009 Project # 9 - Subdivision Development

Cost: $358,166 (Accounts 1830 - $25,730; 1835 - $46,838; 1840 - $63,665; 1845 - $147,467; 1850 - $64,146; 1855 - $10,320)

Need: Norfolk is obligated under the DSC to provide and connect distribution systems for new subdivisions that are funded through contributed capital. The account represents the cost of line extensions and plant alterations to connect new subdivisions. (Related contributed capital is recorded separately in compliance with the Conditions of Service and Economic Valuation Calculation.)

Scope: Miscellaneous line construction to connect new subdivisions.

2009 Project #10 - New Services and Service Upgrades

Cost: $209,747 (Account 1855)

Need: Norfolk is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions for connection assets are collected for commercial / industrial services in accordance with Norfolk's Conditions of Service.

Scope: During 2009, 141 new customers were connected.

TRANSFORMERS

2009 Project # 11 - Purchase Transformers for Inventory

Cost: $158,190 (Account 1850)

Need: In compliance with OEB accounting guidelines, capitalizes transformers at the time they are purchased rather than when installed. As a result prior to 2011 transformers were not recorded to a specific project. This expenditure represents the purchased cost of transformers for installation or inventory.

Scope: Transformers are purchased throughout the year in anticipation of future expected use to service new subdivisions and renewal projects including PCB transformer replacement and prudent backup requirements.

2009 Project # 12 - Meter Installations

Cost: $133,632 (Accounts 1860 - $133,632)

Need: Supply of meters for commercial customers, as required for new services, upgrades and other replacement.

Scope: Conventional meters as required. Expenses for smart meters are recorded in Account 1555 and discussed in Exhibit 9.

CAPITAL CONTRIBUTIONS

Source of Funds: $ 531,414 (Account 1995)

Need: Norfolk must have a sufficient source of funds to finance capital expenditures.

Scope: Capital contributions are charged in compliance with Norfolk's Conditions of Service using the Economic Evaluation Calculation as required by the DSC. Where a Developer constructs a new underground distribution system for a subdivision, Norfolk calculates and pays a rebate to the Developer as new customer services are connected.

GENERAL PLANT

2009 Project #13 – HVAC Upgrades for Computer Room

Cost: $6,315 (Account 1908)

Need: Air conditioning for computer room was unreliable. Quality air conditioning is essential for operation of main frame computer (AS 400).

Scope: Replace HVAC unit.

2009 Project #14 – Office Renovations – Service Centre

Cost: $19,846 (Account 1908)

Need: Boardroom not equipped to use modern technology necessary to accommodate use of various media for effective presentations and communications

Scope: Modify electrical supply and media cabling etc. to accommodate new technology.

2009 Project #15- Office Furniture & Equipment

Cost: $4,075 (Account 1915)

Need: Misc. furniture and equipment was obsolete and did not accommodate computerized work environments.

Scope: Replace furniture and equipment as required.

2009 Project #16 – Computer Hardware

Cost: $24,000 (Account 1920)

Need: NPDI recognizes the need to keep current with computer technology to meet operating and regulatory requirements and to replace existing equipment that is obsolete and inadequate for required applications.

Computer hardware is used by all departments and is essential to the business of NPDI. Upgrades are based on business software applications approved by management or required by software vendors. Every reasonable effort is made to extend the life of computer hardware through prudent deployment practices.

Scope: Laptop replacements ($13,319), monitor replacements ($5,375) UPS ($1,533) and miscellaneous as required.

2009 Project #17 – Computer Software - Daffron iXP Upgrade

Cost: $51,029 (Accounts 1925)

Need: Norfolk financial and reporting software is obsolete resulting in a growing amount of manual work required to gather and report financial and regulatory information to various stakeholders.

Scope: Norfolk enterprise information service provider is “Daffron” corporation who provides an upgrade to the current Daffron financial systems. This expenditure was for the initial startup costs associated with the iXP program. Full rollout is delayed until 2012.

2009 Project #18 - Miscellaneous Computer Software

Cost: $5,005 (Account 1925)

Need: Keep current with vendor software upgrades and pay for annual program user license fees.

Scope: Misc. programs include Windows Server Enterprise, Vision Pro, AutoCAD and miscellaneous.

2009 Project #19 –Miscellaneous Tools and Equipment

Cost: $44,415 (Accounts 1935 - $314; 1940 - $18,146; 1945 - $16,256; 1960 - $9,699)

Need: On a regular basis it is necessary to replace tools and equipment consumed or worn out during daily use. In addition, miscellaneous testing equipment is purchased as required.

Scope: Miscellaneous tools and equipment are acquired as needed subject to management approval and Norfolk's purchasing policy. Examples include: replacement of lineman tools ($17,316); transformer tester ($3,818); primary voltage recorder ($9,595); meter warm up board ($2,842); and field nomenclature ($9,462).

2009 Project #20 – Geographic Information System

Cost: $192,875 (Account 1960)

Need: Norfolk needed more detailed information about their assets in service to support asset management planning by allowing for special analysis of asset attributes. Adding a GIS System allows for the collection of special information about assets and provides key information necessary to assist in decision making.

Scope: Convert information from existing AutoCAD maps and various asset databases to new GIS platform. Attach unique ID numbers and collect GPS coordinates and attributes of all distribution system poles in NPDI's service territory

2009 Project #21 – Portable Diesel Generator

Cost: $41,700 (Account 1960)

Need: During extended power outages, station batteries run down and the station becomes inoperable**.** A portable generator is required to backup DS and Bloomsburg MTS batteries during power outages or scheduled station maintenance.

Scope: Acquire generator in compliance with Norfolk purchasing policy.

2009 Project #22 – SCADA Upgrades

Cost: $4,572 (Account 1980 - $1,875; 1981 - $2,697)

Need: SCADA base station server was becoming obsolete and an upgrade was required to meet program vendor specifications.

Scope: Replace main application server and modem ($2,697) and add SCADA equipment at Bloomsburg MTS ($1,875).

Table 3.5 - 2010 Capital Projects

DISTRIBUTION PLANT - 2010 Actual

Category	Ref. No.	2010 Actual	Land Rights (1806)	TS Building (1808)	TS Equip. (1815)	DS Equip. (1820)	Poles (1830)	OH Cond. (1835)	Conduit (1840)	UG Cond. (1845)	Trans. (1850)	Services (1855)	Meters (1860) (1555)
Trans Station	1	224,749			224,749								
Security	2	734,537					273,886	396,375			64,276		
Renewal	3	135,468					46,072	88,161	1,235				
Renewal	4	398,854					250,421	148,433					
Renewal	5	138,067							64,779	73,288			
Renewal	6	233,638					233,638						
Regulatory	7	146,205					39,010	107,195					
Cust. Demand	8	276,359							94,316	182,043			
Cust. Demand	9	271,076										271,076	
Transformers	10	680,245									680,245		
Meters	11	131,966											131,966
Total Misc. Projects Under Materiality	12	52,354		4,361		33,675	3010	11,308					
Subtotal		3,423,518	0	4,361	224,749	33,675	846,037	751,472	160,330	255,331	744,521	271,076	131,966
Contributed Capital (1995)		(819,501)											
Total Dist.Plant Capital Expend		2,604,017											

GENERAL PLANT - 2010 Actual

Category	Ref. No.	Total	Land (1905)	Serv. Ctre. Bldg. (1908)	Office Equip. (1915)	Comp. Hardware (1920)	Comp Software (1925)	Trucks (1930)	Tools and Equipment (1935) (1940) (1945) (1960)	SCADA Equip (1980) (1981)	Commun. Equip. (1955)
Land		0	0								
Facilities	13	91,650		91,650							
Office Equip	14	5,958			5,958						
Computer HW	15	44,046				44,046					
Computer SW	16	35,884					35,884				
Trucks	17	75,784						75,784			
Tools & Equip.	18	9,199							9,199		
Tools & Equip - GIS	19	15,885							15,885		
Commun Equip	20	1,021									1,021
SCADA	21	550,164								550,164	
Total General Plant Capital Expenditures		829,591	0	91,650	5,958	44,046	35,884	75,784	25,084	550,164	1,021

Distribution Plant	$2,604,017
General Plant	829,591
Total Capital	$3,433,608

TRANSFORMER STATION

2010 Project #1 – Completion of 2nd Transformer at Bloomsburg MTS

Cost: $224,749 (Account 1815)

Need: This project includes necessary protection and control work carried forward from the 2009 installation of the 2nd transformer at Bloomsburg MTS.

Scope: Install, test and commission protection and control equipment.

SECURITY

2010 Project # 2 – Bloomsburg M3 Feeder Extension

Cost: $734,537 (Account 1830 - $273,886; 1835 - $396,375; 1850 - $64,276)

Need: This feeder extension is part of an initiative to increase capacity and reliability to the Port Dover area in the South East section of NPDI service territory. This is a relatively high growth area for NPDI. This area was supplied from a Hydro One owned feeder out of Jarvis TS. The circuit became the end of a long feeder and had limited back-up capabilities. Connecting the Port Dover area to the NPDI Bloomsburg M3 provided switching flexibility and replaced approximately 8 MW of higher cost commodity from the Jarvis TS with lower cost commodity from the Bloomsburg MTS.

Scope: This project extends the Bloomsburg M3 feeder by 5.3 km (from Cockshutt & Concession 6 crossroads to Dover Mills Road, Port Dover) and included 78 poles plus related 3 phase conductor and is the final phase of a feeder extension project started earlier. (see project #9 in 2008).

RENEWAL

2010 Project #3 - Rebuild Maple and Head Streets - Simcoe

Cost: $135,468 (Accounts 1830 - $46,072; 1835 - $88,161; 1840 - $1,235)

Need: Pole line was deteriorated and in poor condition. Four transformers were overloaded and two were PCB contaminated. Transformers were installed below the secondary which is a safety hazard for joint use tenants. Expect improvement in system reliability and performance indices plus reduction in maintenance costs, consistent with having new plant in use.

Scope: Replaced 11 poles, 7 transformers capable of step down from 27.6 kV, 900 meters of 1 phase primary plus 900 meters of secondary conductor.

2010 Project #4 – Miscellaneous Overhead Projects (Under Materiality)

Cost: $398,854 (Accounts 1830 - $250,421; 1835 - $148,433)

Need: Provision for urgent and necessary equipment replacement identified as a result of routine system inspections and customer service calls. Reactive renewal of overhead system assets with a “run to failure” replacement strategy are included in this category (eg. distribution transformers). This category also includes replacement or adjustment to distribution system plant as required to accommodate customer demand work.

Scope: Multiple small overhead construction jobs completed throughout the year as required. Expenditure represents many small construction jobs under $50,000 materiality.

2010 Project #5 – Miscellaneous Underground Projects (Under Materiality)

Cost: $138,067 (Accounts 1840 - $64,779; 1845 - $73,288)

Need: Provision for urgent and necessary underground system equipment replacement identified as a result of routine system inspections and customer service calls. Reactive renewal of underground assets with a "run to failure" replacement strategy are included in this category (eg. distribution transformers, underground cable).

Scope: Multiple small underground construction jobs completed throughout the year as required. Expenditure represents many small construction jobs under $50,000 materiality.

2010 Project #6 - Pole Replacement Program

Cost: $233,638 (Account 1830)

Need: Deteriorated poles at the end of their life expectancy in need of replacement before becoming a safety hazard to the public and/or plant failure resulting in related power outages and high cost of emergency repair or replacement. Poles were identified as high priority through test and treatment program.

Scope: In 2010, 47 priority poles were replaced.

REGULATORY

2010 Project #7 – Plant Relocation for Road Widening

Cost: $146,205 (Accounts 1830 - $39,010; 1835 - $107,195)

Need: Where road widening projects are required as a result of municipal infrastructure development, Norfolk follows the *Public Service Works on Highways Act, 1990* and related regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital from the municipality for 50% of labour and vehicle cost.

Scope: Various miscellaneous road widening projects including Chapel St. in Simcoe to accommodate road widening by the local Municipality.

CUSTOMER DEMAND

2010 Project # 8 - Subdivision Development

Cost: $276,359 (Accounts 1840 - $94,316; 1845 - $182,043)

Need: Norfolk is obligated under the DSC to provide and connect distribution systems for new subdivisions that are funded through contributed capital. Related contributed capital is recorded separately in compliance with the Conditions of Service and Economic Valuation Calculation.

Scope: 2010 expenditure reflects servicing costs for 94 new lots in 13 underground subdivisions. Examples include Pine Ridge Subdivision (11 lots), Harvest Glen Ph 4 (6 lots), Dover Landing (11 lots) etc.

2010 Project #9 - New Services and Service Upgrades

Cost: $271,076 (Account 1855)

Need: Norfolk is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions for connection assets are charged for commercial / industrial services in accordance with Norfolk's Conditions of Service.

Scope: 2010 includes 128 new services plus 92 service upgrades. (Total 220)

2010 Project # 10 - Transformers

Cost: $680,246 (Account 1850)

Need: In compliance with OEB accounting guidelines, Norfolk capitalizes transformers at the time they are purchased. This expenditure represents the purchased cost of transformers for projects during the current year (as detailed above) or inventory backup.

Scope: Transformers are purchased throughout the year in anticipation of timing of future expected use to service new subdivisions and for renewal projects including PCB transformer replacement and prudent backup requirements.

2010 Project # 11 - Meter Installations

Cost: $131,968 (Account 1860)

Need: Provide demand meters and miscellaneous capital not included with smart meters.

Scope: Purchase and install demand meters. Provide for miscellaneous capital projects such as primary metering points exit fees, new PME installations and purchase of service interrupter devices.

2010 Project #12 – Miscellaneous Distribution Plant Projects (Under Materiality)

Cost: $52,354 (Acct's 1808 - $4,361; 1820 - $33,675; 1830 - $3,010; 1835 - $11,308)

Need: Provision for urgent and necessary substation equipment replacement identified as a result of routine system inspections. Replacement of overhead distribution system line switches identified for immediate replacement through the maintenance program. Expenditure represents many small construction jobs under $50,000 materiality.

Scope: Multiple small construction jobs completed throughout the year.

CAPITAL CONTRIBUTIONS

Source of Funds: $819,501 (Account 1995 - $819,501)

Need: Norfolk must have a sufficient source of funds to finance capital expenditures.

Scope: Capital contributions from Developers and others is a significant source of funds for Norfolk. Capital contributions are charged in compliance with NPDI Conditions of Service using the Economic Evaluation Calculation as required by the DSC. Where a Developer constructs a new underground distribution system for a subdivision, Norfolk calculates and pays a rebate to the Developer as new customer services are connected.

GENERAL PLANT

2010 Project #13 – Service Centre Office Modifications

Cost: $91,650 (Account 1908)

Need: HVAC upgrades for energy efficiency plus interior renovations to improve front counter security and safety and accommodate staff and customer needs.

Scope: Relatively modest project designed internally and installed by contractors selected in compliance with Norfolk Purchasing Policy.

2010 Project #14– Office Furniture and Equipment

Cost: $5,958 (Account 1915)

Need: New office work stations required to replace obsolete furniture and accommodate staff changes and office renovations.

Scope: This project is below the NPDI materiality of $50,000 but is included at NPDI discretion. Scope entails regular purchasing process in compliance with NPDI's purchasing policy.

2010 Project #15 - Replace Miscellaneous Computer Hardware

Cost: $44,046 (Account 1920)

Need: NPDI recognizes the need to keep current with computer technology to meet operating and regulatory requirements and to replace existing equipment that is obsolete and inadequate for required applications.

Computer hardware is used by all departments and is essential to the business of NPDI. Upgrades are based on business software applications approved by management or required by software vendors. Every reasonable effort is made to extend the life of computers hardware through prudent deployment practices.

Scope: Add an uninterruptible power source (UPS) to improve reliability. Add hardware to accommodate new "disaster recovery" plan plus network switches and PC/laptop replacements as required.

2010 Project #16 – Purchase and Install Miscellaneous Software

Cost: $35,884 (Account 1925)

Need: Upgrade and replace obsolete software to keep current with the applications needed to retain operating efficiency. It is also necessary to pay for user licenses as required.

Scope: Purchase and install programs including security software for AS 400 main frame computer, E-post setup, Distributech setup, disaster recovery, MS Office pro licenses, Windows OS server upgrade software.

2010 Project #17 – Transportation and Work Equipment

Cost: $75,784 (Account 1930)

Need: Norfolk requires a reliable and cost effective fleet of work platforms, pickup trucks, trailers and transportation vehicles in order to respond to emergencies and perform field work as required.

Scope: Provide new vehicle for Operations ($37,392) plus replace existing pickup truck ($29,642) and new reel trailer ($8,750).

2010 Project #18 – Miscellaneous Tools and Equipment

Cost: $9,199 (Accounts 1935 - $358; 1940 - $6,946; 1945 - $1,895)

Need: On a regular basis it is necessary to replace tools and equipment consumed or worn out during daily use.

Scope: Miscellaneous tools and equipment are acquired as needed subject to management approval.

2010 Project #19 – Complete Installation of Geographic Information Facility

Cost: $15,885 (Account 1960)

Need: This is to complete addition of a GIS system initiated in 2009.

Scope: Continue conversion of AutoCAD rural service drawings to GIS. Complete GIS tagging and collection of pole attribute data. Deploy software to engineering and control room staff.

2010 Project #20 – Add or Replace Miscellaneous Communication Equipment

Cost: $1,021 (Account 1955)

Need: On an annual basis it is necessary to upgrade or replace communication equipment consumed or worn out during daily use. Examples include replacement of truck radios.

Scope: Truck radios are acquired or replaced as needed (under materiality).

2010 Project #21 – SCADA Upgrades

Cost:	$550,164 **(**Account 1980 - $540,068; 1981 - $9,479)
Need:	Norfolk has utilized a Supervisory Control and Data Acquisition facility in support of our System Operators and Control Room activities. The benefits of SCADA include the efficiency of remote operation of the distribution which mitigates the impact of power outages through switching to alternate supply for isolated problems. In addition, SCADA information facilitates efficient system operation including feeder balancing to minimize line losses etc.
Scope:	2010 expenditures includes $493,323 for a high speed fibre communication link to improve control over the substations and distribution system and provide a long term back-haul solution for smart metering data at the West end of Norfolk's service territory plus $47,361 for SCADA equipment to monitor and control the new transformer installed at the Bloomsburg MTS including a backup server at Bloomsburg TS at $ 9,479.

Table 3.6 - 2011 Budget - Capital Project

DISTRIBUTION PLANT - 2011 Budget

Category	Ref. No.	TOTAL	Land Rights (1806)	MS/DS Equip (1820)	Pole (1830)	OH Cond (1835)	Conduit (1840)	UG Cond (1845)	Trans (1850)	Services (1855)	Meters (1860 & 1555)
Land Rights	n/a	1,000	1,000								
Substations	1	75,000		75,000							
Security	2	141,000			16,000	125,000					
Security	3	85,000						85,000			
Renewal	4	549,000			240,000	180,000			129,000		
Renewal	5	103,000			50,000	45,000			8,000		
Renewal	6	153,000			5,000	20,000	70,000	50,000	8,000		
Renewal	7	177,000			56,000	49,000			72,000		
Renewal	8	70,000			36,000	18,000			16,000		
Renewal	9	136,000			20,000		50,000	50,000	16,000		
Renewal	10	119,000			50,000	45,000			24,000		
Renewal	11	480,000			400,000				80,000		
Renewal	12	485,000			125,000	100,000	50,000	50,000	160,000		
Regulatory	13	351,340			98,375	212,912			37,945	2,108	
Regulatory	14	80,000							80,000		
Regulatory	15	147,000			60,000	55,000			32,000		
Customer Demand	16	303,000			40,000		50,000	153,000	60,000		
Customer Demand	17	446,000							180,000	266,000	
Transformers	18	0									
Meters	19	72,000									72,000
SUBTOTAL		3,973,340	1,000	75,000	1,196,375	849,912	220,000	388,000	902,945	268,108	72,000
Capital Contributions		**(861,340)**									
TOTAL DISTRIB. PLANT CAPITAL EXPENDITURES		**3,112,000**	**1,000**	**75,000**	**1,196,375**	**849,912**	**220,000**	**388,000**	**902,945**	**268,108**	**72,000**

GENERAL PLANT - 2011 Budget

Category	Ref. No.	Total	Land (1905)	Serv. Ctre. Bldg. (1908)	Office Equip. (1915)	Comp. Hardware (1920)	Comp Software (1925)	Trucks (1930)	Tools and Equip. (1935) (1940) (1945) (1960)	SCADA Equip (1980) (1981)	Commun. Equip. (1955)
Land	n/a	0	0								
Facilities	20	10,000		10,000							
Office Equip	21	15,000			15,000						
Computer HW	22	30,000				30,000					
Computer SW	23	27,000					27,000				
Trucks	24	440,000						440,000			
Tools & Equip.	25	35,000							35,000		
Commun Equip	26	8,000									8,000
SCADA	27	245,000								245,000	
TOTAL GENERAL PLANT CAPITAL EXPENDITURES		**810,000**	**0**	**10,000**	**15,000**	**30,000**	**27,000**	**440,000**	**35,000**	**245,000**	**8,000**
Total Capital Expenditure		**3,922,000**									

2011 – Projects related to GEA

In 2011 Norfolk has forecast the projects related to the connection of MicroFit and Fit projects under the Green Energy Plan, in Table 3.7. These projects are not part of the capital projects listed in Table 3.6 but are reported here to provide a complete picture of Norfolk's capital spending requirements in 2011. The details related to these projects can be found in Norfolk's Basic GEA Plan in Appendix C, followed by the OPA's response.

Table 3.7: 2011 GEA Projects

Renewable Energy - 2011 Budget							
Category	**TOTAL**	**TS Equip (1815)**	**Poles (1830)**	**OH Conductor (1835)**	**Trans (1850)**	**Services (1855)**	**Meters (1860 & 1555)**
MicroFit	141,000		25,000	6,000	38,000	50,000	22,000
Fit Projects	79,000		10,000	20,000	19,000	10,000	20,000
Enhancement	100,000	100,000					
Total	**320,000**	**100,000**	**35,000**	**26,000**	**57,000**	**60,000**	**42,000**
Less Contributions	**(20,660)**						
Capital Expenditures for IFRS	**299,340**	**100,000**	**35,000**	**26,000**	**57,000**	**60,000**	**42,000**

DISTRIBUTION PLANT PROJECTS

SUBSTATIONS

2011 Project # 1 – Miscellaneous DS Equipment Upgrades

Cost: $75,000 (Account 1820)

Need: Increased load at NP2 has led to a requirement for transformer cooling fans and station service to be installed. Station inspections have identified a damaged load interrupter switch at NP9 that requires replacement. Installation of a dedicated neutral at NP9 has been identified to improve detection and dissipation of fault current and stability. Monitoring equipment at NP11 station service is required to increase data collection related to power quality and fault investigation.

Scope: 2011 Projects include installation of station service and transformer cooling fans at NP2, replacement of a load interrupter switch and installation of an underground dedicated neutral at NP9 and installation of station service (SCADA requirement) Ion meters and connection to fibre network at NP11.

SECURITY

2011 Project #2 – Install Load Interrupter Switches

Cost: $141,000 (Accounts 1830 - $16,000; 1835 - $125,000)

Need: Priority installations to reduce risk of feeder loss and resulting power outages. This is a provision for high priority switch additions that are identified as per the asset management planning process.

Scope: Install 3 load interrupter switches (with remote control capability) at strategic locations.

2011 Project #3 – Add Tie Between Bloomsburg M1 and M5.

Cost: $85,000 (Account 1845)

Need: The tie is required to transfer load off the Bloomsburg J-bus in order to perform maintenance. Without this tie, maintenance cannot be performed without the transfer of load to more expensive supply points and resulting charges for “double peaks” or “pancaking” in the order of $50,000 per month. This represents a high priority item within the overall distribution system.

Scope: Supply and install approximately 800 metres of 1000 MCM aluminum primary cable and separate 250 MCM copper neutral.

RENEWAL

2011 Project #4 – 4.16 kV to 27.6 kV Conversion – Waterford

Cost: $549,000 (Accounts 1830 - $240,000; 1835 - $180,000; 1850 - $129,000)

Need: A large portion of the Waterford area is supplied from an aging Norfolk Substation (NP10). Conversion of various strategic areas will permit the eventual elimination of Norfolk’s NP10 distribution station. Pole lines which are deteriorated and at the end of their useful life have been targeted for conversion. The upgrade will reduce related maintenance costs in the area, improve system reliability due to the presence of new plant and eventually reduce line losses by eliminating 4kV transformation.

Scope: Replace 47 poles, upgrade 15 transformers from 4.16kV to 27.6kV, replace 13 spans 3ph and 23 spans of 1ph overhead primary and associated removals (2,100 metres). This project affects approximately 100 services in the area.

2011 Project #5 - Rebuild Colborne and North Main Street, Simcoe

Cost: $103,000 (Accounts 1830 - $50,000; 1835 - $45,000; 1850 - $8,000)

Need: Replace one PCB contaminated transformer plus replace and relocate 5 poles that are near or at end-of-life and located in the middle of the sidewalk. Removal of PCB contaminated transformers is a high environmental priority as is the replacement of potentially unsafe poles.

Scope: Relocate 5 poles out of the sidewalk, replace one transformer and install new conductor.

2011 Project #6 - Rebuild and Convert Overhead to Underground – Talbot St., Simcoe

Cost: $153,000 (Accounts 1830 - $5,000; 1835 - $20,000; 1840 - $70,000; 1845 - $50,000; 1850 - $8,000)

Need: Distribution equipment at this location is in poor condition and of an obsolete design. NPDI also has a public safety concern as an underground transformer vault grate is located in the sidewalk which the public must traverse. Rebuilding and upgrading the distribution equipment to a standard pad mount transformer and underground cable addresses the safety concerns and improves system reliability consistent with new distribution plant.

Scope: Remove transformer, vault and grate in sidewalk plus overhead dip pole and replace with standard pad mount transformer and up to date terminations.

2011 Project #7 - Rebuild Church Street - Delhi

Cost: $177,000 (Accounts 1830 - $56,000; 1835 - $49,000; 1850 - $72,000)

Need: Line in poor condition and built to obsolete standards not conforming to proper clearances and in need of replacement to avoid power outages.

Scope: Project involves replacing 8 poles, 9 transformers and 250 metres of 3 phase conductor along with secondary buss. This project affects approximately 25 services.

2011 Project #8 - Replace Concrete Poles – Port Dover

Cost: $70,000 (Accounts 1830 - $36,000; 1835 - $18,000; 1850 - $16,000)

Need: Poles are degraded and in poor condition as identified by field inspection and in need of priority replacement.

Scope: Replace 4 concrete poles and 2 transformers plus 180 metres of lashed secondary conductor.

2011 Project #9 - Replace Obsolete Pole Transformers Located in Street Light Poles – Montclair Crescent, Simcoe

Cost: $136,000 (Accounts 1830 - $20,000; 1840 - $50,000; 1845 - $50,000; 1850 - $16,000)

Need: Transformers located inside street light poles (pole trans) are obsolete technology to the extent that replacement parts and transformers are not available. When one fails, it must be replaced with a pad mount transformer spliced into the existing underground distribution system. As many of the existing pole trans are in locations not conducive to pad mount transformers (eg. between driveways) re-engineering of the neighborhood distribution system is expected. Due to the age of the units (over 35 years old) and the increasing risk of transformer failures, NPDI has included this pilot project as a means of generating spare pole trans for inventory. A full conversion program has been developed with implementation scheduled to begin in 2012.

Scope: Replace 4 pole trans with pad-mount transformers, install new primary duct and cable, secondary pedestals and 4 street light poles.

2011 Project #10 – Rebuild Hwy 3, East of Ireland Rd – Simcoe

Cost: $119,000 (Accounts 1830 - $50,000; 1835 - $45,000; 1850 - $24,000)

Need: Spatial analysis of pole condition data has identified this section of 10 poles with 9 at or near their useful end of life. This pole line is also adjacent to a heavily travelled roadway, increasing the safety risk to the public in the event of a pole failure.

Scope: Replace 10 poles, 3 transformers and approximately 500 metres of single phase primary plus 500 metres of secondary service conductor.

2011 Project #11 - Pole Replacement Program

Cost: $480,000 (Accounts 1830 - $400,000; 1850 - $80,000)

Need: To replace deteriorated poles before becoming a safety hazard to the public and/or plant failure resulting in related power outages and high cost of emergency repair or replacement. Poles that are in need of priority replacement are identified through a pole test and treat program. With this data and first-hand knowledge of pole conditions reported by field staff, an annual program of priority pole replacement is determined.

Scope: For 2011, approximately 80 priority poles have been identified for replacement. Provision for the replacement of related transformers has also been included.

2011 Project #12 – Miscellaneous Overhead and Underground Projects

Cost: $485,000 (Accounts 1830 - $125,000; 1835 - $100,000; 1840 - $50,000; 1845 - $50,000; 1850 - $160,000)

Need: Provision for urgent and necessary equipment replacement identified as a result of routine system inspections and customer service calls. Reactive renewal of assets with a "run to failure" replacement strategy are included in this category (eg. distribution transformers, underground cable). This category also includes replacement or modifications to distribution system plant as required to accommodate customer demand work. The estimated cost is based on historical data and is challenging to forecast as a whole due to the unplanned yet expected projects that arise as a part of a utility's operation.

Scope: Complete capital renewal work and system upgrades as required. Expenditure represents many small construction jobs under $50,000 materiality.

REGULATORY

2011 Project #13 – Line Extension – Blueline Road and Port Ryerse Road to Accommodate Solar Farm

Cost: $351,340 (Accounts 1830 - $98,375; 1835 - $212,912; 1850 - $37,945; 1855 - $2,108)

Need: To connect the 9.1MW solar project, Sun E Sky to the distribution system an expansion project is required as poles conductor and transformers require upgrades

Scope: Design and installation of approximately 1600 metres of line. Internal and external resources are required to complete the project. Project was fully funded by customer contributions.

2011 Project #14 – PCB Transformer Replacement Program

Cost: $80,000 (Account 1850 - $80,000)

Need: Ongoing annual program to eliminate PCB contaminated transformers in service for safety, environmental and regulatory compliance.

Scope: 2011 plan includes replacement of 10 PCB contaminated transformers.

2011 Project #15 – Plant Relocation for Road Widening

Cost: $147,000 (Account 1830 - $60,000; 1835 - $55,000; 1850 - $32,000)

Need: Where road widening projects are required as a result of municipal infrastructure development, NPDI follows the *Public Service Works on Highways Act, 1990* and related regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital from the municipality for 50% of NPDI labour and vehicles.

Scope: Adjustments to distribution system equipment as required due to road widening projects established by the Municipality.

CUSTOMER DEMAND

2011 Project # 16 - Subdivision Development

Cost: $303,000

(Accounts 1830 - $40,000; 1840 - $50,000; 1845 - $153,000; 1850 - $60,000)

Need: NPDI is obligated under the DSC to provide and connect distribution systems for new subdivisions that are funded through contributed capital. If the distribution system is constructed by the Developer (to NPDI standards) the account represents the value of the plant turned over to NPDI by the Developer. (Related contributed capital is recorded separately in compliance with NPDI Conditions of Service and Economic Valuation Calculation.)

Scope: Small line extensions and connections to new subdivisions as required. At the time this application was prepared, specifics are unknown but NPDI management considers the provision of $303,000 to be a reasonable estimate consistent with prior years.

2011 Project #17 - New Services and Service Upgrades

Cost: $446,000 (Accounts 1850 - $180,000; 1855 - $266,000)

Need: NPDI is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions for connection assets are charged for commercial / industrial services in accordance with NPDI's Conditions of Service.

Scope: 2011 Budget provides for approximately 175 new services, including 6 commercial / industrial services requiring three phase pad mount transformers, consistent with prior years.

TRANSFORMERS

2011 Project # 18 - Transformers

Cost: $ nil (Account 1850)

Need: Note that the costs of the transformers have been included in individual projects for 2011.

Scope: NA

METERS

2011 Project # 19 - Meter Installations

Cost: $72,000 (Account 1860 - $72,000)

Need: Regulatory requirement to supply and install meters to meet customer demand for new services and for meter replacements as required.

Scope: Single phase demand and interval meters. These meters are not part of the Smart Meter plan.

CAPITAL CONTRIBUTIONS

Source of Funds: $ 861,340 (Account 1995)

Need: Contributions based on customer demand capital expenditures.

Scope: Capital contributions from Developers and others is a significant source of funds for Norfolk. Capital contributions are charged in compliance with Norfolk's Conditions of Service using the Economic Evaluation Calculation as required by the DSC. $351,340 of this amount is related to project 13.

GENERAL PLANT

2011 Project #20 – General Plant Buildings & Fixtures (Facilities)

Cost: $10,000 (Account 1908)

Need: Provide for building upgrades and renovations as required.

Scope: Minor upgrades and renovations to the building (30 years old) as required on a regular basis to avoid falling into disrepair.

2011 Project #21 – Office Furniture & Equipment

Cost: $15,000 (Account 1915)

Need: Provide for miscellaneous office furniture and equipment as required.

Scope: Periodic changes and replacement of office equipment and furniture..

2011 Project # 22 - Computer Hardware

Cost: $30,000 (Account 1920)

Need: NPDI recognizes the need to keep current with computer technology to meet operating and regulatory requirements and to replace existing equipment that is obsolete and inadequate for required applications.

Computer hardware is used by all departments and is essential to the business of NPDI. Upgrades are based on business software applications approved by management or required by software vendors. Every reasonable effort is made to extend the life of computer hardware through prudent deployment practices.

Scope: PCs for office staff are replaced on a 4 year cycle. Miscellaneous replacement of laptops and printers as required. Budget also includes “tough books” for two Meter Technicians.

2011 Project #23 – Purchase and Install Software

Cost: $27,000 (Account 1925)

Need: Upgrade and replace software to keep current with the applications needed to retain operating efficiency. It is also necessary to renew user licenses as required.

Scope: During the course of the year IT staff acquire, document and install these programs as required. Includes upgrade to MS Office 2010.

2011 Project #24 – Replace Work Platform (Bucket Truck and 2 Pickups)

Cost: $440,000 (Account 1930)

Need: Norfolk requires a reliable and cost effective fleet of work platforms, pickup trucks and trailers in order to respond to emergencies and perform field work as required.

Scope: Replace 1 depreciated work platform ($300,000). Replace meter van #22 ($30,000). Add pickup truck ($40,000) and add a reel trailer for substation work ($70,000). Procurement of vehicles is in compliance with NPDI's purchasing policy. Norfolk considers age and condition of vehicles plus recommendations from a consultant and repair service providers and opinion of users when making fleet replacement decisions.

2011 Project #25 – Add or Replace Miscellaneous Tools and Equipment

Cost: $35,000 (Accounts 1935 - $1,000; 1940 - $23,000; 1945 - $6,000; 1960 - $5,000)

Need: On a regular basis it is necessary to replace tools and equipment consumed or worn out during daily use.

Scope: Miscellaneous tools and equipment are acquired as needed subject to management approval and Norfolk purchasing policy.

2011 Project #26 – Add or Replace Communications Equipment

Cost: $8,000 (Account 1955 $8,000)

Need: On an annual basis it is necessary to upgrade/replace miscellaneous communications equipment such as truck radios.

Scope: Procure radio equipment and communications equipment as needed subject to management approval and NPDI purchasing policy *(under materiality).*

2011 Project #27 – SCADA Upgrades

Cost: $245,000 (Account 1980 $245,000)

Need: NPDI has utilized a Supervisory Control and Data Acquisition (SCADA) facility in support of our System Operators and Control Room activities. The benefits of SCADA include the efficiency of remote operation of the distribution system (i.e. switching) which mitigates the impact of power outages through switching to alternate supply for isolated problems. In addition, SCADA information facilitates efficient system operation including feeder balancing to minimize line losses etc.

Scope: Add SCADA monitoring and remote control for (10) new points ($20,000 each). Add a backup base station at the Bloomsburg MTS site for security and disaster recovery.

Table 3.6 - 2012 Test Year - Capital Projects

DISTRIBUTION PLANT - 2012 Budget (Test Year)

Category	Ref. No.	TOTAL	Land Rights (1806)	TS Equip (1815)	MS/DS Equip (1820)	Pole (1830)	OH Cond (1835)	Conduit (1840)	UG Cond (1845)	Trans (1850)	Services (1855)	Meters (1860 & 1555)
Land Rights	n/a	0										
Substations	1	75,000			75,000							
Substations	2	200,000			200,000							
Security	3	220,000				100,000	90,000			30,000		
Renewal	4	230,000				100,000	80,000			20,000	30,000	
Renewal	5	1,600,000				588,000	470,000			372,000	170,000	
Renewal	6	100,000				40,000	30,000			10,000	20,000	
Renewal	7	480,000				400,000	40,000			40,000		
Renewal	8	485,000				125,000	100,000	50,000	50,000	120,000	40,000	
Regulatory	9	150,000				40,000	100,000			10,000		
Customer Demand	10	303,000				40,000		50,000	153,000	60,000		
Customer Demand	11	450,000				30,000	15,000			290,000	115,000	
Transformers	12	0										
Meters	13	348,000										348,000
SUBTOTAL		4,641,000			275,000	1,463,000	925,000	100,000	203,000	952,000	375,000	348,000
Capital Contributions		**(652,000)**										
TOTAL DISTRIBUTION PLANT CAPITAL EXPENDITURES		**3,989,000**			**275,000**	**1,463,000**	**925,000**	**100,000**	**203,000**	**952,000**	**375,000**	**348,000**

GENERAL PLANT - 2012 Budget (Test Year)

Category	Ref. No.	Total	Land (1905)	Land Rights (1906)	Serv. Ctre. Bldg. (1908)	Office Equip. (1915)	Comp. Hardware (1920)	Comp Software (1925)	Trucks (1930)	Tools and Equip. (1935) (1940) (1945) (1960)	SCADA Equip (1980) (1981)	Commun Equip. (1955)
Land	n/a											
Facilities	n/a											
Office Equip	14	15,500				15,500						
Computer HW	15	40,000					40,000					
Computer SW	16	100,000						100,000				
Computer SW	17	42,500						42,500				
Trucks	18	40,000							40,000			
Tools & Equip.	19	28,000								28,000		
Commun Equip	20	53,000										53,000
SCADA	21	100,000									100,000	
TOTAL GENERAL PLANT CAPITAL EXPENDITURES		**419,000**				**15,500**	**40,000**	**142,500**	**40,000**	**28,000**	**100,000**	**53,000**
Total Capital Expenditures		**4,408,000**										

2012 – Projects related to GEA

In 2012 Norfolk has forecast the projects related to the connection of MicroFit and Fit projects under the Green Energy Plan, in Table 3.9. These projects are not part of the capital projects listed in Table 3.6 but are reported here to provide a complete picture of Norfolk's capital requirements in 2012. The details related to these projects can be found in Appendix C Norfolk's Basic GEA Plan.

Table 3.9: 2012 GEA Projects

Renewable Energy - 2012 Budget (Test Year)								
Category	**TOTAL**	**TS Equip (1815)**	**Pole (1830)**	**OH Conductor (1835)**	**Trans (1850)**	**Services (1855)**	**Meters (1860 & 1555)**	**(SCADA 1980/1)**
Expansion - MicroFit	141,000		25,000	6,000	38,000	50,000	22,000	
Expansion - Fit	758,000		190,000	395,000	100,000	23,000	50,000	
Enhancement	120,000	100,000						20,000
Total	**1,019,000**	**100,000**	**215,000**	**401,000**	**138,000**	**73,000**	**72,000**	**20,000**
Less Contributions	**(261,500)**							
Capital Expenditures for IFRS	**757,500**	**100,000**	**215,000**	**401,000**	**138,000**	**73,000**	**72,000**	**20,000**

DISTRIBUTION PLANT PROJECTS

SUBSTATIONS

2012 Project #1 – Miscellaneous DS Equipment Upgrades

Cost: $75,000 (Account 1820)

Need: Current needs include upgrades to instrument PT's at NP6, monitoring and telemetry at NP13 to improve data collection related to power quality and fault investigation and inspections have identified an aging load break switch requiring replacement, an asbestos meter board and animal control issues at NP11.

Scope: This covers the replacement of a load break switch, removal of an asbestos meter board and installation of animal guards at NP11 Port Dover, installation of station PT's for NP6 and installation of PT's to work with SEL relays at NP13 Port Dover.

2012 Project #2 – Replace Transformer Distribution Station NP8- Ann St., Delhi

Cost: $200,000 (Account 1820)

Need: To continue to provide safe and reliable distribution supply to Delhi, the NP8 distribution station transformer requires replacement. This will include an upgrade to meet current and future load and will remove an existing PCB hazard.

Scope: The distribution transformer presently installed and NP8 was built in 1958 (53 years old) and Furan test indicate 583 ppb indicating that breakdown is beginning to happen within the transformer. This transformer also contains 42 ppm of PCB. For reliability purposes in the Delhi area we need to increase the size of this transformer from the present 3750 kVA to 5000 kVA in order to allow complete load transfer back and forth between NP8 and NP9 without concern of overload and voltage issues.

SECURITY

2012 Project #3 – Reroute NP5 F4 to Queen St. S., (Simcoe Fairgrounds)

Cost: $220,000 (Accounts 1830 - $100,000; 1835 - $90,000; 1851 - $30,000)

Need: NP5 F4 feeder is currently routed across the Simcoe Fairgrounds property to South Drive and along to Queen St.. Rebuilding an existing single phase pole line adjacent to the south entrance to the fairgrounds to three phase will permit the removal of 4kV primary line through parking lot, eliminating an potential clearance hazard.

Scope: Rebuild approximately 125m of existing facilities as required to allow for removal of 4kV primary wires crossing parking lot in the Fairgrounds

RENEWAL

2012 Project #4 – 4.16 kV to 27.6 kV Conversion Phase 2 - Distributing Station NP 10 Waterford

Cost: $230,000 (Accounts 1830 - $100,000; 1835 - $80,000; 1851 - $20,000; 1835 $30,000)

Need: The NP10 Distribution Station (DS) is a single transformer station with no backup. Transformer failure would result in an extended outage. Conversion to 27.6 kV would eliminate the need for the DS and facilitate decommissioning. This is phase 2 of a multi-phase project which will improve system efficiency (reduce line loss) and improve reliability by decommissioning an old DS.

Scope: Replace approximately 20 poles, 4 transformers and 1,200m of primary and secondary conductors.

2012 Project #5 – Simcoe 4.16 kV to 27.6 kV Conversion Phase 1

Cost: $1,600,000 (Accounts 1830- $588,000; 1835 - $470,000; 1851 - $372,000; 1835 - $170,000)

Need: Conversion of Simcoe distribution system to reduce loading on aging stations, to improve safety, reliability, power quality and reduce system inventory. Upon completion of the conversion program Simcoe Municipal Stations (MS) 1, 2, 3, and 5 will be decommissioned.

Scope: Overhead rebuild with approx. 120 poles, 30 overhead distribution transformers, 1,300 m of 3ph primary conductor, 2,700 m of 1ph primary conductor. Approx. 350 lots will be included in the conversion. Effected locations include: Tyrell St., Beckett Blvd., Hill St., Foster St., Belleview Ave., Charles St., Payne Ave., Martin Ave., Royal Rd., Holden Ave., Carolyn Blvd., Calvert Cres., Dora Dr., Sunset Dr., Union St. and King Lane.

2012 Project #6 - Rebuild Potts Road, Simcoe

Cost: $100,000 (Accounts 1830 - $40,000; 1835 - $30,000; 1851 - $10,000; 1855 - $20,000)

Need: Field inspection has identified the pole line on Potts Rd. is approaching its end of useful life. A rebuild is required to improve safety, reliability and power quality.

Scope: Replace 8 poles, 1 transformer and approximately 200m of single phase primary and secondary conductors on Potts Rd. from Victoria St., to Oakwood Ave.

2012 Project #7 - Pole Replacement Program

Cost: $480,000 (Accounts 1830 - $400,000; 1835 - $40,000; 1851 - $40,000)

Need: Deteriorated poles in need of replacement before becoming a safety hazard to the public and/or plant failure resulting in related power outages and high cost of emergency repair or replacement. Poles that are in need of priority replacement are identified through a pole test and treat program. With this data and first-hand knowledge of pole conditions reported by field staff, an annual program of priority pole replacement is determined.

Scope: For 2012, approximately 100 priority poles are anticipated to be identified for priority replacement. Provision for the replacement of related transformers has also been included.

2012 Project #8 – Miscellaneous Overhead and Underground Betterments

Cost: $485,000 (Accounts 1830 - $125,000; 1835 - $100,000; 1840 - $50,000; 1845 - $50,000; 1851 - $120,000; 1852 -$40,000)

Need: Provision for urgent and necessary equipment replacement identified as a result of routine system inspections and customer service calls. Reactive renewal of assets with a “run to failure” replacement strategy are included in this category (eg. distribution transformers, underground cable). This category also includes replacement or adjustment to distribution system plant as required to accommodate customer demand work. The estimated cost is based on historical values and is challenging to forecast as a whole due to the unplanned yet expected projects that arise as a part of a utility’s operation.

Scope: Complete capital renewal work and system upgrades as required. Expenditure represents many small construction jobs under $50,000 materiality.

REGULATORY

2012 Project #9 – Plant Relocation for Road Widening

Cost: $150,000 (Accounts 1830 - $40,000; 1835 - $100,000; 1851 - $10,000)

Need: Where road widening projects are required as a result of municipal infrastructure development, Norfolk follows the *Public Service Works on Highways Act, 1990* and related regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital from the municipality for 50% of labour and vehicles.

Scope: The 2012 plan provides for a reasonable allowance road widening projects established by the Municipality. Specifics from the Municipality were not available at the time this application was prepared.

CUSTOMER DEMAND

2012 Project # 10 - Subdivision Development

Cost: $303,000 (Accounts 1830 - $40,000; 1840 - $50,000; 1845 - $153,000; 1852 - $60,000)

Need: NPDI is obligated under the DSC to provide and connect distribution systems for new subdivisions that are funded through contributed capital. If the distribution system is constructed by the Developer (to NPDI standards) the account represents the value of the plant turned over to NPDI by the Developer. (Related contributed capital is recorded separately in compliance with NPDI Conditions of Service and Economic Valuation Calculation.)

Scope: Small line extensions and connections to potential new subdivisions as required. Approximately 180 new lots are anticipated.

2012 Project #11 - New Services and Service Upgrades

Cost: $450,000 (Acc'ts 1830 - $30,000; 1835 - $15,000; 1851 - $140,000; 1852 - $150,000; 1855 -$115,000)

Need: NPDI is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions for connection assets are charged for commercial / industrial services in accordance with NPDI's Conditions of Service.

Scope: 2012 Budget provides for approximately 100 new services, including 6 commercial / industrial services requiring three phase pad mount transformers, consistent with prior years.

2012 Project #12 – Transformer Purchases to Increase Transformers on Hand.

Cost: **$Nil**

Transformers included in projects above.

2012 Project # 13 - Meter Installations

Cost: $348,000 (Accounts 1860)

Need: **S**upply and install meters to convert remaining commercial customers to electronic read meters.

Scope: 2012 Budget provides for a broad range of meter capital works including purchase of new meters for customer additions, primary metering installations.

CAPITAL CONTRIBUTIONS

Source of Funds: $ 652,000 (Account 1995)

Need: Contributions based on estimated demand work.

Scope: Capital contributions are charged in compliance with Norfolk’s Conditions of Service using the Economic Evaluation Calculation as required by the DSC. Where a Developer constructs a new underground distribution system for a subdivision, Norfolk calculates and pays a rebate to the Developer as new customer services are connected.

GENERAL PLANT

2012 Project #14 – Office Furniture & Equipment

Cost: $15,500 (Account 1915)

Under materiality

2012 Project #15 - Computer Hardware

Cost: $40,000 (Account 1920)

Need: Norfolk recognizes the need to keep current with computer technology to meet operating and regulatory requirements and to replace existing equipment that is obsolete and inadequate for required applications.

Scope: Various computer hardware including disaster recovery hardware $19,000, UPS replacements $8,000 and miscellaneous as required.

2012 Project #16 – Purchase and Install Daffron iXP Financial Software

Cost: $100,000 (Account 1925)

Need: Upgrade obsolete financial software system from the 1990s. Existing system is antiquated, and inefficient.

Scope: Implementation of "iXP" is planned for 2012, (deferred from previous years due to staff changes other work requirements). This is a windows based 'front' for the existing Daffron system that is considerably more user friendly and provides increased tracking and reporting capabilities.

2012 Project #17 – Purchase and Install Miscellaneous Software

Cost: $42,500 (Account 1925)

Need: Upgrade and replace obsolete software to keep current with the applications needed to retain operating efficiency. It is also necessary to pay for user licenses as required.

Scope: Includes new software upgrades for the customer service department to meet accessibility compliance.

2012 Project #18 – Replacement Vehicle

Cost: $40,000 (Account 1930 $40,000)

Need: Norfolk requires a reliable and cost effective fleet of work platforms, pickup trucks and trailers in order to respond to emergencies and perform field work as required.

Scope: Replace one existing pickup truck which is at the end of its useful life. Norfolk considers age and condition of vehicles plus recommendations from a consultant and repair service providers and opinion of users when making fleet replacement decisions.

2012 Project #19 – Add or Replace Miscellaneous Tools and Equipment

Cost: $28,000 (Accounts 1935 - $1,000; 1940 - $17,000; 1945 - $5,000; 1960 - $5,000)

Need: On a regular basis it is necessary to replace tools and equipment consumed or worn out during daily use.

Scope: Miscellaneous tools and equipment are acquired as needed subject to management approval. Under materiality.

2012 Project #20 – Upgrade Communications (Phone System)

Cost: $53,000 (Account 1955)

Need: The existing phone system is unable to accommodate call traffic during storm situations and in particular outgoing call capability is very restricted. An upgrade is necessary to provide proper communications during emergency situations. On an annual basis it is also necessary to replace miscellaneous communications equipment such as truck radios worn out during daily use.

Scope: Upgrade phone system and procure radio equipment and communications equipment to meet need outlined above.

2012 Project #21 – SCADA Upgrades

Cost: $100,000 (Account 1980)

Need: Norfolk has utilized a Supervisory Control and Data Acquisition (SCADA) facility in support of our System Operators and Control Room activities. The benefits of SCADA include the efficiency of remote operation of the distribution system (i.e. switching) which mitigates the impact of power outages through switching to alternate supply for isolated problems. In addition, SCADA information facilitates efficient system operation including feeder balancing to minimize line losses etc.

Scope: Add SCADA monitoring and remote control for (5) new points ($20,000 each).

ASSET MANAGEMENT PLAN SUMMARY:

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

Asset management is the professional management of physical infrastructure with a systematic methodology integrating best practices in all aspects of selection, design, construction, operation, maintenance, replacement and disposition. The goal is to use an Asset Management Plan to optimize the whole life business impact of costs, performance and risk exposures of Norfolk physical assets. Performance of the assets is directly related to reliability of the distribution system which is another key regulatory and customer satisfaction measure second only to rates. Norfolk did not have a formal asset management plan in the past so in 2010 AESI was contracted to assist in the development of a comprehensive plan. Accompanying this Schedule as Appendix A is a copy of our Asset Management Plan. It is important to note that Norfolk's Asset Management Plan is in its early development stage. Norfolk has completed a high level review of current assets and their age and has reviewed current strategies in dealing with maintenance and capital improvements. Also under review are the current and potential future activities expected to form the major parts of the Asset Management Plan in the future.

The plan for Substation assets is currently under investigation by Norfolk to determine its context with respect to the strategy for the conversion of distribution system overhead and underground 4.16 kV and 8.32 kV line assets to 27.6 kV thus allowing for a further reduction of the twelve remaining municipal substations.

Norfolk has provided the forecast for 2012, 2013 and 2014 capital expenditures in Tables 3.7, 3.8 and 3.9 below. Amounts are reported under CGAAP. The annual replacement costs are engineering estimates only and the actual expenditure levels in the capital budgets could be adjusted based on project scope, prevailing construction costs and other outside influences (e.g. relocation requests, system expansions, etc.).

Table 3.7 - 2012 Distribution System Capital Expenditure Forecast

Budget Year	Project No.	Category	Project	Total
2012	1	Substations	Miscellaneous DS Equipment Upgrades	$75,000
2012	2	Substations	Replace Transformer - Distribution Station NP8	$200,000
2012	3	Security	Reroute NP5 F4 to Queen St. S., (Simcoe Fairgrounds)	$220,000
2012	4	Renewal	4.16 kV to 27.6 kV Conversion Phase 2- Distributing Station NP 10 Waterford	$230,000
2012	5	Renewal	Simcoe 4.16 kV to 27.6 kV Conversion Phase 1	$1,600,000
2012	6	Renewal	Rebuild Potts Road, Simcoe	$100,000
2012	7	Renewal	Pole Replacement Program	$480,000
2012	8	Renewal	Misc. Overhead and Underground Betterments	$485,000
2012	9	Regulatory	Plant Relocation for Road Widening	$150,000
2012	10	Customer Demand	Subdivision Development	$303,000
2012	11	Customer Demand	New Services and Service Upgrades	$450,000
2012	12	Transformers	Transformer Purchases to Increase Transformers on Hand	$0
2012	13	Meters	Meter Installations	$348,000
			Total:	$4,641,000

Note: The project number refers back to those referenced in Table 3.6

Table 3.8 - 2013 Distribution System Capital Expenditure Forecast

Budget Year	Project No.	Category	Project	Total
2013	1	Transformer Station	Transformer Station Capital (unforeseen)	$50,000
2013	2	Stations	Miscellaneous DS Equipment Upgrades	$75,000
2013	3	Renewal	4.16 kV to 27.6 kV Conversion Phase 3-Distributing Station NP 10 Waterford	$650,000
2013	4	Renewal	Pole Replacement Program - 2013	$480,000
2013	5	Renewal	Misc. Overhead and Underground Betterments	$485,000
2013	6	Renewal	Simcoe 4.16 kV to 27.6 kV Conversion Phase 2	$1,500,000
2013	7	Regulatory	Plant Relocation for Road Widening	$150,000
2013	8	Customer Demand	Subdivision Development	$303,000
2013	9	Customer Demand	New Services and Service Upgrades	$446,000
2013	10	Regulatory	Long Term Load Transfers elimination program - 2013	$300,000
2013	11	Regulatory	Norfolk TS Primary Metering Upgrade	$175,000
2013	12	Other	Fleet Replacement Plan – 2013	$340,000
			Total:	$4,954,000

1 **Table 3.9 - 2014 Distribution System Capital Expenditure Forecast**

Budget Year	Project No.	Category	Project	Total
2014	1	Transformer Station	Transformer Station Capital (unforeseen)	$50,000
2014	2	Stations	Miscellaneous DS Equipment Upgrades (unforeseen)	$75,000
2014	3	Renewal	Pole Replacement Program - 2014	$480,000
2014	4	Renewal	Misc. Overhead and Underground Betterments	$485,000
2014	5	Renewal	Simcoe 4.16 kV to 27.6 kV Conversion Phase 3	$1,500,000
2014	6	Regulatory	Plant Relocation for Road Widening	$150,000
2014	7	Customer Demand	Subdivision Development	$303,000
2014	8	Customer Demand	New Services and Service Upgrades	$446,000
2014	9	Renewal	4.16 kV to 27.6 kV Conversion Phase 4-Distributing Station NP 10 Waterford	$400,000
2014	10	Renewal	4.16 kV to 27.6 kV Conversion Prospect St and Grand St Areas - Port Dover	$400,000
2014	11	Regulatory	Long Term Load Transfers elimination program - 2014	$500,000
2014	12	Other	Fleet Replacement Plan – 2014	$340,000
			Total:	$5,129,000

CAPITALIZATION POLICY:

Norfolk has historically applied the following general capitalization policies and principles based on Canadian Generally Accepted Accounting Principles ("CGAAP"), as well as guidelines set out by the Ontario Energy Board, where applicable. Going forward capitalization will conform to the Modified International Financial Reporting Standards (MIFRS). The information found in this section applies to capitalization under CGAAP only. Changes due to the implementation of MIFRS are described in Tab 5 – Conversion to MIFRS.

The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary costs incurred to place a capital asset into its intended state of operation.

- Assets that are intended to be used on an on-going basis and are expected to provide future economic benefit greater than one year will be capitalized.
- Expenditures that create a physical betterment or improvement of the asset will be capitalized.
- With respect to transportation equipment all costs associated with placing a vehicle into service are capitalized.

GUIDELINES FOR CAPITALIZATION

Capital Assets

Capital Assets include tangible assets which include property, plant, and equipment provided they are held for use in the production or supply of goods and services. A capital expenditure must provide a benefit lasting beyond one year. Capital expenditures also include the improvement or "betterment" of existing assets. Intangible assets are also considered capital assets and are identified as assets that lack physical substance.

Betterment

A “betterment” is a cost which enhances the service potential of a capital asset and is therefore capitalized. A “betterment” includes expenditures which increase the capacity of the asset, lower associated operating costs of the asset, improve the quality of output or extend the asset’s useful life.

Repair

A repair is a cost incurred to maintain the service potential of a capital asset. Expenditures for repairs are expensed to the current operating period. Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are not capital expenditures and should be charged to an operating account.

CAPITAL ASSET COST

Cost

Cost is the amount of consideration given up to acquire, construct, develop or better a capital asset. Capital assets will be recorded at the fully allocated cost.

Fully Allocated costs

Fully allocated costs include all expenditures necessary to put a capital asset in service including all overhead cost based on full absorption costing.

Amortization

Capital assets are amortized based on a method and life set by the OEB which is considered a suitable indicator of estimated useful life for the electrical distribution industry.

Capital Spares

Spare transformers and meters will be accounted for as capital assets since they form an integral part of the reliability program for a distribution system. These spares are held for the purpose of backing up transformers and meters in-service for a distribution system.

SERVICE QUALITY & RELIABILITY PERFORMANCE:

NPDI tracks service reliability statistics SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index) including and excluding loss of supply related incidents. However, reliability statistics excluding loss of supply have only been recorded since 2008. The following shows results for the past three years.

Table 3.8 - Service Reliability Statistics

Year	SAIDI	SAIFI	CAIDI
Including Loss of Supply			
2007	5.07	1.71	2.96
2008	2.53	1.41	1.80
2009	2.88	3.54	0.81
2010	1.95	1.71	1.14
Excluding Loss of Supply			
2008	2.45	1.40	1.76
2009	2.19	1.81	1.21
2010	1.48	1.43	1.03

NPDI is committed to the reliability of the distribution system and has set 2011 target indices for SAIDI and SAIFI as follows:

Table 3.9 – Target Indices for 2011

	Including Loss of Supply	*Excluding Loss of Supply*
SAIDI	2.20	1.77
SAIFI	1.98	1.47

In order to meet these targets NPDI will need to continue to invest in capital and maintenance programs. In particular, the capital programs previously noted in Exhibit 2 with a primary driver of asset renewal are aimed at rebuilding infrastructure with a high probability of failure. Renewal of these assets removes the risk to reliability and safety that would otherwise be unacceptable.

In addition to the reliability indices, NDPI also measures service quality indicators ("SQIs"). The table below summarizes NPDI's reported SQIs for the historical years 2007 and 2008. In 2009, the SQI's were replaced by the Electricity Service Quality Requirements (ESQRs).

Table 3.10 - Reported Service Quality Indicators (SQIs)

Indicator	*OEB Minimum Standard*	*2007*	*2008*	*2009*	*2010*
Connection of New Services – Low Voltage	90% within 5 days	100%	100%	99%	99%
Connection of New Services – High Voltage	90% within 10 days	100%	100%	100%	100%
Underground Cable Locates	90% within 5 days	N/A	N/A	91%	90%
Telephone Call Abandon Rate	65% of calls answered within 30 seconds	83%	92%	88%	96%
Appointments - Scheduled	90% of the time	N/A	N/A	96%	91%
Appointments - Met	90% of the time	N/A	N/A	99%	91%
Written Responses to Inquiries	80% within 10 days	80%	75%	87%	91%
Emergency Response – Urban Areas	80% within 60 minutes	100%	100%	100%	92%
Emergency Response – Rural Areas	80% within 120 minutes	100%	100%	96%	82%

ALLOWANCE FOR WORKING CAPITAL

OVERVIEW AND CALCULATION BY ACCOUNT:

NPDI’s working capital allowance is forecast to be $5,992,935 for 2012 based on the methodology outlined on page 19 of the Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 22, 2011. Namely, 15% of the sum of Cost of Power and Controllable Expenses (Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General), as illustrated on Table 4.1 below. NPDI has provided a spreadsheet setting out NPDI’s Cost of Power calculations as Appendix B.

Table 4.1 - Working Capital Calculation

	2012 Test Year (GAAP)
Operations	1,226,500
Maintenance	1,165,100
Billing & Collecting	1,228,062
Community Relations	37,000
Administration and General	1,544,400
Taxes other than Income Taxes	35,000
Total Operating Expenses for Working Capital Allowance	5,236,062
Cost of Power	34,716,838
Total Base for Working Capital Allowance	39,952,900
Working Capital Allowance (15%)	5,992,935

CONVERSION TO MODIFIED INTERNATIONAL FINANCIAL REPORTING STANDARDS (MIFRS)

The conversion from Canadian Generally Accepted Accounting Principles (CGAAP) to Modified International Financial Reporting Standards (MIFRS) has resulted in a number changes to Norfolk's accounting for Plant Property and Equipment (PP&E).

IMPACT ON FIXED ASSETS:

Norfolk has elected to take the IFRS 1 Exemption for rate regulated entities, which allows the use of the net book value of assets as at the date of transition as the deemed cost of the asset. This change has been reflected in the continuity statements provided below for the 2011 Bridge year (Table 5.1) and the 2012 Test year (Table 5.2). The opening balance of the gross fixed assets for the 2011 Bridge year is the net book value of the assets for the same date under CGAAP. This results in an opening gross fixed asset balance of $49,389,911 and an opening balance of accumulated amortization of $0.

Componentization and Amortization

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 its useful lives, amortization methods and residual values on an annual basis.

Norfolk has reviewed the useful life of its assets with the aid of the Kinectrics report K-418033-RA-001-R000, entitled "Asset Depreciation Study for the Ontario Energy Board", dated July 8th, 2010. Exhibit 4, Tab 4, Schedule 2 outlines the amortization expense based on the new useful lives of the assets.

Norfolk has restated its continuity statements for the 2011 Bridge year and the 2012 Test year to include these changes.

IAS 16 – Property, Plant and Equipment – Measurement after Recognition.

For subsequent periods following the initial recognition of an asset, IAS 16 permits the choice of using either the Cost Model or the Revaluation Model for valuing PP&E. Norfolk will continue to use the Cost Model to measure PP&E.

Table 5.1: Continuity Statement – 2011 Bridge Year (MIFRS)

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	N/A	$ 391,259	$ -		$ 391,259	$ -	$ -		$ -	$ 391,259
	1806	Land Rights		$ 302,784	$ 1,000		$ 303,784	$ -	$ -		$ -	$ 303,784
47	1808	Buildings	2.00%	$ 1,439,503	$ -		$ 1,439,503	$ -	-$ 33,112		-$ 33,112	$ 1,406,391
13	1810	Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.00%	$ 8,387,996	$ -		$ 8,387,996	$ -	-$ 232,330		-$ 232,330	$ 8,155,666
47	1820	Distribution Station Equipment <50 kV	3.30%	$ 2,404,514	$ 65,131		$ 2,469,645	$ -	-$ 161,059		-$ 161,059	$ 2,308,586
47	1825	Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 13,659,082	$ 1,038,945		$ 14,698,027	$ -	-$ 395,240		-$ 395,240	$ 14,302,786
47	1835	Overhead Conductors & Devices	4.00%	$ 8,660,771	$ 738,072		$ 9,398,843	$ -	-$ 191,773		-$ 191,773	$ 9,207,070
47	1840	Underground Conduit	4.00%	$ 2,503,558	$ 191,050		$ 2,694,608	$ -	-$ 60,211		-$ 60,211	$ 2,634,397
47	1845	Underground Conductors & Devices	4.00%	$ 4,923,361	$ 336,943		$ 5,260,304	$ -	-$ 219,158		-$ 219,158	$ 5,041,146
47	1850	Line Transformers	4.00%	$ 5,271,877	$ 784,127		$ 6,056,004	$ -	-$ 174,804		-$ 174,804	$ 5,881,200
47	1855	Services (Overhead & Underground)	4.00%	$ 2,258,010	$ 232,828		$ 2,490,838	$ -	-$ 66,958		-$ 66,958	$ 2,423,880
47	1860	Meters	4.00%	$ 1,781,996	$ 62,526		$ 1,844,522	$ -	-$ 97,707		-$ 97,707	$ 1,746,815
47	1860	Meters (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
N/A	1905	Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 1,466,546	$ 10,000		$ 1,476,546	$ -	-$ 101,372		-$ 101,372	$ 1,375,174
13	1910	Leasehold Improvements	10.00%	$ 2,314	$ -		$ 2,314	$ -	-$ 654		-$ 654	$ 1,660
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 58,409	$ 15,000		$ 73,409	$ -	-$ 15,568		-$ 15,568	$ 57,841
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 159,156	$ 30,000		$ 189,156	$ -	-$ 63,095		-$ 63,095	$ 126,061
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 122,771	$ 27,000		$ 149,771	$ -	-$ 37,574		-$ 37,574	$ 112,197
12	1925	Computer Software (Smart Meters)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1930	Transportation Equipment	10% to 25%	$ 476,107	$ 440,000		$ 916,107	$ -	-$ 82,451		-$ 82,451	$ 833,656
8	1935	Stores Equipment	10.00%	$ 14,447	$ -		$ 14,447	$ -	-$ 3,990		-$ 3,990	$ 10,457
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 133,419	$ 35,000		$ 168,419	$ -	-$ 32,269		-$ 32,269	$ 136,150
8	1945	Measurement & Testing Equipment	10.00%	$ 70,554	$ -	-$ 42,514	$ 28,040	$ -	-$ 12,762		-$ 12,762	$ 15,278
8	1950	Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	10.00%	$ 51,872	$ 8,000	-$ 13,133	$ 46,739	$ -	-$ 23,866		-$ 23,866	$ 22,873
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	10.00%	$ 299,192	$ -	-$ 33,857	$ 265,335	$ -	-$ 99,699		-$ 99,699	$ 165,636
47	1975	Load Management Controls Utility Premises	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	6.70%	$ 829,042	$ 212,761		$ 1,041,803	$ -	-$ 57,234		-$ 57,234	$ 984,569
45.1	1980	System Supervisor Equipment - Hardware	20.00%	$ 15,397	$ -		$ 15,397	$ -	-$ 847		-$ 847	$ 14,550
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 6,541,679	-$ 861,340		-$ 7,403,019	$ -	$ 193,818		$ 193,818	-$ 7,209,201
8	2005	Property Under Capital Lease	10.00%	$ 4,015	$ -		$ 4,015	$ -	-$ 1,004		-$ 1,004	$ 3,011
N/A	2055	Work In Progress	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
		Total		**$ 49,389,911**	**$ 3,367,043**	**-$ 89,504**	**$ 52,667,450**	**$ -**	**-$ 1,970,919**	**$ -**	**-$ 1,970,919**	**$ 50,696,531**

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation	
Transportation	-$ 82,451
Stores & Garage Equipment	-$ 37,263
Computer HW & SW	$ -
Net Depreciation to Inc. Stmt	**-$ 1,851,205**

Table 5.2: Continuity Statement – 2012 Test Year (MIFRS)

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	N/A	$ 391,259	$ -		$ 391,259	$ -	$ -		$ -	$ 391,259
CEC	1806	Land Rights	N/A	$ 303,784	$ -		$ 303,784	$ -	$ -		$ -	$ 303,784
47	1808	Buildings	2.00%	$ 1,439,503	$ -		$ 1,439,503	-$ 33,112	-$ 33,112		-$ 66,224	$ 1,373,279
13	1810	Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.00%	$ 8,387,996	$ -		$ 8,387,996	-$ 232,330	-$ 232,330		-$ 464,660	$ 7,923,336
47	1820	Distribution Station Equipment <50 kV	3.30%	$ 2,469,645	$ 245,564		$ 2,715,209	-$ 161,059	-$ 167,198		-$ 328,257	$ 2,386,952
47	1825	Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 14,698,027	$ 1,306,399		$ 16,004,426	-$ 395,240	-$ 421,300		-$ 816,540	$ 15,187,885
47	1835	Overhead Conductors & Devices	4.00%	$ 9,398,843	$ 825,987		$ 10,224,830	-$ 191,773	-$ 199,428		-$ 391,201	$ 9,833,629
47	1840	Underground Conduit	4.00%	$ 2,694,608	$ 89,296		$ 2,783,904	-$ 60,211	-$ 63,015		-$ 123,226	$ 2,660,678
47	1845	Underground Conductors & Devices	4.00%	$ 5,260,304	$ 181,271		$ 5,441,575	-$ 219,158	-$ 227,795		-$ 446,953	$ 4,994,622
47	1850	Line Transformers	4.00%	$ 6,056,004	$ 850,097		$ 6,906,101	-$ 174,804	-$ 195,231		-$ 370,035	$ 6,536,066
47	1855	Services (Overhead & Underground)	4.00%	$ 2,490,838	$ 334,860		$ 2,825,698	-$ 66,958	-$ 74,055		-$ 141,013	$ 2,684,685
47	1860	Meters	4.00%	$ 930,358	$ 310,750		$ 1,241,108	-$ 44,214	-$ 50,876		-$ 95,090	$ 1,146,018
47	1860	Meters (Smart Meters)	10.00%	$ 3,214,012	$ -		$ 3,214,012	-$ 479,090	-$ 321,401		-$ 800,491	$ 2,413,521
N/A	1905	Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 1,476,546	$ -		$ 1,476,546	-$ 101,372	-$ 101,472		-$ 202,844	$ 1,273,702
13	1910	Leasehold Improvements	10.00%	$ 2,314	$ -		$ 2,314	-$ 654	-$ 654		-$ 1,308	$ 1,006
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 73,409	$ 15,500		$ 88,909	-$ 15,568	-$ 13,790		-$ 29,358	$ 59,551
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 189,156	$ 40,000		$ 229,156	-$ 63,095	-$ 93,720		-$ 156,815	$ 72,341
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 149,771	$ 142,500		$ 292,271	-$ 37,574	-$ 47,211		-$ 84,785	$ 207,486
12	1925	Computer Software (Smart Meters)	25.00%	$ 406,373	$ -		$ 406,373	-$ 129,885	-$ 101,593		-$ 231,478	$ 174,895
10	1930	Transportation Equipment	10% to 25%	$ 916,107	$ 40,000		$ 956,107	-$ 82,451	-$ 98,451		-$ 180,902	$ 775,205
8	1935	Stores Equipment	10.00%	$ 14,447	$ -		$ 14,447	-$ 3,990	-$ 3,107		-$ 7,097	$ 7,350
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 168,419	$ 28,000		$ 196,419	-$ 32,269	-$ 30,959		-$ 63,228	$ 133,191
8	1945	Measurement & Testing Equipment	10.00%	$ 28,040	$ -		$ 28,040	-$ 12,762	-$ 9,772		-$ 22,534	$ 5,506
8	1950	Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	10.00%	$ 46,739	$ 53,000		$ 99,739	-$ 23,866	-$ 22,089		-$ 45,955	$ 53,784
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	10.00%	$ 265,335	$ -		$ 265,335	-$ 99,699	-$ 88,879		-$ 188,578	$ 76,757
47	1975	Load Management Controls Utility Premises	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	6.70%	$ 1,041,803	$ 89,296		$ 1,131,099	-$ 57,234	-$ 64,785		-$ 122,019	$ 1,009,080
45.1	1980	System Supervisor Equipment - Hardware	20.00%	$ 15,397	$ -		$ 15,397	-$ 847	-$ 847		-$ 1,694	$ 13,703
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 7,403,019	-$ 652,000		-$ 8,055,019	$ 193,818	$ 205,507		$ 399,325	-$ 7,655,694
8	2005	Property Under Capital Lease	10.00%	$ 4,015	$ -		$ 4,015	-$ 1,004	-$ 1,004		-$ 2,008	$ 2,007
N/A	2055	Work In Progress	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
		Total		**$ 55,373,671**	**$ 3,900,520**	**$ -**	**$ 59,274,191**	**-$ 2,526,401**	**-$ 2,458,567**	**$ -**	**-$ 4,984,969**	**$ 54,289,222**

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation	
Transportation	-$ 98,451
Stores & Garage Equipment	-$ 32,591
Computer HW & SW	$ -
Net Depreciation to Inc. Stmt	**-$ 2,327,525**

IMPACT ON CAPITALIZATION OF BURDENS & THEREFORE CAPITAL BUDGETS:

Standard IAS 16 – Property, Plant and Equipment (PP&E) states that the cost of an item of PP&E includes those costs 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 CGAAP allowed for the capitalization of general and administrative overhead, IFRS does not.

Norfolk has reviewed the costs included within its burdens to determine which continue to be appropriate expenses to capitalize and which should be removed from the burden and directly expensed as part of OM&A. For 2012 Norfolk has identified a total of $615,555 that was contained in its burden rates and included as capital expense as part of the 2012 capital budget as described in Exhibit 2, Tab 3, as well as amounts reported in the GEA projects. (2011 amount: $597,066). The capital budget and GEA projects for both the 2011 Bridge year and the 2012 Test year have been restated below in Table 5.3 and Table 5.4 with the removal of these amounts. Table 5.5 and Table 5.6 contain the same information by account.

Exhibit 4, Tab 4, Schedule 1 provides a detailed breakdown of these expenses and how they will impact OM&A.

Table 5.3: Summary of 2011 Capital Spending (With Reduction in Burden)

	2011 Test (GAAP)	Burden Amount Removed	2011 Test (IFRS)
Distribution Plant (Net of Contributions)	3,112,000	(522,718)	2,589,282
General Plant	810,000	(32,239)	777,761
GEA Requirements (Net of Contributions)	299,340	(42,109)	257,231
Total	4,221,340	(597,066)	3,624,274

Table 5.4: Summary of 2012 Capital Spending (With Reduction in Burden)

	2012 Test (GAAP)	Burden Amount Removed	2012 Test (IFRS)
Distribution Plant (Net of Contributions)	3,989,000	(496,776)	3,492,224
General Plant	419,000	(10,704)	408,296
GEA Requirements (Net of Contributions)	757,500	(109,075)	648,425
Total	5,165,500	(616,555)	4,548,945

Table 5.5: 2011 Capital Budget and GEA Plan – IFRS Compliant

DISTRIBUTION PLANT - 2011 Budget

Category	TOTAL	Land Rights (1806)	MS/DS Equip (1820)	Pole (1830)	OH Cond (1835)	Conduit (1840)	UG Cond (1845)	Trans (1850)	Services (1855)	Meters (1860 & 1555)
SUBTOTAL	3,973,340	1,000	75,000	1,196,375	849,912	220,000	388,000	902,945	268,108	72,000
IFRS - Less overhead to be expensed	(522,718)		(9,869)	(157,430)	(111,840)	(28,950)	(51,057)	(118,818)	(35,280)	(9,474)
Capital Contributions	**(861,340)**									
TOTAL DISTRIB. PLANT CAPITAL EXPENDITURES	**2,589,282**	**1,000**	**65,131**	**1,038,945**	**738,072**	**191,050**	**336,943**	**784,127**	**232,828**	**62,526**

GENERAL PLANT - 2011 Budget

Category	Total	Land (1905)	Serv. Ctre. Bldg. (1908)	Office Equip. (1915)	Comp. Hardware (1920)	Comp Software (1925)	Trucks (1930)	Tools and Equip. (1935) (1940) (1945) (1960)	SCADA Equip (1980) (1981)	Commun. Equip. (1955)
TOTAL GENERAL PLANT CAPITAL EXPENDITURES	**810,000**		**10,000**	**15,000**	**30,000**	**27,000**	**440,000**	**35,000**	**245,000**	**8,000**
IFRS - Less Overhead to be expensed	**(32,239)**								**(32,239)**	
Capital Expenditures for IFRS	**777,761**		**10,000**	**15,000**	**30,000**	**27,000**	**440,000**	**35,000**	**212,761**	**8,000**

Renewable Energy - 2011 Budget

Category	TOTAL	TS Equip (1815)	Poles (1830)	OH Conductor (1835)	Trans (1850)	Services (1855)	Meters (1860 & 1555)
Total	320,000	100,000	35,000	26,000	57,000	60,000	42,000
IFRS - Less Overhead to be expensed	(42,109)	(13,159)	(4,606)	(3,421)	(7,501)	(7,895)	(5,527)
Less Contributions	(20,660)						
Capital Expenditures for IFRS	257,231	86,841	30,394	22,579	49,499	52,105	36,473

Table 5.6: 2012 Capital Budget and GEA Plan – MIFRS Compliant

DISTRIBUTION PLANT - 2012 Budget (Test Year)

Category	TOTAL	Land Rights (1806)	TS Equip (1815)	MS/DS Equip (1820)	Pole (1830)	OH Cond (1835)	Conduit (1840)	UG Cond (1845)	Trans (1850)	Services (1855)	Meters (1860 & 1555)
SUBTOTAL	4,641,000			275,000	1,463,000	925,000	100,000	203,000	952,000	375,000	348,000
IFRS Adjustment	(496,776)			(29,436)	(156,601)	(99,013)	(10,704)	(21,729)	(101,903)	(40,140)	(37,250)
Capital Contributions	(652,000)										
TOTAL DISTRIBUTION PLANT CAPITAL EXPENDITURES	3,492,224			245,564	1,306,399	825,987	89,296	181,271	850,097	334,860	310,750

GENERAL PLANT - 2012 Budget (Test Year)

Category	Total	Land (1905)	Land Rights (1906)	Serv. Ctre. Bldg. (1908)	Office Equip. (1915)	Comp. Hardware (1920)	Comp Software (1925)	Trucks (1930)	Tools and Equip. (1935) (1940) (1945) (1960)	SCADA Equip (1980) (1981)	Commun Equip. (1955)
TOTAL GENERAL PLANT CAPITAL EXPENDITURES	419,000	0	0	0	15,500	40,000	142,500	40,000	28,000	100,000	53,000
IFRS - Less Overhead to be expensed	(10,704)									(10,704)	
Capital Expenditures for IFRS	408,296	0	0	0	15,500	40,000	142,500	40,000	28,000	89,296	53,000

Renewable Energy - 2012 Budget (Test Year)

Category	TOTAL	TS Equip (1815)	Pole (1830)	OH Conductor (1835)	Trans (1850)	Services (1855)	Meters (1860 & 1555)	(SCADA 1980/1)
Total	1,019,000	100,000	215,000	401,000	138,000	73,000	72,000	20,000
IFRS - Less Overhead to be expensed	(109,075)	(10,704)	(23,014)	(42,923)	(14,772)	(7,814)	(7,707)	(2,141)
Less Contributions	(261,500)							
Capital Expenditures for IFRS	648,425	89,296	191,986	358,077	123,228	65,186	64,293	17,859

MIFRS IMPACT ON RATE BASE:

As can be seen in Table 5.7, the conversion to MIFRS results in an increase in the 2011 net book value of assets by $357,332.

Table 5.7 Impact of MIFRS – Net Book Value

	2011 Bridge GAAP	2011 Bridge IFRS	Variance
Gross Fixed Assets	79,147,237	52,667,450	
Accumulated Depreciation	28,808,038	1,970,919	
Net Book Value	50,339,199	50,696,531	357,332

Consistent with the *Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment* (EB-2008-0408) dated June 13, 2011, Norfolk requests approval to move the variance amount of $357,332 to a PP&E deferral account for disposition to customers. The request for disposition of this amount is contained in Exhibit 9, Tab 7, PP&E Deferral Account and Disposition.

Table 5.8 below provides a comparison of rate base between CGAAP and MIFRS for the 2012 Test Year. The change in net book value has been described above. The working capital allowance has increased under MIFRS as a result of increased operating expenses, stemming from the removal of expenses from capitalized burdens to OM&A.

Table 5.8 2012 Test GAAP vs. 2012 Test IFRS

	2011 Bridge GAAP	2012 Test GAAP	2011 Bridge IFRS	2012 Test IFRS
Gross Fixed Assets	79,147,237	84,994,791	52,667,450	59,274,191
Accumulated Depreciation	28,808,038	31,482,220	1,970,919	4,984,969
Net Book Value	50,339,199	53,512,571	50,696,531	54,289,222
Average Net Book Value		52,991,496		53,568,246
Working Capital Allowance (15%)		5,992,935		6,085,418
Rate Base		58,984,431		59,653,664

A detailed calculation of the Working Capital Allowance is provided below in Table 5.9.

Table 5.9 2012 Test Year Working Capital Allowance - MIFRS

	2012 Test Year (MIFRS)
Operations	1,288,506
Maintenance	1,248,605
Billing & Collecting	1,228,062
Community Relations	37,000
Administration and General	2,015,444
Taxes other than Income Taxes	35,000
Total Operating Expenses for Working Capital Allowance	5,852,617
Cost of Power	34,716,838
Total Base for Working Capital Allowance	40,569,455
Working Capital Allowance (15%)	6,085,418

GREEN ENERGY PLAN :

Norfolk has submitted a basic Green Energy Plan to the OPA and has provided a copy in Appendix C. The OPA provided a Letter of Comment which has been provided in Appendix D. As part of its plan Norfolk has estimated capital spending requirements of $257,231 in 2011 and $648,425 in 2012. (Original plan was submitted under CGAAP, estimates provided here under MIFRS).

As part of this application Norfolk is requesting a funding adder to be included in its rates. This request can be found in Exhibit 9, Tab 6, Green Energy Plan – Funding Adder.

EXHIBIT 2

APPENDIX A

Asset Management Plan

NORFOLK POWER DISTRIBUTION INC.

ASSET MANAGEMENT PLAN

2012 to 2014

The material in this document is proprietary and is intended only for use by Norfolk Power Distribution Inc. This material may not be copied or reproduced, in whole or in part, without the prior and express written permission of Norfolk Power Inc., Norfolk Power Distribution or Norfolk Energy.

Table of Contents

Norfolk Power Distribution Inc.

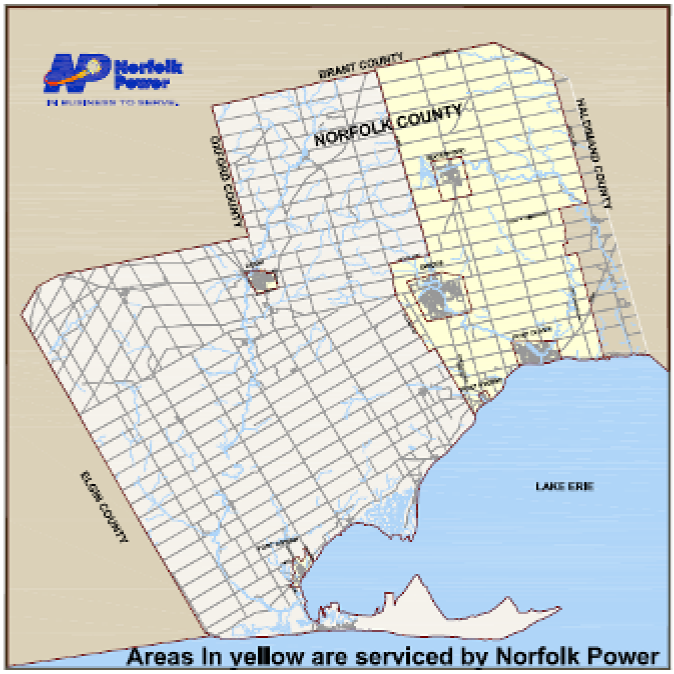
Utility Overview

Norfolk Power Inc. was formed in November 2000 by the amalgamation of four individual distribution utilities: Simcoe Hydro, Norfolk Hydro Electric, Nanticoke (West) Hydro and Delhi Hydro. Norfolk Power Inc. is the holding company for subsidiaries Norfolk Power Distribution and Norfolk Energy.

Norfolk Power Distribution Inc. (NPDI) is a small, Local Distribution Company (LDC), regulated and licensed by the Ontario Energy Board (OEB), with a service area of approximately 693 square kilometers, including 144 square kilometers of high density urban area and 549 square kilometers of low density rural area. NPDI is responsible for providing all regulated electricity distribution services to over 19,000 residential and business customers in distribution service area as set out in Schedule 1 of its Electricity Distribution License (ED-2002-0521) as follows:

1. The westerly half of the former City of Nanticoke within the Municipality of the Town of Norfolk as of December 31, 2000.
2. The former Town of Delhi (in the former Township of Delhi) within the Municipality of the Town of Norfolk as of December 31, 2000.
3. The former Town of Port Rowan (in the former Township of Norfolk) within the Municipality of the Town of Norfolk as of December 31, 2000; and Villages of Long Point Bay, Phase 7, Registered Plan #37M-23, Block 36 & Block 37, Lot #3 to 14 and Lot #17 to 35 being the customers identified in a list provided by Norfolk Power as part of its amended application.

4. The former Town of Simcoe within the Municipality of the Town of Norfolk as of December 31, 2000.



NPDI is committed to providing a reliable supply of electricity at reasonable distribution rates in an environment which focuses on safety, efficiency and increased economic development.

Corporate Values

The team at Norfolk Power Distribution Inc. is dedicated to:

- Delivery of safe and reliable electricity to the consumer
- Responding to power outages and emergencies quickly and efficiently
- Building and maintaining the electric distribution system
- Providing the highest level of service to customers

Asset Management Overview

With the aging infrastructure of Ontario's distribution systems, asset management has become vital to Local Distribution Companies (LDCs) in addressing safety, reliability and business risk challenges. NPDI has established inspection, maintenance and renewal programs to address these challenges, as well as the reporting requirements of the OEB's Distribution System Code (DSC), while cost-effectively improving system performance and reliability, optimizing distribution system asset utilization and meeting or exceeding customer expectations for the safe delivery of electricity at reasonable prices.

Asset Management Objectives

The following outlines key objectives of NPDI's approach to asset management that generally serve to ensure safety, capacity, reliability, security of its distribution system:

- Development of an organized inspection and condition-assessment program for substations, overhead distribution system and underground distribution system
  - Inspection programs should be consistent with good utility practice and regulatory requirements
  - Inspection programs and/or cycles should be adaptive and consider: the acquisition of new asset classes, significant changes to equipment conditions, system design/performance, significance of asset(s) to distribution system or emerging technologies; programs and/or cycles may also be revised based on historical maintenance data or cost/benefit analysis
- Development of organized maintenance programs
  - Maintenance programs should be consistent with good utility practice and manufacturer's recommendations
  - Maintenance programs should be adaptive and consider: the acquisition of new assets, significant changes to equipment condition, system design/performance, significance of asset(s) to the distribution system or emerging technologies; maintenance programs and/or cycles may also be revised based on historical inspection data or cost/benefit analysis
- Long-term preservation of the electric distribution system
- Progress towards achieving performance measures within reasonable budget considerations

- Development of Capital and Operations & Maintenance budgets supported by fact-based data from inspection and maintenance programs, and from reliability, capacity and security reviews.
    - The budget should reflect changes to the distribution system that could allow for improved reliability and enhancements to the distribution system or operational efficiencies
    - The budgets should provide justification for proposed expenditures and be adaptable to changing priorities
- Annual review of the asset management strategy

NPDI Asset Management Roles & Responsibilities

The role of Asset Manager is shared between the Distribution Engineer, Operations Manager, Line Superintendent and Manager of Safety and Technical Support Services. Each has extensive experience with the distribution system and performs many duties pertaining to asset management applicable to electric utilities, as described throughout this Plan.

Generally, these responsibilities include:

- ensuring schedules for inspection and maintenance are adhered to,
- reviewing inspection and maintenance data,
- reviewing data related to the condition of the distribution system over the short, medium and long-term periods to ensure safe and reliable electricity supply in a cost-effective manner,
- performing analysis,
- incorporating activities/solutions within the Capital and OM&A budgets.

Risk Management

Risk management in the electrical distribution industry is a fundamental activity and comprises a methodical approach to assessing distribution system assets and with respect to vulnerability and consequence, to identify and mitigate risk(s) to those assets. Generally, the methodology includes an assessment to identify: assets (including critical assets), condition, age and life expectancy, location, threats, vulnerability of assets to threats (i.e. risk), and consequence of failure. Additionally, and through data analysis, the methodology includes identification of remedy(ies) to remove or mitigate risk and/or failure.

NPDI's systematic approach to risk management, as outlined in the inspections, condition assessment, maintenance programs, and subsequent analysis of data from these programs, contributes to overall awareness and responsiveness to the dynamic nature of the distribution system and to the responsible management of its system.

Inspections and Condition Assessments

Minimum inspection and interval standards are defined within the OEB's DSC. Specifically, Table C-1 identifies the maximum intervals, in years, for visual patrols, which for most urban facilities is 3 years, rural facilities is 6 years and stations is 1 year, 3 years or 6 months. A definition of Patrol Inspection is also included within the requirements document. The major distribution facilities within Norfolk Power's service area are systematically and routinely patrolled to identify condition-related deficiencies and to fulfill the Minimum Inspection Requirements of the DSC.

Overhead Systems

General Practice of System Patrol

NPDI performs annual inspections of its complete service territory whereby approximately one-third of its overhead distribution system, comprised of both urban and rural areas, is visually patrolled on an annual basis, completing the patrol of the entire distribution system on a three year cyclical basis. The patrol, performed by NPDI Power Line Maintainers (PLMs) or other qualified Norfolk Power personnel or contractors, serves as a visual inspection 'to identify obvious structural problems and hazards'[1] and to assess the condition of major distribution system assets. On the overhead distribution system, these assets include poles and pole supports/attachments, distribution transformers, switches and protective devices, conductors and surrounding vegetation, as applicable.

While Appendix C of the DSC stipulates inspections cycles, the OEB has given LDC's discretion in determining the method by which to structure these cycles. NPDI is intending to review alternate methods by which inspection cycles are structured, as proposed in Appendix C. Currently however, NPDI has adopted the method of organizing its inspections based on feeder egress from substations. The Control Room Operator maintains a master list of these feeders, from which one-third representing one-third of the overhead urban and rural distribution system, are extracted and provided to the Operations Manager for scheduling and implementation of inspections. The process of visually patrolling and identifying

---

[1] OEB Appendix C of the Distribution System Code 'Minimum Inspection Requirements', Section C.1, page 1

deficiencies on the overhead distribution system is facilitated through the use of an overhead package for the inspection of one (1) to three (3) feeders from a substation.

This package includes a schematic of the distribution system, highlighting the feeders for which the overhead inspection is to be completed, an ‘Overhead Plant Inspection Report’ (Appendix 1), or spreadsheet equivalent and a copy of Appendix C of the DSC; this document provides guidance as to the types of defects to consider during the visual patrol and, as noted within the document, provides a ‘generic patrol expectation’. Table 1 below outlines conventional overhead assets and examples of deficiencies associated with each asset which may be routinely identified during the patrol.

Table1: Overhead distribution system assets and conventional deficiencies associated with each

ASSET	CONVENTIONAL DEFICIENCIES
Poles/Pole Supports	Bent, rotting or cracked, insect damage, missing guy guards
Pole Hardware/Attachments	Loose or missing, contaminated insulators
Distribution Transformers	Rusted, missing or incorrect phase indicators, leaking oil
Conductors	Low clearance, broken or frayed, exposed or broken ground wires
Switches/Protective Devices	Bent or broken bushings and cutouts, damaged lighting arresters
Vegetation	Overgrown, interference

The ‘Overhead Plant Inspection Report’ is on a ‘report by exception’ basis. That is, defects pertaining to Appendix C of the DSC identified during the inspection are noted on the report, along with the location and description of the deficiency, the related feeder, the category of overhead asset, the date and initials of the person performing the inspection. Although a system by which deficiencies are prioritized has not been formally established or documented, NPDI relies heavily on the extensive experience of its personnel to determine the urgency or severity of deficiencies observed during the visual patrol. Deficiencies posing an immediate health and/or safety risk are categorized as critical and therefore deemed to be highest priority. Such critical deficiencies are immediately reported during a visual patrol. A ‘Service Call’ form (Appendix 2) may, in turn, be issued, with documentation of the reported deficiency. The ‘Service Call’ form developed by NPDI identifies the work to be completed and reported problem (i.e. the deficiency), allowing for such information as a description of the defective equipment (manufacturer, model, and serial number), method of failure, cause of failure, resultant damage and work completed (i.e. the remedial action/reactive maintenance). Also included is auxiliary and supporting information including service call identification number, call source, outage information (if applicable), identification of the nature of the work, confirmation of no undue hazard, identification of employee completing the work and supervisor signature for review by the Line Superintendent.

Following completion of the visual patrol, the remaining inspection reporting forms identifying non-critical deficiencies are returned to the Line Superintendent for subsequent review. On occasion, the Line Superintendent will perform random ‘spot checks’ of the deficiencies reported on the ‘Overhead Plant Inspection Report’. In addition to the routine visual patrol completed by the Norfolk Power personnel, the Line Superintendent also performs an informal patrol coincident with other routine duties. Any deficiencies observed are documented separately within the ‘Pole Line Inspections and Deficiencies’ spreadsheet (Appendix 3).

Poles

NPDI has approximately 11,020 poles; annual visual inspections of these poles are conducted internally by PLMs, , or other qualified Norfolk Power personnel or contractors whereby one third of the total pole count is inspected on a three-year cyclical basis as per the methodology of the general system patrol of the overhead distribution system. These patrols allow NPDI to identify defects, or other issues, concerning the integrity of the pole and its supports, hardware and attachments as outlined within Appendix C of the DSC and as follows:

Poles/Supports

- Bent, cracked or broken poles
- Excessive surface wear or scaling
- Loose, cracked or broken cross arms and brackets
- Woodpecker or insect damage, bird nests
- Broken or dismantled guy strain insulators
- Missing guy guards
- Grading changes or washouts
- Indications of burning

Hardware/Attachments

- Loose or missing hardware
- Insulators unattached from pins
- Conductor unattached from insulators
- Flashed over or obviously contaminated insulators
- Unraveled tie wires
- Broken or removed ground wire
- Broken or removed ground wire guards

Deficiencies, as identified by PLMs or other qualified Norfolk Power personnel or contractors, and noted on the ‘Overhead Plant Inspection Report’, are based on those that are critical and those that are non-critical.

The visual patrol, while allowing for defects to be identified and/or monitored, does not provide a comprehensive technique for the condition-based assessment of wood poles on NPDI’s distribution system. Unlike concrete or steel poles, where the condition is generally more apparent, the condition and integrity of wood poles is often not evident, with the exception of tip feather, exterior rotting, etc. To gain a better assessment of pole conditions, NPDI engages the services of a specialized pole testing contractor to perform wood pole testing and condition assessment, with documentation of condition data and pole attributes. Condition data includes the mechanical condition, overall condition, recommendations, remaining life and general comments about the pole and its supports/attachments. Attribute data includes the pole (and other equipment) identification number, year of manufacture, class, height, species, treatment type and length, diameter and structure at ground level. Collectively, this raw data is maintained within one of NPDI’s databases and supplies data to the ‘Pole Data Sheet’ within a resource database. An overall pole condition is assigned, based on these data, as one of ‘poor’, ‘fair’, or ‘good’ to assist in determining the priority in which to address pole deficiency(ies). Additionally, the condition assessment of poles includes recommendations as follows:

- Replace immediately
- Replace within 1 – 2 years
- Retest within 2 – 5 years
- Retest within 5 – 10 years

Those poles which are recommended for immediate replacement are further analyzed based on likely impact of failure. A review by engineering with consideration to criteria such as exposure to public (pole located adjacent to a highway vs. a secondary road), pole function (switch or transformer pole), condition of adjacent poles etc. is used to determine pole replacement priority. Higher priority poles recommended for immediate replacement are designed and scheduled for replacement almost immediately with those of lower priority scheduled for replacement in the next year or two. Those poles recommended for replacement within one to two years are also prioritized and scheduled for replacement accordingly; while poles in general are not run-to-failure because of safety concerns, these poles are replaced as close to failure as possible and, as such, closely monitored.

The recommendations from the condition assessment for retesting form the basis for establishing a future cycle for pole testing. The pole testing cycle will ultimately be need based rather than time based. Future pole testing will serve to further confirm the condition of these poles and will assist in identifying specific capital pole replacements.

In 2009, the pole inspection and testing program was performed by an outside contractor in conjunction with pole data capture efforts driven by the GIS system implementation. Poles visited for unique ID tagging, GIS mapping and collection of attribute data were also inspected, and tested if it was determined that they were older than 20 years. In Q4 of 2009, 3182 poles were inspected and 2332 were tested. In Q4 of 2010, approximately 3000 poles were inspected and tested. It is expected that by the end of 2011, all NPDI owned poles will have a unique ID assigned, be mapped onto the GIS system and have associated attribute and condition data.

Distribution Transformers

Inspections of pole-mounted transformers, of which there are approximately 3600, are another component of the visual patrol of the overhead system and are therefore inspected on a three year cyclical basis.

The inspection is comprised of a visual assessment of the following based on the OEB's Minimum Inspection Requirements from Appendix C of the DSC:

- Paint and body corrosion
- Accessibility
- Leaking oil
- Flashed or cracked insulators
- Bushing damage/contamination/discolouration or flashover
- Ground lead attachments
- Animal and vegetation interference
- Verification of phase indicators and equipment numbers as per operating maps

As with the general overhead practices, deficiencies associated with distribution transformers are documented on the 'Overhead Plant Inspection Report'.

Conductors

Included within the visual patrol of the overhead distribution system is the inspection of overhead primary and secondary conductors. The inspection is comprised of a visual assessment of the following based on the OEB's Minimum Inspection Requirements from Appendix C of the DSC:

- Conductor clearance(s)

- Condition (broken/frayed conductor or tie wires)
- Broken strands and bird caging
- Insulation fraying (especially on open wire secondary conductors)

With the exception of conductor clearance, deficiencies as described above are a rare occurrence. However, any deficiencies that have been observed are documented on the 'Overhead Plant Inspection Report'.

Switches and Protective Devices

Inspection of solid blade, fused solid and load interrupter and air-break switches is also included as a component of the visual patrol of the overhead distribution system. That is, switches are inspected on a 3 year cyclical basis during the overhead inspection whereby the condition of the switch is noted on the 'Overhead Plant Inspection Report' as described in the practice of system patrol. Generally, overhead switches and protective devices are inspected for bent or broken bushings and cutouts, as well as damaged lighting arresters, control boxes, current and potential transformers.

NPDI has developed a separate procedure for inspection of LIS and Air-Break Switches; this procedure is included with the maintenance instructions further discussed, as inspection and maintenance are performed concurrently where possible.

Underground Systems

General Practice of System Patrol

Similar to the overhead process of visual patrol, the underground distribution system comprising urban and rural regions of NPDI's 8 service areas is also inspected on a three-year cyclical basis by NPDI PLMs. The patrol serves as a visual inspection 'to identify obvious structural problems and hazards' and to assess the condition of major distribution system assets. On the underground distribution system, these assets include cable dips, distribution transformers, switching cubicles and vegetation surrounding these assets.

The visual patrol of the underground distribution system, as noted above, is facilitated through the use of an underground package for the inspection of underground distribution assets. This package includes a schematic showing transformer and switching cubicle locations, the 'Norfolk Power Underground Transformer Inspection' work instructions and the 'Norfolk Power Underground Transformer Inspection' reporting form (Appendix 4). Also included is a copy of Appendix C of the DSC, providing guidance and examples of conventional deficiencies on underground distribution system assets for which to document during patrol; table 2 provides examples of such deficiencies which may be routinely identified by PLMs.

Table 2: Underground assets and conventional deficiencies associated with each

ASSET	CONVENTIONAL DEFICIENCIES
Distribution Transformers	Rusted, leaking oil, lid damage, security lock damage
Switches/Protective Devices	Compromised structural condition of enclosure, damaged locks
Vegetation	Overgrown, interference

As with the overhead system, a system by which deficiencies are prioritized has not been formally established. However, NPDI relies on the extensive experience of its PLMs to determine the urgency or severity of deficiencies observed during the visual patrol. An example of a critical deficiency on the underground distribution system could include visible damage to a transformer that could provide access to live parts. Such, or other, critical deficiencies are reported directly and a ‘Service Call’ form is, in turn, issued with documentation of the deficiency reported.

Following completion of the visual patrol, the remaining inspection reporting forms identifying non-critical deficiencies are returned to the Line Superintendent for subsequent review. On occasion, the Line Superintendent will perform random audits of reported deficiencies.

Distribution Transformers

NPDI’s underground distribution system has approximately 800 distribution transformers, comprised primarily of pad-mounts and Pole-Trans, but also including a few submersible transformers. Inspections of these transformers occur within the visual patrol of the underground distribution system and are therefore inspected on a 3 year cycle, whereby approximately one-third of the transformers within NPDI’s distribution system are scheduled to be inspected on an annual basis. The ‘Norfolk Power Underground Transformer Inspection’ work instruction provides a guideline, based in part on the OEB’s Minimum Inspection Requirements, of deficiencies to identify and document on the corresponding reporting form; the form also allows for other deficiencies to be reported as comments.

Switching Cubicles

Similar to the inspection of distribution transformers, NPDI’s switching cubicles are inspected during the visual patrol of the underground distribution system on a 3-year cyclical basis. The ‘Norfolk Power Underground Transformer Inspection’ work instruction provides a guideline of deficiencies to note during the inspection.

Cable Fault Identification

As noted in Appendix C of the DSC, ‘Patrol inspection of cable chamber is not required since a visual inspection will not reveal faults because the failure mechanism for underground cable (e.g. voids, water trees) is not visually detectable.'[2] NPDI has a run-to-failure replacement strategy for underground cable because of the redundancy afforded in the loop-configuration of NPDI's underground distribution system.

Substations

General Practice of System Patrol

There are 13 NPDI-owned substations of which one is a Transformer Station (TS), operating at 115kV to 27.6kV, and twelve are Distribution Stations (DS), operating at 8.32kV or 4.16kV.

Transformer Station

Transformer Station equipment inspection and maintenance is required to be compliant with the NPCC Regional Reliability Reference Directory #3. The scope of the maintenance testing and inspection covers the following:

1. 115 kV Incoming tower structures c/w Motorized Load Break Switches and grounding switches, HV Current Transformers.
    a. Visual and Mechanical Inspections
        i. Examine the High-Voltage Switch and accessories for:
            - Loose or obviously damaged components
            - Proper identification
            - Physical damage from installation and site specific conditions
            - Motor mechanism for alignment, dents, scratches, fit, and missing hardware
            - Maintenance accessories for servicing and operating all devices
    b. Inspect:
        i. Grounding connections for cleanliness and alignment
        ii. Insulators for evidence of physical damage or contaminated surfaces
        iii. Main and arcing blade alignment, penetration, travel stops, and mechanical operation
        iv. Verify that open blades travel beyond 90 degrees, per manufacturers recommendation.
        v. Verify structure, grounding, and switch assembly:
        vi. Operation and alignment of mechanical safety interlocks
        vii. Tightness of accessible bolted electrical connections by calibrated torque-wrench method in accordance with manufacturers published data

---

[2] OEB Appendix C of the Distribution System Code 'Minimum Inspection Requirements', Section C.1, page 4

c. Clean:
    i. Standoff insulators and suspension insulators in 115 kV structure
    ii. Clean and lubricate motor mechanism as per manufacturer's recommendations.

d. Electrical Tests
    i. Insulation system:
        - Perform a DC high potential test one pole at a time with the other poles and structure grounded
        - Perform and record resistance measurements for:
            - Switch contact resistance (Micro-ohms)
            - Electrically open and close the switch to ensure correct operation of the motor mechanism pallet switches.

2. 25/33/41.4 MVA Oil Filled Power Transformers c/w Bushing Potential Devices, 115 kV Lightning Arresters with surge counters, Liquid Temperature Gauge, Winding Temperature Gauge, Gas Accumulation Relay, Conservator Oil Level Gauge, Oil Monitor, Tapchanger Compartment Over Pressure Relief Device

a. Examine transformer for:
    i. Tank, flanges and cooling fins for alignment, dents, scratches, fit, and missing hardware
    ii. Loose or obviously damaged components
    iii. Proper identification
    iv. Leaks
    v. Verify:
        - The correct liquid level in the conservator tanks and HV bushings
        - That tank grounding is correct
        - Cooling fan blades turn freely and appropriate safety guards are in place
        - That fan motors have correct over current protection
        - That alarm, control, and trip settings on temperature indicators are as specified

b. Examine bushing for:
    i. Physical damage
    ii. Loose or obviously damaged components

- iii. Proper identification
- iv. Damage, defects, and contamination
- v. Verify:
    - Tightness of accessible bolted electrical connections with a calibrated torque-wrench
    - That the bushing has no cracks
    - Bushing is free of dirt or other contaminants
    - That there is no loss of oil or compound

c. Electrical Tests

- i. Perform insulation-resistance tests HV winding & LV winding-to-Gnd and each winding-to-ground with the other winding grounded
- ii. If core ground is accessible, measure core insulation resistance at 500 volts dc
- iii. Perform a turns-ratio test at all tap positions
- iv. Perform a winding resistance test on all taps
- v. Verify that winding polarities are in accordance with nameplate
- vi. Test all phase and neutral current transformers for ratio, polarity and saturation.
- vii. Using temporary control power, verify that cooling fans operate correctly and verify that control and alarm settings on temperature indicators are as specified
- viii. Test operation of all alarm, control, and trip circuits from temperature and level indicators, pressure relief device, and fault pressure relay utilizing oil bath and/or compressed air for activation

d. Doble test the transformer windings as per recommended Doble method.

e. Collect an oil sample and send to a test lab for analysis of the following:

- i. Acid neutralization number
- ii. Specific gravity
- iii. Interfacial tension
- iv. Parts per million water
- v. Visual condition
- vi. Color
- vii. Dielectric breakdown
- viii. Combustible Gas in Oil

f. Perform all additional inspections and tests as recommended by the manufacturer

g. Verify primary bushing potential device voltage is at the correct magnitude and phase angle with respect to the 27.6 kV switchgear bus voltage.

h. Electrical Tests- Bushings

    i. Measure the condition of the Tap-To-Ground insulation when performing Doble tests on bushings equipped with test taps and potential taps. In bushings the tap-to-ground insulation (or, tap insulation) is designated at C2, whereas the main insulation between the center conductor and tap is referred to as C1
    ii. Measure the C1 insulation of the bushing
        - Remove the capacitance (or PF tap) tap cover from the bushing under test and make connections
        - Measure charging current and watt loss
        - Calculate PF and capacitance; correct to 20°C
        - Compare results to manufacturer's PF and capacitance on nameplate
    iii. Measure the C2 insulation of the bushing
        - Remove the capacitance (or PF tap) tap cover from the bushing under test and make connections
        - Guard C1 insulation
        - Measure charging current and watt loss
        - Calculate PF and capacitance; correct to 20°C

i. Transformer Primary Winding Lightning Arresters
    i. Inspection and Test Procedures
        - Examine arrester for:
            - Physical damage
            - Loose or obviously damaged components
            - Proper identification
            - Damage, defects, and contamination
        - Verify:
            - Tightness of accessible bolted electrical connections with a calibrated torque-wrench
            - That the arrester has no cracks
            - Arrester is free of dirt or other contaminants
            - Arrester properly installed and connected
            - Clean each arrester prior to electrical testing
    ii. Electrical Tests
        - Perform an insulation resistance measurement on each arrester.
        - Perform a Doble power factor test on each arrester
        - Perform a grounding continuity test to the ground grid system

- Perform a leakage current measurement for each arrester normal operation by measuring the leakage current through the arrester on the ground side of the surge counter.

3. 16 kV Current Limiting Neutral Reactors (transformer flame detection monitor mounted on reactor pedestal)
    a. Examine reactor for:
        i. Physical damage from installation
        ii. Structure and insulators for alignment, corrosion, scratches, fit, and missing hardware
        iii. Loose or obviously damaged components
        iv. Proper identification
        v. Damage, defects, and contamination to the resistor grid or element
    b. Verify:
        i. Tightness of accessible bolted electrical connections with a calibrated torque-wrench
        ii. That frame, and enclosure grounds are correct
    c. Electrical Tests
        i. Perform insulation-resistance tests from reactor-to-ground
        ii. Verify reactance value using AC 60 Hz test voltage across reactor and measuring voltage, current and phase angle. Calculate reactance value

4. 2- 150 kVA pad mount station service transformer (SST), c/w manual transfer switches mounted beside SST

5. 27.6 kV 1000 kcmil Secondary Cables between transformer and indoor switchgear
    a. Examine the cables for:
        i. Physical damage or deformities to exposed portions of cable
        ii. Jacket and insulation condition
        iii. Correct identification and arrangements
    b. Inspect:
        i. Cable termination or load break elbows
        ii. For proper shield grounding, cable support, and termination
        iii. For signs of overheating, discoloration, tracking and corona
    c. Verify:

    - i. Cables terminated through window-type current transformers
    - ii. Inspect to verify the neutral and ground conductors are correctly placed and that shields are correctly terminated for operation of protective devices
    - iii. That conduits and conduit bushings are correctly installed
    - iv. Unused openings have been properly closed and secured
    - v. Tightness of accessible bolted electrical connections by calibrated torque-wrench method in accordance with manufacturers published data
    - vi. Both ends of cables are properly barricaded off for personnel protection
    - vii. Cable ends are properly isolated from environmental conditions that would affect test results
  - d. Electrical Tests
    - i. Perform a shield-continuity test on each power cable with an ohmmeter
    - ii. Record wet- and dry-bulb temperatures or relative humidity and temperature
    - iii. Perform an insulation-resistance test using a megohmmeter with a voltage output of at least 2500 volts
    - iv. Perform a dc high-potential test on all cables.

6. 115 kV Transformer Station fenced in yard c/w oil containment system, ground mat and fence grounding
  - a. Inspection and Test
    - i. Examine the Ground System and accessories for:
    - ii. Loose or obviously damaged components
    - iii. Proper identification (if applicable)
    - iv. Physical damage from installation
  - b. Inspect:
    - i. Fence Grounding to assure:
      - Gate Post, corner posts, end posts, cross rails, top rails, gates, barbed wire are bonded correctly.
      - Correct termination to the ground system
    - ii. Bonding Tap conductors to assure:
      - Proper size
      - Correct termination to the ground system
      - Correct termination to the equipment
      - Mechanical, compression or cad weld connections are properly terminated
  - c. Electrical Tests

i. Measure the point to point resistance as follows:
  - Grid to internal building ground loop
  - Grid to transformer tanks
  - Grid to switch pedestals
  - Internal building ground loop to switchgear ground bus

7. 27.6 kV Gas Insulated Switchgear c/w 5- F60 Feeder Protection Relays and 4- SEL351 Feeder Protection Relays
    a. Gas Insulated Switchgear
        i. Examine the switchgear line-up, including breakers, and accessories for:
          - Loose or obviously damaged components
          - Proper identification
          - Physical damage from installation
          - Doors, panels, and sections for alignment, dents, scratches, fit, and missing hardware
          - Maintenance accessories for servicing and operating all devices
        ii. Inspect:
          - Inspect all grounding connections for cleanliness and tightness
          - Insulators for evidence of physical damage or contaminated surfaces
          - Surge Arrestor and/or Surge Suppression size, type, installation and connection
          - Breaker Cell(s), for correct SF6 gas pressure and Dew point
          - Alignment and penetration of instrument transformer withdrawal disconnects, current carrying, and grounding components
          - Control power transformers
          - Wiring for damaged insulation, broken leads, tightness of connections, proper crimping, and overall general condition
          - Clean insulating bushings
        iii. Verify structure, grounding, cables and bus assembly:
          - Verify the grounding electrode conductor is properly terminated
          - Verify the grounding of instruments, panels and connections
          - That conductors are properly identified
          - Cable termination tightness

- Tightness of accessible bolted electrical connections by calibrated torque-wrench method in accordance with manufacturers published data

iv. Verify control and instrumentation:
  - That all VT and CT ratios properly correspond to drawings and that polarity is correct
  - That shorting screws and bars are removed from CT's and terminal blocks as required
  - That primary and secondary fuse ratings or circuit breakers match drawings
  - Meter scaling and type match drawings
  - That circuit breaker and meter addresses are set for microprocessor-communication packages
  - That accessible moving components are adequately lubricated

v. Verify Mechanical Interlock System:
  - Proper sequencing to comply with operating instructions
  - Attempt to close locked-open devices.
  - Attempt to open locked-closed devices

vi. Electrical Tests
  - Insulation system:
    - Perform insulation-resistance tests on each bus section, phase-to-phase and phase-to-ground.
    - Perform insulation-resistance tests at 500 volts dc on all control wiring
  - Instrumentation:
    - Perform the following tests on potential transformers
      - Perform insulation-resistance tests. Perform measurements from winding-to-winding and each winding-to-ground.
      - Verify correct secondary voltage by energizing primary winding with system voltage.
      - Perform secondary wiring integrity test. Confirm potential at all devices
  - Perform the following tests on current transformers
    - Ratio
    - Saturation

- Protection devices:
  - Determine accuracy of protective relays

b. Protective Relays

   i. Mechanical Inspections

   - Examine relay and accessories for:
     - Loose or obviously damaged components
     - Proper identification
     - Physical damage from installation
     - Condition of wiring on panels and switchboards
     - Clips of fuse holder for tightness and alignment
     - Relay for alignment, dents, scratches, fit, and missing hardware

   ii. Inspect:

   - All connections for tightness
   - Current transformers for proper rating, polarity and wiring
   - Condition of internal insulation and tightness of internal connections

   iii. Electrical Tests

   - Perform insulation resistance test on each branch circuit to frame
   - Timing test should be performed at three points on the time dial curve to verify the timing characteristics of the relay
   - Pickup target and seal-in units
   - Verify trip signals to open blocking switches
   - Special tests as required to check operation of restraint, directional, and other elements per manufacturer's instruction manual

   iv. Function Testing

   - Perform complete tripping and operational tests to verify all control and protective functions and alarms.
   - Perform breaker fail function testing
   - Verify supervisory control and alarm points from station to control room.
   - Verify transfer trip circuits in conjunction with HONI
   - Verify auto reclose schemes

8. 4 sets- 27.6kV 1000 kcmil feeder cables

   a. Examine the cables for:

      i. Physical damage or deformities to exposed portions of cable

        ii. Jacket and insulation condition
        iii. Correct identification and arrangements
    b. Inspect:
        i. Cable termination or load break elbows
        ii. For proper shield grounding, cable support, and termination
        iii. For signs of overheating, discoloration, tracking and corona
    c. Verify:
        i. Cables terminated through window-type current transformers
        ii. Inspect to verify the neutral and ground conductors are correctly placed and that shields are correctly terminated for operation of protective devices
        iii. That conduits and conduit bushings are correctly installed
        iv. Unused openings have been properly closed and secured
        v. Tightness of accessible bolted electrical connections by calibrated torque-wrench method in accordance with manufacturers published data
        vi. Both ends of cables are properly barricaded off for personnel protection
        vii. Cable ends are properly isolated from environmental conditions that would affect test results
    d. Electrical Tests
        i. Perform a shield-continuity test on each power cable with an ohmmeter
        ii. Record wet- and dry-bulb temperatures or relative humidity and temperature
        iii. Perform an insulation-resistance test using a megohmmeter with a voltage output of at least 2500 volts
        iv. Perform a dc high-potential test on all cables.

9. 6- Relay Protection Panels c/w
    a. Panel 1- Transfer Trip #1 Relay, D30 Line Distance Relay, SEL351A Bus Backup Relay
    b. Panel 2- T60 Transformer A Protection, SEL387 Transformer B Protection Panel 3- DC-DC Converter
    c. Panel 4- Tap Changer position monitor for T1 & T2, SEL 734 Meters, TCX relay for AVR
    d. Panel 5- Transfer Trip #2 Relay, ABB Type NSD570, D30 Line Distance Relay, SEL351A Bus Backup Relay

- e. Panel 6- T60 Transformer A Protection, SEL387 Transformer B Protection, SEL2407 Satellite Synchronizing Clock, SEL 2411 and 4- SEL2440 Automation Controllers

10. Battery Charger A, Staticon Type 125B75 c/w 60 cells of Absolyte Sealed Lead-Acid
    - a. Inspection and Test Procedures
        - i. Inspect the structural integrity of the battery rack and/or cabinet
        - ii. Verify that all applicable warning labels are visual and in readable condition
        - iii. Inspect inter cell connections and main terminals for proper torque values
        - iv. Inspect for evidence of corrosion at terminations and on the mounting structure
        - v. Perform a detailed visual inspection of each cell
        - vi. Inspect all wet cells for proper acid level
        - vii. Measure input voltage to the battery charger
        - viii. Measure input current of the battery charger
        - ix. Measure float voltage + to -
        - x. Measure battery system voltage + to –. Calculate the float voltage on a per cell basis and compare to battery specifications.
        - xi. Measure battery system voltage + to ground
        - xii. Measure battery system voltage – to ground
        - xiii. Measure battery charger output volts
        - xiv. Measure battery charger output amps
        - xv. Measure voltage of each cell
        - xvi. Measure the impedance of each cell using a battery impedance tester. Measuring AC ripple voltage across each cell is not adequate.
        - xvii. Measure specific gravity of each wet cell
        - xviii. Verify alarm circuits for each charger

11. Battery Charger B, Staticon Type 120B75 c/w 60 Cells of C&D Lead Acid (Wet)
    - a. Inspection and Test Procedures
        - i. Inspect the structural integrity of the battery rack and/or cabinet
        - ii. Verify that all applicable warning labels are visual and in readable condition
        - iii. Inspect inter cell connections and main terminals for proper torque values
        - iv. Inspect for evidence of corrosion at terminations and on the mounting structure
        - v. Perform a detailed visual inspection of each cell
        - vi. Inspect all wet cells for proper acid level

    vii. Measure input voltage to the battery charger
    viii. Measure input current of the battery charger
    ix. Measure float voltage + to -
    x. Measure battery system voltage + to –. Calculate the float voltage on a per cell basis and compare to battery specifications.
    xi. Measure battery system voltage + to ground
    xii. Measure battery system voltage – to ground
    xiii. Measure battery charger output volts
    xiv. Measure battery charger output amps
    xv. Measure voltage of each cell
    xvi. Measure the impedance of each cell using a battery impedance tester. Measuring AC ripple voltage across each cell is not adequate.
    xvii. Measure specific gravity of each wet cell
    xviii. Verify alarm circuits for each charger

12. UP1 & UP2 Transfer Switches, UPS Distribution Panel, UP1 & UP2 Distribution Panels, DC Panels A & B
    a. Examine the panelboard, including breakers, and accessories for:
        i. Loose or obviously damaged components
        ii. Proper identification
        iii. Physical damage from installation
        iv. Doors, panels, and sections for alignment, dents, scratches, fit, and missing hardware
        v. Maintenance accessories for servicing and operating all devices
    b. Inspect:
        i. Panelboard components for:
            - Deterioration
            - Physical damage
            - Signs of overheating
            - Loose or improper terminal connections
            - Condition of door latches
        ii. For correctly applied circuit breakers and hardware
        iii. Manufacturer’s nameplates is properly displayed
        iv. Inspect all grounding connections for cleanliness and tightness
        v. Main Bonding Jumper for proper size and termination

      vi. Insulators for evidence of physical damage or contaminated surfaces
      vii. Surge Arrester and/or Surge Suppression size, type, installation and connection to determine if they are in accordance with the drawings
      viii. Wiring for damaged insulation, broken leads, tightness of connections, proper crimping, and overall general condition
   b. Verify structure, grounding, cables and bus assembly:
      i. Anchorage (per local codes, wind and seismic considerations)
      ii. Verify the bonding electrode conductor is properly terminated
      iii. That conductors are properly identified (as applicable)
      iv. Cables are properly secured and routed
      v. That all cables have been properly installed, routed and supported and are clear of energized parts
      vi. Unused openings have been properly closed and secured
      vii. Signs of moisture, wetness or drips
      viii. Tightness of accessible bolted electrical connections by calibrated torque-wrench method in accordance with manufacturers published data
   c. Exercise each circuit breaker several times
   d. Electrical Tests
      i. Insulation system:
         - Perform insulation-resistance tests on each bus section, phase-to-phase and phase-to-ground

13. Basement Sump Pump and Controls c/w Basement SF6 Gas Detection System
   a. Verify correct operations of building sump pump system and verify sump pump alarms to Scada system
   b. Verify correct operation of transformer oil containment system and verify oil containment alarms into Scada
   c. Verify the operation of the basement SF6 alarm system
   d. Verify the operation of the outdoor transformer flame detector alarms

Distribution Substations

Distribution Substation inspection encompasses an assessment of the following, as per the appropriate station reporting form (Appendix 5):

1. Transformer(s), including
    - Oil temperature/level
    - Bushing condition
    - Valves
    - Nomenclature/phase markers
    - Paint condition
2. Station, including
    - Yard debris/vegetation
    - Ground grid and grounding condition
    - Stone depth
    - Fence/wire condition & accessibility
    - Structure/insulator condition
    - Lighting arrester/switch/fuse condition
    - Bus/cable condition
    - Security
    - Nomenclature/phase markers/signage
3. Protection
    - Breaker/fuse/recloser condition
4. Station Loading
5. Metering
    - PT/CT condition
    - Cables/connections condition
    - Nomenclature
6. Civil
    - Concrete base condition
    - Drainage
7. Environmental

Deficiencies identified during the inspection are documented on the reporting form and in a subsequent report issued identifying findings and recommendations for corrective action (Appendix 6). Following the general practice of inspections and deficiency reporting for overhead and underground systems, critical deficiencies identified during station inspections are also immediately reported.

Maintenance

General maintenance is essential to maintaining the functional integrity of the distribution system. Furthermore, such maintenance may reduce overall costs, service disruptions and the need for immediate or emergency expenditures. There are many approaches to maintenance of distribution assets, but NPDI has recognized the benefits of reactive maintenance and preventative maintenance. Reactive maintenance generally occurs during or following inspections and service calls and serves to remediate deficiencies as they become evident; advantages of reactive maintenance include reductions in labour and material expenditures, for example. Preventative maintenance differs from reactive maintenance in that the former is a proactive, structured and time-based approach to maintenance, often before deficiencies are identified through inspection programs. This maintenance program incorporates many factors, but primarily considers good utility practice, manufacturer's recommendations, significance or impact to operational safety and system reliability, and/or available or new technology.

Reactive Maintenance on the Overhead Distribution System

Deficiencies identified during the visual patrol of the overhead distribution system are documented on the appropriate reporting form(s). Where critical deficiencies, that is those posing a health and/or safety risk, are identified, the deficiency is immediately reported and a 'Service Call' form may be issued as previously described. If the critical deficiency can be remediated immediately, that is, within 24 to 48 hours (occurring the majority of the time) then the remedial action is completed by the qualified personnel during the inspection and the 'Service Call' form, along with the original inspection form, are returned for review. If however, reactive maintenance to remediate the critical deficiency cannot be completed immediately (as locates may be required, for example), then the deficiency is secured until such maintenance occurs. The 'Service Call' form is subsequently completed by the PLM and again, with the original inspection form, submitted for review, mapping and equipment nomenclature changes within the GIS where applicable. Remedial action for the remaining deficiencies, generally categorized as non-critical, is scheduled and performed by NPDI's Maintenance Crew and completed within a few months; following corrective action, records are updated to reflect date of completion. Random 'spot checks' may occasionally be performed to verify completed reactive maintenance.

Poles

There are three approaches to reactive maintenance of pole or pole-related deficiencies identified during the patrol of the overhead distribution system. For urgent, critical deficiencies, such as a broken pole, a 'Service Call' form is issued for immediate reactive maintenance; if immediate corrective action may not be taken, the pole is secured until such time, typically within 24 to 48 hours. Alternatively, deficiencies may be identified as urgent (although not necessarily critical) or as requiring coordinated efforts internally, within NPDI, or externally. A ‘Job Planning Folder’ (Appendix 7) and ‘Service Call’ form are subsequently issued to address the deficiency, for example a damaged pole. The ‘Job Planning Folder’ provides a description of the reactive maintenance required, the location, distribution system information and additional information required for coordinated efforts, such as locates, inspection and tools/vehicles coordination. The ‘Job Planning Folder’ also provides for commentary and review by Engineering, Control Room, Operations/Lines and Metering departments, before and after reactive maintenance. Following a review of reactive maintenance completed and of the completed ‘Service Call’ form and ‘Job Planning Folder’, the Line Superintendent provides his signature, confirming approval, and forwards to Control for records updates. Lastly, remaining inspection reporting forms identifying non-critical and minor deficiencies, for example missing guy guards, are returned to the Line Superintendent for subsequent review and scheduling of reactive maintenance.

Distribution Transformers

Deficiencies associated with distribution transformers identified during the visual patrol are documented on the ‘Overhead Plant Inspection Report’. Critical deficiencies are remediated within 24 to 48 hours following issuance of a ‘Service Call’ form, while reactive maintenance to address remaining deficiencies is arranged by the Line Superintendent.

While reactive maintenance to address deficiencies is performed, overhead distribution transformers are generally run-to-failure due to the limited number of customers on each and readily available stock maintained at NPDI. 600V Delta and Pole-Trans transformers, however, are not run-to-failure as the former are not a CSA-recognized configuration and the latter are no longer manufactured. As such, and due to the high cost associated with replacing these transformers on a reactive, or unplanned basis, NPDI has implemented a program for the gradual replacement of the 600V delta and Pole-Trans transformers, as identified in its capital investment plan.

In the event that reactive maintenance requires the replacement of a transformer, information concerning the removed and installed transformer is noted on NPDI’s ‘Equipment Change Sheet’. This information includes transformer size, manufacturer, serial number, year of manufacture, primary and secondary voltage and phase; the impedance (%), oil quantity and dry weight are also noted for the transformer installed. Similar information is also noted on the ‘Service Call’ form when issued for reactive maintenance (generally for critical deficiencies only) and subsequently used to update the GIS and Control Room records by a Draftsperson.

Conductors

Conductor-related deficiencies, for example bird-caging or insulation fraying as described above, are a rare occurrence, with the exception of conductor clearance. Remediation of conductor deficiencies may warrant replacement; however, this too is rare and replacement of conductor is generally limited to new conductor installation at the time of a pole-line rebuild.

Any deficiencies that have been observed are documented on the ‘Overhead Plant Inspection Report’. Critical deficiencies are remediated within 24 to 48 hours following issuance of a ‘Service Call’ form while reactive maintenance to address the remaining deficiencies is arranged by the Line Superintendent.

Switches and Protective Devices

Maintenance to repair defects as noted on the ‘Overhead Plant Inspection Report’ follows inspection, where maintenance could not be performed at the time of inspection. Generally, such maintenance is structured as follows: critical deficiencies are remediated within 24 to 48 hours following issuance of a ‘Service Call’ form while the reactive maintenance to address the remaining deficiencies is arranged by the Line Superintendent. In the event a new switch or protective device is installed during reactive maintenance, as is typically involved with reactive maintenance of switches and protective devices, the attributes of the device are documented on NPDI’s ‘Equipment Change Sheet’. These attributes include device number, type, manufacturer, model and serial numbers, year of manufacture, phase and voltage. The GIS and Control Room records are subsequently updated by a Draftsperson for consistency of records throughout the organization. While protective devices are maintained, NPDI plans to establish a more comprehensive maintenance program for load interrupter and air-break switches by end of 2010; the documentation for this maintenance procedure, including inspection instructions, is included as Appendix 8.

Preventative Maintenance on the Overhead Distribution System

Switch Maintenance

Preventative switch maintenance is currently being scheduled, whereby approximately half the switches were maintained in 2010, while the remaining will be scheduled for preventative maintenance in 2011. The priority of switches undergoing maintenance in these two years will be determined by Control. Following these initiatives, preventative maintenance will be performed on a three year cyclical basis.

Insulator Washing

Contamination has not been a significant contributor to flashovers on the NPDI system and therefore insulator washing is not performed. However, should contamination become more of a contributing factor to flashovers, NPDI is prepared to implement an insulator washing program based on identified needs and industry best practices.

Infrared Thermography

A cycle has not yet been proposed but NPDI will establish a defined cycle for this program based on industry practices, following re-certification and training of PLMs in 2012.

Vegetation Management

Currently, vegetation management, or tree trimming maintenance, is scheduled by the Manager of Safety and Technical Support Services on a 4-year and 7-year cycle for urban and rural service areas, respectively. However, future activities for both areas will be combined and scheduled on a 5-year cycle.

Vegetation management is completed by an external contractor whereby ¼ of urban and 1/7 of rural service areas are maintained annually; included in this is line clearing, tree trimming and tree removal, organized feeder by feeder. Line clearing includes all primary and secondary lines, within the specific feeders; also included are all lines on normal road allowances and those NPDI-owned lines on private property (up to the first 30m of privately-owned lines). Tree trimming includes the entire length of multiple primary circuits on an existing pole line.

Maps detailing each feeder are provided to the contractor for reference. Following completion of pre-defined groupings of feeders, NPDI arranges for an additional inspection by a Forestry Supervisor who reviews to ensure required clearances have been established. Deficiencies, that is, segments of feeders where clearances have not been met, are documented and forwarded to the Manager of Safety and Technical Support Services. The list of deficiencies, in turn, is forwarded to the contractor for remedial action and completed within the year. In addition to the pre-defined vegetation management activities, the contractor is also required to perform ‘demand work’ that includes emergency line clearing identified through customer or trouble calls and ‘as requested’ line clearing identified by PLM’s during the visual patrol and communicated via ‘Service Call’ forms or, more typically, through informal communication or email.

Reactive Maintenance on the Underground Distribution System

Where critical deficiencies can be remediated immediately (that is, within 24 to 48 hours) corrective action is performed by the PLM during the inspection and the ‘Service Call’ form, along with the original inspection form, are submitted to the Line Superintendent for review. If however, reactive maintenance to remediate the critical deficiency cannot be completed immediately, then the deficiency is secured until such maintenance occurs. The Service Call is completed by the PLM and again, with the original inspection form, submitted to the Line Superintendent for review.

The Service Call form (and ‘Equipment Change Sheet’, if applicable) is subsequently returned to Control and the Engineering Draftsperson for updates to the maps and equipment numbers within the GIS. Reactive maintenance of non-critical deficiencies is initiated when the Line Superintendent provides a list of remaining deficiencies to PLMs be remediated. Alternatively, remedial action may be coordinated through Engineering and/or with the issuance of a ‘Job Planning Folder’ for more elaborate work or where reactive maintenance requires coordinated efforts and/or replacement. As with overhead distribution transformers, underground distribution transformers are generally run-to-failure due to the limited number of customers on each and readily available stock maintained at NPDI, at which time the transformer is replaced. Underground cable is also run-to-failure because of the redundancy afforded in the loop-configuration of NPDI’s underground distribution system. As NPDI tracks cable faults, three failures (a number derived based on experience and empirical data), indicates end-of-life and that the cable has run-to-failure, at which time the cable is replaced. Switching cubicles are preemptively replaced due to longer lead-times for a replacement. In the event that a transformer, cable or switching cubicle requires replacement, or where reactive maintenance requires coordinated efforts, reactive maintenance is then subsequently scheduled by the Line Superintendent. Again, following completion of corrective action, the Service Call form (and ‘Equipment Change Sheet’, if applicable) is subsequently returned to Control and the Engineering Draftsperson for updates to the maps and equipment numbers within the GIS.

Reactive maintenance to address distribution transformer and switching cubicle-related deficiencies follows the practice described above. Vault washing is performed on transformers where excessive environmental contamination has caused an outage. Additionally, PLMs will install locks and penta bolts, where missing or damaged, as a maintenance initiative during the inspection.

Preventative Maintenance on the Underground Distribution System

Vegetation Management

Vegetation concerns surrounding underground distribution plant are identified during the visual patrol of distribution transformers and documented on the corresponding reporting form. Following a review of the form, the Line Superintendent compiles a list of concerns and notifies the Manager of Safety and Technical Support Services for remedial action by the contractor, as described in the methodology of vegetation management for the overhead distribution system.

Infrared Thermography

NPDI will establish a defined cycle for this program based on industry practices, following re-certification and training of PLMs in 2012.

Reactive Maintenance on Substations

Deficiencies identified during the inspection are documented. Following the general practice of inspections and deficiency reporting for overhead and underground systems, critical deficiencies identified during station inspections are also immediately reported to the Manager of Safety & Technical Support Services. The critical deficiency may be remediated at this time, provided materials are on-hand and the contractor is qualified to perform such work. Alternatively, the deficiency may be secured until such work can be performed, either within several days or in coordination with annual preventative maintenance while the station is off-line. Remaining non-critical deficiencies or other concerns are noted on the inspection form and within the follow-up report. The report is reviewed and deficiencies not yet remediated are informally prioritized for completion throughout the year.

Preventative Maintenance on Substations

Preventative maintenance encompasses three practices: oil analysis, infrared thermography and general substation maintenance and testing.

Oil Analysis

Oil analysis of the TS and DS transformers is performed annually by a contractor and consists of Dissolved Gas Analysis (DGA), Chemical Analysis (ASTM/Water) and Polychlorinated Biphenyl (PCB). Actual lab results are provided in a summary report (Appendix 9) that also outlines overall findings and recommendations.

These recommendations are reviewed by the Manager of Safety & Technical Support Services to determine remedial action to be taken, as well as planning and scheduling of such actions.

Thermographic Inspection

An annual thermographic inspection of NPDI's TS and DSs is also completed annually by a qualified contractor. The non-destructive, non-invasive and non-intrusive inspection allows for a condition-assessment whereby concerns (i.e. thermal anomalies) are summarized and prioritized, with probable causes and recommendations noted in a report (Appendix 10). The report is subsequently reviewed by the Manager of Safety & Technical Support Services to determine corrective action.

Thermal anomalies categorized as 'severe', representing acute overheating are immediately addressed through coordination with the contractor and a Control Room Operator. 'High' priority anomalies, whereby overheating has developed, are generally addressed within one month, as indicated by the Manger of Safety & Technical Support Services. Scheduling of reactive maintenance to address remaining 'moderate' or 'low' thermal anomalies generally occur at the next opportune moment and may be remediated within the year.

Substation Maintenance and Testing Program

The substation maintenance and testing program is also performed by a qualified contractor. This program requires the station to be taken out of service such that inspection, testing and maintenance of the following can be performed:

- Tower and Yard
- High Voltage Air Break Switch
- High Voltage Fuse
- Lightning Arrester
- Power Transformer – mechanical inspections and electrical tests
- Switchgear Assembly
- High Voltage Cables

For the majority of these activities, inspection and maintenance are performed together where required to mitigate additional station outages.

Following completion of the program, a summary report (Appendix 11) is prepared and outlines scope of work, test results, comments (where no action is required) and concerns specifying recommended corrective action for remediation not completed during testing/maintenance. The report is subsequently reviewed by the Manager of Operations or designate for prioritization and scheduling of such corrective action.

Documentation & Document Management

Documentation of the above programs, complete with instructions, inspection and maintenance data, is essential to a comprehensive asset management program and for subsequent analysis, trending and reporting. While the majority of documents are largely paper-based, NPDI retains many of its original instructions, data and reporting forms in electronic format. On the overhead distribution system, these include: the ‘Minimum Inspection Requirements’ of the DSC, the ‘Overhead Plant Inspection Report’, the ‘Maintenance and Inspection Program LIS / Air Break Switches’ form and the ‘Equipment Change Sheet’.

On the underground distribution system, these include the ‘Norfolk Power Underground Transformer Inspection’ work instructions and reporting forms. For substations, these include the ‘Oil Analysis Report’, the ‘Thermographic Inspection’ report and the ‘Substation Maintenance and Testing Program’ report.

NPDI intends to leverage its existing Geographic Information System (GIS) for incorporating and maintaining these inspection and maintenance data and is currently investigating appropriate methods to realize this objective.

In addition to being retained electronically in various databases, NPDI has a large amount of data that is also maintained electronically. The Outage Statistics database, developed in MS Access and primarily utilized by Control Room Operators, allows for ‘Service Call’ forms to be generated and maintained electronically. As previously noted, the form provides details of the problem reported, equipment affected and defective equipment (if applicable), work to be performed and work completed, as electronically documented initially by Control Room Operators and further completed manually by PLMs during remedial action.

Hard copies of the completed ‘Service Call’ forms are returned to Control and data is subsequently and manually updated in the database. Documented by PLMs, and of particular significance to this database, is outage information. From these records, NPDI is able to produce and electronically maintain outage statistics for subsequent analysis and reporting. Also prepared and maintained electronically by Control Room Operators is the system condition report, the details of which are outlined below.

As noted in the section ‘General Practice of System Patrol’ for the overhead distribution system, a condition assessment of approximately 9500 poles was performed with documentation of condition data and pole attributes recorded. Collectively, these data were recorded and have since been maintained within an MS Access database. Through NPDI's Resource Database, an electronic 'Pole Data Sheet' may be produced individually for each pole, presenting data from the condition assessment as maintained in the Access database. Also pertaining to the overhead distribution system and maintained electronically is the 'Pole Line Inspections and Deficiencies' spreadsheet.

Other records maintained electronically by NPDI include the substation reporting forms, substation inspection and deficiency reports, and data from the 'Equipment Change Sheet'.

Reporting & Data Analysis

With increasing economic constraints and accountability to customers and other stakeholders, LDC's are more compelled to improve safety, reliability, operational efficiency, and customer service, often with more financial constraints. As such, it has become essential for LDCs to refine their methods of retrieving and interpreting data for better analysis and optimized asset management practices, the result of which is an efficiently managed and reliable distribution system with fewer capital investments and OM&A expenditures.

Reporting

Various reports may be prepared from NPDI databases and other electronic records that contribute to effectively and responsibly managing the distribution system. These include various service interruption and statistical reports, a system condition report, a feeder analysis report, various pole condition reports and corporate-wide report prepared for NPDI's Board of Directors. The following provides an overview of each of these reports that NPDI considers relevant to asset and risk management.

Service Interruption and Statistical Reports

Data from the Outage Statistics database is compiled such that four primary reports may be prepared for monthly review by NPDI's Operations Manager. These reports include an Outage Report, a Monthly Statistics Report, an Emergency Response Indices Report and a Service Reliability Indices Report.

Outage Report

The Outage Report (Appendix 12) is produced on a monthly basis and, for each service interruption experienced within a given month, outlines the outage date, outage location, reported time, restoration time, outage duration, number of affected customers, density and cause of the outage.

A similar outage report is also produced on a monthly basis and used to monitor and chart service reliability indices, in particular the System Average Interruption Duration Index (SAIDI) and the System

Average Interruption Frequency Index (SAIFI) values (where the Customer Average Interruption Duration Index, i.e. CAIDI, may be subsequently calculated from SAIDI and SAIFI values). This report also documents the cause of service interruption in accordance with the categories identified by the OEB.

Data from each monthly report is maintained in a cumulative report (Appendix 13) outlining each of the total service interruption time (in customer hours) and total customers affected by outage cause and calculations of year-to-date (YTD) SAIDI, SAIFI and CAIDI values. Lastly, the YTD SAIDI and YTD SAIFI values are displayed graphically, together with customer hours of interruption time for each category of interruption (Appendix 14) for analysis.

Monthly Statistics Report

The Monthly Statistics Report (Appendix 15) is also reviewed by the Operations Manager and identifies, either monthly or cumulatively, the number of calls received and source of the call, the type of call (i.e. the nature of the reported problem), the number of unplanned outages, the number of trouble calls, the average and maximum response time for urban and rural regions, and the restoration time. This report also identifies, for each month, the total customer hours of interruptions, the total customer interruptions and total number of customers for calculation of SAIDI, SAIFI and CAIDI values.

Emergency Response Indices Report

The Emergency Response Indices Report (Appendix 16) is a year-to-date report outlining, for each of rural and urban regions, the number of emergency calls, the number of emergency calls where NPDI was on-site within 120 minutes, and the ratio of these two values.

System Condition Report

The System Condition Report is created and updated on a daily basis by a Control Room Operator to reflect ongoing system events including operating conditions, ongoing work protections and capacitor status. Also identified in this report is the cause of the event, for example defective equipment or burn-off. As noted previously, it is in this report that primary underground cable faults would be documented.

Feeder Analysis Report

The Feeder Analysis Report (Appendix 17) is prepared a Control Room Operator on an annual basis to identify opportunities for improvement based on service reliability indices, particularly SAIDI and SAIFI, on a per feeder basis. The contribution of overall SAIDI and SAIFI values per feeder are calculated, categorized by cause of service interruption and graphed; the four (4) worst-performing feeders are subsequently identified. Also included within this report are conclusions made from the data as well as recommendations for improvement. The Feeder Analysis Report is further reviewed by the Operations Manager.

Pole Condition Reports

Pole condition data, gathered from condition assessments and subsequently assigned an overall condition as one of ‘poor’, ‘fair’, or ‘good’, and pole age data maintained in NPDI’s database and incorporated within the GIS may be queried to produce various illustrative reports for general analysis of pole condition data. Examples of such reports include a profile of pole age and condition (Appendix 18) and a plan view of pole condition for Port Dover (Appendix 19). Although a relatively new endeavour, NPDI will regularly produce such reports for further trending and analysis of this asset.

Monthly Board of Directors Reports

On a monthly basis, a general report is prepared for NPDI’s Board of Directors (BOD) and presented to the BOD by NPDI’s President/CEO and managers within each of the Engineering, Operations, Finance, Customer Service, Metering and Information Technology (IT) departments. The report provides an overview of current projects and key activities, as well as operational statistics, prepared by Operations.

Data Analysis

All of the reports produced by NPDI summarize events, service interruption data and, more generally, the performance of the distribution system in various formats. The existing databases and GIS allow for relative ease in querying a variety of data for analysis of performance and reliability of the distribution system, asset condition or, more generally, the effectiveness of inspection and maintenance programs. It is this data analysis that is essential to assist in identifying and supporting its capital and operations/maintenance expenditures.

Data analysis of reports is regularly performed by the Operations Manager. In this informal review, current performance/reliability data is compared to previous data and/or compared with targets to ensure, at a minimum, continued performance. Furthermore, an evaluation may be performed to determine whether new targets could be established. Where variations exist and have reduced performance or reliability or where endeavoring to improve service reliability indices, an informal root-cause analysis is performed to identify and mitigate the problem and potential recurrence. Subsequently, opportunities for improvement are proposed and discussed internally in the context of an informal cost-benefit analysis; alternatively, new or improved processes/procedures may also be presented. The mitigating measure(s) may then be implemented or proposed for consideration in the capital or maintenance budget to improve performance and reliability or achieve targeted indices. This overall process described is generally iterative whereby problems are identified, mitigating measures implemented and then monitored for effectiveness.

Review of reports and data is not limited to performance/reliability analysis, but also extended to analysis of asset condition. Pole-related data, particularly condition assessment data, was recently reviewed and colour-coded in the GIS for spatial analysis of pole condition; this analysis allows for identification of patterns in various regions. Alternatively, a pole age versus condition profile may be produced for all poles within NPDI's distribution system. Such analysis may be performed to aid in identifying and prioritizing further inspection or maintenance (testing) for those poles in 'fair' or 'poor' condition; additionally, sections of pole lines in 'poor' condition may be identified for rebuild. Further analysis of data could aid in prioritization of rebuilds and provide the necessary business case for subsequent inclusion within the capital investment plan. For example, poles assessed prior to 2009 and in 'poor' condition were deemed 'priority poles'; individual poles were addressed prior to 2009 whereas sections of pole lines were further prioritized based on a condition analysis of other assets on the pole. Those poles with open-wire secondary or #6 copper primaries, for example, were deemed higher priority and scheduled for rebuild in the short term while others were deferred to subsequent years within the capital investment plan.

Although analysis of pole testing data is a relatively new practice, it will be a major foundation moving forward for identifying and prioritizing rebuild projects for inclusion within the capital investment plan. As noted earlier, NPDI intends to leverage its existing GIS for incorporating data from inspection and maintenance activities for all assets. The GIS would thus allow mapping of inspection and maintenance data of assets for spatial analysis and subsequent identification of changes to inspection or maintenance programs for optimization of those programs; alternatively, spatial analysis could assist in identifying areas where assets are at or near end-of-life based on condition data realized through inspection or maintenance programs.

It is this approach to inspections, maintenance, condition and age assessment and data analysis that allows NPDI to comprehensively identify asset risks and consider the these risks with respect to capital expenditures for replacement, maintenance expenditures for refurbishment and/or changes to existing inspection and maintenance programs.

System Planning

Continuous monitoring of all assets on the distribution system is an essential practice to responsible asset management. In addition to reporting and data analysis, meetings, such as the Engineering & Operations meetings and utility planning meetings, contribute to the monitoring and effective planning of NPDI's stations, overhead and underground distribution system, and effective expenditures for its system.

Engineering & Operations Meetings

The Engineering & Operations meetings occur every month and generally include stakeholders invested in projects, including but not limited to representation from the control room and meter department, as well as the Distribution Engineer, the Line Superintendent and the Operations Manager .The focus of this meeting is to review and discuss the status of near-term capital and maintenance projects.

More specifically, it is a forum to discuss design, scheduling, coordination and construction of projects designated as 'in design', 'issued for construction', 'under construction', 'completed' and 'on hold'. Although infrequent, concerns relating to inspection and maintenance programs may also be broached and discussed during the Engineering & Operations meetings.

Development Coordinating Committee Meetings

Conducted by Norfolk County (the 'County'), the Development Coordinating Committee Meetings are monthly meetings in which NPDI, and specifically the Distribution Engineer, participates. Regional planning and economic development services projects (such as major commercial development or new subdivisions) for the County are identified and discussed with respect to potential impact to attendees of the meeting, such as NPDI.

Participation in this meeting affords NPDI the opportunity to forecast such projects, categorize as near-term, short-term or long-term, and plan its infrastructure and expenditures accordingly.

Annual Reviews

In planning of the distribution system, NPDI performs three strategic reviews on an annual basis: the System Reliability Review, the Security Review and the Capacity Review. These reviews ensure adequate capacity and security of the distribution system thereby providing delivery of reliable and safe electricity to the consumer, consistent with its corporate and asset management objectives.

System Reliability Review

As noted above, NPDI monitors the reliability of its distribution system. Such monitoring and data capture, combined with analysis of data, allows NPDI to compare current performance/reliability data with previous statistics or established performance targets to determine and identify areas within its system that have surpassed, met or fallen short of targets. NPDI's Annual System Reliability Review allows for the identification of variations in performance and reliability. Where variations exist and have reduced performance or reliability, a root-cause analysis is performed, to identify and mitigate the problem and potential recurrence, and opportunities for performance improvement are investigated. Additionally, the review allows for network performance indices (defined below) targets to be set, based on an improvement of the three-year rolling average.

- SAIFI (System Average Interruption Frequency Index) = *The average number of interruptions per customer per year*
- SAIDI (System Average Interruption Duration Index) = *The average customer interruption duration (in hours)*
- CAIDI (Customer Average Interruption Duration Index) = *The average customer interruption duration per interruption (in hours)*

NPDI has recognized, from the Feeder Analysis Report, that feeders and investment in feeders, are of particular significance in its endeavour's to improve reliability.

Recommended action may include a proposed capital project or modifications to the inspection and/or maintenance program and are considered in development of the capital investment plan or Operations, Maintenance and Administrative (OM&A) budget.

Security Review

The Security Review, performed annually at the feeder level and Distribution Station transformer level, allows for contingency planning in the event a major asset should fail and provides means to supply affected customers from a back-up source. The Security Review encompasses many actions across Engineering and Operations, beginning with a first contingency review at the Distribution Station transformer level. At this level, historical monthly peak load data is collected for each station transformer; condition and maintenance history is also assembled and reviewed/analyzed. Next, an individual station transformer loss scenario is considered under peak summer loading conditions to assist in the development of contingency plans to supply those customers, from an alternate source, affected by the transformer loss scenario. Additionally, those customers that cannot be supplied using existing distribution assets are identified.

At the feeder level, the review begins with the collection of historical data for each feeder to identify its monthly peaks. Subsequently, the back-up feeder(s) for each individual feeder is identified. Possible load-transfers are then added to each of the identified feeder's monthly peak and represented graphically in a load forecast chart; the chart aids in the identification of feeders (potentially) exceeding its rated capacity.

While the above actions for both feeders and station transformers are completed by Operations, Engineering and Operations collaborate to identify opportunities for improvement through capital investment to resolve excess capacity on over-loaded feeders; these projects could take the form of switch installations for sectionalizing or voltage conversion to reduce loading, for example. Finally, such projects are proposed for consideration in the capital investment plan in the development process identified below.

Asset Renewal Review

Asset renewal is considered annually within the Security Review. As noted above, voltage conversion projects are considered to reduce station and/or feeder loading. Within this consideration asset renewal benefit is also reviewed. Where assets are close to or at end-of-life, voltage conversion is generally selected as the most beneficial project and proposed for consideration within the capital investment plan. Additionally, asset renewal is considered following testing or condition assessments of poles. Pole lines found to be in ‘poor’ condition are further prioritized for renewal based on the condition of other assets on the pole line. Where the pole line and its assets are found to be close to or at end-of-life, a higher priority is given for the rebuild/renewal and therefore proposed for consideration in the short-term within the capital investment plan.

Capacity Review

Similar to the Security Review, the Capacity Review is an annual planning process to ensure reliability of service for existing customers while considering and planning for future growth with new customers. While the plan is as described in the following, the execution of the review is still in progress; however, NPDI has recently developed a tool to obtain the required information for the review and intends on utilizing this tool to assist in the review in the near future. The process also begins with the collection of historical data for each feeder to identify its monthly peaks; artificial peaks, such as those caused by abnormal transfers in the system, are filtered. A load forecast chart is then created using the filtered monthly peaks, and a trend line is applied to estimate future loading. Subsequently, known future spot loads forecasted to be greater than 500 kVA are applied to the appropriate feeder(s). From this, NDPI is able to identify any feeder(s) (potentially) exceeding its rated capacity within five years. While these actions are completed by Operations, Engineering and Operations collaborate to identify opportunities for improvement through capital investment to reduce load to acceptable limits. Such opportunities, in the form of projects, are proposed for consideration in the capital investment plan in the development process identified below.

Innovation & New Technology

Supervisory Control and Data Acquisition (SCADA)

NPDI's Supervisory Control and Data Acquisition (SCADA) system is a Windows-based, dual-redundant system, installed in 2004. The dual-redundant configuration allows for seamless operation and transition of data to a back-up system, providing a high level of reliability. For greater reliability and system security, NPDI has established a back-up control room to its existing facility. NPDI also anticipates that it will complete modeling its primary feeders, as well as switches and other protective devices, within the SCADA system by the end of 2011, to replace its existing paper map and pin system and provide greater safety and operating control.

Currently, the SCADA system models one TS and seven (7) DSs, with full telemetry for data acquisition of various real-time analog (e.g. real power, power factor) and status points (e.g. breaker position) at the stations; of these stations, full control of station breakers is available on most. Alarm reporting and event logging is enabled to allow data retention and analysis; these data are further catalogued in an independent file on a monthly basis by a Control Room Operator.

Geographic Information System (GIS)

NPDI's Geographic Information System (GIS), implemented in 2009, is primarily utilized for mapping distribution system assets with respect to the land base of its service territory. The attributes of individual assets, for example equipment size or identification number, are also maintained within the GIS. NPDI intends to leverage the GIS for incorporating and maintaining inspection and maintenance data and is currently investigating appropriate methods to realize this objective. The GIS could then be utilized to perform spatial queries and allow for analysis of data to identify geographical significance. Alternatively, the GIS could be used to allow for scheduling of asset inspection and maintenance. The proposed system, combined with current functionality, is expected to facilitate data retrieval, queries and analysis.

Capital Investment Plan

As capital investment projects typically require significant expenditures and long-term commitments, it is critical to evaluate each proposed project relative to the organizational and asset management objectives, such that responsible and optimized decisions are made about the best allocation of funds to develop a capital project portfolio.

Development Process

NPDI has developed a sound process that contributes to the development of a value-driven three year capital investment plan. This process commences in the first quarter and continues throughout the second and third quarters whereby a portfolio of project submissions is developed by NPDI staff as determined through inspections, maintenance programs, planning meetings, data analysis, capacity/security/reliability reviews or general internal communications; projects providing opportunity for innovation or new technology may also be included within this portfolio. Project submissions are individually identified through a 'Capital Expenditure Proposal' form (Appendix 20). Completed by the department manager or supervisor, this form is intended to provide as much detail as possible concerning the project to make a decision about whether to proceed with the capital expenditure. Project proposals are recorded by the Distribution Engineer (acting as the "gatekeeper") and prioritized based on risk and overall strategic value as described below. Projects that have a high strategic value are identified for inclusion in the annual capital program. Those that have a lesser strategic value may be deferred to future years. Capital Expenditure Proposals identified for inclusion in the 2012 – 2014 plan can be found in Appendix 21.

Prioritization Criteria

Prioritization of projects follows a bottom-up approach in which data from the Capital Expenditure Proposals are first considered to determine categorization as one of near term (1 to 2 years), short-term (3 to 4 years) or long-term (5 or more years). Generally, prioritization is as follows:

1. Externally-Driven Projects (non-discretionary)
    a. Municipally or Regulatory Mandated
    b. Customer Mandated
2. Internally-Driven Projects (discretionary)

The system of prioritization considers safety to public and employees, equipment condition and age (resulting from inspection and maintenance data), reliability and performance, data analysis and other drivers internal or external to NPDI. Projects are further categorized as one of 'high', 'medium-high', 'medium', 'medium-low' or 'low' based on these considerations. The table below provides examples of capital investment drivers and corresponding priority levels:

HIGH	Regulatory/Municipally-driven project(s); Customer demand driven projects
	Infrastructure renewal project(s) where assets present a safety or environmental risk
	System reliability, supply/capacity or contingency planning project(s)
MED-HIGH	Infrastructure renewal project(s) where assets are nearing end-of-life
	Specific or small-scale system reliability, supply/capacity or contingency planning project(s)
	Distribution Automation project(s)
	Tools/Fleet/Internal System-related project(s)
MEDIUM	Replacement of obsolete/vintage plant project(s)
	System Optimization
	System Studies
MED-LOW	Rebuild of non-standard design project(s)
LOW	Unique, ‘one-off’ project(s)

Externally-driven projects are those mandated by Norfolk County, and/or as identified by the OEB, the Electrical Safety Authority (ESA) or other governing agencies. These projects may include a pole-line relocation to accommodate road reconstruction or new construction to accommodate load-transfer agreements, for example. Other such projects may also include customer requests for service. As NPDI endeavour’s to meet the obligations to respond to customer demands, County or government directives, externally-driven projects are deemed ‘high’ priority in the year of implementation and almost always included within the capital investment plan.

Internally-driven projects are those implemented to achieve NPDI corporate values or asset management objectives as defined above and through aforementioned considerations, particularly analysis of inspection, maintenance and reliability data or of the capacity, security and reliability reviews; these projects may also be considered ‘high’ priority, or classified as a lower priority. Generally, capital expansion or enhancement projects to ensure supply, contingency or service reliability at a system level are considered higher priority and necessitate inclusion within the capital investment plan.

Alternatively, infrastructure renewal projects where infrastructure currently exists but concern assets posing a health, safety or environmental risk are also considered higher priority; assets such as these typically warrant replacement rather than refurbishment and are therefore included within the capital investment plan. Added benefits or objectives may also be realized through implementation of these projects such as improvements to maintenance programs, aesthetics or accessibility, for example. Similarly, where assets are at end-of-life (as identified through inspection and maintenance programs), projects proposed to replace these assets are also deemed ‘high’ priority. NPDI may further capitalize on a rebuild project to achieve other objectives such as a voltage conversion or relocation, provided the incremental cost of the latter is minimal compared to the initial investment required for the rebuild. Infrastructure renewal projects, at times a rebuild of a portion of the underground or overhead distribution system, may alternatively be deemed a ‘medium-high’ (or lower) priority, where assets are approaching the end-of-life but dependent on specific conditions; as with renewal projects of ‘high’ priority, a voltage conversion or relocation may be simultaneously be implemented to capitalize on the initial expenditures. Generally, projects relating to distribution automation or expenditures for tools, fleet or internal systems are deemed ‘medium-high’ priority. Also categorized as this priority are improvements to capacity, reliability or contingency planning; whereas projects at the system level are ‘high’ priority, smaller-scale projects or those specific to fewer customers are deemed ‘medium-high’ priority. Projects deemed ‘medium’, ‘medium-low’, or ‘low’ priority may be required to enhance or optimize a component of the NPDI distribution system or internal operations, but are flexible in their proposed schedule of implementation. Projects such as these may include replacement of obsolete or vintage assets, rebuild of non-standard construction or system studies, for example. Lastly, very specific, single-purpose projects, while dependent on the nature of the project, may generally be categorized as ‘low’ priority and deferred to subsequent years in the capital investment plan.

It should be noted that prioritization of projects, and subsequently the capital investment plan, is a rolling forecast whereby project priorities are reassessed in accordance with new or shifting data.

Approval of the Capital Investment Plan

The process by which capital investment projects are prioritized results in:

1. Identification of near-term (1 - 2 years), short-term (3 - 4 year) and long-term (5+ year) projects on a continuous basis, directing planning activities with a future outlook
2. A relatively objective capital investment plan, comprising sustaining, expansion and improvement capital expenditures, resulting from a consistent method of analyzing qualitative and quantitative data

A draft of the capital investment plan is submitted to the President and CEO in the fourth quarter of the calendar year; the President and CEO reviews the contents of the proposed plan for discrepancies and/or to ensure alignment with NPDI objectives. Following this review, the plan may be revised in consideration of these items and/or in consideration of added projects which reasonably could not have been foreseen during the budget period. Once approved by the President and CEO, the capital investment plan is presented, also in the fourth quarter, by NPDI executives to the Board of Directors for approval.

Material Expenditures and Variances

Following approval of the capital investment plan, funds are appropriated accordingly. Material and labour expenditures for approved projects are then charged to a work order, translating into the relevant Uniform System of Accounts (USoA), as prescribed by the OEB. Periodic financial statements are also prepared summarizing year-to-date (YTD) actual and annual budgeted amounts for total operating revenue and expenses. Within the summary of operating expenses, further details are provided regarding YTD actual and budgeted amounts for capital projects, distribution system operation and maintenance, as well as administrative and general expenses, categorized under the appropriate USoAs. Financial statements are reviewed by NPDI’s President and CEO to ensure controls, as necessary, are in place to remain within the approved budget or account for variations where they exist.

Variations or amendments to appropriated funds may occur following approval of the plan, for example where changes to scope arise from new municipal directives. While NPDI endeavour’s to mitigate these occurrences, it may become necessary to reallocate funding from a lower priority project. Under these circumstances and provided the aggregate total of the capital investment plan is unchanged, approval must first be obtained by the President and CEO. If, however, the variation alters the aggregate total materially from that originally approved by the Board of Directors, an application for variance must be made and presented to the Board of Directors for approval.

Capital Investment Plan 2012 to 2014

The following table outlines the capital investment plan for years 2012 to 2014:

Proposed Year	ID	Project Name	Location	Area	Project Scope	Cost Estimate
2012	1	Miscellaneous DS Equipment Upgrades	Distribution Stations	Various	Installation of a replacement load brake switch, removal of an asbestos meter board and installation of animal at NP11 Pt Dover, installation of station PT's for NP6 and installation of PT's for relays at NP13 Pt Dover.	$75,000
2012	2	Replace Transformer - Distribution Station NP8	Ann St.	Delhi	Purchase and replace the existing transformer with a new 5MVA transformer. The distribution transformer presently installed and NP8 built in 1958 (53 years old). This transformer also contains 42 PPM of PCB.	$200,000
2012	3	Reroute NP5 F4 to Queen St. S., (Simcoe Fairgrounds)	Queen St & South Dr	Simcoe	Rebuild approximately 125m of existing facilities as required to allow for removal of 4kV primary wires crossing parking lot in the Fairgrounds	$220,000
2012	4	4.16 kV to 27.6 kV Conversion Phase 2- Distributing Station NP 10 Waterford	St James St./Leamon St.	Waterford	Replace approximately 20 poles, 4 transformers and approximately 600 metres of single phase primary and 600m of secondary service wire. This project affects approximately 75 services.	$230,000
2012	5	Simcoe 4.16 kV to 27.6 kV Conversion Phase 1	Tyrell and Beckett St.	Simcoe	OH rebuild with approx 120 poles, 30 transformers, 1300m of 3ph primary, 2700m of 1ph primary. Approximately 350 services will be included in the conversion. The following locations will be affected: Tyrell St., Beckett Blvd., Hill St., Foster St., Belleview Ave., Charles St., Payne Ave., Martin Ave., Royal Rd., Holden Ave., Carolyn Blvd., Calvert Cres., Dora Dr., and Sunset Dr. As well as parts of: Union St. and King Ln.	$1,600,000
2012	6	Rebuild Potts Road, Simcoe	Potts Rd.	Simcoe	Replace 8 poles, 1 transformer and approx. 200m of single phase primary and secondary conductors on Potts Rd from Victoria St to Oakwood Ave	$100,000
2012	7	Pole Replacement Program	Various	Various	Replacement of 80 priority poles and related transformers. Project cost and scope to be updated following 2010/2011 pole testing and analysis.	$480,000
2012	8	Misc. Overhead and Underground Betterments	Various	Various	Complete capital renewal work and system upgrades as required.	$485,000
2012	9	Plant Relocation for Road Widening	Various	Various	Adjustments to distribution system equipment as required due to road widening projects established by the Municipality.	$150,000
2012	10	Subdivision Development	Various	Various	Small line extensions and connections to new subdivisions as required. Approximately 180 new lots	$303,000
2012	11	New Services and Service Upgrades	Various	Various	Approximately 100 new services, including 6 commercial / industrial services requiring three phase pad mount transformers.	$450,000
2012	12	Meter Installations	Various	Various	A broad range of meter capital works including purchase of new meters for customer additions, primary metering installations.	$348,000

	ID	Project Name	Location	Area	Project Scope	Cost Estimate
2013	13	Transformer Station Capital (miscellaneous)	Bloomsburg TS	Simcoe	A provision for Station projects such as a backup inverter system including a UPS2 transfer switch and a modification to UPS1 with a transfer switch and resealing of station metering	$50,000
2013	14	Miscellaneous DS Equipment Upgrades	Distribution Stations	Various	Provision for urgent station work identified from routine inspection.	$75,000
2013	15	4.16 kV to 27.6 kV Conversion Phase 3- Distributing Station NP10 Waterford	Brown St./ Montclair Cres.	Waterford	Phase 3 of the 4.16 kV to 27.6 kV conversion project in Waterford to remove dependence on the NP10 Distribution Station as the single transformer station has no back-up and would allow consideration for the decommissioning of NP10 DS and sale of the station assets and property. This project affects approximately 90 services.	$650,000
2013	16	Pole Replacement Program - 2013	Various	Various	Replacement of 80 priority poles and related transformers. Project cost and scope to be updated following 2011/2012 pole testing and analysis.	$480,000
2013	17	Misc. Overhead and Underground Betterments	Various	Various	Complete capital renewal work and system upgrades as required.	$485,000
2013	18	Simcoe 4.16 kV to 27.6 kV Conversion Phase 2	Berkley Cres. & Cherry St.	Simcoe	Phase 2 of the 4.16 kV to 27.6 kV conversion project in Simcoe. Rebuild consists of approx. 29 new poles, 3 O/H Transformers, 32 padmounted transformers, 800m O/H primary conductor, 7000m U/G primary cable, 1350m U/G secondary cable in the Berkley Cres. & Cherry St. areas. This project affects approximately 300 services.	$1,500,000
2013	19	Plant Relocation for Road Widening	Various	Various	Adjustments to distribution system equipment as required due to road widening projects established by the Municipality.	$150,000
2013	20	Subdivision Development	Various	Various	Small line extensions and connections to new subdivisions as required. Approximately 180 new lots	$303,000
2013	21	New Services and Service Upgrades	Various	Various	Approximately 100 new services, including 6 commercial / industrial services requiring three phase pad mount transformers.	$446,000
2013	22	Long Term Load Transfers elimination program - 2013	Various	Various	Eliminate Long Term Load Transfers as per plan (Part 1)	$300,000
2013	23	Norfolk TS primary metering upgrade	Norfolk TS	Simcoe	Replace metering equipment as required to meet new requirements	$175,000
2013	24	Fleet replacement plan	NPDI	Simcoe	Purchase new line truck	$300,000
2013	25	Fleet replacement plan	NPDI	Simcoe	Purchase new pickup/van	$40,000

Proposed Year	ID	Project Name	Location	Area	Project Scope	Cost Estimate
2014	26	Transformer Station Capital (Miscellaneous)	Bloomsburg TS	Simcoe	A provision for Station projects such as a backup inverter system including a UPS2 transfer switch and a modification to UPS1 with a transfer switch and resealing of station metering	$50,000
2014	27	Miscellaneous DS Equipment Upgrades	Distribution Stations	Various	Provision for urgent station work identified from routine inspection.	$75,000
2014	28	Pole Replacement Program - 2014	Various	Various	Replacement of 80 priority poles and related transformers. Project cost and scope to be updated following 2011/2012 pole testing and analysis.	$480,000
2014	29	Misc. Overhead and Underground Betterments	Various	Various	Complete capital renewal work and system upgrades as required.	$485,000
2014	30	Simcoe 4.16 kV to 27.6 kV Conversion Phase 3	Kennedy Rd & Brock St.	Simcoe	Phase 3 of the 4.16 kV to 27.6 kV conversion project in Simcoe. Rebuild consists of approx. 4 new poles, 45 padmounted transformers, 3500m U/G primary cable, 700m U/G secondary cable. This project affects approximately 325 services.	$1,500,000
2014	31	Plant Relocation for Road Widening	Various	Various	Adjustments to distribution system equipment as required due to road widening projects established by the Municipality.	$150,000
2014	32	Subdivision Development	Various	Various	Small line extensions and connections to new subdivisions as required. Approximately 180 new lots	$303,000
2014	33	New Services and Service Upgrades	Various	Various	Approximately 100 new services, including 6 commercial / industrial services requiring three phase pad mount transformers.	$446,000
2014	34	4.16 kV to 27.6 kV Conversion Phase 4- Distributing Station NP 10 Waterford	Blueline Rd./ Thompson Rd.	Waterford	Phase 4 of the 4.16 kV to 27.6 kV conversion project in Waterford to remove dependence on the NP10 Distribution Station as the single transformer station has no back-up and would allow consideration for the decommissioning of NP10 DS and sale of the station assets and property.	$400,000
2014	35	4.16 kV to 27.6 kV Conversion Prospect St and Grand St Areas - Port Dover	Prospect St, Grand St areas	Port Dover	Replace approximately 30 poles, 8 transformers and approximately 1500m of primary and secondary conductors. This project affects approximately 150 services.	$400,000
2014	36	Long Term Load Transfers elimination program - 2014	Various	Various	Eliminate Long Term Load Transfers as per plan (Part 2)	$500,000
2014	37	Fleet Replacement plan	NPDI	Simcoe	Purchase new line truck	$260,000
2014	38	Fleet Replacement plan	NPDI	Simcoe	Purchase new pickup and van	$80,000

Operations & Maintenance Budget

It is essential to ensure operations and maintenance expenditures accurately reflect the costs that must be incurred to safely and reliably maintain the distribution system. As such, spending associated with maintenance activities is forecasted using leading and lagging indicators. Leading indicators typically identify the incremental maintenance costs required to address recommendations from inspection and/or maintenance programs to ensure continued asset operation to realize its useful life. Additional leading indicators may include proposed capital expenditures impacting maintenance activities and, ultimately reducing operations and maintenance expenditures. Lagging indicators typically represent historical values for routine inspection and maintenance expenditures.

Development and Approval Process

Development of a draft operations and maintenance budget occurs within the third quarter whereby routine and non-routine operations and maintenance activities for the upcoming year are identified. Such activities are categorized as one of inspections, overhead reactive or preventative maintenance, underground reactive or preventative maintenance, substation reactive or preventative maintenance, or, general system maintenance. Routine activities occurring annually, such as vegetation management, are equated to forecasted expenditures based on historical values. Where applicable, these expenditures are adjusted to reflect anticipated scope of work as identified through program data, recommendations or analysis of inspection and maintenance activities. For routine activities occurring on a cyclical basis, associated expenditures are only included within the operations and maintenance budget for the year in which the activity is scheduled to be performed. While the majority of operations and maintenance activities are recurring, non-routine or single occurrence expenditures may be warranted to reflect changes to performance priorities or new operations and maintenance programs. These expenditures are forecasted based on either an estimate of internal labour hours required to complete the activity or, alternatively, estimated based on proposals or quotations. Lastly, administrative expenditures, such as staff training, are identified and included prior to completion of the draft operations and maintenance budget.

As with the capital investment plan, the draft operations and maintenance budget is presented, within the fourth quarter, to the President and CEO for review and approval. Where adjustments are required, the draft is revised accordingly prior to presentment to the Board of Directors for budget approval.

Inspection and Maintenance Plan 2012 to 2014

Pole Inspection and Testing

An aggressive pole inspection and testing program will continue in future years to complete data capture of pole attributes and condition data for inclusion in the GIS system **Activity**	**Annual Quantity**
Wood Pole Testing,	variable
Infrared Thermography	1/3 of overhead system
Tree Trimming	(1/4 urban, 1/7 rural, converting to 1/5 all areas beginning in 2012)
Overhead Inspections (urban)	1/3 system
Overhead Inspections (rural)	1/6 system
Underground Inspections	1/3 system
Overhead switch maintenance	1/3 of all switches
Substations (DS) (monthly inspections)	All stations
Substation transformer oil analysis (DS)	All station transformers
Substation thermography	All stations
TS maintenance program	1 transformer station

APPENDIX 1

Feeder Inspected:

Overhead Plant Inspection Report

Reviewed by	**Name:**		**Title:**	
	Signature:		**Date:**	

Area where inspection was Completed (crossroads)	

Overhead Plant Inspected

Transformers		**Capacitors**		**Vegetation**	
Switching & Protective Devices		**Conductor**		**Check Appropriate Boxes**	
Voltage Regulators		**Poles**			

Deficiencies Found		**Address/Pole ID #/Tx # or Sw #**	**911 #**
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			

APPENDIX 2

Norfolk Power

SERVICE CALL

ID:

Date: (dd/mm/yy)

Customer Name

House #

Address:

Township/ Town

Phone #:

Time Called

Date/Time on Site: (dd/mm/yy)

Date/Time on Site: (dd/mm/yy)

Time Cleared

Ans. Service:

Electrician/Contractor:

Phone #:

Wesys #:

Daffron #:

OUTAGES
Start Time:
Completed Time:

Defective Equipment
Description:
Manufacturer:
Type/Model:
How did it fail? (Eg. Melted)
Describe the resultant damage:
Cause of failure:

Call Source	**Problem Reported**	**Equipment Affected**
☐ Ans. Service	☐ No Power	☐ Fuse # ______
☐ Control Room	☐ MVA (report)	☐ Reclosure# ______
☐ Operation/ Engineering	☐ 911	☐ Switch # ______
	☐ Part Power	☐ Tx # ______
	☐ Power Quality	☐ Lightning Arrestor
	☐ Wire Down	☐ Termination Failure
	☐ General Trouble Call	
	☐ Emergency Locate	

Cause/Work to be Done:

Work Done:
Fuse Replaced:
Follow up Needed ☐

Using:
☐ Work has been completed and there are NO UNDO HAZARDS
☐ Legacy Construction
☐ Like for Like Replacements
☐ Emergency Work

Date
Name
Signature
Position

Hand in to Lines superintendent with Tailboard

Supervisor

Date

APPENDIX 3

Pole Line Inspections & Deficiencies

TOWN	TRANS#	ADDRESS	DESCRIPTION	Date Repaired	Crew

APPENDIX 4

Norfolk Power
Underground Transformer Inspection

We are required to inspect our underground plant as per the Ontario Energy Board. We have developed a list of items to be inspected and recorded. Below is a guide to the items required:

- Paint condition and corrosion
- Placement of the pad on the vault – does it need moving
- Is there a lock
- Is there a penta bolt
- Has the grading changed around the unit
- Has the access changed – landscaping, shrubs or such interference with the opening of the lid
- Leaking oil
- Phase indicators and nomenclature and does it match the map
- Flashed or cracked insulators
- Elbow condition
- Insert condition
- Lid condition – hinges damaged
- Condition of the unit – cabinet damaged, rust, holes
- Tie downs inside missing
- Take a reading of the temperature of the unit then readings of the elbows and secondary to see if there is a difference in temperature that may indicate a hot spot. A temperature difference of 10 degrees will indicate this.
- Is there a PCB test sticker – this will be a white sticker to indicate it was tested
- Grounding – check the grounding inside the pad mount
- Any grading changes that may cause the underground cables to be exposed or become too close to the surface.

The list above is a guide. We need to complete the information sheet for each pad mount and list any deficiencies (in the comment section) that may be found and are not listed. The goal is to inspect each transformer and record the information and we will make arrangements to go back at a later date to make all the necessary repairs and maintenance.

We will take locks and penta bolts along while doing the inspections and install them were necessary.

Pictures of each pad mount (inside and outside) will be taken.

Areas to be inspected – 1. Pt. Rowan, 2. Delhi

Norfolk Power
Underground Transformer Inspection

Tx #: ____________ St # ________ Street ______________ KVA: ________ Pad ☐ PoleTrans ____________

Phase: ________ Serial # ____________ Year ________ P Voltage ________ SecVoltage ________ PriTaps 100% ____________

Manufacturer: ______________ PCB Test: Y / N Pri Sw: Y / N Sec Sw.: Y / N Arrestor ______________

Elbow Size ________ Elbow Posi Break: Y / N Insert Posi Break: Y / N Elbow Condition: ____________

Flashed or Cracked Inserts: ________ Cable Size: ________ FCI: Y / N Temp C or F ____________

Hot Spots: ____________ Pri Labeled: Y/ N Sec Labeled: Y / N

Paint Condition: ____________ Lid Condition: ______________ Placement on Pad: ______________

Lock: ________ Penta Bolt: ________ Access Change: ________ Grading Change: ________ Leaking Oil: ____________

Water in Pad: Y / N Nomenclature on Pad inside and outside: ________ Safety Stickers: ____________

Grounding: ________ Tie Down Bolts: Y / N Completed By: ______________ Date: ____________

Other Comments: ____

APPENDIX 5

Delhi Industrial NP9 - 2009 Monthly Inspections

Date	26-May	29-Sep	29-Oct	26-Nov	22-Dec	
Ambient Temp (C)						
Time						

TRANSFORMER						
Oil Temperature (Inst/Peak) in C						
Oil Level in main tank						
Pressure guage						
Oil Leaks						
H.V. Bushing Condition						
L.V. Bushing Condition						
Transformer Paint Condition						
Sample Valve Plug						
Sample Valve locked						
Tapchanger locked						
Tap Position						
Explosion vent intact						
Grounding						
Nomenclature in place						
Phase markers in place						

STATION - Within Station Compound						
Yard Debris/Vegetation						
Crushed Stone Depth (10cm)						
Ground Grid Condition						

STATION - Primary Structure						
Structure Condition (explanation)						
Insulator Condition (explanation)						
Grounding						
Lighting Arrester Condition						
Switch Condition						
Fuse Condition						
Bus/cables intact						
Switch locked						
Animal guard in place						
Nomenclature in place						
Phase markers in place						

STATION - Secondary Structure Metal Clad						
Structure Condition (explanation)						
Insulator Condition (explanation)						
Grounding						
Lighting Arrester Condition						
Switch Condition						
Fuse Condition						
Bus/cables intact						
Switch locked						
Nomenclature in place						
Phase markers in place						

PROTECTION						
☐ Breakers ☐ Fuses ☐ Recloser						
Manufacture						
Condition						
Type						
Spare Fuses						

Station Loading ☐ **SCADA** ☐ **LOCAL**						
Feeder #1 Red Phase (Peak)						
Feeder #1 Red Phase (Instant)						
Feeder #1 White Phase (Peak)						
Feeder #1 White Phase (Instant)						
Feeder #1 Blue Phase (Peak)						
Feeder #1 Blue Phase (Instant)						
Feeder #2 Red Phase (Peak)						
Feeder #2 Red Phase (Instant)						
Feeder #2 White Phase (Peak)						
Feeder #2 White Phase (Instant)						
Feeder #2 Blue Phase (Peak)						
Feeder #2 Blue Phase (Instant)						
Total Amps (Peak)						
Total Amps (Instant)						
kWh meter (Instant/peak)						
Nomenclature in place on all feeders						
Phase markers in place						

Station Fence						
Fence Condition						
Fence Grounding						
Barb Wire Condition						
Barb Wire (lean in/lean out)						
Fence "DANGER" Sign in Place						
Station Address Sign in Place						
Fence height						
Fence Accessibility						
Gates						
Locks in Place						

METERING - Equipment						
PT condition						
CT condition						
Cables/Connections						
Cabinets/box condition						
Nomenclature in place						

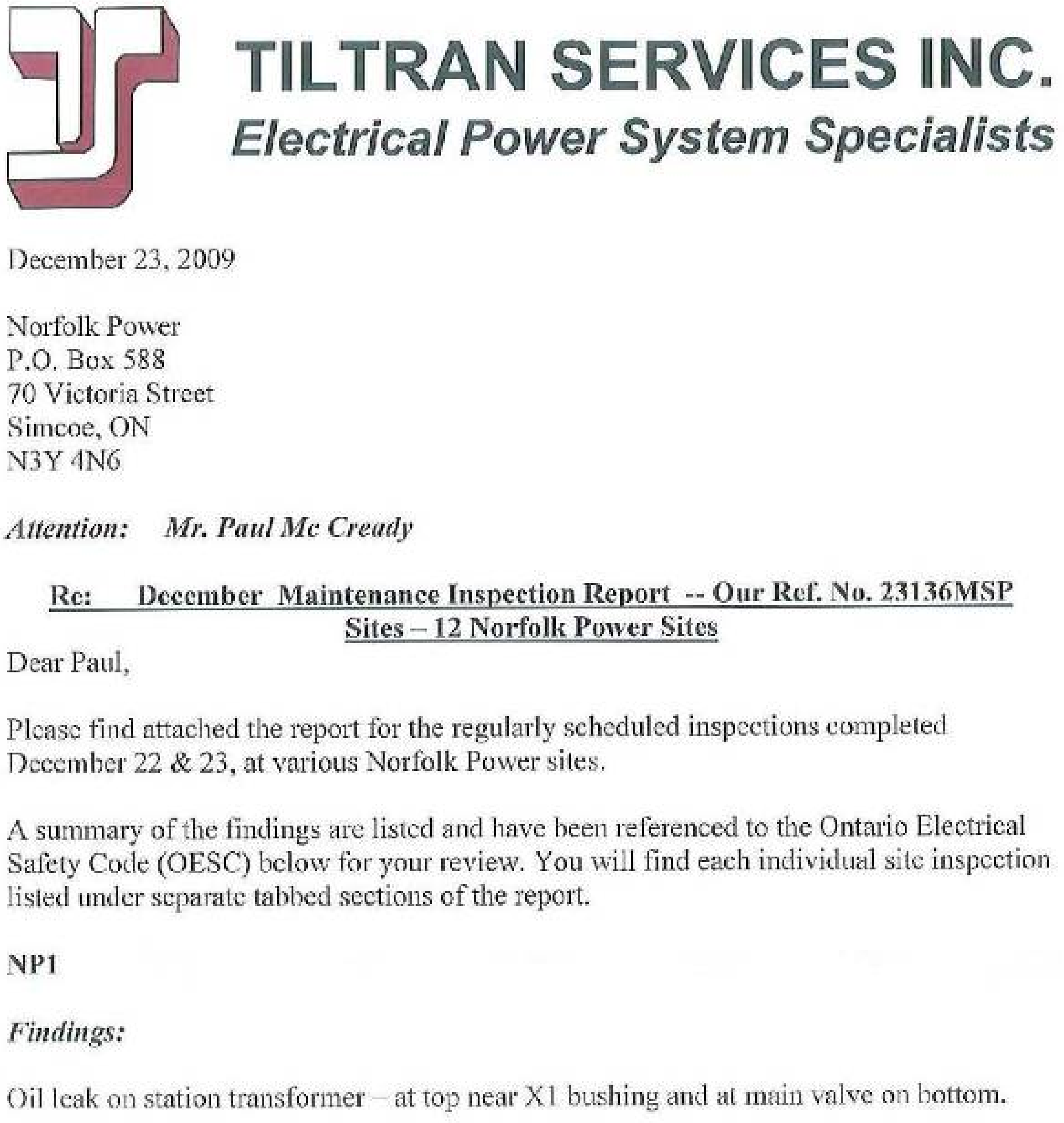
CIVIL						
Concrete bases						
Drainage						

ENVIRONMENTAL						
Emergency spill kit in place						
Knowledge of PCB's						
PCB notification in place						
Knowledge of Asbestos						
Asbestos notification in place						
Drips						

NOTES

Inspection Performed By:						

APPENDIX 6



TILTRAN SERVICES INC.
Electrical Power System Specialists

December 23, 2009

Norfolk Power
P.O. Box 588
70 Victoria Street
Simcoe, ON
N3Y 4N6

Attention: ***Mr. Paul Mc Cready***

Re: December Maintenance Inspection Report -- Our Ref. No. 23136MSP
Sites – 12 Norfolk Power Sites

Dear Paul,

Please find attached the report for the regularly scheduled inspections completed December 22 & 23, at various Norfolk Power sites.

A summary of the findings are listed and have been referenced to the Ontario Electrical Safety Code (OESC) below for your review. You will find each individual site inspection listed under separate tabbed sections of the report.

NP1

Findings:

Oil leak on station transformer – at top near X1 bushing and at main valve on bottom.

- Two decommissioned PILC cables, potheads and associated structure still in station.
- Primary cable terminations at transformer appear contaminated – looks like deposits on skirts.
- Abandoned concrete structures still in station, represent tripping hazard.
- Additional gravel needed to reduce gap at bottom of fence fabric. OESC 26-312 (3)
- Rear of secondary switch gear needs to be sanded and have touch up paint in two locations.
- Concentric neutrals of primary cables between riser pole and transformer are bonded at both ends.

Recommendations:

- Refurbish or replace station transformer to address oil leaks. This should be prioritized as the leaks are moderate and the station is located adjacent to a stream.
- Remove decommissioned equipment from station.
- Add gravel.
- Sand and apply paint to rear of secondary switchgear.

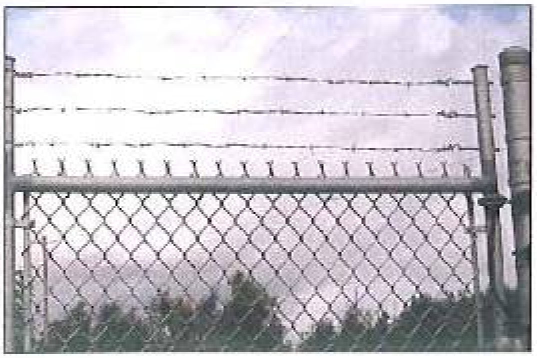
NP2

Findings:

- Multiple oil leaks at station transformer – lid and possibly the bushings. Oil level at bottom of scale, should be topped up. Level gauge glass is cracked.

- X0 bushing has chip out of it and should be repaired with Sylgard type treatment to prevent further damage.

- Barb wire on gate not bonded. OESC 36-312 (4)



- Not enough gravel in station, too large of a gap at bottom of fence fabric. OESC 26-312 (3)

- Secondary wiring on current transformers in poor shape.

Recommendations:

- Add oil to transformer.
- Refurbish or replace station transformer to address oil leaks.
- Apply treatment to damaged X0 bushing.
- Bond barb wire on gate.
- Add gravel.
- As current transformers aren't being used, they should be removed or have secondary's shorted directly at the CT.

NP3

Findings:

- Slight oil leak at temperature gauge and possibly from bushing(s) on station transformer.

- Chip out of H2 bushing on station transformer. Appears to have been painted already. Not clear on type of treatment used for repair.

- Building filter saturated.

- Bonding was previously stolen from station, repairs have been completed.

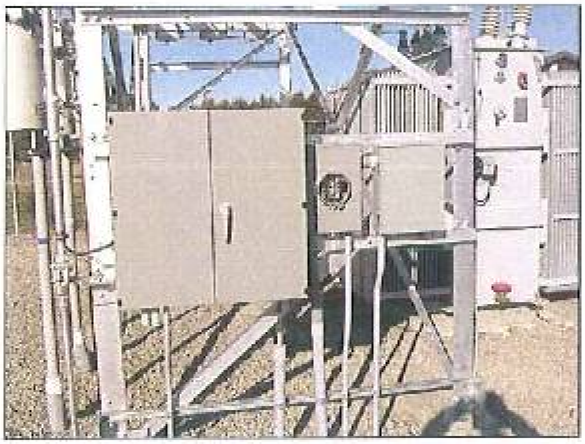
Recommendations:

- Continued monitoring of oil leak(s).
- Replace building filter.

NP4

Findings:

- NP4 is now online



- Metering and other minor issues still outstanding and to be completed by Tiltran Services Inc

NP5

Findings:

- Metal wall covering inside station transformer compound not bonded adequately. OESC 36-308 (e)

- No indication of feeder ID's on 5kV riser poles.

- No voltage indication signs on man doors. OESC 36-006 (1)

- F3 knife blades open on riser

Recommendations:

- Add bonding to wall covering in station transformer area.
- Add additional nomenclature to 5kV riser poles.
- Install Danger High voltage signs on entrance door and substation man door

NP6

Findings:

- Maximum indicator on temperature gauge won't reset lower than 90°C.

Too large a gap at bottom of fence fabric. OESC 26-312 (3)

- Warning sign for de-energized operation of primary fuses not legible. OESC 36-006 (3)

- Feeder 6F2 Red Phase lightning arrestor found blown.

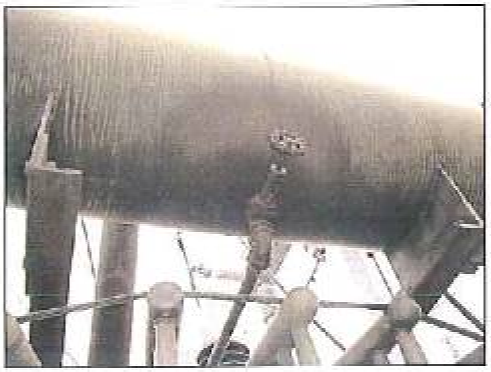
Recommendations:

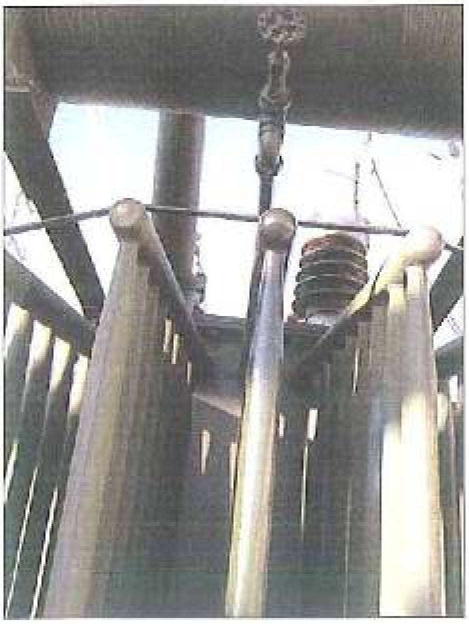
- Specialized tools to be brought on next inspection to see if temp gauge can be fixed.
- Continued monitoring of oil leak.
- Add gravel around fence.
- Replace the failed lightning arrestor.
- Replace the primary fuse warning sign during next maintenance.

NP8

Findings:

- Oil leak at bottom of conservator and lid near X1 bushing.





- Paint on station transformer faded

Recommendations:

- Continued monitoring of oil leaks from station transformer.

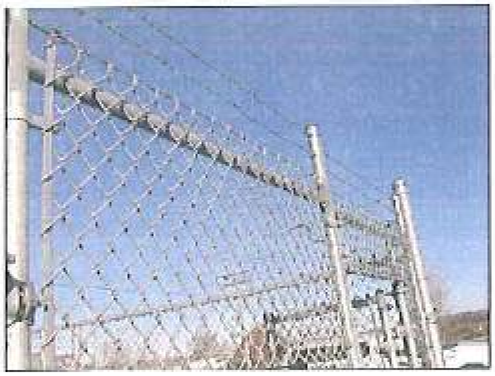
- NP9

Findings:

- Not enough gravel around secondary switch gear.

Warning sign for de-engerized operation of primary fuses not legible.
OESC 36-006 (3)

- Barb wire on gate not bonded, tension wire at bottom of fence fabric not bonded.
OESC 36-312 (4)



- Interlock required on air break switch on tower to prevent operating when under load. OESC 36-006 (2)

- Nomenclature in metering cell doesn't correspond to Feeder ID's. Instructions (inside the metering cell) for fuse sizes appears outdated and doesn't correspond to actual spare fuses on site.

Recommendations:

- Complete bonding repairs to gate barb and fence fabric tension wire.
- Add gravel.
- Replace warning sign for de-energized operation of primary fuses.
- Replace existing nomenclature with up to date lamicoids.
- Verify required fuse sizes and amend instruction sheet or replace spare fuses with appropriate sizes.
- Install interlock on tower

NP10

Findings:

No warning sign for de-energized operation of primary fuses. OESC 36-006 (3)

- Multiple oil leaks on station transformer. Concrete pad is saturated.

- Membrane on explosion vent of station transformer damaged.

- Not enough gravel in station, too large a gap at bottom of fence fabric. Incorrect type of stone. OESC 26-312 (3)

- Gate barb wire not bonded. OESC 36-312 (4)
- Wooden cross arms on primary structure are deteriorating.
- Meter board in shed is made of asbestos.

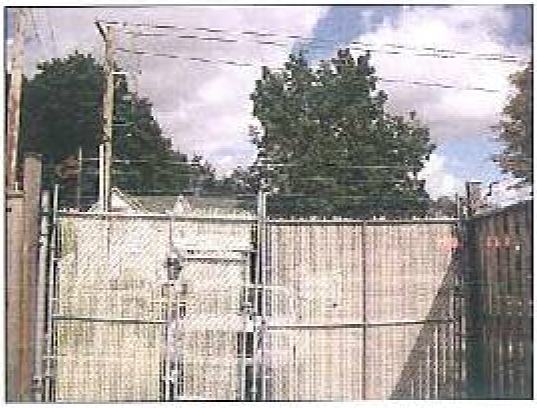
Recommendations:

- Refurbish or replace the station transformer. Due to the age of the unit and the large number of leaks, refurbishment may not be feasible. Remedial action for this transformer should be considered a priority.
- Install warning sign for de-energized operation of primary fuses during next maintenance.
- Add gravel.
- Add bonding to barb wire on gate.
- Replace wooden cross arms on primary structure.
- Add sign to meter board in shed to indicate asbestos composition.

NP11

Findings:

- Barb wire on gate not bonded. Barb wire between wooden and steel portions of fence not bonded. Gate needs adjustment. OESC 36-312 (1-4)



- Piles of gravel in station not spread out.
- Neighboring business continue to use station driveway for parking.

- No interlock on tower OESC 36-006 (2)

Recommendations:

- Add bonding to barb wire at gate and between wooden and steel portions of fence.
- Rake gravel out in station.
- Maintain access to station.
- Install interlock on incoming tower to prevent opening under load

NP12

Findings:

- Barb wire on gate not bonded. OESC 36-312 (4)

- PT fuses for local metering not installed. Demand and kWh readings not available.

- No interlock on Air break switch
  OESC 36-006 (2)

Recommendations:

- Add bonding to gate barb wire.
- Re-install metering PT fuses.
- Monitoring required on south tower leg deterioration
- Install interlock on incoming tower to prevent opening under load

NP13

Findings:

- Oil leaks at conservator, tap changer and main valve on station transformer.

- Barb wire on both gates not bonded. Gate at north side doesn't close completely – allow unauthorized access to animals. SW man gate barb not bonded.
  OESC 36-312 (4)

- Broken neutral bushing (X0) on auxiliary PT.

- Metering cabinets severely rusted.

Recommendations:

- Add bonding to barb wire on gates.
- Dig out stone and get north gate to close completely.
- Replace auxiliary PT with broken X0 bushing.
- Paint metering cabinets.
- Monitor oil leaks

Bloomsburg TS

Findings:

- Entire station offline during inspection.

Site supervisor Gary from BG Electric asked that an inspection not be performed until Norfolk Power has gained control over the station.

All other equipment that we inspected appears in satisfactory condition, suitable for continued service.

Please give us a call should you wish us to provide you pricing and services for any or all of the recommended repairs listed in this report.

If you have any questions/concerns please do not hesitate to contact me. We look forward to being of continued service to Norfolk Power.

Sincerely,
TILTRAN SERVICES INC.

Doug Charron
Electrical Technician/ Master Electrician
Maintenance & Technical Services
Phone: (519) 842-6458 x227
Fax: (519) 842-2496
Cell: (519) 521-2600

APPENDIX 7

Norfolk Power

JOB PLANNING FOLDER

JOB DESCRIPTION: ____________________

Street Address: ____________________

Job Prepared By: ____________________

Distribution System Information

TS/MS	Feeder(s)	Tx Location #	Tx KVA	Pri Voltage	Sec Voltage

Job Planning Information

Job Type: ☐ Customer Request ☐ Capital Project ☐ System Maintenance

Site Visit: Date ____________ Second Site Visit (if Required):Date ____________

Pole Ownership: ☐ NPI ☐ Hydro One ☐ Bell ☐ Private ☐ Other ____________

Locates Required: ☐ Yes ☐ No Joint Use Pole Application Required: ☐ Yes ☐ No

Capital Contribution Required: ☐ Yes ☐ No If Yes Date Received: ____________

Approvals Required: ☐ MTO ☐ County ☐ Rail ☐ Gas ☐ Bell ☐ Hydro One ☐ Other ____________

Materials: ☐ Long Lead Items Date Orderd: ☐ NonStandard Items Date Ordered:

Operations/Lines Information

Locates Called:	Date	____________	Traffic Control Person:	Yes	No
Material List to Stores:	Date	____________	Traffic Control Permit:	Yes	No
ESA Inspection Received:	Date	____________	Backhoe:	Yes	No
Operations/Lines Review:	Date	____________	Vac Truck:	Yes	No
Meter Dept. Scheduled	Date	____________	Work Protection:	Yes	No
Job Scheduled To Start:	Date	____________	Notice of Project:	Yes	No
Job Estimate:	Men	Hrs	Tree Trimming:	Yes	No

Engineering Comments/Review

Signature ______________________________ Date ____________________

Control Room Comments/Review

Signature ______________________________ Date ____________________

Operation/Lines Comments/Review

Signature ______________________________ Date ____________________

Metering Comments/Review

Signature ______________________________ Date ____________________

If required, attach 2 hole paper fastener here

Telephone Numbers

Emergency (Control Room)	519-426-2394	or	519-426-0536
OPP Simcoe	519-426-3434	Fire/Ambulance	911

Control Rm:	519 426-4440	ext 2262	Ministry of Environment:	1-800-268-6060
Engineering:	519 426-4440	ext 2247	Ministry of Labour:	1-877-202-0008
Operations	519 426-4440	ext 2240	Electrical Safety Authority:	1-877-372-7233

Project Notes & Comments

Work Crew Comments/Review

Transformer Change Sheets to Stores ☐ Yes ☐ No Initial ____________

PROJECT CERTIFICATE

(If project includes both standard design work and legacy work select both)

This is to certify that the construction recorded in this folder is consistent with approved plans, approved drawings, standard designs, or work instruction and that approved equipment has been used.

Work has been completed using Legacy Construction or Like for Like Replacements and there are NO UNDO HAZARDS.

Name: ______________________ Date: ______________

Signature: ______________________ Position: ______________

Lines Superintendent Comments/Review

Signature: ______________________ Date: ______________

APPENDIX 8

Norfolk Power
Maintenance and Inspection Program
LIS/Air Break Switches

Switch Number: ____________
Location: ____

AS FOUND CONDITION: To include the visual inspection/operating inspection

Using the check boxes indicate the condition of the switch when you first arrive. Note- a check indicates you agree with the statement. If you do not agree leave the box unchecked.

- Nomenclature- correct with map-- ☐
- Phasing discs are correct--- ☐
- Pole is not damaged--- ☐
- Grounding is not missing/damaged-- ☐
- Insulators are not cracked/damaged-- ☐
- Operating handle is not damaged-- ☐
- Switch opens/closes freely-- ☐
- Interrupters or arc chutes operate freely-- ☐
- Contacts are clean, aligned and free from corrosion---------------------------------- ☐
- Moving parts operate freely (switch and operating handle------------------------- ☐
- Mounting hardware is tight and free of defects-- ☐
- Electrical contacts and conductors to main line are tight and corrosion free---- ☐
- By pass switches are not damaged --- ☐

MAINTENANCE PERFORMED

Grounding	Not Required	☐Or________________________________
Switch Movement	Not Required	☐Or________________________________
Mounting Hardware	Not Required	☐Or________________________________
Switch Components	Not Required	☐Or________________________________
Interrupters	Not Required	☐Or________________________________
Lubrication of Parts	Not Required	☐Or________________________________

Comments: ____

____

Optimization of Maintenance Program
Indicate which one of the following statements applies to this particular switch;
☐ A The maintenance was unnecessary; it could have been done later
☐ B The maintenance was performed at the right time; only normal maintenance was req'd
☐ C The maintenance should have been done earlier; major faults were found

Employee: ___________________________ **Date Work Completed:** _________________________

Inspection and Maintenance Procedure

Step 1 - Pre- Check before Operating Switch

Inspect shape of pole

Nomenclature- check that the switch number and operating map correspond
Phasing Discs- check phasing discs correspond to map

Grounding- Inspect that all grounding is connected and not missing

Ground Rod- Measure ground rod resistance with meter

Ground Moulding- inspect all ground wires are covered with molding

Insulators- check all insulators for cracks, breaks or burns

Power Conductors- be sure all conductors are routed so they do not impede switch operation

Mounting Hardware- Inspect and tighten all thru bolts and mounting hardware. Inspect all pins, rivets and bolted connections for damaged and worn out parts

Step 2 – Cycle Switch

Open and close switch several times to clean the contact surfaces and loosen moving parts. Make sure interrupters or arc chutes are operating freely.

Step 3 - Check Switching Sequence

Inspect the switch for proper operating sequence.

Step 4 - Inspect Switch Components

Inspect for eroded fault making contacts
Inspect for alignment and corrosion of “live parts”
Lubricate all contacts with silicone grease or equivalent

Step 5 – Inspect Moving Parts

Inspect all inter-phase and moving parts for damaged or worn out components
Lubricate as needed all control components with silicone spray or equivalent

Step 6 – Inspect Interrupter or Arc Chutes

Make sure interrupters or arc chutes are operating freely

Notes – Replace any damaged or worn parts as required and complete the Maintenance Form

APPENDIX 9

TILTRAN SERVICES INC.
Electrical Power System Specialists

June 23, 2009

Norfolk Power Distribution Inc.
70 Victoria Street
P.O. Box 588
Simcoe, ON
N3Y 4N6

Attention:* *Mr. Paul McCready

Re: 2009 Oil Analysis Report -- Our Ref. No. 22932LSP

Dear Paul:

Attached are the results of oil analysis of the samples taken recently from the transformers located at your facility.

It is recommended throughout this report that several re-samples be taken to confirm the findings in the analysis and the actions that are required to be taken.

- ***Ferranti Packard, Serial no. 2301601*** NOP5
  - **Dissolved Gas Analysis (DGA)**
    The oil analysis indicates that the oil appears to be satisfactory, with all measured parameters staying within the currently recommended IEEE standards. However, there is a high concentration of Hydrogen (H2) present. Elevated Hydrogen on its own is typical of high loading / high heating.
  - **Chemical Analysis (ASTM/Water)**
    Chemically, there were no abnormalities found in the sample. The oil remains satisfactory, clear with no appreciable water content or sediments.
  - **Polychlorinated Biphenyl (PCB)**
    The result of the PCB analysis indicates that the unit contains **<1.0ppm of PCB**. This is below the Ministry of the Environments current acceptable level of **<50ppm**, so no additional precautions are required at this time.
- ***ABB, Serial no. 852501*** BLOOMSBURG
  - **Dissolved Gas Analysis (DGA)**
    The oil analysis indicates that the oil appears to be satisfactory, with all measured parameters staying within the currently recommended IEEE standards.
  - **Chemical Analysis (ASTM/Water)**
    Chemically, there were no abnormalities found in the sample. The oil remains satisfactory, clear with no appreciable water content or sediments.

- **Polychlorinated Biphenyl (PCB)**
  The result of the PCB analysis indicates that the unit contains **<1.0ppm of PCB**. This is below the Ministry of the Environments current acceptable level of **<50ppm**, so no additional precautions are required at this time.

➢ ***Ferranti Packard, Serial no. 304307*** NP6

- **Dissolved Gas Analysis (DGA)**
  This unit is experiencing high Carbon Dioxide (CO2) and Carbon Monoxide (CO) concentrations that have exceeded the IEEE recommended levels. These gases are accompanied by medium concentrations of Methane (CH4) and small concentrations of Hydrogen (H2), Ethane (C2H6) and Ethylene (C2H4).

- **Chemical Analysis (ASTM/Water)**
  Chemically, there were no abnormalities found in the sample. The oil remains satisfactory, clear, with no appreciable water content but contains a trace of sediments.

- **Polychlorinated Biphenyl (PCB)**
  The result of the PCB analysis indicates that the unit contains **2.4ppm of PCB**. This is below the Ministry of the Environments current acceptable level of **<50ppm**, so no additional precautions are required at this time.

➢ ***Common Wealth, Serial no. 35414*** NP 2

- **Dissolved Gas Analysis (DGA)**
  This unit is experiencing high Carbon Dioxide (CO2) and Carbon Monoxide (CO) concentrations that have exceeded the IEEE recommended levels. These gases are accompanied by small to medium concentrations of Hydrogen (H2), Methane (CH4), Ethane (C2H6) and Ethylene (C2H4).

- **Chemical Analysis (ASTM/Water)**
  Chemically, there were no abnormalities found in the sample. The oil remains satisfactory, clear with no sediments present. However, we do find troubling, an elevated Water Content of **33ppm** and a low Interfacial Tension level of **16.2 mN/M.** The recommended limit for water content is >15ppm to a maximum action limit of **35ppm** and a minimum Interfacial Tension level of **24.0 mN/M.** This may be an anomaly in the sampling as the Dielectric Breakdown, which can be greatly affected by high Water Content, do not seem to show any large-scale ill effects. High water content is still very detrimental to the windings paper insulation in the transformer. Possible paper degradation may be present.

  Acidity is also elevated **(0.357 mg KOH/g)** and should be reviewed and monitored next sampling. The recommended maximum for Acidity is **0.320mg KOH/g.** Acids can induce rusting and cause sludge in the oil. This will promote breakdown of the insulation. It also reduces the openings between windings, causing circulation problems thereby contribute to possible overheating.

  <u>It is recommended that an oil resample be taken, due to the low value of the Interfacial Tension, to confirm our findings and closer monitor this potential problem.</u>

- **Polychlorinated Biphenyl (PCB)**
  The result of the PCB analysis indicates that the unit contains **2.4ppm of PCB**. This is below the Ministry of the Environments current acceptable level of **<50ppm**, so no additional precautions are required at this time.

- ***Reliance, Serial no. P51111*** NP8

  - **Dissolved Gas Analysis (DGA)**
    This unit is experiencing high Carbon Dioxide (CO2) that has exceeded the IEEE recommended level.

  - **Chemical Analysis (ASTM/Water)**
    Chemically, there were no abnormalities found in the sample. The oil remains satisfactory, clear with no sediments present. However, we do find troubling, an elevated Water Content of **24ppm**. The recommended limit for water content is >15ppm to a maximum action limit of **35ppm**. This may be an anomaly in the sampling as the Dielectric Breakdown and Interfacial Tension, which can be greatly affected by high Water Content, do not seem to show any large-scale ill effects.

  - **Polychlorinated Biphenyl (PCB)**
    The result of the PCB analysis indicates that the unit contains **60ppm of PCB**. This is above the Ministry of the Environments current acceptable level of **<50 ppm**. Additional precautions are required.

    You may want to consider having the current level reduced. This is highly recommended to avoid future costs, liabilities, and problems associated with spills, containment facilities, government regulations, occupational health considerations, and waste disposal. Taking a proactive approach now, would also greatly minimize any environmental impact in the future. We would be pleased to quote this work for you.

- ***Westinghouse, Serial no. A31S0411***

  - **Dissolved Gas Analysis (DGA)**
    The oil analysis indicates that the oil appears to be satisfactory, with all measured parameters staying within the currently recommended IEEE standards. However, there is a medium concentration of Hydrogen (H2) present. Elevated Hydrogen on its own is typical of high loading / high heating.

  - **Chemical Analysis (ASTM/Water)**
    Chemically, there were no abnormalities found in the sample. The oil remains satisfactory, clear with no sediments present. However, we do find troubling, an elevated Water Content of **16ppm**. The recommended limit for water content is >15ppm to a maximum action limit of **35ppm**. This may be an anomaly in the sampling as the Dielectric Breakdown and Interfacial Tension, which can be greatly affected by high Water Content, do not seem to show any large-scale ill effects.

  - **Polychlorinated Biphenyl (PCB)**
    The result of the PCB analysis indicates that the unit contains **22.0ppm of PCB**. This is below the Ministry of the Environments current acceptable level of **<50ppm**, so no additional precautions are required at this time.

- ***Westinghouse, Serial no. A3S6297*** NP 11

  - **Dissolved Gas Analysis (DGA)**
    The oil analysis indicates that the oil appears to be satisfactory, with all measured parameters staying within the currently recommended IEEE standards.

- **Chemical Analysis (ASTM/Water)**
  The chemistry (ASTM) tests show that the oil itself is in satisfactory condition, remains clear and has no appreciable water content or sediments.

- **Polychlorinated Biphenyl (PCB)**
  The result of the PCB analysis indicates that the unit contains **5.4ppm of PCB**. This is below the Ministry of the Environments current acceptable level of **<50ppm**, so no additional precautions are required at this time.

➢ ***Ferranti Packard, Serial no. 105439*** NP4 T2

- **Dissolved Gas Analysis (DGA)**
  This unit is experiencing high Carbon Dioxide (CO2) and Carbon Monoxide (CO) concentrations that have exceeded the IEEE recommended levels. These gases are accompanied by medium concentrations of Hydrogen (H2) and small concentrations of Methane (CH4), Ethane (C2H6) and Ethylene (C2H4).

- **Chemical Analysis (ASTM/Water)**
  Chemically, there were no abnormalities found in the sample. The oil remains satisfactory, clear with no sediments present. However, we do find troubling, an elevated Water Content of **32ppm** and a low Interfacial Tension level of **17.5 mN/M**. The recommended limit for water content is >15ppm to a maximum action limit of **35ppm** and a minimum Interfacial Tension level of **24.0 mN/M**. This may be an anomaly in the sampling as the Dielectric Breakdown, which can be greatly affected by high Water Content, do not seem to show any large-scale ill effects. High water content is still very detrimental to the windings paper insulation in the transformer. Possible paper degradation may be present.

  Acidity is also elevated **(0.313 mg KOH/g)** and should be reviewed and monitored next sampling. The recommended maximum for Acidity is **0.320mg KOH/g**. Acids can induce rusting and cause sludge in the oil. This will promote breakdown of the insulation. It also reduces the openings between windings, causing circulation problems thereby contribute to possible overheating.

  It is recommended that an oil resample be taken, due to the low value of the Interfacial Tension, to confirm our findings and closer monitor this potential problem.

- **Polychlorinated Biphenyl (PCB)**
  The result of the PCB analysis indicates that the unit contains **25.0ppm of PCB**. This is below the Ministry of the Environments current acceptable level of **<50ppm**, so no additional precautions are required at this time.

➢ ***Ferranti Packard, Serial no. 105440*** NP4 T3

- **Dissolved Gas Analysis (DGA)**
  This unit is experiencing high Carbon Dioxide (CO2) and Carbon Monoxide (CO) concentrations that have exceeded the IEEE recommended levels. These gases are accompanied by high concentrations of Hydrogen (H2) and small to medium concentrations of Methane (CH4) , Ethane (C2H6) and Ethylene (C2H4).

- **Chemical Analysis (ASTM/Water)**
  Chemically, there were no abnormalities found in the sample. The oil remains satisfactory, clear with no sediments present. However, we do find troubling, an elevated Water Content of **28ppm** and a low Interfacial Tension level of **16.4 mN/M**. The recommended limit for water content is >15ppm to a maximum action limit of **35ppm** and a minimum Interfacial Tension level of **24.0 mN/M.** This may be an anomaly in the sampling as the Dielectric Breakdown, which can be greatly affected by high Water Content, do not seem to show any large-scale ill effects. High water content is still very detrimental to the windings paper insulation in the transformer. Possible paper degradation may be present.

  Acidity is also elevated **(0.341 mg KOH/g)** and should be reviewed and monitored next sampling. The recommended maximum for Acidity is **0.320mg KOH/g**. Acids can induce rusting and cause sludge in the oil. This will promote breakdown of the insulation. It also reduces the openings between windings, causing circulation problems thereby contribute to possible overheating.

  <u>It is recommended that an oil resample be taken, due to the low value of the Interfacial Tension, to confirm our findings and closer monitor this potential problem.</u>

- **Polychlorinated Biphenyl (PCB)**
  The result of the PCB analysis indicates that the unit contains **6.0ppm of PCB**. This is below the Ministry of the Environments current acceptable level of **<50ppm**, so no additional precautions are required at this time.

➢ ***Ferranti Packard, Serial no. 105438*** NP4 T1

- **Dissolved Gas Analysis (DGA)**
  This unit is experiencing high Carbon Dioxide (CO2) and Carbon Monoxide (CO) concentrations that have exceeded the IEEE recommended levels. These gases are accompanied by high concentrations of Hydrogen (H2) and small to medium concentrations of Methane (CH4) , Ethane (C2H6) and Ethylene (C2H4).

- **Chemical Analysis (ASTM/Water)**
  Chemically, there were no abnormalities found in the sample. The oil remains satisfactory, clear with no sediments present. However, we do find troubling, an elevated Water Content of **28ppm** and a low Interfacial Tension level of **16.6 mN/M**. The recommended limit for water content is >15ppm to a maximum action limit of **35ppm** and a minimum Interfacial Tension level of **24.0 mN/M.** This may be an anomaly in the sampling as the Dielectric Breakdown, which can be greatly affected by high Water Content, do not seem to show any large-scale ill effects. High water content is still very detrimental to the windings paper insulation in the transformer. Possible paper degradation may be present.

  Acidity is also elevated **(0.343 mg KOH/g)** and should be reviewed and monitored next sampling. The recommended maximum for Acidity is **0.320mg KOH/g**. Acids can induce rusting and cause sludge in the oil. This will promote breakdown of the insulation. It also reduces the openings between windings, causing circulation problems thereby contribute to possible overheating.

  <u>It is recommended that an oil resample be taken, due to the low value of the Interfacial Tension, to confirm our findings and closer monitor this potential problem.</u>

- **Polychlorinated Biphenyl (PCB)**
  The result of the PCB analysis indicates that the unit contains **21.0ppm of PCB**. This is below the Ministry of the Environments current acceptable level of **<50ppm**, so no additional precautions are required at this time.

➢ ***ABB, Serial no. 85201***

- **Dissolved Gas Analysis (DGA)**
  The oil analysis indicates that the oil appears to be satisfactory, with all measured parameters staying within the currently recommended IEEE standards.

- **Chemical Analysis (ASTM/Water)**
  The chemistry (ASTM) tests show that the oil itself is in satisfactory condition, remains clear and has no appreciable water content or sediments.

- **Polychlorinated Biphenyl (PCB)**
  The result of the PCB analysis indicates that the unit contains **<1.0ppm of PCB**. This is below the Ministry of the Environments current acceptable level of **<50ppm**, so no additional precautions are required at this time.

➢ ***Brush, Serial no. 44603*** NP 13

- **Dissolved Gas Analysis (DGA)**
  The oil analysis indicates that the oil appears to be satisfactory, with all measured parameters staying within the currently recommended IEEE standards.

- **Chemical Analysis (ASTM/Water)**
  The chemistry (ASTM) tests show that the oil itself is in satisfactory condition, remains clear and has no appreciable water content or sediments.

- **Polychlorinated Biphenyl (PCB)**
  The result of the PCB analysis indicates that the unit contains **3.0ppm of PCB**. This is below the Ministry of the Environments current acceptable level of **<50ppm**, so no additional precautions are required at this time.

➢ ***Westinghouse, Serial no. A3S6121*** NP 1

- **Dissolved Gas Analysis (DGA)**
  The oil analysis indicates that the oil appears to be satisfactory, with all measured parameters staying within the currently recommended IEEE standards.

- **Chemical Analysis (ASTM/Water)**
  The chemistry (ASTM) tests show that the oil itself is in satisfactory condition, remains clear and has no appreciable water content or sediments.

- **Polychlorinated Biphenyl (PCB)**
  The result of the PCB analysis indicates that the unit contains **34.0ppm of PCB**. This is below the Ministry of the Environments current acceptable level of **<50ppm**, so no additional precautions are required at this time.

- ***Porter, Serial no. 20120*** NP.12

  - **Dissolved Gas Analysis (DGA)**
    The oil analysis indicates that the oil appears to be satisfactory, with all measured parameters staying within the currently recommended IEEE standards.

  - **Chemical Analysis (ASTM/Water)**
    The chemistry (ASTM) tests show that the oil itself is in satisfactory condition, remains clear and has no appreciable water content or sediments. However, we do find troubling, an elevated Water Content of **20.0ppm**. The recommended limit for water content is >15ppm to a maximum action limit of **35ppm**.

  - **Polychlorinated Biphenyl (PCB)**
    The result of the PCB analysis indicates that the unit contains **1.2ppm of PCB**. This is below the Ministry of the Environments current acceptable level of **<50ppm**, so no additional precautions are required at this time.

- ***Surelco, Serial no. 152710111*** NP9

  - **Dissolved Gas Analysis (DGA)**
    This unit is experiencing high Carbon Dioxide (CO2) and Carbon Monoxide (CO) concentrations that have exceeded the IEEE recommended levels. These gases are accompanied by small to medium concentrations of Hydrogen (H2), Methane (CH4), Ethane (C2H6) and Ethylene (C2H4).

  - **Chemical Analysis (ASTM/Water)**
    The chemistry (ASTM) tests show that the oil itself is in satisfactory condition, remains clear and has no appreciable water content or sediments.

  - **Polychlorinated Biphenyl (PCB)**
    The result of the PCB analysis indicates that the unit contains **<1.0ppm of PCB**. This is below the Ministry of the Environments current acceptable level of **<50ppm**, so no additional precautions are required at this time.

- ***Westinghouse, Serial no. 199137*** NP10

  - **Dissolved Gas Analysis (DGA)**
    The oil analysis indicates that the oil appears to be satisfactory, with all measured parameters staying within the currently recommended IEEE standards.

  - **Chemical Analysis (ASTM/Water)**
    Chemically, there were no abnormalities found in the sample. The oil remains satisfactory, clear with no sediments present. However, we do find troubling, an elevated Water Content of **20.0ppm** and a low Interfacial Tension level of **23.8 mN/M**. The recommended limit for water content is >15ppm to a maximum action limit of **35ppm** and a minimum Interfacial Tension level of **24.0 mN/M.** This may be an anomaly in the sampling as the Dielectric Breakdown, which can be greatly affected by high Water Content, do not seem to show any large-scale ill effects. High water content is still very detrimental to the windings paper insulation in the transformer. Possible paper degradation may be present.

    It is recommended that an oil resample be taken, due to the low value of the Interfacial Tension, to confirm our findings and closer monitor this potential problem.

- **Polychlorinated Biphenyl (PCB)**
  The result of the PCB analysis indicates that the unit contains **9.1ppm of PCB**. This is below the Ministry of the Environments current acceptable level of **<50ppm**, so no additional precautions are required at this time.

➢ *Commonwealth, Serial no. 35309*

- **Dissolved Gas Analysis (DGA)**
  The oil analysis indicates that the oil appears to be satisfactory, with all measured parameters staying within the currently recommended IEEE standards.

- **Chemical Analysis (ASTM/Water)**
  Chemically, there were no abnormalities found in the sample. The oil remains satisfactory, clear with no appreciable water content or sediments. However, we do find troubling, an Interfacial Tension of **19.4 mN/M**. The IEEE recommended level is a minimum level of **24.0 mN/M**. Interfacial Tension measures the tension at the interface between oil and water when placed together in a sample jar. Good, clean oil will lie on top of distilled pure water with very little mixing. This test is sensitive to contaminants due to oil decay or soluble material from the insulating papers of the winding, because they reduce the surface tension between the two liquids.

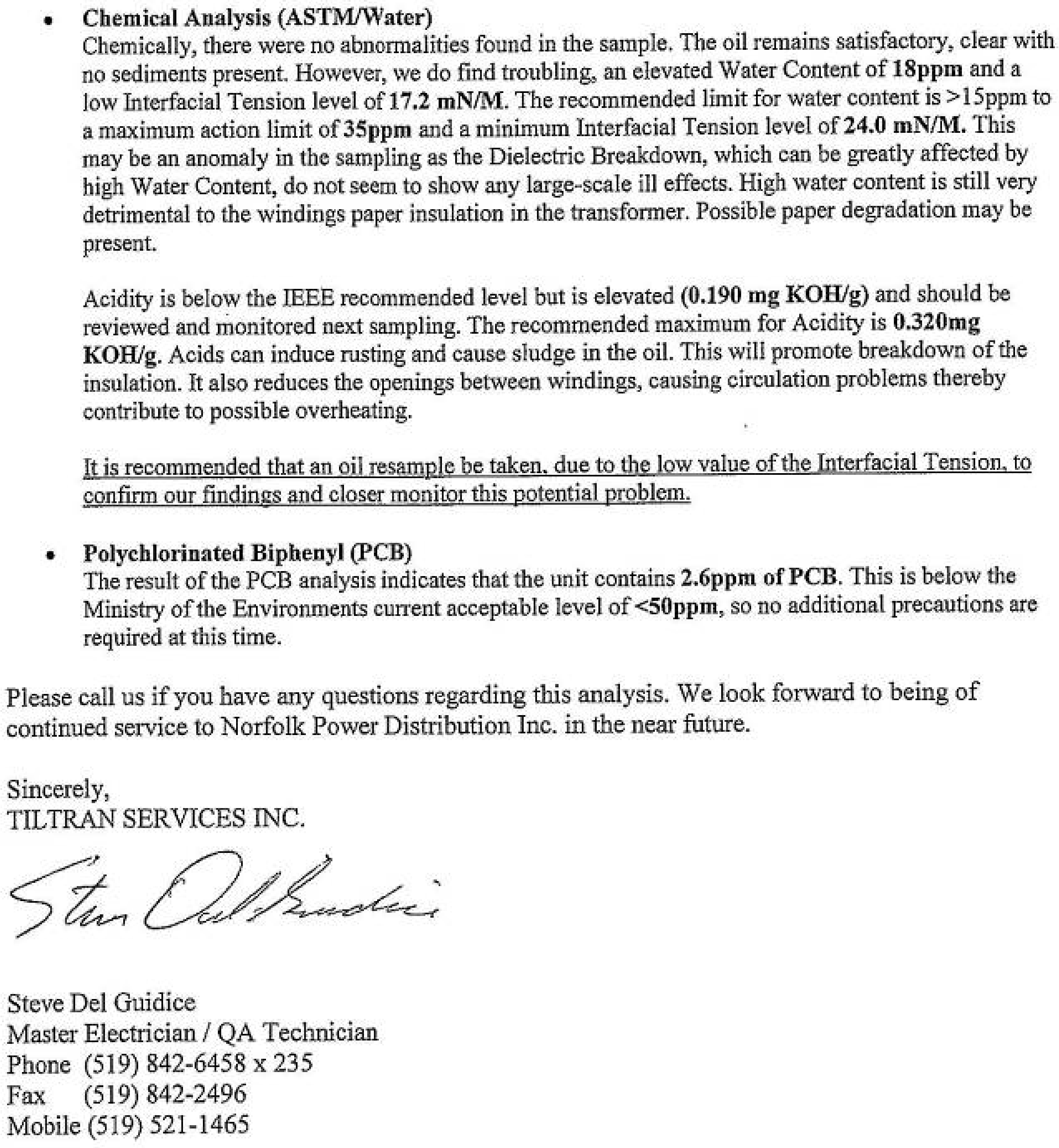
  The chemistry (ASTM) tests show that the oil is satisfactory, remains clear, with no appreciable sediments. It is noted that dielectric breakdown level is **28**, IEEE recommendation is not less than **27**.

  Due to the low value of the Interfacial Tension, it is recommended that the transformer oil be reclaimed, or disposed and replaced. Another solution is to change out the transformer, with one which exceeds IEEE standards. If left unresolved, this could result in a very hazardous situation. We would be pleased to quote you on rectifying this deficiency.

- **Polychlorinated Biphenyl (PCB)**
  The result of the PCB analysis indicates that the unit contains **1.6ppm of PCB**. This is below the Ministry of the Environments current acceptable level of **<50ppm**, so no additional precautions are required at this time.

➢ *English Electric, Serial no. 254900* NP3

- **Dissolved Gas Analysis (DGA)**
  There was a finding of elevated levels of Carbon Dioxide (CO2) and Carbon Monoxide (CO). The IEEE recommended levels for these are 350ppm and 2500ppm respectively. These gases are accompanied by medium concentrations of Hydrogen (H2), Methane (CH4) and Ethane (C2H6). It is also noted that a finding of **129ppm** of Ethylene (C2H4) was found. This level exceeds the IEEE recommendations of **50ppm.** These gases are typical of high loading / high heating with the possibility of corona (partial discharge fault) being present.



- **Chemical Analysis (ASTM/Water)**
  Chemically, there were no abnormalities found in the sample. The oil remains satisfactory, clear with no sediments present. However, we do find troubling, an elevated Water Content of **18ppm** and a low Interfacial Tension level of **17.2 mN/M.** The recommended limit for water content is >15ppm to a maximum action limit of **35ppm** and a minimum Interfacial Tension level of **24.0 mN/M.** This may be an anomaly in the sampling as the Dielectric Breakdown, which can be greatly affected by high Water Content, do not seem to show any large-scale ill effects. High water content is still very detrimental to the windings paper insulation in the transformer. Possible paper degradation may be present.

  Acidity is below the IEEE recommended level but is elevated **(0.190 mg KOH/g)** and should be reviewed and monitored next sampling. The recommended maximum for Acidity is **0.320mg KOH/g.** Acids can induce rusting and cause sludge in the oil. This will promote breakdown of the insulation. It also reduces the openings between windings, causing circulation problems thereby contribute to possible overheating.

  It is recommended that an oil resample be taken, due to the low value of the Interfacial Tension, to confirm our findings and closer monitor this potential problem.

- **Polychlorinated Biphenyl (PCB)**
  The result of the PCB analysis indicates that the unit contains **2.6ppm of PCB**. This is below the Ministry of the Environments current acceptable level of **<50ppm**, so no additional precautions are required at this time.

Please call us if you have any questions regarding this analysis. We look forward to being of continued service to Norfolk Power Distribution Inc. in the near future.

Sincerely,
TILTRAN SERVICES INC.

Steve Del Guidice
Master Electrician / QA Technician
Phone (519) 842-6458 x 235
Fax (519) 842-2496
Mobile (519) 521-1465

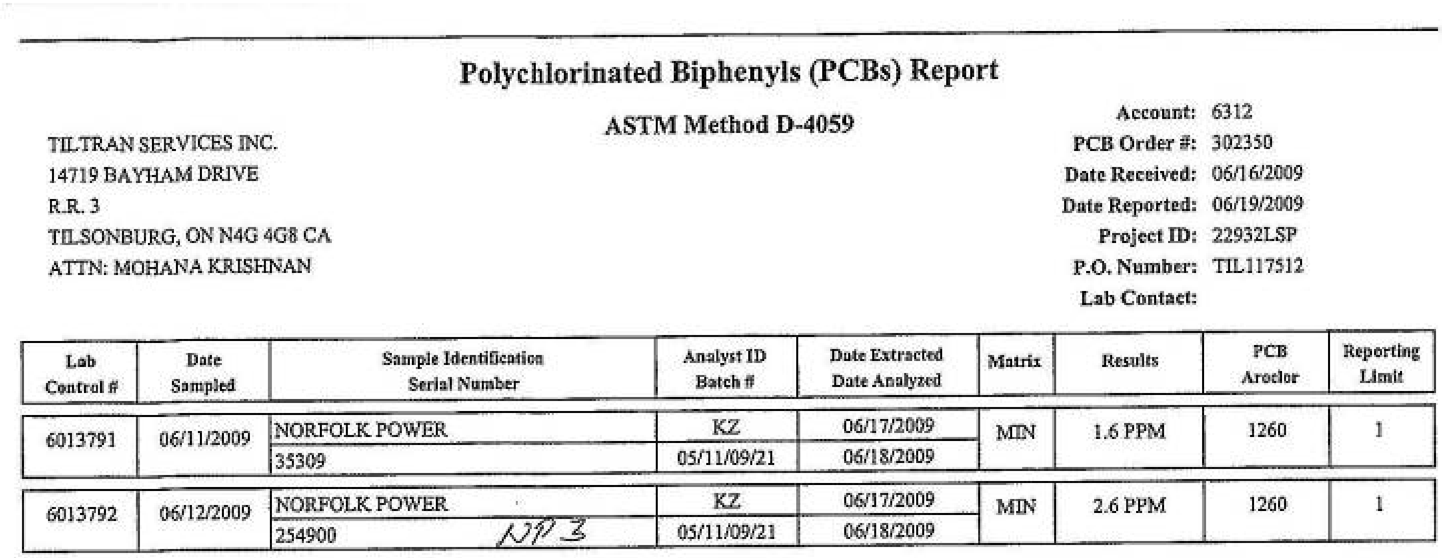
Polychlorinated Biphenyls (PCBs) Report

ASTM Method D-4059

TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN

Account: 6312
PCB Order #: 302350
Date Received: 06/16/2009
Date Reported: 06/19/2009
Project ID: 22932LSP
P.O. Number: TIL117512
Lab Contact:

Lab Control #	Date Sampled	Sample Identification Serial Number	Analyst ID Batch #	Date Extracted Date Analyzed	Matrix	Results	PCB Aroclor	Reporting Limit
6013750	06/12/2009	NORFOLK POWER 2301601 NP5	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	< 1.0 PPM	ND	1
6013751	06/12/2009	NORFOLK POWER 852501 BLM5	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	< 1.0 PPM	ND	1
6013752	06/12/2009	NORFOLK POWER 304307 NP6	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	2.4 PPM	1254	1
6013753	06/12/2009	NORFOLK POWER 35414 NP2	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	2.4 PPM	1260	1
6013758	06/11/2009	NORFOLK POWER P51111 NP8	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	60.0 PPM	1260	1
6013760	06/11/2009	NORFOLK POWER A31S0411	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	22.0 PPM	1254	1
6013762	06/11/2009	NORFOLK POWER A3S6297 NP11	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	5.4 PPM	1254	1
6013765	06/11/2009	NORFOLK POWER 105439 NP4-T2	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	25.0 PPM	1260	1
6013768	06/11/2009	NORFOLK POWER 105440 NP4-T3	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	6.0 PPM	1260	1
6013771	06/11/2009	NORFOLK POWER 105438 NP4-T1	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	21.0 PPM	1260	1
6013774	06/11/2009	NORFOLK POWER 85201	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	< 1.0 PPM	ND	1
6013777	06/11/2009	NORFOLK POWER 44603 NP13	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	3.0 PPM	1260/1254	1
6013778	06/12/2009	NORFOLK POWER A3S6121 NP1	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	34.0 PPM	1254	1
6013782	06/11/2009	NORFOLK POWER 20120 NP12	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	1.2 PPM	1260	1
6013786	06/11/2009	NORFOLK POWER 152710111 NP9	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	< 1.0 PPM	ND	1
6013789	06/11/2009	NORFOLK POWER 199137 NP10	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	9.1 PPM	1260	1



Polychlorinated Biphenyls (PCBs) Report

ASTM Method D-4059

TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN

Account: 6312
PCB Order #: 302350
Date Received: 06/16/2009
Date Reported: 06/19/2009
Project ID: 22932LSP
P.O. Number: TIL117512
Lab Contact:

Lab Control #	Date Sampled	Sample Identification Serial Number	Analyst ID Batch #	Date Extracted Date Analyzed	Matrix	Results	PCB Aroclor	Reporting Limit
6013791	06/11/2009	NORFOLK POWER 35309	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	1.6 PPM	1260	1
6013792	06/12/2009	NORFOLK POWER 254900 NP3	KZ 05/11/09/21	06/17/2009 06/18/2009	MIN	2.6 PPM	1260	1

TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

Location: NORFOLK POWER
Serial #: 2301601
Bank/Ph:
Tank: TRANSFORMER
Breathing: SEAL
Fluid: MIN Gallons: 616

NP5

Mfr: FERRANTI
KV: 27.6
KVA: 5000
Imp.(% Z):
Container: BG212 BG212
Project ID: 22932LSP

Account: 6312
Order #: 302350
Control #: 6013750
Received: 06/16/2009
Reported: 06/19/2009
Customer ID:

ASTM D-3612
Report Units: PPM

Dissolved Gas Analysis

Lab Control Number:	6013750
Date Sampled:	06/12/2009
Order Number:	302350
Oil Temp.(C):	35
Hydrogen (H2):	83
Methane (CH4):	18
Ethane (C2H6):	5
Ethylene (C2H4):	3
Acetylene (C2H2):	0
Carbon Monoxide (CO):	154
Carbon Dioxide (CO2):	750
Nitrogen (N2):	81348
Oxygen (O2):	8935
Total Dissolved Gas:	91296
Total Dissolved Combustible Gas:	263
Equivalent TCG Percent:	0.301

Oil Screen

D-1533B	Moisture in Oil	(ppm):	5
D-971	Interfacial Tension	(dynes/cm):	40.2
D-974	Acid Number	(mg KOH/g):	0.006
D-1500	Color Number	(Relative):	L1.0
D-1524	Visual Exam.	(Relative):	CLR&SPRK
D-1524	Sediment Exam.	(Relative):	ND
D-877	Dielectric Breakdown	(kV):	39
D-1816	Dielectric Breakdown 1 mm	(kV mm-C):	
D-1816	Dielectric Breakdown 2 mm	(kV mm-C):	
D-924	Power Factor @ 25C	(%):	
D-924	Power Factor @ 100C	(%):	
D-1298	Specific Gravity	(Relative):	0.872
WDS	Passivator	(ppm):	
D-2668	Oxidation Inhibitor	(wt. %):	

Diagnostics

DGA Key Gas / Interpretive Method: IEEE (C57.104) (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene within condition 1 limits (50 ppm). Carbon Monoxide within condition 1 limits (350 ppm). Overall equipment condition code: 1.
DGA Rogers Ratio Method:	Analyzed gases do not exceed warning thresholds. Rogers Ratios do not apply.
DGA Cellulose (Paper) Insulation:	CO2/CO Ratio not applicable - neither gas exceeds its limit.
DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
Moisture in Oil:	Acceptable for in-service oil (35 ppm max).
Interfacial Tension:	Acceptable for in-service oil (25 dynes/cm min).
Acid Number:	Acceptable for in-service oil (0.2 mg KOH/g max).
Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
Dielectric Breakdown D-1816:	
Power Factor @ 25C:	
Power Factor @ 100C:	
Oxidation Inhibitor:	

TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

Burns

Location:	NORFOLK POWER	Mfr:	ABB	Account:	6312
Serial #:	852501	KV:	110	Order #:	302350
Bank/Ph:		KVA:	41700	Control #:	6013751
Tank:	TRANSFORMER	Imp.(% Z):		Received:	06/16/2009
Breathing:	SEAL	Container:	BF720 BF720	Reported:	06/19/2009
Fluid:	MIN Gallons: 32900 L	Project ID:	22932LSP	Customer ID:	

ASTM D-3612
Report Units: PPM

Dissolved Gas Analysis

Lab Control Number:	6013751
Date Sampled:	06/12/2009
Order Number:	302350
Oil Temp.(C):	30
Hydrogen (H2):	8
Methane (CH4):	16
Ethane (C2H6):	21
Ethylene (C2H4):	1
Acetylene (C2H2):	0
Carbon Monoxide (CO):	69
Carbon Dioxide (CO2):	228
Nitrogen (N2):	15362
Oxygen (O2):	2430
Total Dissolved Gas:	18135
Total Dissolved Combustible Gas:	115
Equivalent TCG Percent:	0.4082

Oil Screen

D-1533B	Moisture in Oil	(ppm):	5
D-971	Interfacial Tension	(dynes/cm):	36.8
D-974	Acid Number	(mg KOH/g):	0.003
D-1500	Color Number	(Relative):	L0.5
D-1524	Visual Exam.	(Relative):	CLR&SPRK
D-1524	Sediment Exam.	(Relative):	ND
D-877	Dielectric Breakdown	(kV):	53
D-1816	Dielectric Breakdown 1 mm	(kV mm-C):	
D-1816	Dielectric Breakdown 2 mm	(kV mm-C):	
D-924	Power Factor @ 25C	(%):	
D-924	Power Factor @ 100C	(%):	
D-1298	Specific Gravity	(Relative):	0.882
WDS	Passivator	(ppm):	
D-2668	Oxidation Inhibitor	(wt. %):	

Diagnostics

DGA Key Gas / Interpretive Method: IEEE (C57.104) (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene within condition 1 limits (50 ppm). Carbon Monoxide within condition 1 limits (350 ppm). Overall equipment condition code: 1.
DGA Rogers Ratio Method:	Analyzed gases do not exceed warning thresholds. Rogers Ratios do not apply.
DGA Cellulose (Paper) Insulation:	CO2/CO Ratio not applicable - neither gas exceeds its limit.
DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
Moisture in Oil:	Acceptable for in-service oil (25 ppm max).
Interfacial Tension:	Acceptable for in-service oil (30 dynes/cm min).
Acid Number:	Acceptable for in-service oil (0.15 mg KOH/g max).
Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
Dielectric Breakdown D-1816:	
Power Factor @ 25C:	
Power Factor @ 100C:	
Oxidation Inhibitor:	

TILTRAN SERVICES INC.
,4719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

Location: NORFOLK POWER
Serial #: 304307
Bank/Ph:
Tank: TRANSFORMER
Breathing: SEAL
Fluid: MIN Gallons: 664

NP6

Mfr: FERRANTI
KV: 27.6
KVA: 5000
Imp.(% Z):
Container: 5862 5862
Project ID: 22932LSP

Account: 6312
Order #: 302350
Control #: 6013752
Received: 06/16/2009
Reported: 06/19/2009
Customer ID:

ASTM D-3612
Report Units: PPM

Dissolved Gas Analysis

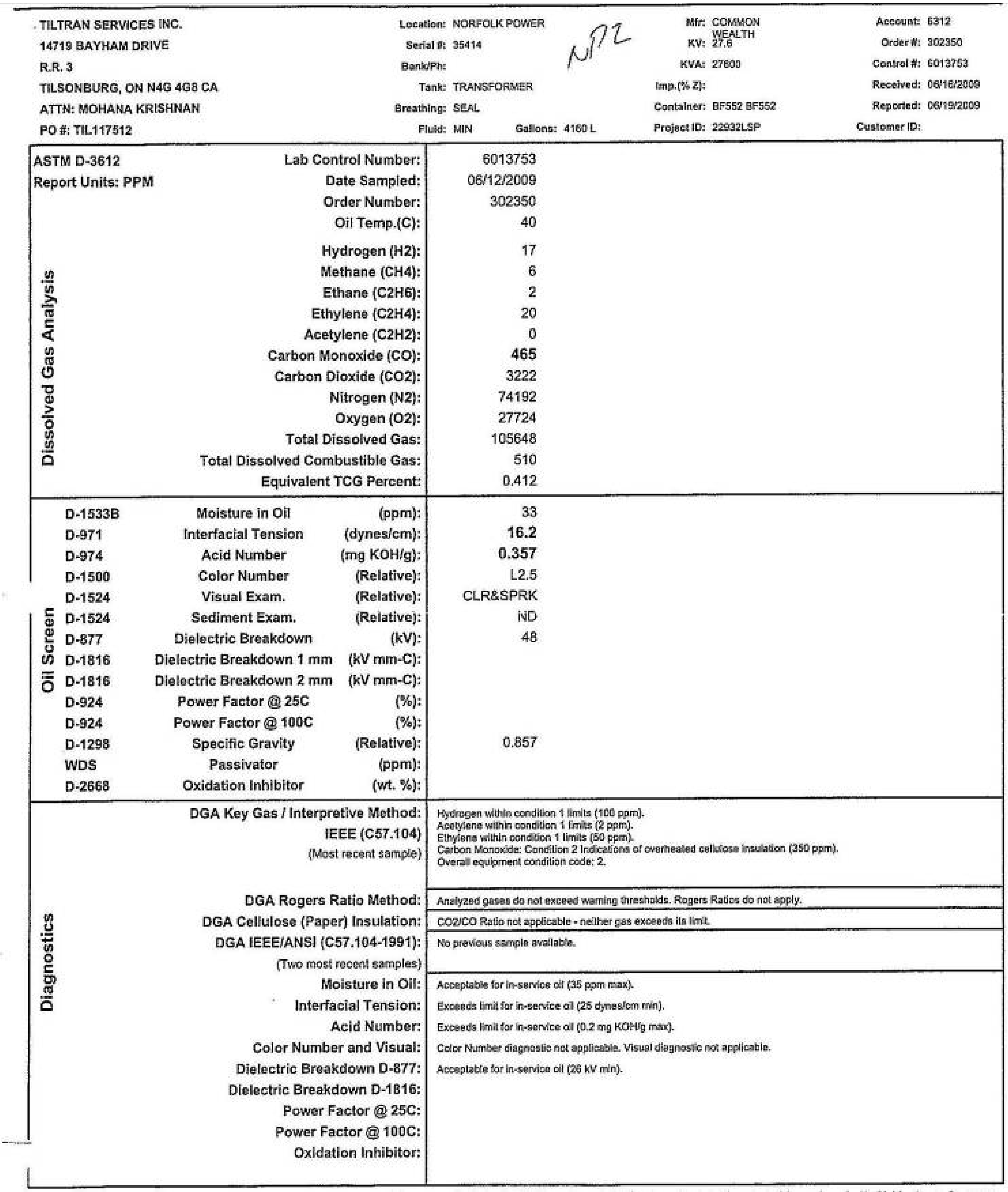
Lab Control Number:	6013752
Date Sampled:	06/12/2009
Order Number:	302350
Oil Temp.(C):	30
Hydrogen (H2):	4
Methane (CH4):	42
Ethane (C2H6):	18
Ethylene (C2H4):	13
Acetylene (C2H2):	0
Carbon Monoxide (CO):	**692**
Carbon Dioxide (CO2):	2940
Nitrogen (N2):	85390
Oxygen (O2):	746
Total Dissolved Gas:	89845
Total Dissolved Combustible Gas:	**769**
Equivalent TCG Percent:	0.6016

Oil Screen

D-1533B	Moisture in Oil	(ppm):	9
D-971	Interfacial Tension	(dynes/cm):	34.4
D-974	Acid Number	(mg KOH/g):	0.020
D-1500	Color Number	(Relative):	L1.5
D-1524	Visual Exam.	(Relative):	CLR&SPRK
D-1524	Sediment Exam.	(Relative):	TRACE
D-877	Dielectric Breakdown	(kV):	36
D-1816	Dielectric Breakdown 1 mm	(kV mm-C):	
D-1816	Dielectric Breakdown 2 mm	(kV mm-C):	
D-924	Power Factor @ 25C	(%):	
D-924	Power Factor @ 100C	(%):	
D-1298	Specific Gravity	(Relative):	0.902
WDS	Passivator	(ppm):	
D-2668	Oxidation Inhibitor	(wt. %):	

Diagnostics

DGA Key Gas / Interpretive Method: IEEE (C57.104) (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene within condition 1 limits (50 ppm). Carbon Monoxide: Condition 3 Indications of significantly overheated cellulose insulation (570 ppm). Overall equipment condition code: 3.
DGA Rogers Ratio Method:	Rogers Ratios suggest a low temperature thermal fault.
DGA Cellulose (Paper) Insulation:	CO2/CO < 7: Indication of thermal decomposition of cellulose.
DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
Moisture in Oil:	Acceptable for in-service oil (35 ppm max).
Interfacial Tension:	Acceptable for in-service oil (25 dynes/cm min).
Acid Number:	Acceptable for in-service oil (0.2 mg KOH/g max).
Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
Dielectric Breakdown D-1816:	
Power Factor @ 25C:	
Power Factor @ 100C:	
Oxidation Inhibitor:	



TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

Location: NORFOLK POWER
Serial #: 35414
Bank/Ph:
Tank: TRANSFORMER
Breathing: SEAL
Fluid: MIN Gallons: 4160 L

N72

Mfr: COMMON WEALTH
KV: 27.6
KVA: 27600
Imp.(% Z):
Container: BF552 BF552
Project ID: 22932LSP

Account: 6312
Order #: 302350
Control #: 6013753
Received: 06/16/2009
Reported: 06/19/2009
Customer ID:

ASTM D-3612
Report Units: PPM

Lab Control Number:	6013753
Date Sampled:	06/12/2009
Order Number:	302350
Oil Temp.(C):	40

Dissolved Gas Analysis

Hydrogen (H2):	17
Methane (CH4):	6
Ethane (C2H6):	2
Ethylene (C2H4):	20
Acetylene (C2H2):	0
Carbon Monoxide (CO):	**465**
Carbon Dioxide (CO2):	3222
Nitrogen (N2):	74192
Oxygen (O2):	27724
Total Dissolved Gas:	105648
Total Dissolved Combustible Gas:	510
Equivalent TCG Percent:	0.412

Oil Screen

D-1533B	Moisture in Oil	(ppm):	33
D-971	Interfacial Tension	(dynes/cm):	**16.2**
D-974	Acid Number	(mg KOH/g):	**0.357**
D-1500	Color Number	(Relative):	L2.5
D-1524	Visual Exam.	(Relative):	CLR&SPRK
D-1524	Sediment Exam.	(Relative):	ND
D-877	Dielectric Breakdown	(kV):	48
D-1816	Dielectric Breakdown 1 mm	(kV mm-C):	
D-1816	Dielectric Breakdown 2 mm	(kV mm-C):	
D-924	Power Factor @ 25C	(%):	
D-924	Power Factor @ 100C	(%):	
D-1298	Specific Gravity	(Relative):	0.857
WDS	Passivator	(ppm):	
D-2668	Oxidation Inhibitor	(wt. %):	

Diagnostics

DGA Key Gas / Interpretive Method: IEEE (C57.104) (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene within condition 1 limits (50 ppm). Carbon Monoxide: Condition 2 Indications of overheated cellulose insulation (350 ppm). Overall equipment condition code: 2.
DGA Rogers Ratio Method:	Analyzed gases do not exceed warning thresholds. Rogers Ratios do not apply.
DGA Cellulose (Paper) Insulation:	CO2/CO Ratio not applicable - neither gas exceeds its limit.
DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
Moisture in Oil:	Acceptable for in-service oil (35 ppm max).
Interfacial Tension:	Exceeds limit for in-service oil (25 dynes/cm min).
Acid Number:	Exceeds limit for in-service oil (0.2 mg KOH/g max).
Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
Dielectric Breakdown D-1816:	
Power Factor @ 25C:	
Power Factor @ 100C:	
Oxidation Inhibitor:	

TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

NT8

Location: NORFOLK POWER
Serial #: P61111
Bank/Ph:
Tank: TRANSFORMER
Breathing: SEAL
Fluid: MIN **Gallons:** 710 L

Mfr: RELIANCE
KV: 27.6
KVA: 3750
Imp.(% Z):
Container: BG293 BG293
Project ID: 22932LSP

Account: 6312
Order #: 302350
Control #: 6013758
Received: 06/16/2009
Reported: 06/19/2009
Customer ID:

ASTM D-3612
Report Units: PPM

Dissolved Gas Analysis

Lab Control Number:	6013758
Date Sampled:	06/11/2009
Order Number:	302350
Oil Temp.(C):	32
Hydrogen (H2):	8
Methane (CH4):	2
Ethane (C2H6):	0
Ethylene (C2H4):	10
Acetylene (C2H2):	0
Carbon Monoxide (CO):	138
Carbon Dioxide (CO2):	2673
Nitrogen (N2):	73978
Oxygen (O2):	37615
Total Dissolved Gas:	114424
Total Dissolved Combustible Gas:	158
Equivalent TCG Percent:	0.1217

Oil Screen

D-1533B	Moisture in Oil	(ppm):	24
D-971	Interfacial Tension	(dynes/cm):	33.9
D-974	Acid Number	(mg KOH/g):	0.025
D-1500	Color Number	(Relative):	L1.0
D-1524	Visual Exam.	(Relative):	CLR&SPRK
D-1524	Sediment Exam.	(Relative):	ND
D-877	Dielectric Breakdown	(kV):	36
D-1816	Dielectric Breakdown 1 mm	(kV mm-C):	
D-1816	Dielectric Breakdown 2 mm	(kV mm-C):	
D-924	Power Factor @ 25C	(%):	
D-924	Power Factor @ 100C	(%):	
D-1298	Specific Gravity	(Relative):	0.855
WDS	Passivator	(ppm):	
D-2668	Oxidation Inhibitor	(wt. %):	

Diagnostics

DGA Key Gas / Interpretive Method: IEEE (C57.104) (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene within condition 1 limits (50 ppm). Carbon Monoxide within condition 1 limits (350 ppm). Overall equipment condition code: 1.
DGA Rogers Ratio Method:	Analyzed gases do not exceed warning thresholds. Rogers Ratios do not apply.
DGA Cellulose (Paper) Insulation:	CO2/CO Ratio not applicable - neither gas exceeds its limit.
DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
Moisture in Oil:	Acceptable for in-service oil (35 ppm max).
Interfacial Tension:	Acceptable for in-service oil (25 dynes/cm min).
Acid Number:	Acceptable for in-service oil (0.2 mg KOH/g max).
Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
Dielectric Breakdown D-1816:	
Power Factor @ 25C:	
Power Factor @ 100C:	
Oxidation Inhibitor:	

TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

1

Location:	NORFOLK POWER	**Mfr:**	WESTINGHOUSE	**Account:**	6312
Serial #:	A31S0411	**KV:**	27.8	**Order #:**	302350
Bank/Ph:		**KVA:**	3000	**Control #:**	6013760
Tank:	TRANSFORMER	**Imp.(% Z):**		**Received:**	06/16/2009
Breathing:	SEAL	**Container:**	BE933 BE933	**Reported:**	06/19/2009
Fluid:	MIN **Gallons:** 587 L	**Project ID:**	22932LSP	**Customer ID:**	

ASTM D-3612
Report Units: PPM

	Lab Control Number:	6013760
	Date Sampled:	06/11/2009
	Order Number:	302350
	Oil Temp.(C):	25
Dissolved Gas Analysis	**Hydrogen (H2):**	44
	Methane (CH4):	1
	Ethane (C2H6):	0
	Ethylene (C2H4):	2
	Acetylene (C2H2):	0
	Carbon Monoxide (CO):	6
	Carbon Dioxide (CO2):	1092
	Nitrogen (N2):	71779
	Oxygen (O2):	39201
	Total Dissolved Gas:	112125
	Total Dissolved Combustible Gas:	53
	Equivalent TCG Percent:	0.087

Oil Screen	**D-1533B**	**Moisture in Oil**	**(ppm):**	16
	D-971	**Interfacial Tension**	**(dynes/cm):**	42.8
	D-974	**Acid Number**	**(mg KOH/g):**	0.003
	D-1500	**Color Number**	**(Relative):**	L1.0
	D-1524	**Visual Exam.**	**(Relative):**	CLR&SPRK
	D-1524	**Sediment Exam.**	**(Relative):**	ND
	D-877	**Dielectric Breakdown**	**(kV):**	37
	D-1816	**Dielectric Breakdown 1 mm**	**(kV mm-C):**	
	D-1816	**Dielectric Breakdown 2 mm**	**(kV mm-C):**	
	D-924	**Power Factor @ 25C**	**(%):**	
	D-924	**Power Factor @ 100C**	**(%):**	
	D-1298	**Specific Gravity**	**(Relative):**	0.872
	WDS	**Passivator**	**(ppm):**	
	D-2668	**Oxidation Inhibitor**	**(wt. %):**	

Diagnostics	**DGA Key Gas / Interpretive Method:** **IEEE (C57.104)** (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene within condition 1 limits (50 ppm). Carbon Monoxide within condition 1 limits (350 ppm). Overall equipment condition code: 1.
	DGA Rogers Ratio Method:	Analyzed gases do not exceed warning thresholds. Rogers Ratios do not apply.
	DGA Cellulose (Paper) Insulation:	CO2/CO Ratio not applicable - neither gas exceeds its limit.
	DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
	Moisture in Oil:	Acceptable for in-service oil (35 ppm max).
	Interfacial Tension:	Acceptable for in-service oil (25 dynes/cm min).
	Acid Number:	Acceptable for in-service oil (0.2 mg KOH/g max).
	Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
	Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
	Dielectric Breakdown D-1816:	
	Power Factor @ 25C:	
	Power Factor @ 100C:	
	Oxidation Inhibitor:	

TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

Location: NORFOLK POWER
Serial #: A3S6297
Bank/Ph:
Tank: TRANSFORMER
Breathing: SEAL
Fluid: MIN Gallons: 821

NP11

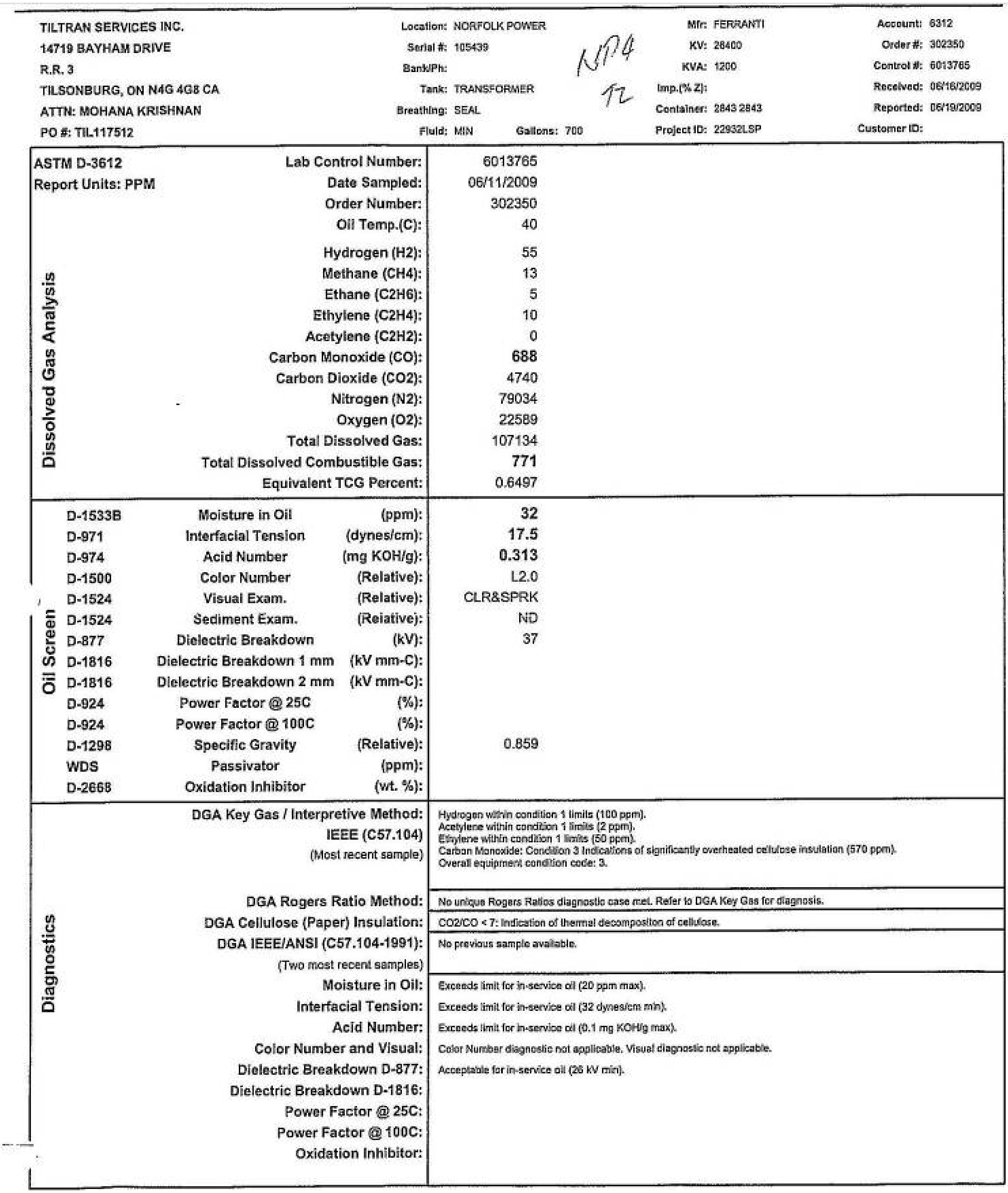
Mfr: WESTINGHOUSE
KV: 27.6
KVA: 5000
Imp.(% Z):
Container: BG522 BG522
Project ID: 22932LSP

Account: 6312
Order #: 302350
Control #: 6013762
Received: 06/16/2009
Reported: 06/19/2009
Customer ID:

ASTM D-3612	Lab Control Number:	6013762
Report Units: PPM	Date Sampled:	06/11/2009
	Order Number:	302350
	Oil Temp.(C):	35
Dissolved Gas Analysis	Hydrogen (H2):	26
	Methane (CH4):	4
	Ethane (C2H6):	1
	Ethylene (C2H4):	1
	Acetylene (C2H2):	0
	Carbon Monoxide (CO):	55
	Carbon Dioxide (CO2):	1598
	Nitrogen (N2):	68779
	Oxygen (O2):	9093
	Total Dissolved Gas:	79557
	Total Dissolved Combustible Gas:	87
	Equivalent TCG Percent:	0.1165

Oil Screen	D-1533B	Moisture in Oil	(ppm):	4
	D-971	Interfacial Tension	(dynes/cm):	47.3
	D-974	Acid Number	(mg KOH/g):	0.003
	D-1500	Color Number	(Relative):	L1.0
	D-1524	Visual Exam.	(Relative):	CLR&SPRK
	D-1524	Sediment Exam.	(Relative):	ND
	D-877	Dielectric Breakdown	(kV):	40
	D-1816	Dielectric Breakdown 1 mm	(kV mm-C):	
	D-1816	Dielectric Breakdown 2 mm	(kV mm-C):	
	D-924	Power Factor @ 25C	(%):	
	D-924	Power Factor @ 100C	(%):	
	D-1298	Specific Gravity	(Relative):	0.868
	WDS	Passivator	(ppm):	
	D-2668	Oxidation Inhibitor	(wt. %):	

Diagnostics	DGA Key Gas / Interpretive Method: IEEE (C57.104) (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene within condition 1 limits (50 ppm). Carbon Monoxide within condition 1 limits (350 ppm). Overall equipment condition code: 1.
	DGA Rogers Ratio Method:	Analyzed gases do not exceed warning thresholds. Rogers Ratios do not apply.
	DGA Cellulose (Paper) Insulation:	CO2/CO Ratio not applicable - neither gas exceeds its limit.
	DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
	Moisture in Oil:	Acceptable for in-service oil (35 ppm max).
	Interfacial Tension:	Acceptable for in-service oil (25 dynes/cm min).
	Acid Number:	Acceptable for in-service oil (0.2 mg KOH/g max).
	Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
	Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
	Dielectric Breakdown D-1816:	
	Power Factor @ 25C:	
	Power Factor @ 100C:	
	Oxidation Inhibitor:	



TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

Location: NORFOLK POWER
Serial #: 105439
Bank/Ph:
Tank: TRANSFORMER
Breathing: SEAL
Fluid: MIN Gallons: 700

NP4
T2

Mfr: FERRANTI
KV: 28400
KVA: 1200
Imp.(% Z):
Container: 2843 2843
Project ID: 22932LSP

Account: 6312
Order #: 302350
Control #: 6013765
Received: 06/16/2009
Reported: 06/19/2009
Customer ID:

ASTM D-3612
Report Units: PPM

Dissolved Gas Analysis

Lab Control Number:	6013765
Date Sampled:	06/11/2009
Order Number:	302350
Oil Temp.(C):	40
Hydrogen (H2):	55
Methane (CH4):	13
Ethane (C2H6):	5
Ethylene (C2H4):	10
Acetylene (C2H2):	0
Carbon Monoxide (CO):	**688**
Carbon Dioxide (CO2):	4740
Nitrogen (N2):	79034
Oxygen (O2):	22589
Total Dissolved Gas:	107134
Total Dissolved Combustible Gas:	**771**
Equivalent TCG Percent:	0.6497

Oil Screen

D-1533B	Moisture in Oil	(ppm):	**32**
D-971	Interfacial Tension	(dynes/cm):	**17.5**
D-974	Acid Number	(mg KOH/g):	**0.313**
D-1500	Color Number	(Relative):	L2.0
D-1524	Visual Exam.	(Relative):	CLR&SPRK
D-1524	Sediment Exam.	(Relative):	ND
D-877	Dielectric Breakdown	(kV):	37
D-1816	Dielectric Breakdown 1 mm	(kV mm-C):	
D-1816	Dielectric Breakdown 2 mm	(kV mm-C):	
D-924	Power Factor @ 25C	(%):	
D-924	Power Factor @ 100C	(%):	
D-1298	Specific Gravity	(Relative):	0.859
WDS	Passivator	(ppm):	
D-2668	Oxidation Inhibitor	(wt. %):	

Diagnostics

DGA Key Gas / Interpretive Method: IEEE (C57.104) (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene within condition 1 limits (50 ppm). Carbon Monoxide: Condition 3 Indications of significantly overheated cellulose insulation (570 ppm). Overall equipment condition code: 3.
DGA Rogers Ratio Method:	No unique Rogers Ratios diagnostic case met. Refer to DGA Key Gas for diagnosis.
DGA Cellulose (Paper) Insulation:	CO2/CO < 7: Indication of thermal decompositon of cellulose.
DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
Moisture in Oil:	Exceeds limit for in-service oil (20 ppm max).
Interfacial Tension:	Exceeds limit for in-service oil (32 dynes/cm min).
Acid Number:	Exceeds limit for in-service oil (0.1 mg KOH/g max).
Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
Dielectric Breakdown D-1816:	
Power Factor @ 25C:	
Power Factor @ 100C:	
Oxidation Inhibitor:	

TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

Location: NORFOLK POWER
Serial #: 105440
NP4-73
Bank/Ph:
Tank: TRANSFORMER
Breathing: SEAL
Fluid: MIN Gallons: 700 L

Mfr: FERRANTI
KV: 26.4
KVA: 1200
Imp.(% Z):
Container: AK438 AK438
Project ID: 22932LSP

Account: 6312
Order #: 302350
Control #: 6013768
Received: 06/16/2009
Reported: 06/19/2009
Customer ID:

ASTM D-3612
Report Units: PPM

Dissolved Gas Analysis

Lab Control Number:	6013768
Date Sampled:	06/11/2009
Order Number:	302350
Oil Temp.(C):	40
Hydrogen (H2):	68
Methane (CH4):	17
Ethane (C2H6):	7
Ethylene (C2H4):	9
Acetylene (C2H2):	0
Carbon Monoxide (CO):	**940**
Carbon Dioxide (CO2):	5933
Nitrogen (N2):	80956
Oxygen (O2):	19600
Total Dissolved Gas:	107530
Total Dissolved Combustible Gas:	**1041**
Equivalent TCG Percent:	0.868

Oil Screen

D-1533B	Moisture in Oil	(ppm):	28
D-971	Interfacial Tension	(dynes/cm):	**16.4**
D-974	Acid Number	(mg KOH/g):	**0.341**
D-1500	Color Number	(Relative):	L2.0
D-1524	Visual Exam.	(Relative):	CLR&SPRK
D-1524	Sediment Exam.	(Relative):	ND
D-877	Dielectric Breakdown	(kV):	50
D-1816	Dielectric Breakdown 1 mm	(kV mm-C):	
D-1816	Dielectric Breakdown 2 mm	(kV mm-C):	
D-924	Power Factor @ 25C	(%):	
D-924	Power Factor @ 100C	(%):	
D-1298	Specific Gravity	(Relative):	0.86
WDS	Passivator	(ppm):	
D-2668	Oxidation Inhibitor	(wt. %):	

Diagnostics

DGA Key Gas / Interpretive Method: IEEE (C57.104) (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene within condition 1 limits (50 ppm). Carbon Monoxide: Condition 3 Indications of significantly overheated cellulose insulation (570 ppm). Overall equipment condition code: 3.
DGA Rogers Ratio Method:	No unique Rogers Ratios diagnostic case met. Refer to DGA Key Gas for diagnosis.
DGA Cellulose (Paper) Insulation:	CO2/CO < 7: Indication of thermal decompositon of cellulose.
DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
Moisture in Oil:	Acceptable for in-service oil (35 ppm max).
Interfacial Tension:	Exceeds limit for in-service oil (25 dynes/cm min).
Acid Number:	Exceeds limit for in-service oil (0.2 mg KOH/g max).
Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
Dielectric Breakdown D-1816:	
Power Factor @ 25C:	
Power Factor @ 100C:	
Oxidation Inhibitor:	

TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

NP4
-T1

Location:	NORFOLK POWER	Mfr:	FERRANTI	Account:	6312
Serial #:	105436	KV:	26.4	Order #:	302350
Bank/Ph:		KVA:	1200	Control #:	6013771
Tank:	TRANSFORMER	Imp.(% Z):		Received:	06/16/2009
Breathing:	SEAL	Container:	BF724 BF724	Reported:	05/19/2009
Fluid:	MIN Gallons: 700	Project ID:	22932LSP	Customer ID:	

ASTM D-3612
Report Units: PPM

Dissolved Gas Analysis

Lab Control Number:	6013771
Date Sampled:	06/11/2009
Order Number:	302350
Oil Temp.(C):	45
Hydrogen (H2):	48
Methane (CH4):	12
Ethane (C2H6):	5
Ethylene (C2H4):	8
Acetylene (C2H2):	0
Carbon Monoxide (CO):	**614**
Carbon Dioxide (CO2):	4186
Nitrogen (N2):	79697
Oxygen (O2):	24154
Total Dissolved Gas:	108724
Total Dissolved Combustible Gas:	687
Equivalent TCG Percent:	0.5692

Oil Screen

D-1533B	Moisture in Oil	(ppm):	28
D-971	Interfacial Tension	(dynes/cm):	**16.6**
D-974	Acid Number	(mg KOH/g):	**0.343**
D-1500	Color Number	(Relative):	L2.0
D-1524	Visual Exam.	(Relative):	CLR&SPRK
D-1524	Sediment Exam.	(Relative):	ND
D-877	Dielectric Breakdown	(kV):	43
D-1816	Dielectric Breakdown 1 mm	(kV mm-C):	
D-1816	Dielectric Breakdown 2 mm	(kV mm-C):	
D-924	Power Factor @ 25C	(%):	
D-924	Power Factor @ 100C	(%):	
D-1298	Specific Gravity	(Relative):	0.857
WDS	Passivator	(ppm):	
D-2668	Oxidation Inhibitor	(wt. %):	

Diagnostics

DGA Key Gas / Interpretive Method: **IEEE (C57.104)** (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene within condition 1 limits (50 ppm). Carbon Monoxide: Condition 3 Indications of significantly overheated cellulose insulation (570 ppm). Overall equipment condition code: 3.
DGA Rogers Ratio Method:	No unique Rogers Ratios diagnostic case met. Refer to DGA Key Gas for diagnosis.
DGA Cellulose (Paper) Insulation:	CO2/CO < 7: Indication of thermal decomposition of cellulose.
DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
Moisture in Oil:	Acceptable for in-service oil (35 ppm max).
Interfacial Tension:	Exceeds limit for in-service oil (25 dynes/cm min).
Acid Number:	Exceeds limit for in-service oil (0.2 mg KOH/g max).
Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
Dielectric Breakdown D-1816:	
Power Factor @ 25C:	
Power Factor @ 100C:	
Oxidation Inhibitor:	

TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

Location: NORFOLK POWER
Serial #: 85201 1
Bank/Ph:
Tank: TRANSFORMER
Breathing: SEAL
Fluid: MIN **Gallons:** 1300

Mfr: ABB
KV: 110
KVA: 41700
Imp.(% Z):
Container: BG482 BG482
Project ID: 22932LSP

Account: 6312
Order #: 302350
Control #: 6013774
Received: 06/16/2009
Reported: 06/18/2009
Customer ID:

ASTM D-3612
Report Units: PPM

Dissolved Gas Analysis

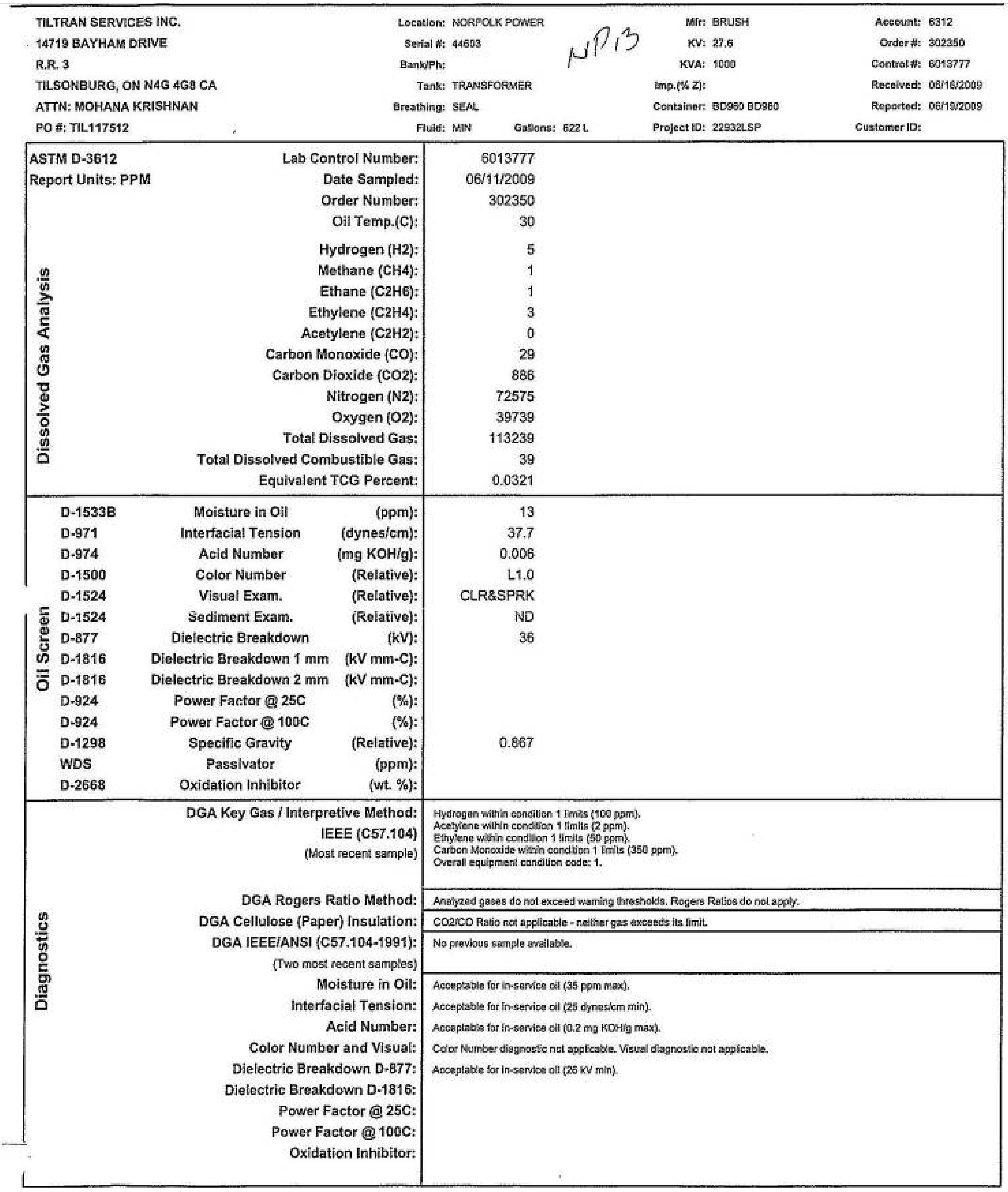
Lab Control Number:	6013774
Date Sampled:	06/11/2009
Order Number:	302350
Oil Temp.(C):	30
Hydrogen (H2):	0
Methane (CH4):	1
Ethane (C2H6):	0
Ethylene (C2H4):	2
Acetylene (C2H2):	0
Carbon Monoxide (CO):	5
Carbon Dioxide (CO2):	443
Nitrogen (N2):	69677
Oxygen (O2):	37376
Total Dissolved Gas:	107504
Total Dissolved Combustible Gas:	8
Equivalent TCG Percent:	0.0044

Oil Screen

D-1533B	**Moisture in Oil**	**(ppm):**	10
D-971	**Interfacial Tension**	**(dynes/cm):**	38.0
D-974	**Acid Number**	**(mg KOH/g):**	0.003
D-1500	**Color Number**	**(Relative):**	L0.5
D-1524	**Visual Exam.**	**(Relative):**	CLR&SPRK
D-1524	**Sediment Exam.**	**(Relative):**	ND
D-877	**Dielectric Breakdown**	**(kV):**	41
D-1816	**Dielectric Breakdown 1 mm**	**(kV mm-C):**	
D-1816	**Dielectric Breakdown 2 mm**	**(kV mm-C):**	
D-924	**Power Factor @ 25C**	**(%):**	
D-924	**Power Factor @ 100C**	**(%):**	
D-1298	**Specific Gravity**	**(Relative):**	0.889
WDS	**Passivator**	**(ppm):**	
D-2668	**Oxidation Inhibitor**	**(wt. %):**	

Diagnostics

DGA Key Gas / Interpretive Method: **IEEE (C57.104)** (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene within condition 1 limits (50 ppm). Carbon Monoxide within condition 1 limits (350 ppm). Overall equipment condition code: 1.
DGA Rogers Ratio Method:	Analyzed gases do not exceed warning thresholds. Rogers Ratios do not apply.
DGA Cellulose (Paper) Insulation:	CO2/CO Ratio not applicable - neither gas exceeds its limit.
DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
Moisture in Oil:	Acceptable for in-service oil (25 ppm max).
Interfacial Tension:	Acceptable for in-service oil (30 dynes/cm min).
Acid Number:	Acceptable for in-service oil (0.15 mg KOH/g max).
Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
Dielectric Breakdown D-1816:	
Power Factor @ 25C:	
Power Factor @ 100C:	
Oxidation Inhibitor:	



TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

Location: NORFOLK POWER
Serial #: 44603
Bank/Ph:
Tank: TRANSFORMER
Breathing: SEAL
Fluid: MIN Gallons: 622 L

NP13

Mfr: BRUSH
KV: 27.6
KVA: 1000
Imp.(% Z):
Container: BD960 BD960
Project ID: 22932LSP

Account: 6312
Order #: 302350
Control #: 6013777
Received: 06/16/2009
Reported: 06/19/2009
Customer ID:

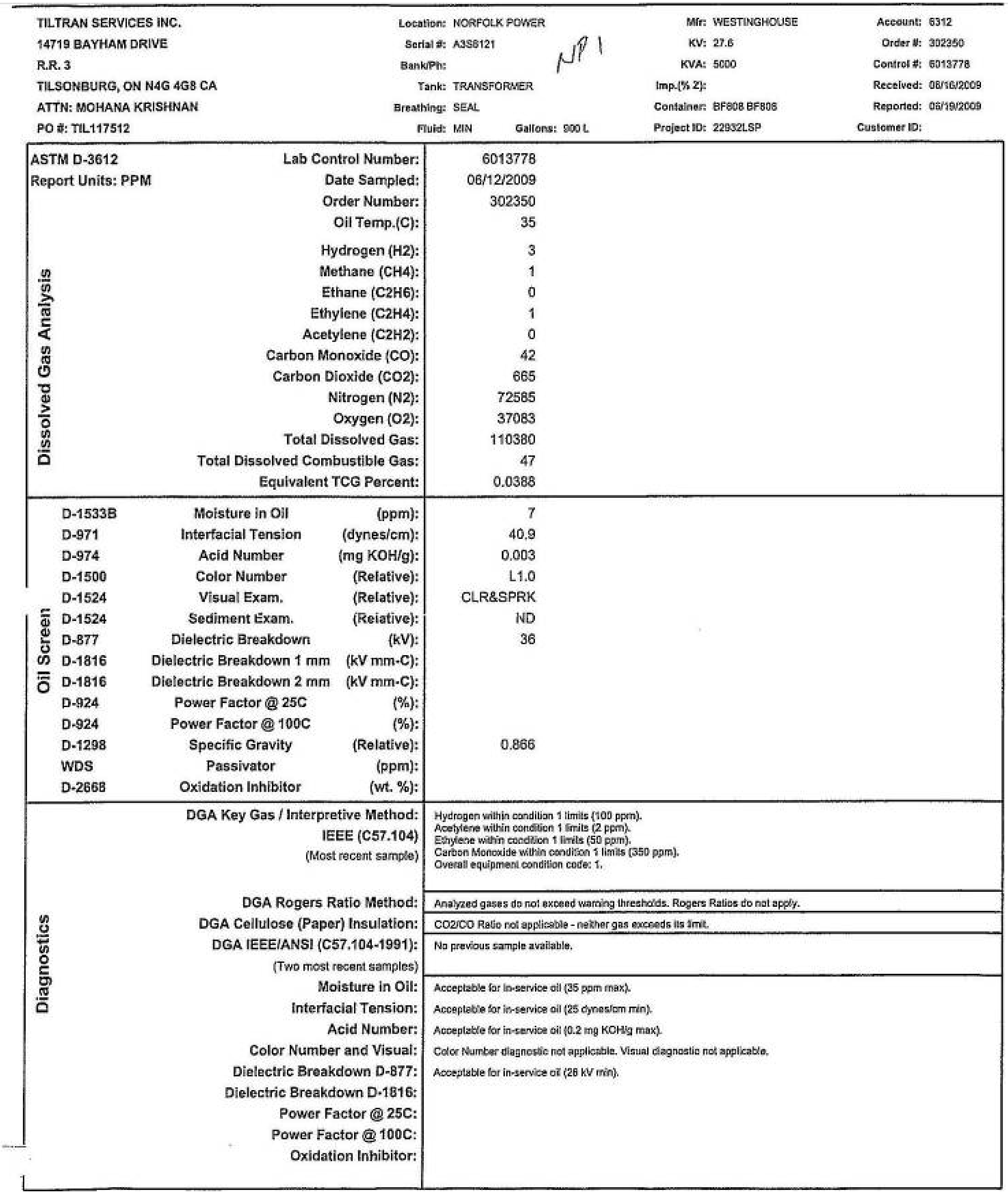
ASTM D-3612	Lab Control Number:	6013777
Report Units: PPM	Date Sampled:	06/11/2009
	Order Number:	302350
	Oil Temp.(C):	30
Dissolved Gas Analysis	Hydrogen (H2):	5
	Methane (CH4):	1
	Ethane (C2H6):	1
	Ethylene (C2H4):	3
	Acetylene (C2H2):	0
	Carbon Monoxide (CO):	29
	Carbon Dioxide (CO2):	886
	Nitrogen (N2):	72575
	Oxygen (O2):	39739
	Total Dissolved Gas:	113239
	Total Dissolved Combustible Gas:	39
	Equivalent TCG Percent:	0.0321

Oil Screen

D-1533B	Moisture in Oil	(ppm):	13
D-971	Interfacial Tension	(dynes/cm):	37.7
D-974	Acid Number	(mg KOH/g):	0.006
D-1500	Color Number	(Relative):	L1.0
D-1524	Visual Exam.	(Relative):	CLR&SPRK
D-1524	Sediment Exam.	(Relative):	ND
D-877	Dielectric Breakdown	(kV):	36
D-1816	Dielectric Breakdown 1 mm	(kV mm-C):	
D-1816	Dielectric Breakdown 2 mm	(kV mm-C):	
D-924	Power Factor @ 25C	(%):	
D-924	Power Factor @ 100C	(%):	
D-1298	Specific Gravity	(Relative):	0.867
WDS	Passivator	(ppm):	
D-2668	Oxidation Inhibitor	(wt. %):	

Diagnostics

DGA Key Gas / Interpretive Method: IEEE (C57.104) (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene within condition 1 limits (50 ppm). Carbon Monoxide within condition 1 limits (350 ppm). Overall equipment condition code: 1.
DGA Rogers Ratio Method:	Analyzed gases do not exceed warning thresholds. Rogers Ratios do not apply.
DGA Cellulose (Paper) Insulation:	CO2/CO Ratio not applicable - neither gas exceeds its limit.
DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
Moisture in Oil:	Acceptable for in-service oil (35 ppm max).
Interfacial Tension:	Acceptable for in-service oil (25 dynes/cm min).
Acid Number:	Acceptable for in-service oil (0.2 mg KOH/g max).
Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
Dielectric Breakdown D-1816:	
Power Factor @ 25C:	
Power Factor @ 100C:	
Oxidation Inhibitor:	



TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

Location: NORFOLK POWER
Serial #: A3S8121
Bank/Ph:
Tank: TRANSFORMER
Breathing: SEAL
Fluid: MIN Gallons: 900 L

NP 1

Mfr: WESTINGHOUSE
KV: 27.6
KVA: 5000
Imp.(% Z):
Container: BF808 BF808
Project ID: 22932LSP

Account: 6312
Order #: 302350
Control #: 6013778
Received: 06/16/2009
Reported: 06/19/2009
Customer ID:

ASTM D-3612
Report Units: PPM

Lab Control Number:	6013778
Date Sampled:	06/12/2009
Order Number:	302350
Oil Temp.(C):	35

Dissolved Gas Analysis

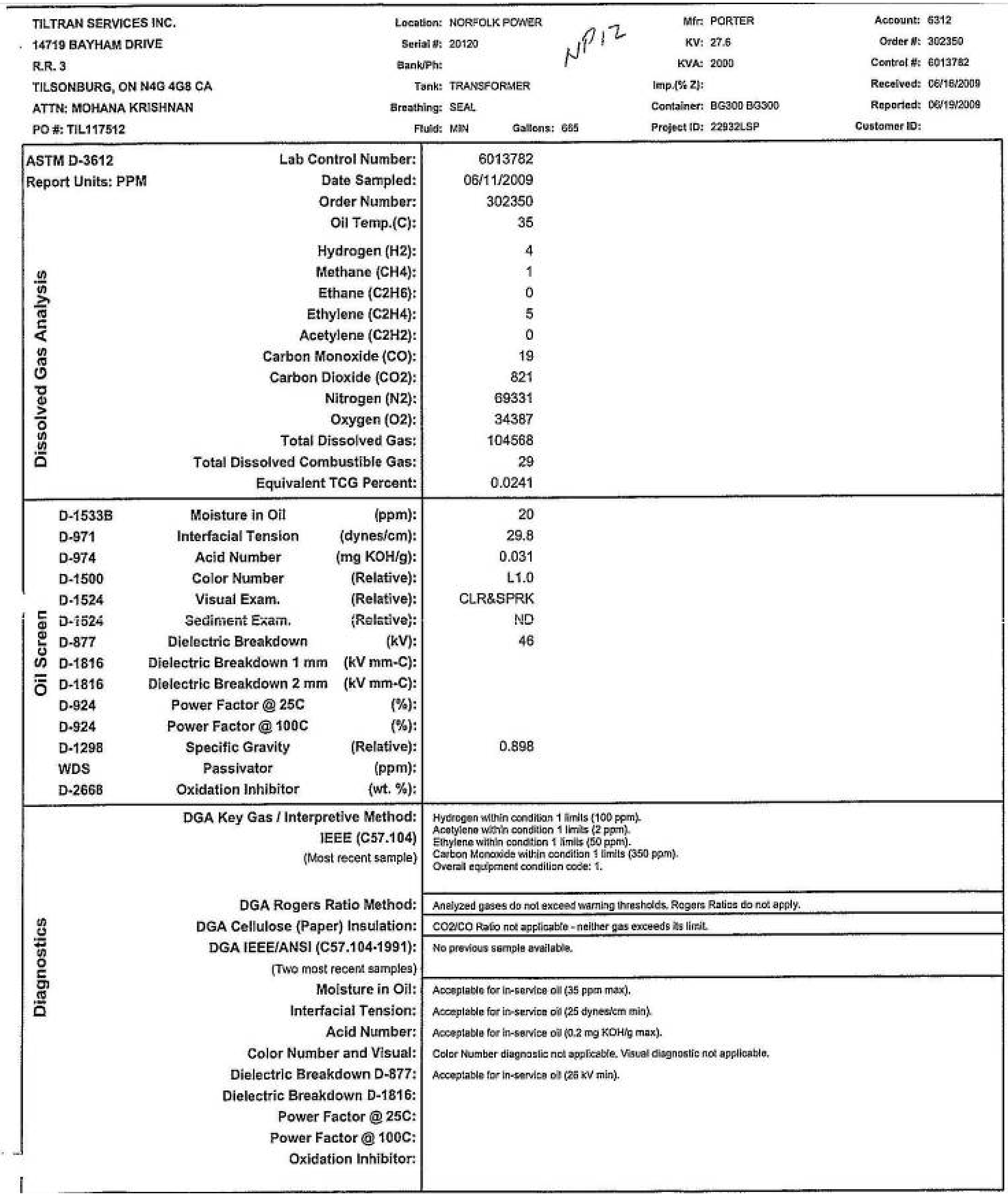
Hydrogen (H2):	3
Methane (CH4):	1
Ethane (C2H6):	0
Ethylene (C2H4):	1
Acetylene (C2H2):	0
Carbon Monoxide (CO):	42
Carbon Dioxide (CO2):	665
Nitrogen (N2):	72585
Oxygen (O2):	37083
Total Dissolved Gas:	110380
Total Dissolved Combustible Gas:	47
Equivalent TCG Percent:	0.0388

Oil Screen

D-1533B	Moisture in Oil	(ppm):	7
D-971	Interfacial Tension	(dynes/cm):	40.9
D-974	Acid Number	(mg KOH/g):	0.003
D-1500	Color Number	(Relative):	L1.0
D-1524	Visual Exam.	(Relative):	CLR&SPRK
D-1524	Sediment Exam.	(Relative):	ND
D-877	Dielectric Breakdown	(kV):	36
D-1816	Dielectric Breakdown 1 mm	(kV mm-C):	
D-1816	Dielectric Breakdown 2 mm	(kV mm-C):	
D-924	Power Factor @ 25C	(%):	
D-924	Power Factor @ 100C	(%):	
D-1298	Specific Gravity	(Relative):	0.866
WDS	Passivator	(ppm):	
D-2668	Oxidation Inhibitor	(wt. %):	

Diagnostics

DGA Key Gas / Interpretive Method: IEEE (C57.104) (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene within condition 1 limits (50 ppm). Carbon Monoxide within condition 1 limits (350 ppm). Overall equipment condition code: 1.
DGA Rogers Ratio Method:	Analyzed gases do not exceed warning thresholds. Rogers Ratios do not apply.
DGA Cellulose (Paper) Insulation:	CO2/CO Ratio not applicable - neither gas exceeds its limit.
DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
Moisture in Oil:	Acceptable for in-service oil (35 ppm max).
Interfacial Tension:	Acceptable for in-service oil (25 dynes/cm min).
Acid Number:	Acceptable for in-service oil (0.2 mg KOH/g max).
Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
Dielectric Breakdown D-1816:	
Power Factor @ 25C:	
Power Factor @ 100C:	
Oxidation Inhibitor:	



TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

NP12

Location:	NORFOLK POWER	Mfr:	PORTER	Account:	6312
Serial #:	20120	KV:	27.6	Order #:	302350
Bank/Ph:		KVA:	2000	Control #:	6013782
Tank:	TRANSFORMER	Imp.(% Z):		Received:	06/16/2009
Breathing:	SEAL	Container:	BG300 BG300	Reported:	06/19/2009
Fluid:	MIN Gallons: 685	Project ID:	22932LSP	Customer ID:	

ASTM D-3612
Report Units: PPM

Lab Control Number:	6013782
Date Sampled:	06/11/2009
Order Number:	302350
Oil Temp.(C):	35

Dissolved Gas Analysis

Hydrogen (H2):	4
Methane (CH4):	1
Ethane (C2H6):	0
Ethylene (C2H4):	5
Acetylene (C2H2):	0
Carbon Monoxide (CO):	19
Carbon Dioxide (CO2):	821
Nitrogen (N2):	69331
Oxygen (O2):	34387
Total Dissolved Gas:	104568
Total Dissolved Combustible Gas:	29
Equivalent TCG Percent:	0.0241

Oil Screen

D-1533B	Moisture in Oil	(ppm):	20
D-971	Interfacial Tension	(dynes/cm):	29.8
D-974	Acid Number	(mg KOH/g):	0.031
D-1500	Color Number	(Relative):	L1.0
D-1524	Visual Exam.	(Relative):	CLR&SPRK
D-1524	Sediment Exam.	(Relative):	ND
D-877	Dielectric Breakdown	(kV):	46
D-1816	Dielectric Breakdown 1 mm	(kV mm-C):	
D-1816	Dielectric Breakdown 2 mm	(kV mm-C):	
D-924	Power Factor @ 25C	(%):	
D-924	Power Factor @ 100C	(%):	
D-1298	Specific Gravity	(Relative):	0.898
WDS	Passivator	(ppm):	
D-2668	Oxidation Inhibitor	(wt. %):	

Diagnostics

DGA Key Gas / Interpretive Method: IEEE (C57.104) (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene within condition 1 limits (50 ppm). Carbon Monoxide within condition 1 limits (350 ppm). Overall equipment condition code: 1.
DGA Rogers Ratio Method:	Analyzed gases do not exceed warning thresholds. Rogers Ratios do not apply.
DGA Cellulose (Paper) Insulation:	CO2/CO Ratio not applicable - neither gas exceeds its limit.
DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
Moisture in Oil:	Acceptable for in-service oil (35 ppm max).
Interfacial Tension:	Acceptable for in-service oil (25 dynes/cm min).
Acid Number:	Acceptable for in-service oil (0.2 mg KOH/g max).
Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
Dielectric Breakdown D-1816:	
Power Factor @ 25C:	
Power Factor @ 100C:	
Oxidation Inhibitor:	

TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

Location: NORFOLK POWER
Serial #: 152710111
Bank/Ph:
Tank: TRANSFORMER
Breathing: SEAL
Fluid: MIN Gallons: 5450

ND 9

Mfr: SURELCO
KV: 27.6
KVA: 5000
Imp.(% Z):
Container: AF987 AF967
Project ID: 22932LSP

Account: 6312
Order #: 302350
Control #: 6013786
Received: 06/16/2009
Reported: 06/19/2009
Customer ID:

ASTM D-3612
Report Units: PPM

	Lab Control Number:	6013786
	Date Sampled:	06/11/2009
	Order Number:	302350
	Oil Temp.(C):	42
Dissolved Gas Analysis	Hydrogen (H2):	4
	Methane (CH4):	4
	Ethane (C2H6):	1
	Ethylene (C2H4):	22
	Acetylene (C2H2):	0
	Carbon Monoxide (CO):	435
	Carbon Dioxide (CO2):	4253
	Nitrogen (N2):	75800
	Oxygen (O2):	23585
	Total Dissolved Gas:	104104
	Total Dissolved Combustible Gas:	466
	Equivalent TCG Percent:	0.3646

Oil Screen	D-1533B	Moisture in Oil	(ppm):	3
	D-971	Interfacial Tension	(dynes/cm):	40.2
	D-974	Acid Number	(mg KOH/g):	0.005
	D-1500	Color Number	(Relative):	L1.0
	D-1524	Visual Exam.	(Relative):	CLR&SPRK
	D-1524	Sediment Exam.	(Relative):	ND
	D-877	Dielectric Breakdown	(kV):	46
	D-1816	Dielectric Breakdown 1 mm	(kV mm-C):	
	D-1816	Dielectric Breakdown 2 mm	(kV mm-C):	
	D-924	Power Factor @ 25C	(%):	
	D-924	Power Factor @ 100C	(%):	
	D-1298	Specific Gravity	(Relative):	0.864
	WDS	Passivator	(ppm):	
	D-2668	Oxidation Inhibitor	(wt. %):	

Diagnostics	DGA Key Gas / Interpretive Method: IEEE (C57.104) (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene within condition 1 limits (50 ppm). Carbon Monoxide: Condition 2 indications of overheated cellulose insulation (350 ppm). Overall equipment condition code: 2.
	DGA Rogers Ratio Method:	Analyzed gases do not exceed warning thresholds. Rogers Ratios do not apply.
	DGA Cellulose (Paper) Insulation:	CO2/CO Ratio not applicable - neither gas exceeds its limit.
	DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
	Moisture in Oil:	Acceptable for in-service oil (35 ppm max).
	Interfacial Tension:	Acceptable for in-service oil (25 dynes/cm min).
	Acid Number:	Acceptable for in-service oil (0.2 mg KOH/g max).
	Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
	Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
	Dielectric Breakdown D-1816:	
	Power Factor @ 25C:	
	Power Factor @ 100C:	
	Oxidation Inhibitor:	

TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

Location: NORFOLK POWER
Serial #: 159137
Bank/Ph:
Tank: TRANSFORMER
Breathing: SEAL
Fluid: MIN Gallons: 900 L

NP 10

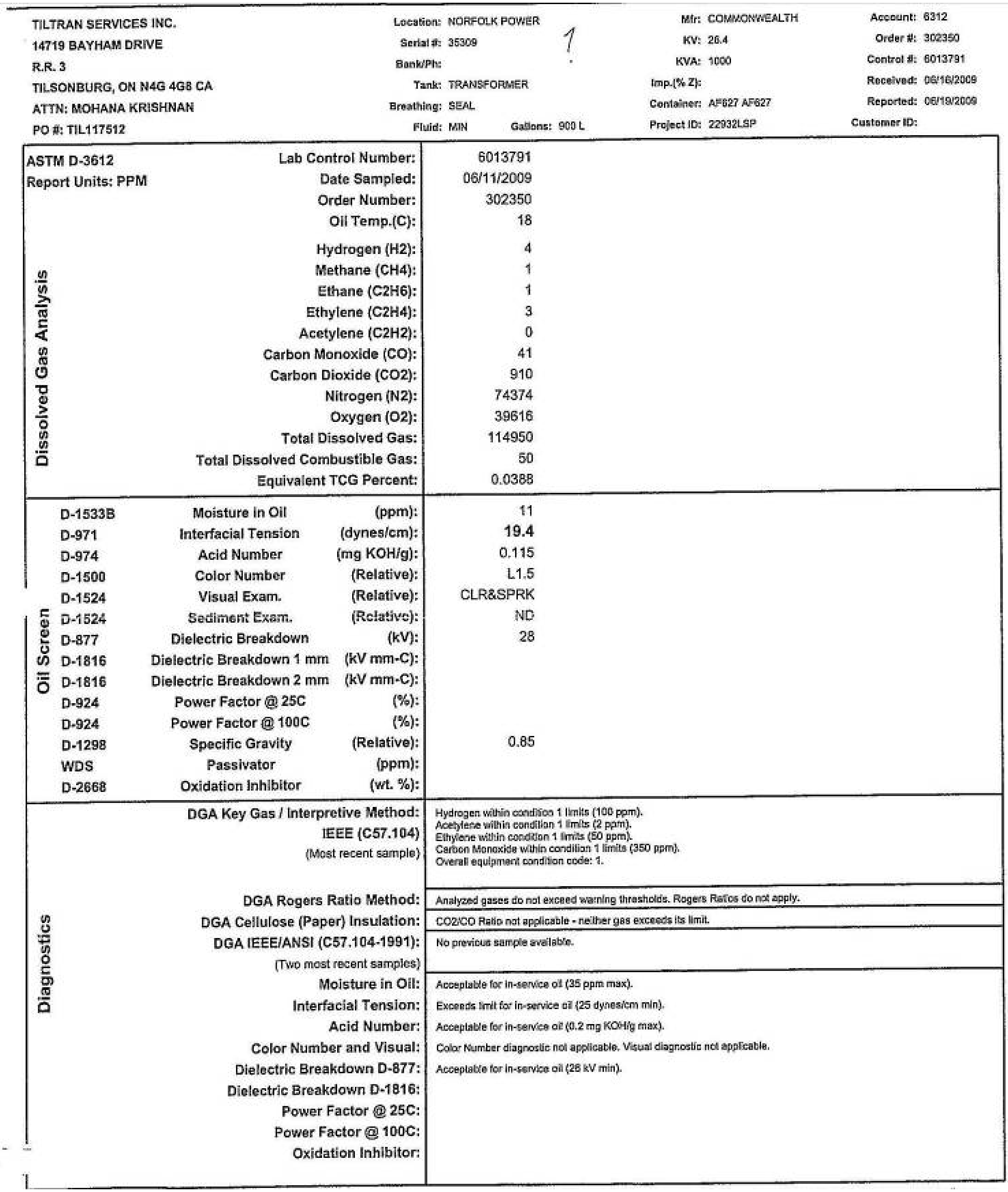
Mfr: WESTINGHOUSE
KV: 27.6
KVA: 2000
Imp.(% Z):
Container: BF427 BF427
Project ID: 22932LSP

Account: 6312
Order #: 302350
Control #: 6013789
Received: 06/16/2009
Reported: 06/19/2009
Customer ID:

ASTM D-3612	Lab Control Number:	6013789
Report Units: PPM	Date Sampled:	06/11/2009
	Order Number:	302350
	Oil Temp.(C):	
Dissolved Gas Analysis	Hydrogen (H2):	0
	Methane (CH4):	1
	Ethane (C2H6):	0
	Ethylene (C2H4):	4
	Acetylene (C2H2):	0
	Carbon Monoxide (CO):	38
	Carbon Dioxide (CO2):	883
	Nitrogen (N2):	72919
	Oxygen (O2):	39314
	Total Dissolved Gas:	113159
	Total Dissolved Combustible Gas:	43
	Equivalent TCG Percent:	0.0298

Oil Screen	D-1533B	Moisture in Oil	(ppm):	20
	D-971	Interfacial Tension	(dynes/cm):	**23.8**
	D-974	Acid Number	(mg KOH/g):	0.094
	D-1500	Color Number	(Relative):	L1.5
	D-1524	Visual Exam.	(Relative):	CLR&SPRK
	D-1524	Sediment Exam.	(Relative):	ND
	D-877	Dielectric Breakdown	(kV):	45
	D-1816	Dielectric Breakdown 1 mm	(kV mm-C):	
	D-1816	Dielectric Breakdown 2 mm	(kV mm-C):	
	D-924	Power Factor @ 25C	(%):	
	D-924	Power Factor @ 100C	(%):	
	D-1298	Specific Gravity	(Relative):	0.861
	WDS	Passivator	(ppm):	
	D-2668	Oxidation Inhibitor	(wt. %):	

Diagnostics	DGA Key Gas / Interpretive Method: IEEE (C57.104) (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene within condition 1 limits (50 ppm). Carbon Monoxide within condition 1 limits (350 ppm). Overall equipment condition code: 1.
	DGA Rogers Ratio Method:	Analyzed gases do not exceed warning thresholds. Rogers Ratios do not apply.
	DGA Cellulose (Paper) Insulation:	CO2/CO Ratio not applicable - neither gas exceeds its limit.
	DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
	Moisture in Oil:	Acceptable for in-service oil (35 ppm max).
	Interfacial Tension:	Exceeds limit for in-service oil (25 dynes/cm min).
	Acid Number:	Acceptable for in-service oil (0.2 mg KOH/g max).
	Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
	Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
	Dielectric Breakdown D-1816:	
	Power Factor @ 25C:	
	Power Factor @ 100C:	
	Oxidation Inhibitor:	



TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

Location: NORFOLK POWER
Serial #: 35309
Bank/Ph:
Tank: TRANSFORMER
Breathing: SEAL
Fluid: MIN Gallons: 900 L

1

Mfr: COMMONWEALTH
KV: 26.4
KVA: 1000
Imp.(% Z):
Container: AF627 AF627
Project ID: 22932LSP

Account: 6312
Order #: 302350
Control #: 6013791
Received: 06/16/2009
Reported: 06/19/2009
Customer ID:

ASTM D-3612
Report Units: PPM

Lab Control Number:	6013791
Date Sampled:	06/11/2009
Order Number:	302350
Oil Temp.(C):	18

Dissolved Gas Analysis

Hydrogen (H2):	4
Methane (CH4):	1
Ethane (C2H6):	1
Ethylene (C2H4):	3
Acetylene (C2H2):	0
Carbon Monoxide (CO):	41
Carbon Dioxide (CO2):	910
Nitrogen (N2):	74374
Oxygen (O2):	39616
Total Dissolved Gas:	114950
Total Dissolved Combustible Gas:	50
Equivalent TCG Percent:	0.0388

Oil Screen

D-1533B	Moisture in Oil	(ppm):	11
D-971	Interfacial Tension	(dynes/cm):	**19.4**
D-974	Acid Number	(mg KOH/g):	0.115
D-1500	Color Number	(Relative):	L1.5
D-1524	Visual Exam.	(Relative):	CLR&SPRK
D-1524	Sediment Exam.	(Relative):	ND
D-877	Dielectric Breakdown	(kV):	28
D-1816	Dielectric Breakdown 1 mm	(kV mm-C):	
D-1816	Dielectric Breakdown 2 mm	(kV mm-C):	
D-924	Power Factor @ 25C	(%):	
D-924	Power Factor @ 100C	(%):	
D-1298	Specific Gravity	(Relative):	0.85
WDS	Passivator	(ppm):	
D-2668	Oxidation Inhibitor	(wt. %):	

Diagnostics

DGA Key Gas / Interpretive Method: IEEE (C57.104) (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene within condition 1 limits (50 ppm). Carbon Monoxide within condition 1 limits (350 ppm). Overall equipment condition code: 1.
DGA Rogers Ratio Method:	Analyzed gases do not exceed warning thresholds. Rogers Ratios do not apply.
DGA Cellulose (Paper) Insulation:	CO2/CO Ratio not applicable - neither gas exceeds its limit.
DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
Moisture in Oil:	Acceptable for in-service oil (35 ppm max).
Interfacial Tension:	Exceeds limit for in-service oil (25 dynes/cm min).
Acid Number:	Acceptable for in-service oil (0.2 mg KOH/g max).
Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
Dielectric Breakdown D-1816:	
Power Factor @ 25C:	
Power Factor @ 100C:	
Oxidation Inhibitor:	

TILTRAN SERVICES INC.
14719 BAYHAM DRIVE
R.R. 3
TILSONBURG, ON N4G 4G8 CA
ATTN: MOHANA KRISHNAN
PO #: TIL117512

Location: NORFOLK POWER
Serial #: 254900
Bank/Ph:
Tank: TRANSFORMER
Breathing: SEAL
Fluid: MIN Gallons: 690

NP3

Mfr: ENGLISH ELEC
KV: 27.6
KVA: 3000
Imp.(% Z):
Container: BE164 BE164
Project ID: 22932LSP

Account: 6312
Order #: 302350
Control #: 6013792
Received: 06/16/2009
Reported: 06/19/2009
Customer ID:

ASTM D-3612 **Report Units: PPM**	**Lab Control Number:**	6013792
	Date Sampled:	06/12/2009
	Order Number:	302350
	Oil Temp.(C):	42
Dissolved Gas Analysis	**Hydrogen (H2):**	9
	Methane (CH4):	36
	Ethane (C2H6):	25
	Ethylene (C2H4):	**129**
	Acetylene (C2H2):	1
	Carbon Monoxide (CO):	75
	Carbon Dioxide (CO2):	1881
	Nitrogen (N2):	69714
	Oxygen (O2):	36462
	Total Dissolved Gas:	108332
	Total Dissolved Combustible Gas:	275
	Equivalent TCG Percent:	0.0962

Oil Screen	**D-1533B**	**Moisture in Oil**	**(ppm):**	18
	D-971	**Interfacial Tension**	**(dynes/cm):**	**17.2**
	D-974	**Acid Number**	**(mg KOH/g):**	0.190
	D-1500	**Color Number**	**(Relative):**	L2.0
	D-1524	**Visual Exam.**	**(Relative):**	CLR&SPRK
	D-1524	**Sediment Exam.**	**(Relative):**	ND
	D-877	**Dielectric Breakdown**	**(kV):**	45
	D-1816	**Dielectric Breakdown 1 mm**	**(kV mm-C):**	
	D-1816	**Dielectric Breakdown 2 mm**	**(kV mm-C):**	
	D-924	**Power Factor @ 25C**	**(%):**	
	D-924	**Power Factor @ 100C**	**(%):**	
	D-1298	**Specific Gravity**	**(Relative):**	0.874
	WDS	**Passivator**	**(ppm):**	
	D-2668	**Oxidation Inhibitor**	**(wt. %):**	

Diagnostics	**DGA Key Gas / Interpretive Method:** **IEEE (C57.104)** (Most recent sample)	Hydrogen within condition 1 limits (100 ppm). Acetylene within condition 1 limits (2 ppm). Ethylene: Condition 3 indications of significantly overheated oil (100 ppm). Carbon Monoxide within condition 1 limits (350 ppm). Overall equipment condition code: 3.
	DGA Rogers Ratio Method:	Rogers Ratios suggest a thermal fault > 700 °C.
	DGA Cellulose (Paper) Insulation:	CO2/CO Ratio not applicable - neither gas exceeds its limit.
	DGA IEEE/ANSI (C57.104-1991): (Two most recent samples)	No previous sample available.
	Moisture in Oil:	Acceptable for in-service oil (35 ppm max).
	Interfacial Tension:	Exceeds limit for in-service oil (25 dynes/cm min).
	Acid Number:	Acceptable for in-service oil (0.2 mg KOH/g max).
	Color Number and Visual:	Color Number diagnostic not applicable. Visual diagnostic not applicable.
	Dielectric Breakdown D-877:	Acceptable for in-service oil (26 kV min).
	Dielectric Breakdown D-1816:	
	Power Factor @ 25C:	
	Power Factor @ 100C:	
	Oxidation Inhibitor:	

APPENDIX 10

Thermographic Inspection

T.S, MS & DS Stations - Norfolk County

Customer:	Norfolk Power Inc.
	70 Victoria Street
	P.O. Box 588
	Simcoe, ON N3Y 4N6

Compiled By:	Rondar Inc.
	333 Centennial Parkway North
	Hamilton, ON L8E 2X6
Telephone:	(905) 561 - 2808
Fax:	(905) 561 - 8871
E-mail	techserv@rondar.com

Attention:	Mr. Paul McCready
Cc:	
Reference Number:	A5492
Certified Thermographer:	Charles Monachino, C. Tech.
Inspection Date:	June 15, 2009
Report Date:	June 15, 2009

ACADEMY OF INFRARED THERMOGRAPHY
CERTIFIED THERMOGRAPHER
LEVEL II
Charles Monachino
#2-326

Signature:

RONDAR INC.

Index

Introduction

On June 15, 2009, a thermographic inspection was performed for Norfolk Power Inc. located at 70 Victoria Street in Simcoe, Ontario.

The report contains thermal anomalies that were found on your facility's electrical system. The equipment under analysis was inspected in an **"as found"** condition, meaning that no attempts were made to put load on equipment that was not operating or was under minimal load at the time of the inspection.

Loading of electrical equipment is critical in performing thermographic inspections. A maximum possible loading but not less than 40% of rated load of the equipment being inspected is recommended. Refer to ANSI/NFPA 70B-1994, Section 18-16 (Infra-red Inspection). Equipment operating under partial or light load may mask the presence of an anomaly.

It should be understood that the inability of an infra-red imager to see through opaque materials (such as: metal, plastics, glass, etc.), does not allow for images to be taken from the inside of enclosures, (i.e. bus ducts). However, a significant thermal rise on the inside of an enclosure can be detected on the outside. Note that the temperature read from the outside will always be cooler than the actual fault temperature inside.

Generally, thermal anomalies found on electrical equipment can be tied to a high resistance connection. However, the root cause of the high resistance is not always obvious. Improper tension of connections is often, but not always the cause, and it can be dangerous to automatically assume that tightening the connection will resolve the problem. High resistance can also be due to pitting, corrosion, or oxidation on mating contacts or connection surfaces. Sometimes the problem can be a combination of the above factors. A recommended course of action for a suspect component is to dismantle, inspect and clean all contact and connection surfaces, then reassemble assuring proper torque requirements. The component should always be checked for signs of thermal degradation, which can result from excessive temperatures or repeated thermal cycling. Parts such as springs, fuse clips, or bus clips, lose their ability to maintain contact pressure and need to also be replaced to achieve an effective repair. The scheduling of a re-inspection is vital following repairs, to confirm that the problem areas have been properly rectified. Thermographic inspections identify that a problem exists, however, further investigation or utilization of other complimentary testing methods (i.e. Ultra-Sound) may be necessary to pin-point the exact cause of the anomaly.

The non-destructive, non-invasive, and non-intrusive thermographic inspection is one form of condition monitoring, which provides a means of determining whether maintenance is required and when it is required. The thermal information gathered provides an understanding of the operating condition of an electrical system. The inspection provides objective methods of assessing the state of (electrical / mechanical) equipment in order to predictively determine the need for maintenance. The thermographic inspection is not to be used as a substitute for annual inspections, but rather as a tool to aid in the customer's overall maintenance program. Locating problems on electrical systems before failure, provides many benefits to the recipient which include:

- Increased safety
- Improved system reliability
- Reduced unscheduled outage or downtime
- Reduced repair costs
- Reduced maintenance costs
- Quality production rates
- Quality assurance of new installations and repairs

Should you require further assistance or have any questions, please do not hesitate to contact our office.

General Scope of Inspection

NP-1 - Simcoe - 73 Victoria Street - Simcoe

NP-3 - 270 Chapel Street - Simcoe

NP-6 - 656 Ireland Road - Simcoe

NP-9 - 60 Industrial Drive - Delhi

NP-11 - 121 St. Andrew Street - Port Dover

NP-13 - 179 Prospect Street - Port Dover

NP-2 - 16 Wellington Street South - Simcoe

NP-5 - 61 Evergreen Hill - Simcoe

NP-8 - 176 Anne Street - Delhi

NP-10 - 2276 Blueline Road - Waterford

NP-12 - 13 Scott Street - Port Dover

Anomaly Classification

Temperature Rise (From Reference Component)	**Repair Priority**
> 50°C	Acute overheating. Immediate repairs required.
30°C to 50°C	Developed overheating. Should be repaired as soon as possible.
10°C to 29°C	Second stage of overheating. Should be attended to at the first opportune moment.
< 10°C	First stage of overheating. Should be monitored and repaired during next scheduled maintenance.

* "Reference Component" refers to a benchmark comparator that is chosen by the Thermographer. Usually it is a similar component with a comparable loading, such as another phase of the same device. In the case of a single phase device, another section of the same phase may be chosen. Where no comparable reference component is available, ambient temperature may be used as the benchmark.

The choice of the reference component, and the evaluation of the severity of the anomaly, depend heavily on the judgment, experience and knowledge of the Thermographer, and the given situation that may exist during the moment of the inspection.

The above classification is intended to be used as a **guideline** only.

The final decision as to the priority of the repair for each anomaly and the scheduling of maintenance rests solely with the client. Rondar Inc. and Thermographers of Rondar assume no liability, directly or indirectly, as a result of the inspection.

A further inspection should also be made after an anomaly has been repaired to ensure it has been corrected properly.

To allow for seasonal changes, (Electrical / Mechanical) predictive maintenance inspections should be performed at least twice a year.

RONDAR INC.

Summary of Thermal Anomalies
at

T.S, MS & DS Stations - Norfolk County

Priority Legend

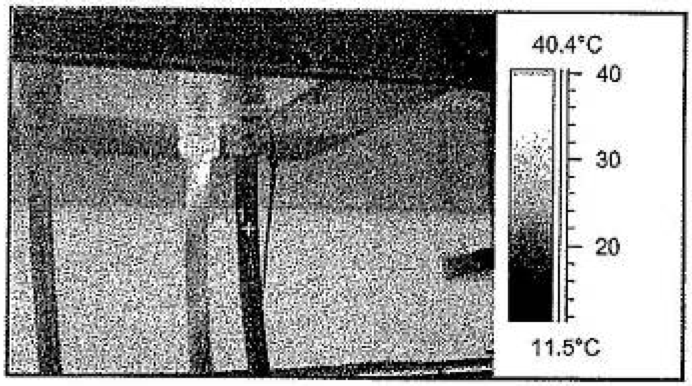
Low - (Attend to repair at the next scheduled maintenance)
Moderate - (Attend to repair at the first opportune moment)
High - (Attend to repair as soon as possible)
Severe - (Attend to repair immediately)

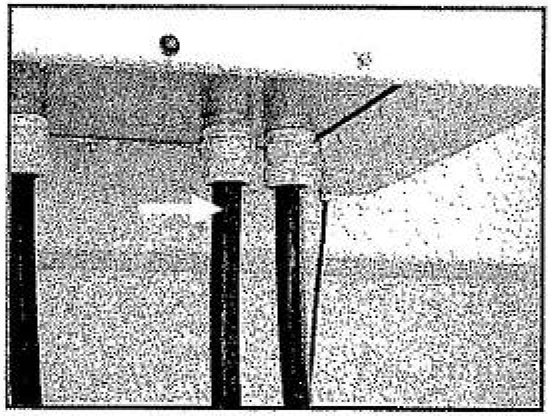
Location	Item	Pg	Priority
Bloomsburg T.S. - Simcoe	Transformer No. 1 - 27.6 kV - Blue Phase Cable - (Left)	7	High
Bloomsburg T.S. - Simcoe	Transformer No. 1 - 27.6 kV - Red Phase Cable - (Left)	8	Low
Bloomsburg T.S. - Simcoe	Transformer No. 1 - 27.6 kV - Blue Phase Cable - (Right)	9	Low
Bloomsburg T.S. - Simcoe	Transformer No. 1 - 27.6 kV - White Phase Cable - (Right)	10	Low
NP-2 - Simcoe	2-F1 - Blue Phase - Fuse Clip	11	Severe
NP-2 - Simcoe	2-F2 - Blue Phase - Fuse Clip	12	Severe

RONDAR INC.

Reference Number: A5492
Customer: Norfolk Power Inc.
Thermographer: Charles Monachino, C. Tech.

Thermographic Inspection





Date Of Inspection: 15/06/2009
Time Of Inspection: 9:12:38 AM
Infra-Red Equipment: FLIR SYSTEMS ThermaCam - 595
Thermal Anomaly No.: 1
Location: Bloomsburg T.S. - Simcoe
Item: Transformer No. 1 - 27.6 kV - Blue Phase Cable - (Left)
Actual Temperature: 40.4°C
Reference Temperature: 18.9°C
Temperature Rise: 21.45°C
Priority: High

Load Measurements

Load Current - (Amps):	Phase - A	376	Phase - B	365	Phase - C	366
Rated Load - (Amps):	N/A	**Percent Load - (%)**	N/A			

Probable Cause / Recommendations:

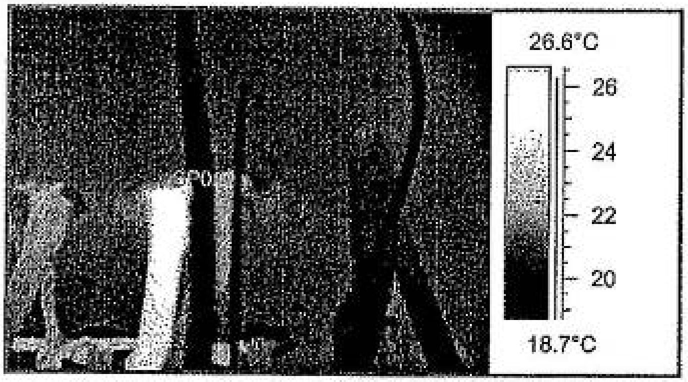
Degradation of the concentric neutral or the abnormal flow of circulating current may be contributing to the production of heat in that particular area.

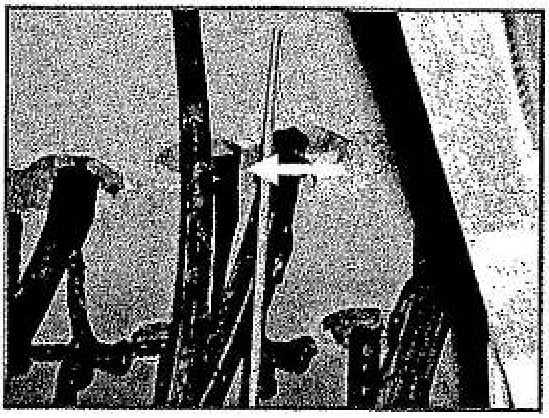
Further investigation and inspection is necessary in order to make an accurate diagnosis and repair.

RONDAR INC.

Reference Number: A5492
Customer: Norfolk Power Inc.
Thermographer: Charles Monachino, C. Tech.

Thermographic Inspection





Date Of Inspection:	15/06/2009
Time Of Inspection:	9:23:53 AM
Infra-Red Equipment:	FLIR SYSTEMS ThermaCam - 595
Thermal Anomaly No.:	2
Location:	Bloomsburg T.S. - Simcoe
Item:	Transformer No. 1 - 27.6 kV - Red Phase Cable - (Left)
Actual Temperature:	26.6°C
Reference Temperature:	21.9°C
Temperature Rise:	4.66°C
Priority:	Low

Load Measurements

Load Current - (Amps):	Phase - A	376	Phase - B	365	Phase - C	366
Rated Load - (Amps):	N/A	**Percent Load - (%)**	N/A			

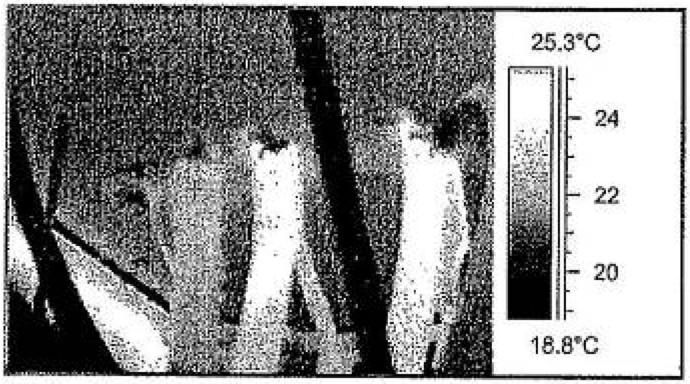
Probable Cause / Recommendations:

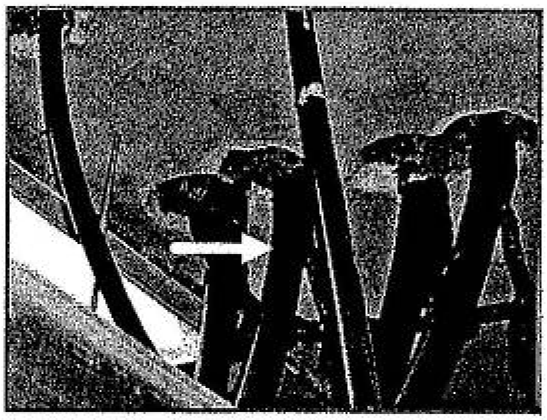
Improper tension of the red phase cable/SF6 switchgear pfisterer connection may exist.

Further investigation is necessary, in order to make an accurate diagnosis and repair.

Reference Number: A5492
Customer: Norfolk Power Inc.
Thermographer: Charles Monachino, C. Tech.

Thermographic Inspection





Date Of Inspection: 15/06/2009
Time Of Inspection: 9:26:44 AM
Infra-Red Equipment: FLIR SYSTEMS ThermaCam - 595
Thermal Anomaly No.: 3
Location: Bloomsburg T.S. - Simcoe
Item: Transformer No. 1 - 27.6 kV - Blue Phase Cable - (Right)
Actual Temperature: 25.3°C
Reference Temperature: 22.0°C
Temperature Rise: 3.24°C
Priority: Low

Load Measurements

Load Current - (Amps):	Phase - A	376	Phase - B	365	Phase - C	366
Rated Load - (Amps):	N/A	**Percent Load - (%)**	N/A			

Probable Cause / Recommendations:

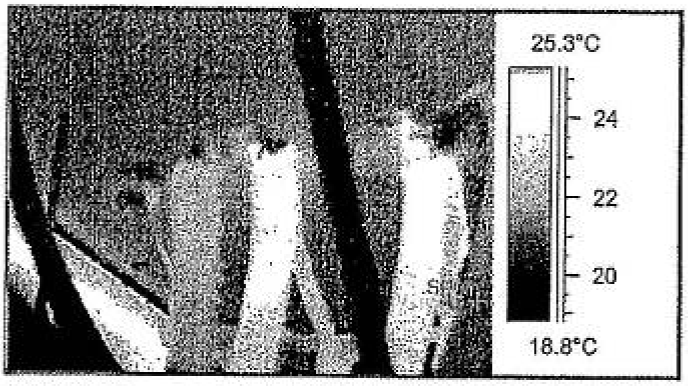
Degradation of the concentric neutral or the abnormal flow of circulating current may be contributing to the production of heat in that particular area.

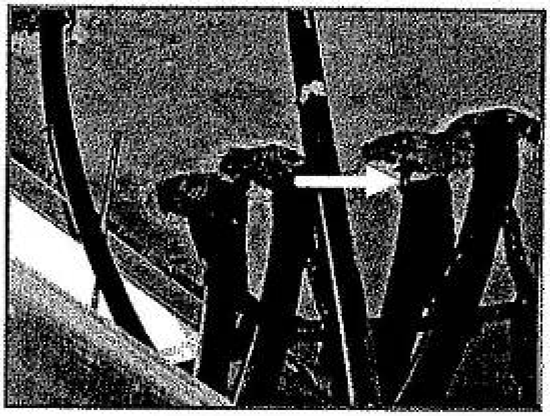
Further investigation and inspection is necessary in order to make an accurate diagnosis and repair.

RONDAR INC.

Reference Number:	A5492
Customer:	Norfolk Power Inc.
Thermographer:	Charles Monachino, C. Tech.

Thermographic Inspection





Date Of Inspection:	15/06/2009
Time Of Inspection:	9:26:44 AM
Infra-Red Equipment:	FLIR SYSTEMS ThermaCam - 595
Thermal Anomaly No.:	4
Location:	Bloomsburg T.S. - Simcoe
Item:	Transformer No. 1 - 27.6 kV - White Phase Cable - (Right)
Actual Temperature:	25.3°C
Reference Temperature:	21.0°C
Temperature Rise:	4.25°C
Priority:	Low

Load Measurements

Load Current - (Amps):	Phase - A	376	Phase - B	365	Phase - C	366
Rated Load - (Amps):	N/A	**Percent Load - (%)**	N/A			

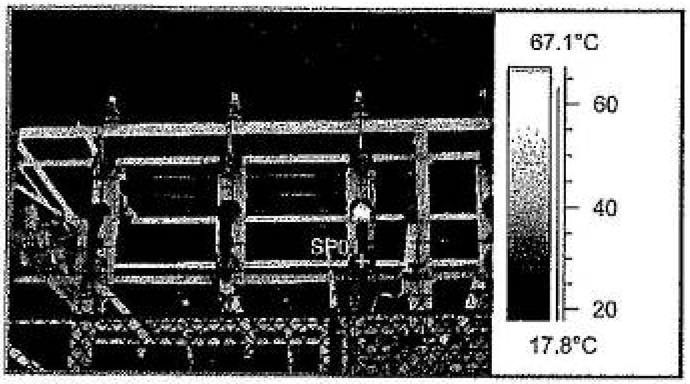
Probable Cause / Recommendations:

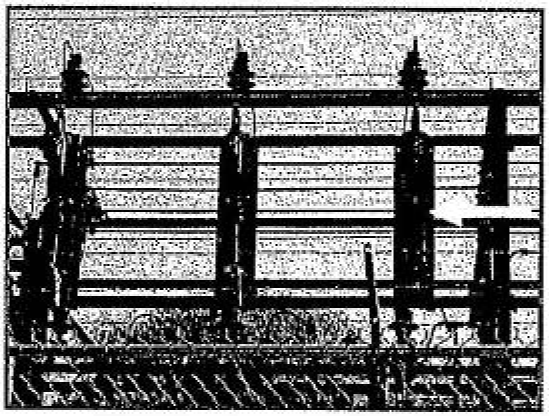
Improper tension of the white phase cable/SF6 switchgear pfisterer connection may exist.

Further investigation is necessary, in order to make an accurate diagnosis and repair.

Reference Number: A5492
Customer: Norfolk Power Inc.
Thermographer: Charles Monachino, C. Tech.

Thermographic Inspection





Date Of Inspection:	15/06/2009
Time Of Inspection:	11:00:59 AM
Infra-Red Equipment:	FLIR SYSTEMS ThermaCam - 595
Thermal Anomaly No.:	5
Location:	NP-2 - Simcoe
Item:	2-F1 - Blue Phase - Fuse Clip
Actual Temperature:	66.8°C
Reference Temperature:	27.0°C
Temperature Rise:	39.78°C
Priority:	Severe

Load Measurements

Load Current - (Amps):	Phase - A	N/A	Phase - B	N/A	Phase - C	N/A
Rated Load - (Amps):	N/A	**Percent Load - (%)**	N/A			

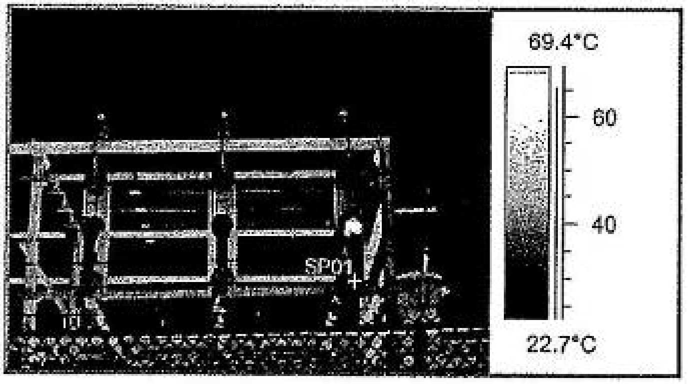
Probable Cause / Recommendations:

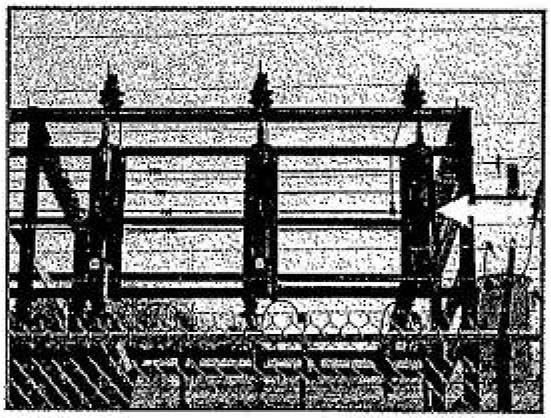
Improper tension, faulty fuse link or high contact resistance of the blue phase - line side fuse clip. Further investigation is necessary, in order to make an accurate diagnosis and repair. Dismantle, inspect and clean contact surfaces. The replacement of the fuse link and or holder assembly may be necessary in order to achieve a long term repair method.

RONDAR INC.

Reference Number: A5492
Customer: Norfolk Power Inc.
Thermographer: Charles Monachino, C. Tech.

Thermographic Inspection





Date Of Inspection: 15/06/2009
Time Of Inspection: 11:02:25 AM
Infra-Red Equipment: FLIR SYSTEMS ThermaCam - 595
Thermal Anomaly No.: 6
Location: NP-2 - Simcoe
Item: 2-F2 - Blue Phase - Fuse Clip
Actual Temperature: 68.8°C
Reference Temperature: 29.1°C
Temperature Rise: 39.69°C
Priority: Severe

Load Measurements

Load Current - (Amps):	Phase - A	N/A	Phase - B	N/A	Phase - C	N/A
Rated Load - (Amps):	N/A	**Percent Load - (%)**	N/A			

Probable Cause / Recommendations:

Improper tension, faulty fuse link or high contact resistance of the blue phase - line side fuse clip.

Further investigation is necessary, in order to make an accurate diagnosis and repair.

Dismantle, inspect and clean contact surfaces.

The replacement of the fuse link and or holder assembly may be necessary in order to achieve a long term repair method.

APPENDIX 11

RONDAR INC.

October 23, 2009

Norfolk Power Inc.
P.O. Box 588
70 Victoria Street
Simcoe, ON
N3Y 4N6

Attention: **Mr. Paul McCready**

Subject: **2009 Substation Maintenance and Testing Program**
Rondar Reference Number: A5495

On October 20, 2009, Rondar Inc. personnel completed the inspection, testing and maintenance of the main outdoor primary/secondary electrical distribution system at the Delhi NP-9 Distribution Station located at 61 Industrial Drive in Delhi, Ontario.

The following includes the scope of work, comments (no action required), concerns (action required).

SCOPE OF WORK

Main Outdoor – Distribution

• Primary Distribution High Voltage Structure:	High Voltage Air Break Switch S & C High Voltage Fuses High Voltage Lightning Arrester Protection
• Main Outdoor Transformer:	Surelco Ltd. (Serial Number: 22200-2) Type ONAN - 27.6kV– 8.320/4800 kV – 5000 kVA
• Secondary Metal Enclosed Switchgear:	High Voltage Air Break Switch & Fuse (9-F1) High Voltage Air Break Switch & Fuse (9-F2) High Voltage Feeder Cable – F1 & F2

COMMENTS

Main Outdoor – Yard

The inspection of the main outdoor substation yard revealed that the gravel levels should be brought-up to fill-in low areas around the secondary metal enclosed switchgear unit.

Main Outdoor – Primary Distribution Structure

The primary high voltage switch, fuses, and stand-offs were inspected, cleaned and subjected to insulation resistance tests. Contact resistance tests were performed on the primary high voltage switch and fuses.

Concern 1

Contact resistance results for the main switch have increased dramatically since the last maintenance shutdown performed on June 10, 2003. Depending on loading, high contact resistance can contribute to the production of heat which can eventually case failure. Due to the style and age of the existing switch, it is recommended that the unit be budgeted for replacement in the near future.

Main Outdoor Transformer (S/N: 22200-2)

The main outdoor transformer was subjected to electrical tests which included; turns ratio on the "as found" tap setting, capacitance/dissipation and winding insulation resistance. The tests found the transformer to be in good electrical and mechanical operating condition.

Main Outdoor Secondary Distribution – Metal-Clad Switchgear – 8 kV

Feeders F1 and F2 secondary high voltage switch, fuses, and stand-offs were inspected, cleaned and subjected to insulation resistance tests. Contact resistance tests were performed on high voltage switches and fuses. The equipment was found to be in good electrical and mechanical operating condition. The switchgear bus and cable connections were cleaned and mechanically inspected for tightness. In addition, both bus and cables were subjected to insulation resistance tests and found to be in satisfactory electrical condition.

Note 1

Visual inspection of the switchgear indicated various areas of corrosion development and weathering. The switchgear unit should be sandblasted, primed and re-painted in order to prevent further deterioration.

Note 2

During the inspection, no evidence of spare primary fuse links for Feeder's 1 and 2 was found. The placement of six (6) spare fuse links in the door compartment holders for each feeder, can avoid costly outages as delivery of such items could range from three (3) to six (6) weeks.

RECOMMENDATIONS

Upon your request, Rondar Inc. can provide you a quotation on a separate cover in regards to the above mentioned concerns/notes:

Enclosed are the test results performed during the shutdown.

We thank you for the opportunity to be of service. Should you require any further information or have any questions, please do not hesitate to contact our office.

RONDAR INC.

Charles Monachino, C. Tech.
Technical Service Representative

CM/sr

Encl.

RONDAR INC.

File No	A5495
Customer	Norfolk Power Inc.
Date	October 20, 2009

OUTDOOR SUBSTATION - TOWER & YARD

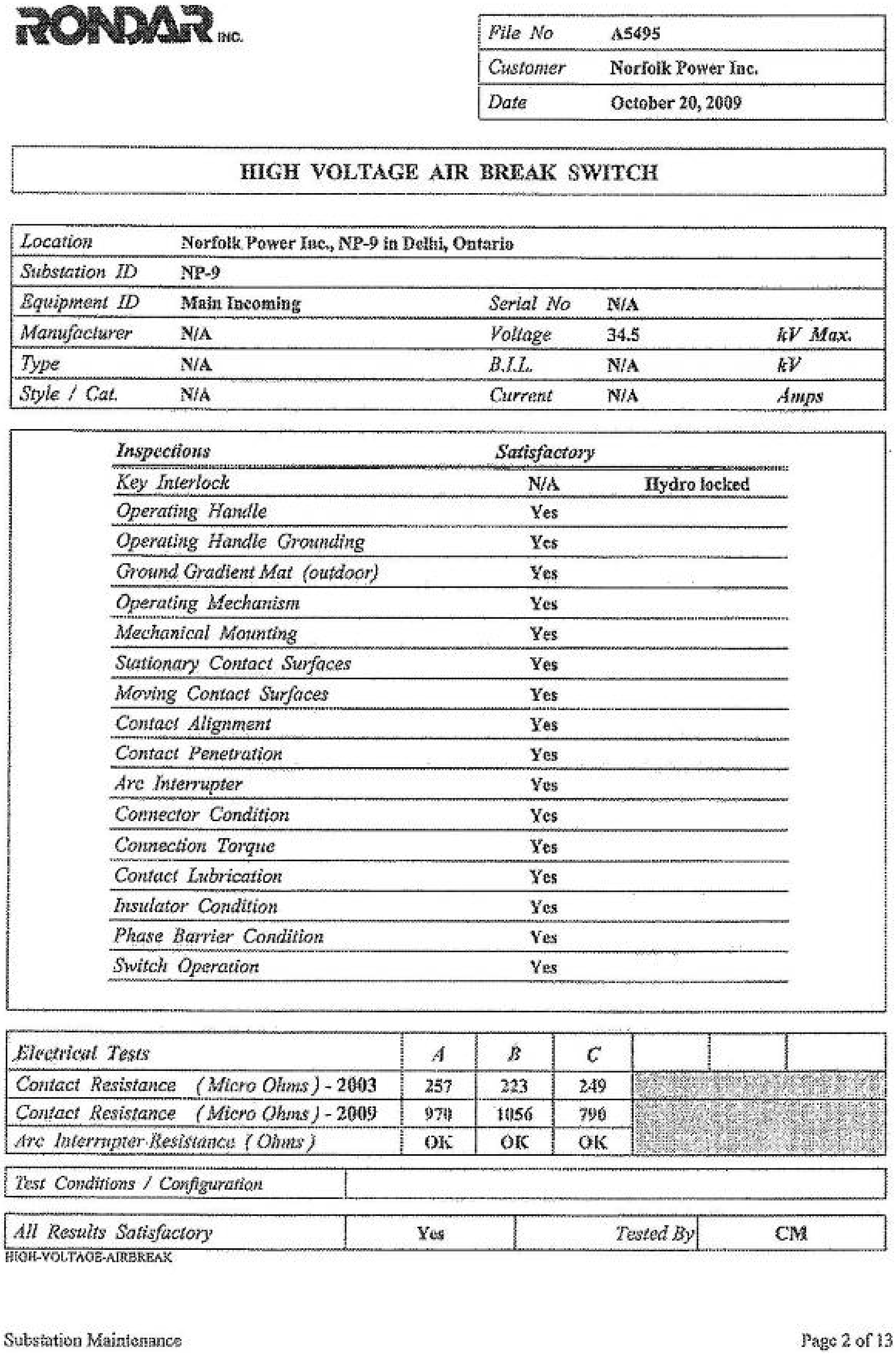
Location	Norfolk Power Inc., NP-9 in Delhi, Ontario
Substation ID	NP-9

Inspections	*Satisfactory*	
Tower Hardware	Yes	
Tower Galvanizing	Yes	
Tower Foundations	Yes	
Tower Grounding	Yes	
Insulators	Yes	
Lightning Arrestors	Yes	
Fence Posts & Frame	Yes	
Barbed Wire	Yes	
Gate Hardware	Yes	
Gate Locks	Yes	
Warning Signs	Yes	
Crushed Stone Depth	No	Requires gravel to fill hole under switchgear pad.
Yard Debris	Yes	
Weed Control	Yes	
Ground Grid	Yes	
Connections To :		
- Ground Rods	Yes	
- Fence Fabric	Yes	
- Top Rail	Yes	
- Barbed Wire	Yes	
- Gate	Yes	
- Lightning Arrestors	Yes	

Electrical Tests

All Results Satisfactory	No	*Tested By*	CM

OUTDOOR-SUBSTATION-TOWER 7/23/99



RONDAR INC.

File No	A5495
Customer	Norfolk Power Inc.
Date	October 20, 2009

HIGH VOLTAGE AIR BREAK SWITCH

Location	Norfolk Power Inc., NP-9 in Delhi, Ontario			
Substation ID	NP-9			
Equipment ID	Main Incoming	*Serial No*	N/A	
Manufacturer	N/A	*Voltage*	34.5	*kV Max.*
Type	N/A	*B.I.L.*	N/A	*kV*
Style / Cat.	N/A	*Current*	N/A	*Amps*

Inspections	*Satisfactory*	
Key Interlock	N/A	Hydro locked
Operating Handle	Yes	
Operating Handle Grounding	Yes	
Ground Gradient Mat (outdoor)	Yes	
Operating Mechanism	Yes	
Mechanical Mounting	Yes	
Stationary Contact Surfaces	Yes	
Moving Contact Surfaces	Yes	
Contact Alignment	Yes	
Contact Penetration	Yes	
Arc Interrupter	Yes	
Connector Condition	Yes	
Connection Torque	Yes	
Contact Lubrication	Yes	
Insulator Condition	Yes	
Phase Barrier Condition	Yes	
Switch Operation	Yes	

Electrical Tests	*A*	*B*	*C*			
Contact Resistance (Micro Ohms) - 2003	257	223	249			
Contact Resistance (Micro Ohms) - 2009	970	1056	790			
Arc Interrupter Resistance (Ohms)	OK	OK	OK			

Test Conditions / Configuration	

All Results Satisfactory	Yes	*Tested By*	CM

HIGH-VOLTAGE-AIRBREAK

RONDAR INC.

File No	A5495
Customer	Norfolk Power Inc.
Date	October 20, 2009

HIGH VOLTAGE FUSE

Location	Norfolk Power Inc., NP-9 in Delhi, Ontario		
Substation ID	NP-9		
Equipment ID	Main incoming	*Serial No*	

Fuse Holder				
Manufacturer	S/C			
Type	SM5	*Voltage*	34.5	***kV Max.***
Style / Cat.		*Current*	400E	***Amps Max.***

Fuse Link			
Type	SM5	*Size*	150E
Style / Cat.	134250R4	*TCC*	153.4

Inspections	*Satisfactory*
Moving Contact Surfaces	Yes
Stationary Contact Surfaces	Yes
Contact Penetration	Yes
Connector Condition	Yes
Connection Torque	Yes
Contact Lubrication	Yes
Insulator Condition	Yes
Phase Barrier Condition	N/A
Fuse Holder Condition	Yes
Spare Links	No
All Links Identical	Yes

☐

Electrical Tests	*A*	*B*	*C*			
Insulation Resistance (Megohms)	N/A	N/A	N/A			
Link Resistance (Micro Ohms)	596	579	599	▨	▨	▨

Test Conditions / Configuration	

All Results Satisfactory	Yes	*Tested By*	RB

HIGH-VOLTAGE-FUSE 7/22/99

RONDAR INC.

File No	A5495
Customer	Norfolk Power Inc.
Date	October 20, 2009

LIGHTNING ARRESTER

Location	Norfolk Power Inc., NP-9 in Delhi, Ontario
Substation ID	NP-9
Equipment ID	Main Incoming LA

Manufacturer	Cooper			
Model	Varistar	*Units / Phase*	1	
Type	Intermediate	*Voltage*	21	*kV*
Style / Cat.	VI0210171231A11	*M. C. O. V.*	17	*kV*

Inspections	***Satisfactory***
Polymer Condition	Yes
Mounting & Frame	Yes
Connections	Yes
Grounding	Yes

Serial Nos.: *2030802689*
2030802680
2030802686

Electrical Tests	*A*	*B*	*C*
Insulation Resistance (Megohms) @ 10 kVDC	60,000	80,000	80,000
Line side of fuse to HV Switch Including New LAS			

Test Conditions / Configuration	

All Results Satisfactory	Yes	*Tested By*	CM

LIGHTNING-ARRESTOR 7/23/99

RONDAR INC.

File No	**A5495**
Customer	**Norfolk Power Inc.**
Date	**October 20, 2009**

POWER TRANSFORMER - MECHANICAL INSPECTIONS

Location	**Norfolk Power Inc., NP-9 in Delhi, Ontario**		
Substation ID	**NP-9**		
Equipment ID	**Main Outdoor TX**	*Serial No*	**22200-2**

Inspections	*Satisfactory*	
Breather	N/A	
Silica Gel	N/A	Sealed TX
Explosion Vent Gaskets	Yes	
Oil Level	Yes	
Con. Tank Gaskets	N/A	
Con. Tank Valve	N/A	
Insp. Cover Gaskets	Yes	
Main Cover Gaskets	Yes	
Prim. Bushing Gaskets	Yes	
Prim. Bushing Porcelain	Yes	
Prim. Bushing Gauge	N/A	
Prim. Bushing Conn.	Yes	
Sec. Bushing Gaskets	Yes	
Sec. Bushing Porcelain	Yes	
Sec. Bushing Conn.	Yes	
Sec. Throat Gaskets	N/A	
Radiator Gasket	N/A	
Radiator Valve	N/A	
Gas Relay Valve	N/A	
Tank Valve(s)	Yes	
Sample Valve	Yes	
Oil Leaks	Yes	
Paint Condition	Yes	
Pad	Yes	
Grounding	Yes	
Oil Temp. Gauge	Yes	
Oil Temp. Run / Max.		30/60°C Reset
Winding Temp. Gauge	N/A	
Winding Temp Run / Max	N/A	/ °C
Fan Control	N/A	
Tap Changer	Yes	
Control Door Gasket	Yes	
Control Heaters	N/A	

All Results Satisfactory	Yes	*Tested By*	RB

RONDAR INC.

File No	A5495
Customer	Norfolk Power Inc.
Date	October 20, 2009

POWER TRANSFORMER - ELECTRICAL TESTS

Location	Norfolk Power Inc., NP-9 in Delhi, Ontario		
Substation ID	NP-9		
Equipment ID	Main Outdoor TX	*Serial No*	22200-2
Manufacturer	Surelco Ltd.	*Year Manufactured*	1976
Rating	5000kVA	*Impedance*	5.58 % @ 75 °C
Type	ONAN	*High Voltage*	27.6
Neutral Grounding	Yes	*Low Voltage*	8320Y/4800
Phases	3	*Temp. Rise*	55 °C
Frequency	60 Hz	*OnLine T/C Liquid*	5450 Litres
HV B.I.L.	KV	*Tank Liquid*	Oil/Oil Weight 4681 L
Drawing No.	Ref NRE176	*Total Weight*	16919 kg
	LV BIL 95		

Ratio Tests

Tap	*H.V.*	*L.V.*	*Cal. Ratio*	*X0 - X2* *H1 - H2*	*X0 - X3* *H2 - H3*	*X0 - X1* *H3 - H1*
1	27600	4800	17.391	N/T	N/T	N/T
*2	26910	4800	17.837	**17.842	**17.843	**17.843
3	26220	4800	18.306	N/T	N/T	N/T
4	25530	4800	18.801	N/T	N/T	N/T
5	24840	4800	19.323	N/T	N/T	N/T

* *Indicates Tap in use*
** *Indicates Final Position Checked*

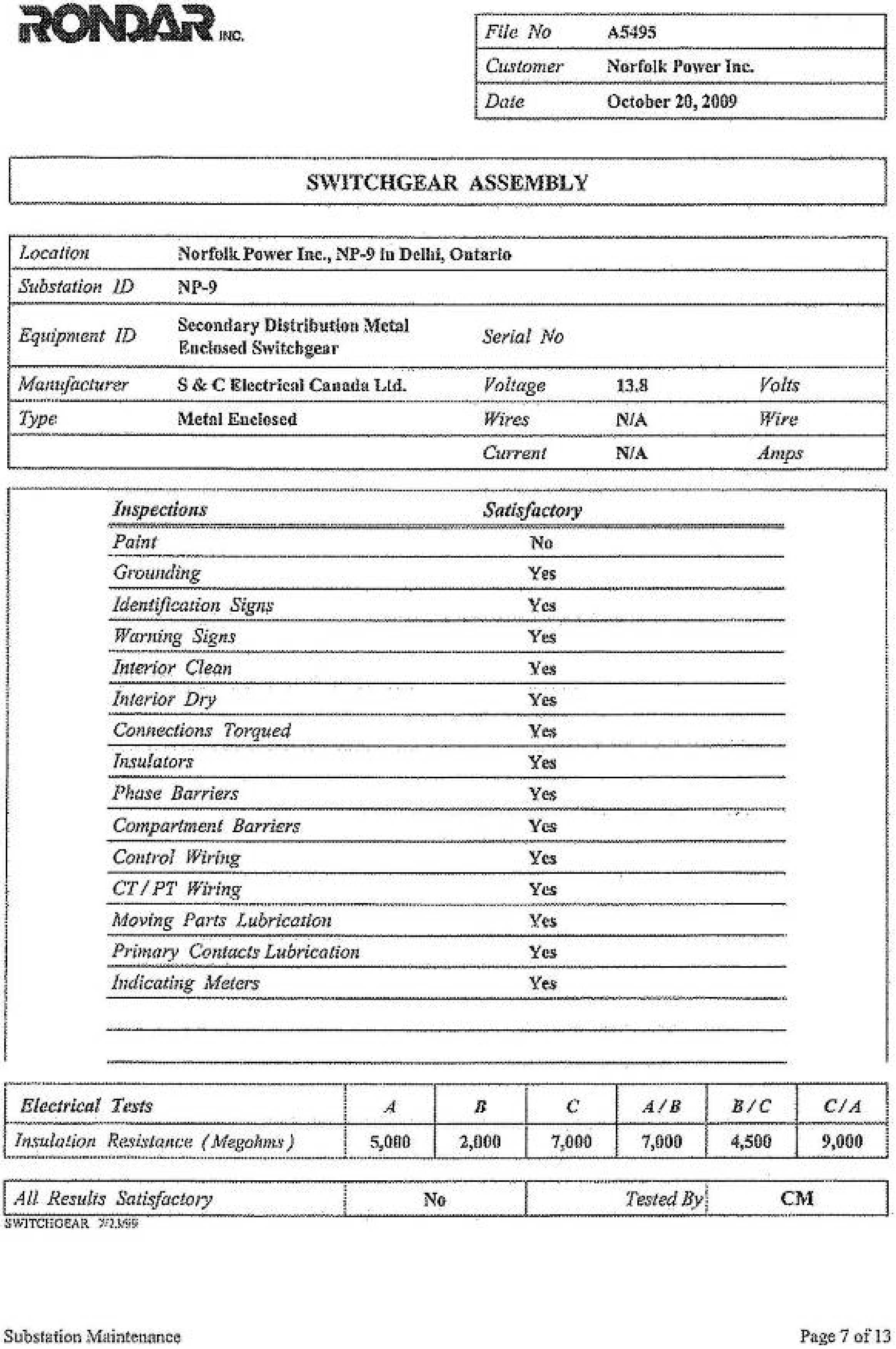
Insulation Tests

	L - GND *(H – LG)*	*H - GND* *(L - HG)*	*UST* *(H - L)*	*H - Guard* *(L - G)*	*L - Guard* *(H - G)*	*Core Ground*
Megohms @ 13 °C	14,000	20,000	20,000	N/A	N/A	N/A
Megohms @ 20 °C	10,500	15,000	15,000	N/A	N/A	N/A
Capacitance (pf)	8,297	13,721	5,605			
DF % @ 13 °C	0.48	0.54	0.41			
DF % @ 20 °C	0.53	0.60	0.45			

Test Conditions / Configurations Secondary bus disconnected. Fuses Pulled

All Results Satisfactory	Yes	*Tested By*	RB

TRANSFORMER-ELECTRICAL 7/23/99



RONDAR INC.

File No	A5495
Customer	Norfolk Power Inc.
Date	October 20, 2009

SWITCHGEAR ASSEMBLY

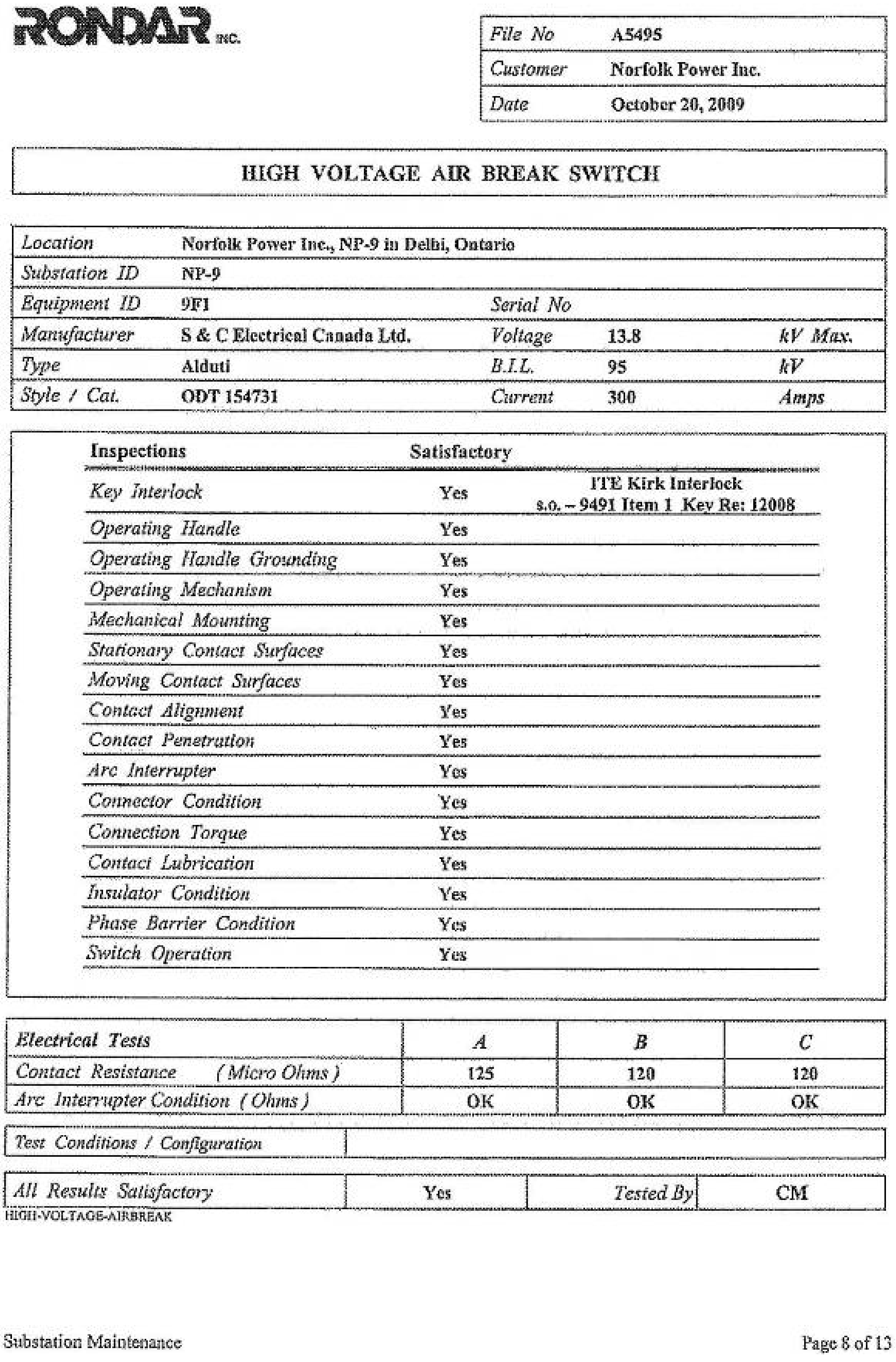
Location	Norfolk Power Inc., NP-9 in Delhi, Ontario			
Substation ID	NP-9			
Equipment ID	Secondary Distribution Metal Enclosed Switchgear	*Serial No*		
Manufacturer	S & C Electrical Canada Ltd.	*Voltage*	13.8	*Volts*
Type	Metal Enclosed	*Wires*	N/A	*Wire*
		Current	N/A	*Amps*

Inspections	*Satisfactory*
Paint	No
Grounding	Yes
Identification Signs	Yes
Warning Signs	Yes
Interior Clean	Yes
Interior Dry	Yes
Connections Torqued	Yes
Insulators	Yes
Phase Barriers	Yes
Compartment Barriers	Yes
Control Wiring	Yes
CT / PT Wiring	Yes
Moving Parts Lubrication	Yes
Primary Contacts Lubrication	Yes
Indicating Meters	Yes

Electrical Tests	*A*	*B*	*C*	*A / B*	*B / C*	*C / A*
Insulation Resistance (Megohms)	5,000	2,000	7,000	7,000	4,500	9,000

All Results Satisfactory	No	*Tested By*	CM

SWITCHGEAR 2/23/99



RONDAR INC.

File No	A5495
Customer	Norfolk Power Inc.
Date	October 20, 2009

HIGH VOLTAGE AIR BREAK SWITCH

Location	Norfolk Power Inc., NP-9 in Delhi, Ontario			
Substation ID	NP-9			
Equipment ID	9F1	*Serial No*		
Manufacturer	S & C Electrical Canada Ltd.	*Voltage*	13.8	*kV Max.*
Type	Alduti	*B.I.L.*	95	*kV*
Style / Cat.	ODT 154731	*Current*	300	*Amps*

Inspections	**Satisfactory**	
Key Interlock	Yes	ITE Kirk Interlock s.o. – 9491 Item 1 Key Re: 12008
Operating Handle	Yes	
Operating Handle Grounding	Yes	
Operating Mechanism	Yes	
Mechanical Mounting	Yes	
Stationary Contact Surfaces	Yes	
Moving Contact Surfaces	Yes	
Contact Alignment	Yes	
Contact Penetration	Yes	
Arc Interrupter	Yes	
Connector Condition	Yes	
Connection Torque	Yes	
Contact Lubrication	Yes	
Insulator Condition	Yes	
Phase Barrier Condition	Yes	
Switch Operation	Yes	

Electrical Tests	*A*	*B*	*C*
Contact Resistance (Micro Ohms)	125	120	120
Arc Interrupter Condition (Ohms)	OK	OK	OK

Test Conditions / Configuration	

All Results Satisfactory	Yes	*Tested By*	CM

HIGH-VOLTAGE-AIRBREAK

File No	A5495
Customer	Norfolk Power Inc.
Date	October 20, 2009

HIGH VOLTAGE FUSE

Location	Norfolk Power Inc., NP-9 in Delhi, Ontario			
Substation ID	NP-9			
Equipment ID	9F1	*Serial No*		

Fuse Holder				
Manufacturer	S&C Electric Canada Ltd.			
Type	SM-4S	*Voltage*	15.5	*kV Max.*
Style / Cat.	86632-R1	*Current*	200E	*Amps Max.*

Fuse Link			
Type	SM-4S	*Size*	200E E15kV
Style / Cat.	122 300 R4	*TCC*	153-4

Inspections	*Satisfactory*	
Moving Contact Surfaces	Yes	
Stationary Contact Surfaces	Yes	
Contact Penetration	Yes	
Connector Condition	Yes	
Connection Torque	Yes	
Contact Lubrication	Yes	
Insulator Condition	Yes	
Phase Barrier Condition	Yes	
Fuse Holder Condition	Yes	
Spare Links	No	None
All Links Identical	Yes	

Electrical Tests	*A*	*B*	*C*
Link Resistance (Mirco Ohms)	461	469	510

Test Conditions / Configuration	

All Results Satisfactory	No	*Tested By*	CM

HIGH-VOLTAGE-FUSE 7/22/99

RONDAR INC.

File No	**A5495**
Customer	**Norfolk Power Inc.**
Date	**October 20, 2009**

HIGH VOLTAGE CABLES

Location	**Norfolk Power Inc., NP-9 in Delhi, Ontario**
Substation ID	**NP-9**
Equipment ID	**9F1**

Manufacturer	**Unknown**	*Voltage*	**15**	*kV*
Conductor Size	**Unknown**	*Percent Insulation*	**Unknown**	*%*
Conductor Material	**Copper**	*B.I.L.*	**Unknown**	*kV*
Insulation Type	**Unknown**			

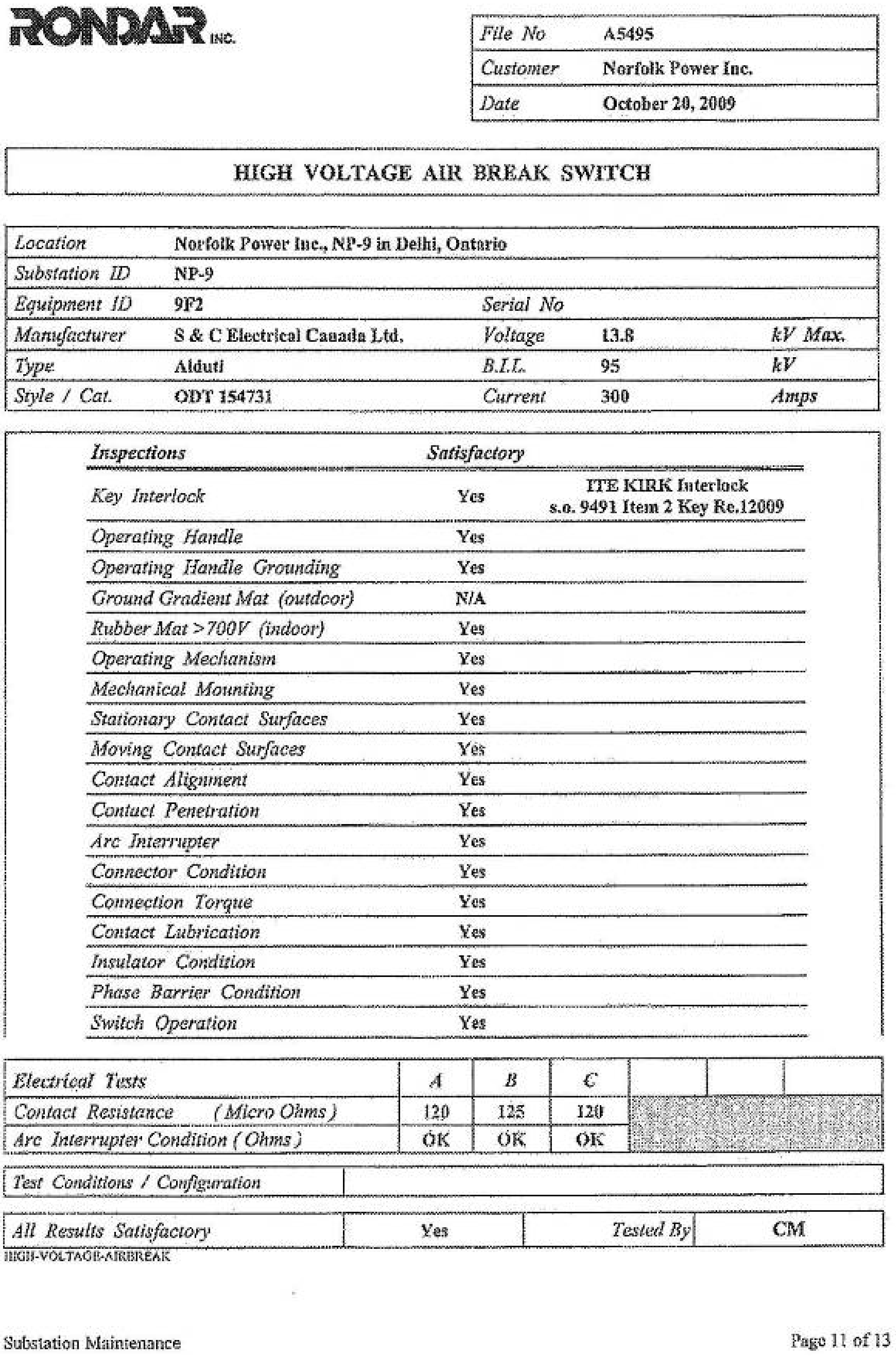
Inspections	*Satisfactory*
Jacket	Yes
Insulation	Yes
Terminations	Yes
Connection Torque	Yes
Connector Condition	Yes
Grounding	Yes
Phase Markings	Yes

Electrical Tests	A Red	*B White*	*C Blue*	*Spare*
Insulation Resistance (Megohms) @ 20 °C	700	1,000	700	NONE

Test Conditions / Configuration	

All Results Satisfactory	Yes	*Tested By*	CM

HIGH-VOLTAGE-CABLE 7/21/99



RONDAR INC.

File No	A5495
Customer	Norfolk Power Inc.
Date	October 20, 2009

HIGH VOLTAGE AIR BREAK SWITCH

Location	Norfolk Power Inc., NP-9 in Delhi, Ontario			
Substation ID	NP-9			
Equipment ID	9F2	*Serial No*		
Manufacturer	S & C Electrical Canada Ltd.	*Voltage*	13.8	*kV Max.*
Type	Alduti	*B.I.L.*	95	*kV*
Style / Cat.	ODT 154731	*Current*	300	*Amps*

Inspections	*Satisfactory*	
Key Interlock	Yes	ITE KIRK Interlock s.o. 9491 Item 2 Key Rc.12009
Operating Handle	Yes	
Operating Handle Grounding	Yes	
Ground Gradient Mat (outdoor)	N/A	
Rubber Mat >700V (indoor)	Yes	
Operating Mechanism	Yes	
Mechanical Mounting	Yes	
Stationary Contact Surfaces	Yes	
Moving Contact Surfaces	Yes	
Contact Alignment	Yes	
Contact Penetration	Yes	
Arc Interrupter	Yes	
Connector Condition	Yes	
Connection Torque	Yes	
Contact Lubrication	Yes	
Insulator Condition	Yes	
Phase Barrier Condition	Yes	
Switch Operation	Yes	

Electrical Tests	*A*	*B*	*C*			
Contact Resistance (Micro Ohms)	120	125	120	▨	▨	▨
Arc Interrupter Condition (Ohms)	OK	OK	OK	▨	▨	▨

Test Conditions / Configuration	

All Results Satisfactory	Yes	*Tested By*	CM

HIGH-VOLTAGE-AIRBREAK

RONDAR INC.

File No	A5495
Customer	Norfolk Power Inc.
Date	October 20, 2009

HIGH VOLTAGE FUSE

Location	Norfolk Power Inc., NP-9 in Delhi, Ontario		
Substation ID	NP-9		
Equipment ID	9F2	*Serial No*	

Fuse Holder				
Manufacturer	S & C Electrical Canada Ltd.			
Type	SM - 4S	*Voltage*	15.5	*kV Max.*
Style / Cat.	86632R1	*Current*	200E	*Amps Max.*

Fuse Link			
Type	SM-4	*Size*	200E @ 15kV
Style / Cat.	122300R4	*TCC*	153-4

Inspections	***Satisfactory***	
Moving Contact Surfaces	Yes	
Stationary Contact Surfaces	Yes	
Contact Penetration	Yes	
Connector Condition	Yes	
Connection Torque	Yes	
Contact Lubrication	Yes	
Insulator Condition	Yes	
Phase Barrier Condition	Yes	
Fuse Holder Condition	Yes	
Spare Links	No	None
All Links Identical	Yes	
Fuse Operation	Yes	

Electrical Tests	*A*	*B*	*C*
Link Resistance (Micro Ohms)	476	450	450

Test Conditions / Configuration	

All Results Satisfactory	No	*Tested By*	CM

HIGH-VOLTAGE-FUSE 7/22/99

RONDAR INC.

File No	**A5495**
Customer	**Norfolk Power Inc.**
Date	**October 20, 2009**

HIGH VOLTAGE CABLES

Location	**Norfolk Power Inc., NP-9 in Delhi, Ontario**
Substation ID	**NP-9**
Equipment ID	**9F2**

Manufacturer	**Unknown**	*Voltage*	**15**	*kV*
Conductor Size	**Unknown**	*Percent Insulation*	**Unknown**	*%*
Conductor Material	**Copper**	*B.I.L.*	**Unknown**	*kV*
Insulation Type	**Unknown**			

Inspections	*Satisfactory*
Jacket	Yes
Insulation	Yes
Terminations	Yes
Connection Torque	Yes
Connector Condition	Yes
Grounding	Yes
Phase Markings	Yes

Electrical Tests @ 5kV	*A (Red)*	*B (White)*	*C (Blue)*	*Spare*
Insulation Resistance (Megohms) @ 20 °C	**11,000**	**1,000**	**2,000**	**N/A**

Test Conditions / Configuration	

All Results Satisfactory	Yes	*Tested By*	**CM**

HIGH-VOLTAGE-CABLE 7/21/99

RONDAR INC

Reference No.: A5495

Customer: Norfolk Power Inc.

Date: October 29, 2009

SAFETY PLANNING WORKSHEET

SCOPE OF WORK:	NORFOLK POWER INC - NP-9 - 61 INDUSTRIAL DRIVE DELHI ONTARIO - 2009 POWER SYSTEM SERVICE / MAINTENANCE SHUTDOWN
SUPPORTING FORMS: (ATTACHED)	☐ PC2 ☐ PC10A ☐ PC10C ☐ PC17B
PERMIT NO.	NP2-265 / 09:26 / 15:00
GUARANTEE NO.	N/A

CELL (519) 420-0369

SITE CONTACT:	Mr. PAUL McCREADY	SITE PHONE NO.	(519) 426-4440
EMERGENCY NUMBERS:	911		EXT 2320

SAFETY MEETING

ISOLATION OF APPARATUS	[✓ YES] N/A
POTENTIAL BACKFEEDS	[✓ YES] N/A
TEMPORARY GROUNDING	[✓ YES] N/A
LIMITS OF APPROACH	YES [✓ N/A]
OTHER WORK GROUPS	YES [✓ N/A]
DESCRIPTION OF JOB SCHEDULES	[✓ YES] N/A
WORK ALLOCATION OF EACH INDIVIDUAL	[✓ YES] N/A
ANY SAFETY, CLIMBING HAZARDS OR CONCERNS NOTED	[✓ YES] N/A
PROCEDURE FOR NOTING PROBLEM ENCOUNTERED	[✓ YES] N/A
STANDARD PPE	[✓ YES] N/A
LOCATION OF FIRST AID KIT & EMERGENCY SHOWERS	[✓ YES] N/A
LOCATION OF TELEPHONE & WASHROOM	YES [✓ N/A]
WEATHER CONDITIONS	[✓ YES] N/A
ADJACENT STRUCTURE	YES [✓ N/A]
UNDERGROUND UTILITIES	YES [✓ N/A]

LOCKOUT PROCEDURE REQUIRED	YES [✓ N/A]
SINGLE LINE DIAGRAM AVAILABLE	[✓ YES] N/A

SPECIFIC SAFETY EQUIPMENT REQUIRED	
HV GLOVES	[✓ YES] N/A
POTENTIAL INDICATOR DEVICE	[✓ YES] N/A
HOT STICK & GROUNDS	[✓ YES] N/A
LOCKS	YES [✓ N/A]
CLIMBING HARNESS	[✓ YES] N/A
DANGER OR CAUTION TAPE	YES [✓ N/A]

MAJOR HAZARDS IDENTIFIED	STEPS TAKEN TO ELIMINATE / CONTROL
1.	1.
2.	2.
3.	3.
4.	4.
5.	5.
6.	6.
7.	7.
8.	8.

PROXIMITY WORK SHEET

LOCATION:

VOLTAGE LEVELS

(CIRCLE APPROPRIATE)

<750V	750V - 15kV	15kV - 44kV	115kV - 230kV

ACTUAL VOLTAGE(S)

SCOPE OF WORK

(CIRCLE APPROPRIATE)

TESTING PROTECTIVE RELAYS	HI-POTENTIAL PHASING
METERING OR MONITORING	INVESTIGATIVE STUDIES
THERMOSCAN	SWITCHING / ISOLATION
OIL SAMPLING	INSPECT & TEST PROGRAM
HI-POT TESTING - SWITCHGEAR / CABLES	TROUBLE SHOOTING

DISTANCE / CLEARANCE / CLASSIFICATION OF AREA

(CIRCLE APPROPRIATE)

ADJACENT - 10 FEET TO	WITHIN METALCLAD SWITCHGEAR
WITHIN 10 FEET OF	ADJACENT TO METALCLAD SWITCHGEAR
EXPOSED / ENERGIZED	TRANSFORMER / CAPACITOR BANKS
EXPOSED / ISOLATED / UNDERGROUND	SITE HOT WORK PERMITS

IF PROTECTION IS REQUIRED....INDICATE THE "TYPE", "SIZE", "NUMBER"

BARRIERS	CAUTION TAPE
RUBBER COVER UP	FLASH GUARDS
RUBBER MATS	ARC FLASH PROTECTIVE GEAR

SPECIFIC DETAILS FOR PROXIMITY / POTENTIAL HAZARD PROTECTION & PRECAUTIONS:

DETAILED SWITCHING & LOCKOUT SHEET

HYDRO PHONE NO. NORFOLK POWER CONTROL ROOM (519) 426-2394

EQUIPMENT IDENTIFICATION	OPEN	LOCK	NO.	GROUNDS	PERFORMED BY	RONDAR INITIALS	TIME
	CLOSE	TAG					

ISOLATION

HOLD-OFF	EQUIPMENT	HOLDER	ISSUED BY
		EFFECTIVE TIME & DATE	SURRENDERED TIME & DATE

ENERGIZATION

HOLD-OFF	EQUIPMENT	HOLDER	ISSUED BY
		EFFECTIVE TIME & DATE	SURRENDERED TIME & DATE

I, THE WORKER, HAVE HAD THE SAFETY HAZARDS, PRECAUTIONS AND RESPONSIBILITIES OF THIS JOB EXPLAINED TO ME AND UNDERSTAND THEM.

	SIGN IN	DATE & TIME	SIGN OUT	DATE & TIME
B	Rowan Berrowe	OCT 20/2009 08:30	RB	OCT 20/09 15:00
C	Lance Weber	Oct 20/09 12:30	LW	Oct 20/09 14:35
D				
E				
F				
G				
H				
I				
J				
K				
L				
M				
N				
O				
P				
Q				
R				
S				
T				
U				
V				
W				

SITE SUPERVISOR'S FINAL INSPECTION:

☑ ALL PERSONNEL SIGNED OUT ☑ TEMPORARY DE-ENERGIZATION DEVICES REMOVED. NUMBER OF SETS 1

☑ VISUAL INSPECTION OF CELLS FUSES & PT'S RE-INSTALLED ☑ YES ~~☑ N/A~~ CORE GROUNDS RECONNECTED ☐ YES ☑ N/A

CUSTOMER NOTIFIED OF ANY SAFETY ISSUES / CONCERNS: ☑ YES ☐ N/A

EQUIPMENT LEFT: ☑ AS FOUND ☐ AS INSTRUCTED BY: ____________________

COMMENTS:

SITE SUPERVISOR:

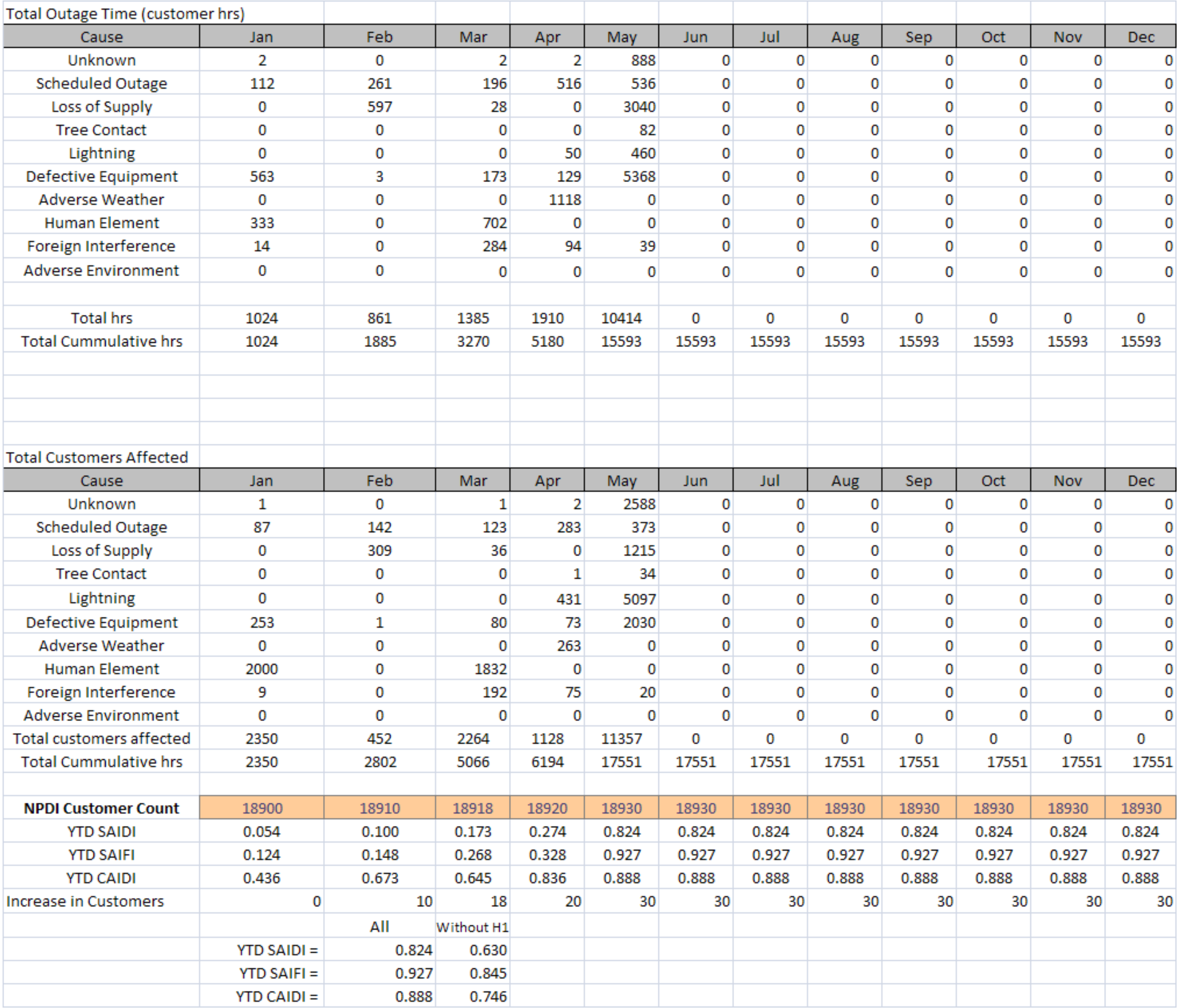
	SIGN IN	DATE & TIME	SIGN OUT	DATE & TIME
A		OCTOBER 20 2009 08:30	cm	OCTOBER 20 2009 15:00
	SIGN IN	DATE & TIME	SIGN OUT	DATE & TIME

APPENDIX 12

Outages

Outage ID	Date	Address/Area	Town/Township	Time of Call	Restoration Time	Duration Minutes	Cust Affected	Density	Cause	Details
January 2010				**Total Outages**		5				
1161	5-Jan-10	HWY 3 E	TOWNSEND	9:39	9:55	16	80	RURAL	DEFECTIVE EQUIPMENT	ARRESTER FAILURE
1182	11-Jan-10	HILLCREST RD	SIMCOE	17:45	19:20	95	9	URBAN	FOREIGN INTERFERENCE	VEHICLES
1195	24-Jan-10	MOST OF SIMCOE	SIMCOE	11:47	11:57	10	2,000	URBAN	HUMAN ELEMENT	INADVERTENT OPERATION
1198	25-Jan-10	PORT RYERSE RD	PORT RYERSE	6:19	9:27	188	173	RURAL	DEFECTIVE EQUIPMENT	INSULATOR BROKEN
1202	28-Jan-10	NORFOLK COUNT	TOWNSEND TO	22:40	0:15	95	1	RURAL	DEFECTIVE EQUIPMENT	ARRESTER FAILURE
February 2010				**Total Outages**		2				
1215	6-Feb-10	BAY ST	PORT ROWAN	2:29	4:25	116	309	URBAN	LOSS OF SUPPLY	HYDRO 1 INTERRUPTION
1221	12-Feb-10	PORT RYERSE RD	SIMCOE	6:40	9:30	170	1	RURAL	DEFECTIVE EQUIPMEN	INSULATOR BROKEN
March 2010				**Total Outages**		7				
1256	7-Mar-10	MAIN ST N	WATERFORD	13:00	15:00	120	1	URBAN	DEFECTIVE EQUIPMENT	TERMINATION FAILURE
1271	13-Mar-10	HWY 24	TOWNSEND	18:24	23:00	276	6	RURAL	LOSS OF SUPPLY	HYDRO 1 INTERRUPTION
1270	13-Mar-10	MC MICHAEL RD	TOWNSEND	20:06	22:00	114	70	RURAL	DEFECTIVE EQUIPMENT	TERMINATION FAILURE
1287	24-Mar-10	SHORELINE LANE	PORT DOVER	12:30	17:02	272	8	URBAN	DEFECTIVE EQUIPMENT	TRANSFORMER FAILURE
1296	25-Mar-10	NORTH MAIN ST	SIMCOE	18:40	20:00	80	22	URBAN	FOREIGN INTERFERENCE	OTHER
1289	28-Mar-10		TOWNSEND	14:25	14:48	23	1,832	URBAN	HUMAN ELEMENT	INADVERTENT OPERATION
1295	28-Mar-10	CON 2	TOWNSEND TO	6:20	8:10	110	1	RURAL	DEFECTIVE EQUIPMENT	DROP LEAD
April 2010				**Total Outages**		7				
1316	7-Apr-10	BRANT AVE	PORT DOVER	19:15	23:30	255	263	URBAN	ADVERSE WEATHER	RAIN
1335	16-Apr-10	CON 6	TOWNSEND TO	11:10	12:45	95	1	RURAL	FOREIGN INTERFERENCE	ANIMALS
1334	21-Apr-10	CON 8	TOWNSEND TO	6:30	11:05	145	1	RURAL	DEFECTIVE EQUIPMENT	TRANSFORMER FAILURE
1341	25-Apr-10	NORFOLK ST N	SIMCOE	9:07	10:45	60	1	URBAN	UNKNOWN/OTHER	FUSE BLOWN
1342	28-Apr-10	CON 8	TOWNSEND	12:20	13:00	40	1	RURAL	UNKNOWN/OTHER	FUSE BLOWN
1351	30-Apr-10	FOURTEENTH ST	SIMCOE	0:55	3:25	150	1	RURAL	FOREIGN INTERFERENCE	ANIMALS
1354	30-Apr-10	LYNN PARK AVE	PORT DOVER	16:18	18:47	107	70	URBAN	DEFECTIVE EQUIPMENT	OH CONDUCTOR FAILURE
May 2010				**Total Outages**		4				
1346	3-May-10	NORFOLK STREET	SIMCOE	8:41	9:20	39	1	RURAL	LIGHTNING	FUSE BLOWN
1364	5-May-10		PORT DOVER	18:12	18:14	2	2,529	URBAN	LIGHTNING	DIRECT HIT
1393	7-May-10	CON 7	TOWNSEND	19:18	22:00	162	30	RURAL	TREE CONTACTS	TREE FELL ON LINE
1387	13-May-10	CON 6	TOWNSEND TO	1:34	3:50	136	16	RURAL	FOREIGN INTERFERENCE	ANIMALS

APPENDIX 13



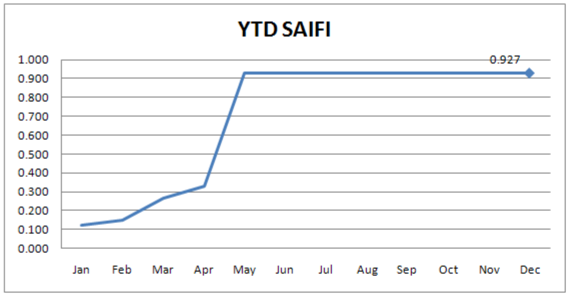
Total Outage Time (customer hrs)

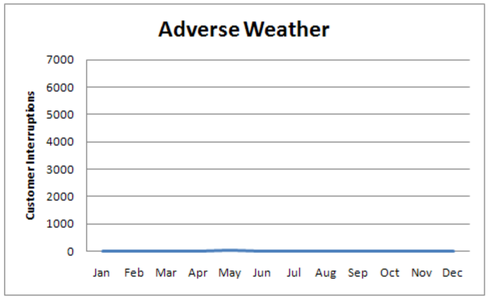
Cause	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Unknown	2	0	2	2	888	0	0	0	0	0	0	0
Scheduled Outage	112	261	196	516	536	0	0	0	0	0	0	0
Loss of Supply	0	597	28	0	3040	0	0	0	0	0	0	0
Tree Contact	0	0	0	0	82	0	0	0	0	0	0	0
Lightning	0	0	0	50	460	0	0	0	0	0	0	0
Defective Equipment	563	3	173	129	5368	0	0	0	0	0	0	0
Adverse Weather	0	0	0	1118	0	0	0	0	0	0	0	0
Human Element	333	0	702	0	0	0	0	0	0	0	0	0
Foreign Interference	14	0	284	94	39	0	0	0	0	0	0	0
Adverse Environment	0	0	0	0	0	0	0	0	0	0	0	0
Total hrs	1024	861	1385	1910	10414	0	0	0	0	0	0	0
Total Cummulative hrs	1024	1885	3270	5180	15593	15593	15593	15593	15593	15593	15593	15593

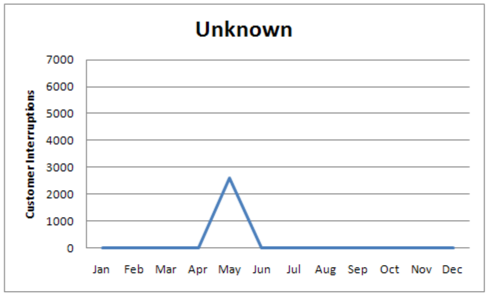
Total Customers Affected

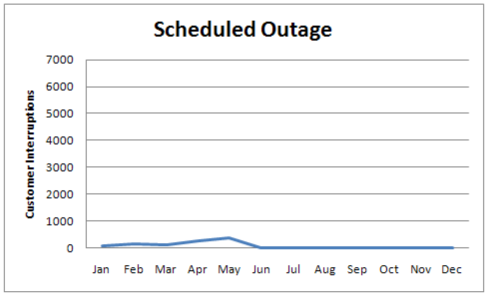
Cause	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Unknown	1	0	1	2	2588	0	0	0	0	0	0	0
Scheduled Outage	87	142	123	283	373	0	0	0	0	0	0	0
Loss of Supply	0	309	36	0	1215	0	0	0	0	0	0	0
Tree Contact	0	0	0	1	34	0	0	0	0	0	0	0
Lightning	0	0	0	431	5097	0	0	0	0	0	0	0
Defective Equipment	253	1	80	73	2030	0	0	0	0	0	0	0
Adverse Weather	0	0	0	263	0	0	0	0	0	0	0	0
Human Element	2000	0	1832	0	0	0	0	0	0	0	0	0
Foreign Interference	9	0	192	75	20	0	0	0	0	0	0	0
Adverse Environment	0	0	0	0	0	0	0	0	0	0	0	0
Total customers affected	2350	452	2264	1128	11357	0	0	0	0	0	0	0
Total Cummulative hrs	2350	2802	5066	6194	17551	17551	17551	17551	17551	17551	17551	17551
NPDI Customer Count	18900	18910	18918	18920	18930	18930	18930	18930	18930	18930	18930	18930
YTD SAIDI	0.054	0.100	0.173	0.274	0.824	0.824	0.824	0.824	0.824	0.824	0.824	0.824
YTD SAIFI	0.124	0.148	0.268	0.328	0.927	0.927	0.927	0.927	0.927	0.927	0.927	0.927
YTD CAIDI	0.436	0.673	0.645	0.836	0.888	0.888	0.888	0.888	0.888	0.888	0.888	0.888
Increase in Customers	0	10	18	20	30	30	30	30	30	30	30	30
		All	Without H1									
	YTD SAIDI =	0.824	0.630									
	YTD SAIFI =	0.927	0.845									
	YTD CAIDI =	0.888	0.746									

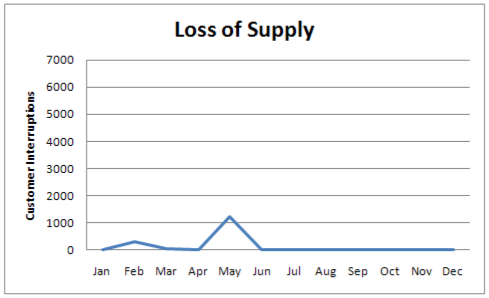
APPENDIX 14

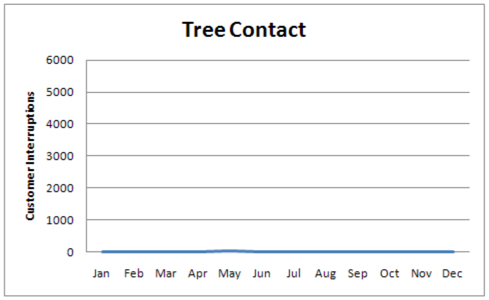

YTD SAIFI
1.000
0.900
0.800
0.700
0.600
0.500
0.400
0.300
0.200
0.100
0.000
0.927
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec

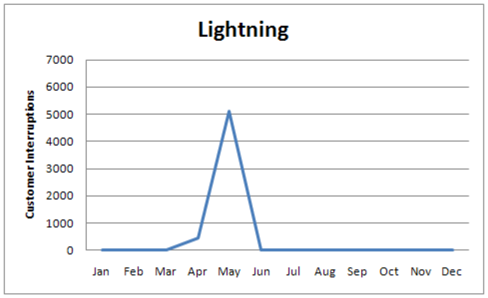

Adverse Weather
Customer Interruptions
7000
6000
5000
4000
3000
2000
1000
0
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec

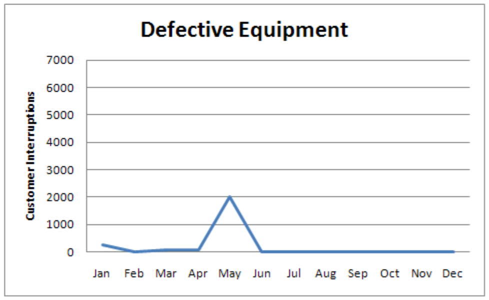

Unknown
Customer Interruptions
7000
6000
5000
4000
3000
2000
1000
0
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec

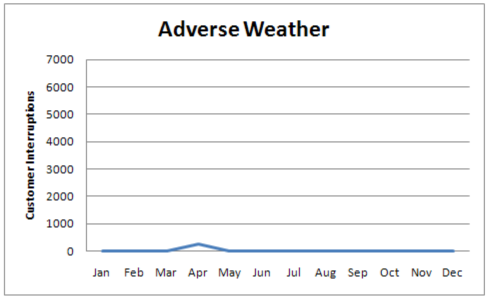

Scheduled Outage
Customer Interruptions
7000
6000
5000
4000
3000
2000
1000
0
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec

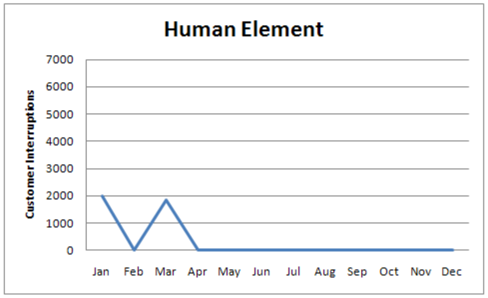

Loss of Supply
Customer Interruptions
7000
6000
5000
4000
3000
2000
1000
0
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec

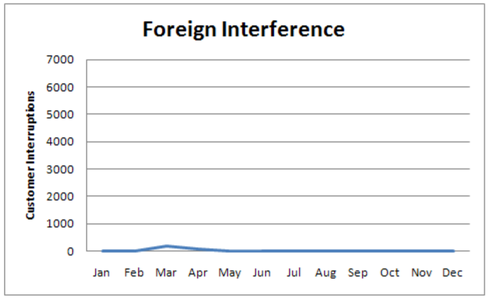

Tree Contact
Customer Interruptions
6000
5000
4000
3000
2000
1000
0
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec


Lightning
Customer Interruptions
7000
6000
5000
4000
3000
2000
1000
0
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec


Defective Equipment
Customer Interruptions
7000
6000
5000
4000
3000
2000
1000
0
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec


Adverse Weather
Customer Interruptions
7000
6000
5000
4000
3000
2000
1000
0
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec


Human Element
Customer Interruptions
7000
6000
5000
4000
3000
2000
1000
0
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec


Foreign Interference
Customer Interruptions
7000
6000
5000
4000
3000
2000
1000
0
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec

APPENDIX 15

Monthly Statistics Report

From **1-Jan-10** **To: 30-May-10**

Calls Received

Source	**Total**
	0
Ans Service	51
Control Room	85
Operation/Engineering	4
Total	**140**

Calls Type

Type of Call	**Number of Calls**
No Power	120
MVA-911	2
Part Power	9
Power Quality	3
Wire Down	5
General Trouble Call	3
Total	**142**

# of Unplanned Outages	**64**
# of Trouble Calls	**164**

Statistic	**Avg (min)**	**Max (min**		**# of Calls**	**Response Time Met**
Response Time Urban	**53**	**240**			
Response Time Rural	**66**	**240**	Emergency Response Urban	4	4
Restore Time	**118**	**400**	Emergency Response Rural	1	1

2010 AVERAGE	**Total Cust Hours of Interruptions (1)**	**Total Cust Interruptions (2)**	**Total Number of Customers (3)**	**SAIDI (4)=(1)/(3)**	**SAIFI (5)=(2)/(3)**	**CAIDI (6)=(4)/(5)**
January	1,024.40	2350	18900	0.054201	0.124339	0.435915
February	860.78	452	18910	0.04552	0.023903	1.904381
March	1,384.87	2264	18918	0.073204	0.119674	0.611692
April	1,909.70	1128	18920	0.100936	0.059619	1.692996
May	10,413.60	11354	18930	0.550111	0.599789	0.917175

APPENDIX 16

2010 - Emergency Response Rural

2009	Number of emergency calls for rural customers where on-site within 120 min (1)	Number of emergency calls for rural customers (2)	% of rural emergency call where on-site within 120 minutes (1) / (2)
January	2	2	100.00%
February	2	2	100.00%
March	3	3	100.00%
April	0	0	0.00%
May	1	1	100.00%
Totals	8	8	100.00%

2010 - Emergency Response Urban

2009	Number of emergency calls for urban customers where on-site within 60 min (1)	Number of emergency calls for urban customers (2)	% of urban emergency call where on-site within 60 minutes (1) / (2)
January	5	5	100.00%
February	2	2	100.00%
March	0	0	0.00%
April	3	3	100.00%
May	4	4	100.00%
Totals	14	14	100.00%

APPENDIX 17

Feeder Analysis

Purpose:

We use the 2009 analysis methodology shown above to perform yearly analysis of our system. The 2010 results (summarized below) help to identify any areas of improvement to our service quality indices on a feeder by feeder basis for 2011.

Methodology:

1. Calculate the contribution of overall SAIDI and SAIFI per feeder.
2. Graph results from highest to lowest contributors
3. Identified 4 worst performers for both SAIDI and SAIFI
4. Total Customers = (Cust. End of Year + Cust. Start of Year)/2
5. Group each outage on these feeders in one of 6 categories (Hydro 1, Equipment Failure, Tree Contact, Storm, Animals & Other)

Findings for 2010:

SAIDI

~ 10,857 Cust Hr’s were caused by Tree Contact
~ 6,837 Cust Hr’s were caused by Equipment Failure
~ 1,119 Cust Hr’s were caused by Storms
~ 8.932 Cust Hr’s were caused by Hydro 1 controlled equipment
~ 1,047 Cust Hr’s were caused by Animals
~ 2.363 Cust Hr’s were caused by Other

SAIFI

~ 32 incidents were caused by Animals
~ 25 incidents were caused by Storms
~ 27 incidents were caused by Equipment Failure
~ 40 incidents were caused by Other
~ 116 incidents were caused by Hydro 1 controlled equipment
~ 10 incidents were caused by Tree Contacts

Conclusions:

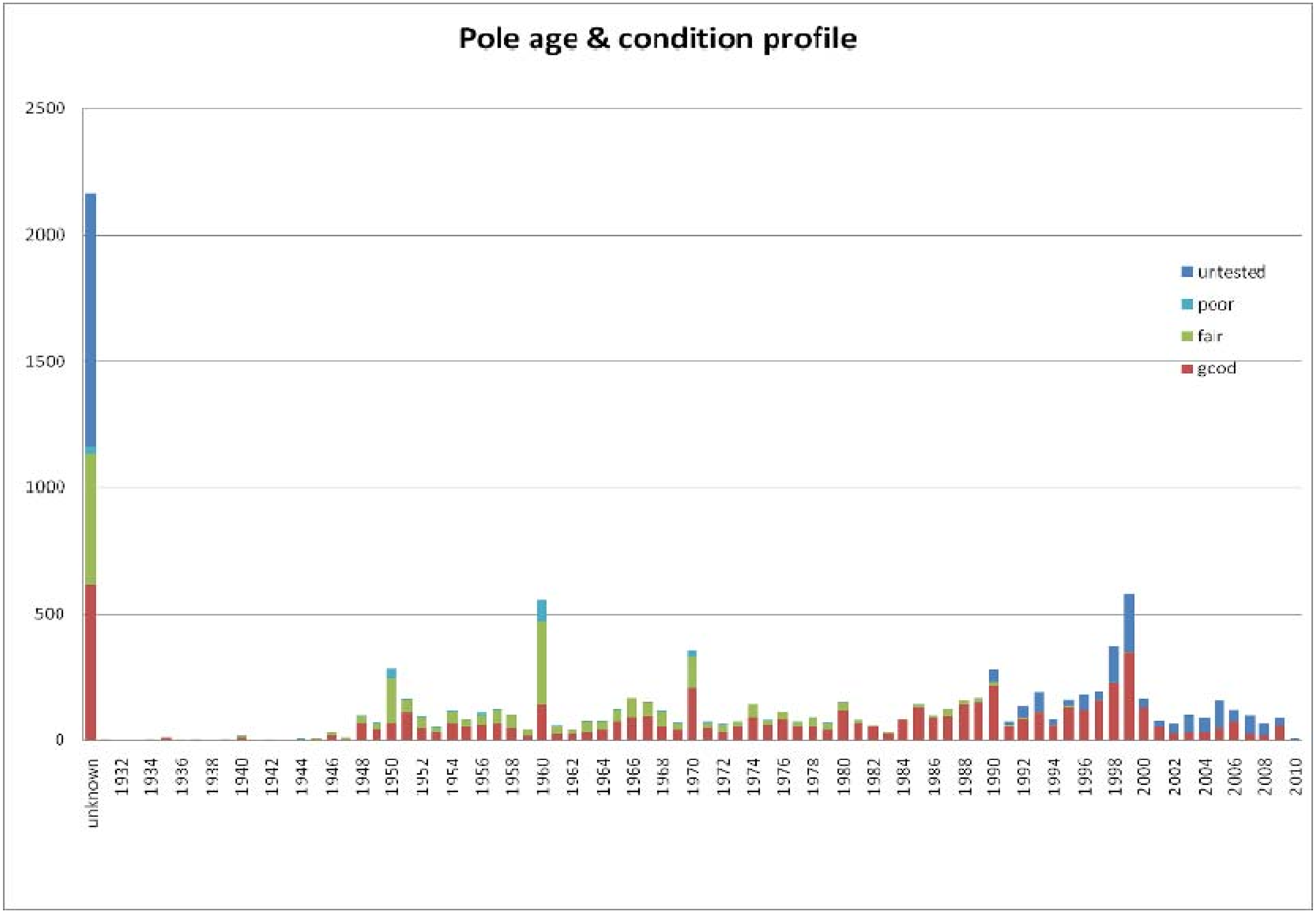
- Tree contacts were the largest contributor to SAIDI, but Storms in which trees fell on the line occurred in May and December. With the lowest amount of incidents, this category is hard to improve on; depending on the damage the time to repair is great.
- Defective equipment had a significant number of incidents, as well it was the 2nd largest contributor to the overall SAIDI. We are looking at the age/maintenance of some of the field equipment.
- Storms were the next largest contributor with a large number of incidents. This category is relatively uncontrollable.
- Hydro 1 controlled equipment has routinely been a problem . They are pursuing an aggressive tree trimming program in their territory in 2011.
- Other has vehicle accidents and unknown trips. These incidents are relatively uncontrollable.

Recommendations:

- There are no definitive areas of improvement from this analysis.
- Need to define each area of Main Causes and when this cause is to be used
- When a significant outage occurs (over 1000 customer hr’s) we should have the outage analyzed to find a root cause and recommend any action (committee)
- If Hydro 1 owned equipment is feeding an area we should perform feeder inspections on these feeders and recommend any corrective action to Hydro 1 to improve reliability.
- With an increase in Defective Equipment incidents we will need to develop a process to identify weak areas and endeavor to rebuild before failure.

Prepared By: Control Room

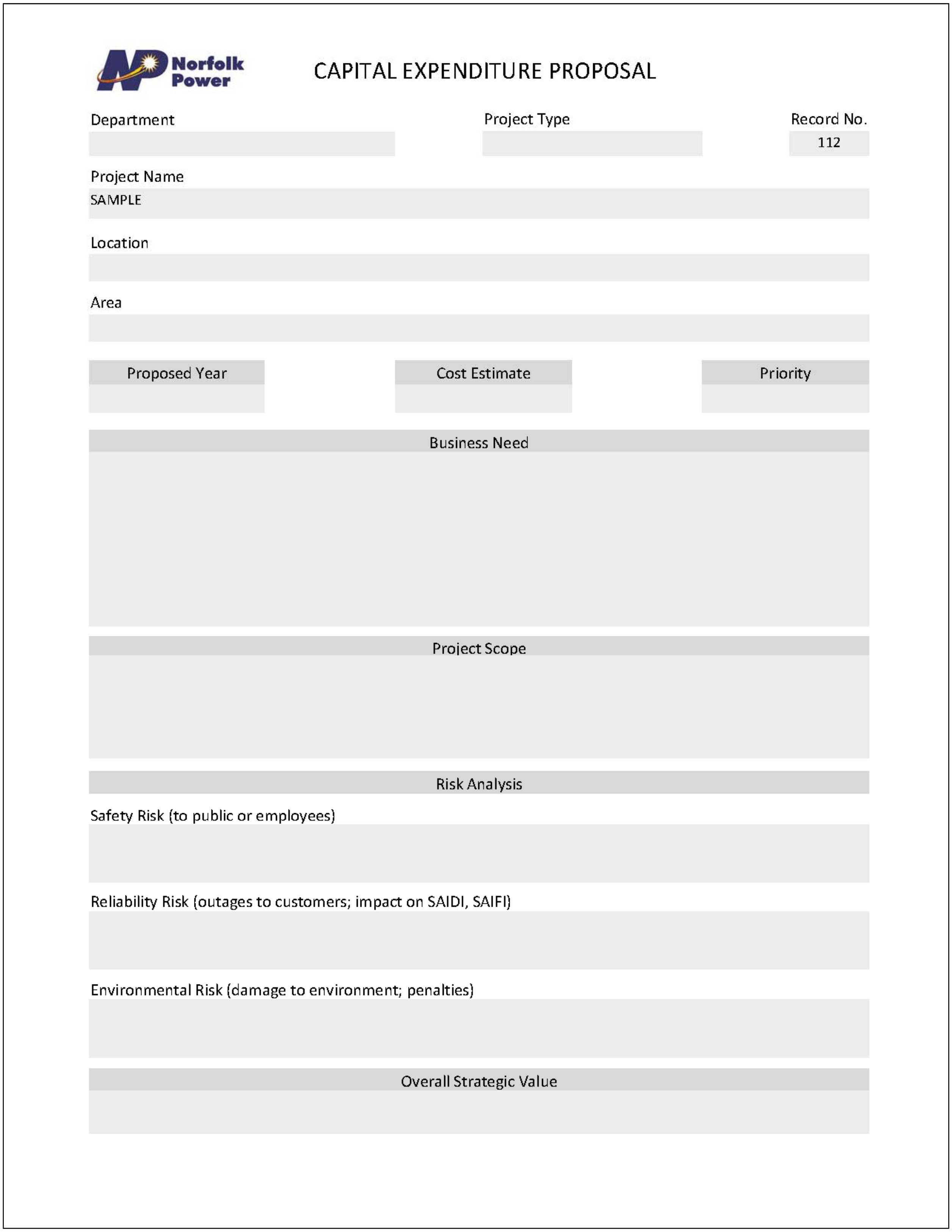
APPENDIX 18


Pole age & condition profile
2500
2000
1500
1000
500
0
unknown
1932
1934
1936
1938
1940
1942
1944
1946
1948
1950
1952
1954
1956
1958
1960
1962
1964
1966
1968
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
untested
poor
fair
good

APPENDIX 19

Norfolk Power - Pole Condition, Port Dover

APPENDIX 20



Norfolk Power

CAPITAL EXPENDITURE PROPOSAL

Department

Project Type

Record No.
112

Project Name
SAMPLE

Location

Area

Proposed Year	Cost Estimate	Priority

Business Need

Project Scope

Risk Analysis

Safety Risk (to public or employees)

Reliability Risk (outages to customers; impact on SAIDI, SAIFI)

Environmental Risk (damage to environment; penalties)

Overall Strategic Value

APPENDIX 21

(Capital Expenditure Proposals, 2012-2014)

Department	Project Type	Record No.
Engineering	Substations	1

Project Name

Miscellaneous DS Equipment Upgrades

Location

Distribution Stations

Area

Various

Proposed Year	Cost Estimate	Priority
2012	$75,000	High

Business Need

Provision for urgent station work identified from routine inspection. Current needs include upgrades to instrument PT's at NP6, monitoring and telemetry at NP13 to improve data collection related to power quality and fault investigation and inspections have identified an aging load break switch requiring replacement, an asbestos meter board and animal control issues at NP11.

Project scope

This provision covers a the replacement of a load brake switch, removal of an asbestos meter board and installation of animal at NP11 Port Dover, installation of station PT's for NP6 and installation of PT's to work with SEL relays at NP13 Port Dover.

Risk Analysis

Safety Risk

to be reviewed at project level

Reliability Risk

to be reviewed at project level

Environmental Risk

to be reviewed at project level

Overall Strategic Value

High - Projects are considered urgent if Safety, Reliability or Environmental Risk is determined to be high if the project is not completed

Department	Project Type	Record No.
Engineering	Substations	2

Project Name

Replace Transformer – Distribution Station NP8

Location

NP8

Area

Delhi

Proposed Year	Cost Estimate	Priority
2012	$200,000	Medium

Business Need

The distribution transformer presently installed and NP8 built in 1958 (53 years old) and Furan test indicate that 583 ppb. Indicating that breakdown is beginning to happen within the transformer. This transformer also contains 42 PPM of PCB. In order to provide good reliability in the Delhi area we need to increase the size of this transformer from the present 3750KVA to 5000KVA in order to allow complete load transfer between NP8 & NP9 without concern of overload and voltage issues.

Project scope

To continue to provide safe and reliable distribution supply to Delhi, the NP8 distribution station transformer requires replacement with a new 5MVA transformer. This includes an uprating to meet current and future load and will remove the existing PCB hazard.

Risk Analysis

Safety Risk

High – Possible public or employee risk of exposure to PCB contaminated oil

Reliability Risk

Medium - possible risk of asset failure resulting in reduced reliability

Environmental Risk

High – Possible risk of PCB contaminated oil spill

Overall Strategic Value

Medium - Regulations require the removal of all PCB transformers by 2025. Along with age of the unit and breakdown occurring in the unit

Department	Project Type	Record No.
Engineering	Security	3

Project Name

Reroute NP5 F4 to Queen St S (Simcoe Fairgrounds)

Location

Queen St & South Dr

Area

Simcoe

Proposed Year	Cost Estimate	Priority
2012	$220,000	Med-High

Business Need

The NP5 F4 feeder is currently routed across the Simcoe Fairgrounds property, to South Drive and then to Queen St S. This is a heavily used public area with vehicle traffic. Rebuilding an existing single phase pole line adjacent to the south entrance to the fairgrounds to three phase will permit the removal of 4kV primary lines through the parking lot.

Project scope

Rebuild approximately 125m of existing facilities as required to allow for removal of 4kV primary wires crossing parking lot

Risk Analysis

Safety Risk

High - possible risk of asset failure in a public area (fairgrounds)

Reliability Risk

Medium - possible risk of asset failures resulting in reduced reliability

Environmental Risk

Low - no identified environmental risks

Overall Strategic Value

Med-High - reduce equipment located on private property

Department	Project Type	Record No.
Engineering	Renewal	4

Project Name

4.16kV to 27.6kV Conversion Phase 2- Distributing Station NP10 Waterford

Location

St. James St./Leamon St.

Area

Waterford

Proposed Year	Cost Estimate	Priority
2012	$230,000	High

Business Need

Conversion of the customer base supplied by the NP10 Distribution Station in the Waterford area would allow consideration for the decommissioning of NP10 DS and sale of the station assets and property. This would improve reliability and power quality for the service area. The NP10 distribution station is a single transformer station with no backup. Transformer failure would result in an extended outage (greater than 8 hrs) to 355 residential customers.

Project scope

Replace approximately 20 poles, 4 transformers and approximately 600 metres of single phase primary and 600m of open wire secondary. This project affects approximately 75 services.

Risk Analysis

Safety Risk

Low – Need is not safety related

Reliability Risk

High – loss of station results in extended outages, project will improve power quality

Environmental Risk

Low

Overall Strategic Value

High - This project is phase 2 of a multi-phase project to convert the NP10 4.16kV distribution area to 27.6kV.

Department	Project Type	Record No.
Engineering	Renewal	5

Project Name

Simcoe 4.16 kV to 27.6 kV Conversion Phase 1

Location

Tyrell and Beckett St.

Area

Simcoe

Proposed Year	Cost Estimate	Priority
2012	$1,600,000	Medium

Business Need

Conversion of Simcoe distribution system to reduce loading on aging stations, to improve safety, reliability, power quality and reduce system inventory. Upon completion of the conversion program Simcoe Municipal Stations (MS) 1, 2, 3, and 5 may be decommissioned.

Project scope

Overhead rebuild with approx. 120 poles, 30 transformers, 1,300 m of 3ph primary, 2,700 m of 1ph primary. Approx. 350 services will be included in the conversion. Effected locations include: Tyrell St., Beckett Blvd., Hill St., Foster St., Belleview Ave., Charles St., Payne Ave., Martin Ave., Royal Rd., Holden Ave., Carolyn Blvd., Calvert Cres., Dora Dr., Sunset Dr., Union St. and King Lane.

Risk Analysis

Safety Risk

Medium – Aging assets nearing end of service life

Reliability Risk

High – Aging assets nearing end of service life, power quality (voltage) will improve

Environmental Risk

Low

Overall Strategic Value

Medium - Conversion Program

Department	Project Type	Record No.
Engineering	Renewal	6

Project Name

Rebuild Potts Rd, Simcoe

Location

Potts Rd.

Area

Simcoe

Proposed Year	Cost Estimate	Priority
2012	$100,000	Med-High

Business Need

Field inspection has identified the pole line on Potts St. is approaching its end of useful life.

Project scope

Replace 8 poles, 1 transformer and approximately 200m of single phase primary and secondary conductors on Potts Rd from Victoria St to Oakwood Ave

Risk Analysis

Safety Risk

High - assets at or near end of life

Reliability Risk

Medium - possible risk of asset failures resulting in reduced reliability

Environmental Risk

Medium - possible risk of transformer pole failure resulting in oil spill less than 100L

Overall Strategic Value

Med-High

Department	Project Type	Record No.
Engineering	Renewal	7

Project Name

Pole Replacement Program

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2012	$480,000	High

Business Need

Deteriorated poles in need of replacement before becoming a safety hazard to the public and/or plant failure resulting in related power outages and high cost of emergency repair or replacement. Poles that are in need of priority replacement are identified through a pole test and treat program. With this data and first-hand knowledge of pole conditions reported by field staff, an annual program of priority pole replacement is determined.

Project scope

For 2012, approximately 100 priority poles are anticipated to be identified for priority replacement. Provision for the replacement of related transformers has also been included.

Risk Analysis

Safety Risk

High - assets at or near end of life

Reliability Risk

Medium - possible risk of asset failures resulting in reduced reliability

Environmental Risk

Medium - possible risk of transformer pole failure resulting in oil spill less than 100L

Overall Strategic Value

High - annual pole replacement program

Department	Project Type	Record No.
Engineering	Renewal	8

Project Name

Miscellaneous Overhead and Underground Betterments

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2012	$485,000	High

Business Need

Provision for urgent and necessary equipment replacement identified as a result of routine system inspections and customer service calls. Reactive renewals of assets with a “run to failure” replacement strategy are included in this category (e.g. distribution transformers, underground cable). This category also includes replacement or adjustment to distribution system plant as required to accommodate customer demand work.

Project scope

Complete capital renewal work and system upgrades as required.

Risk Analysis

Safety Risk

to be reviewed at project level

Reliability Risk

to be reviewed at project level

Environmental Risk

to be reviewed at project level

Overall Strategic Value

High - Projects are considered urgent if Safety, Reliability or Environmental Risk is determined to be high if the project is not completed

Department	Project Type	Record No.
Engineering	Regulatory	9

Project Name

Plant Relocation for Road Widening

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2012	$150,000	High

Business Need

Where road widening projects are required as a result of municipal infrastructure development, NPDI follows the Public Service Works on Highways Act, 1990 and related regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital for 50% of NPDI labour and vehicles.

Project scope

Adjustments to distribution system equipment as required due to road widening projects established by the Municipality.

Risk Analysis

Safety Risk

N/A

Reliability Risk

N/A

Environmental Risk

N/A

Overall Strategic Value

High - Municipally driven, partial cost recovery

Department	Project Type	Record No.
Engineering	Customer Demand	10

Project Name

Subdivision Development

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2012	$303,000	High

Business Need

NPDI is obligated under the DSC to provide and connect distribution systems for new subdivisions. Capital contributions are determined based on the economic evaluation methodology outlined in Appendix B of the DSC.

Project scope

Small line extensions and connections to new subdivisions as required. Approximately 180 new lots.

Risk Analysis

Safety Risk

N/A

Reliability Risk

N/A

Environmental Risk

N/A

Overall Strategic Value

High - Customer demand driven

Department	Project Type	Record No.
Engineering	Customer Demand	11

Project Name

New Services and Service Upgrades

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2012	$450,000	High

Business Need

NPDI is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions for connection assets are charged for commercial / industrial services in accordance with NPDI's Conditions of Service.

Project scope

2012 Budget provides for approximately 100 new services, including 6 commercial / industrial services requiring three phase pad mount transformers, consistent with prior years.

Risk Analysis

Safety Risk

N/A

Reliability Risk

N/A

Environmental Risk

N/A

Overall Strategic Value

High - Customer demand driven

Department	Project Type	Record No.
Engineering	Meters	12

Project Name

Meter Installations

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2012	$348,000	High

Business Need
Supply and install meters to convert remaining commercial customers to electronic read meters.

Project scope
2012 Budget provides for a broad range of meter capital works including purchase of new meters for customer additions, primary metering installations.

Risk Analysis

Safety Risk

N/A

Reliability Risk

N/A

Environmental Risk

N/A

Overall Strategic Value
High – Regulatory requirement

Department	Project Type	Record No.
Engineering	Transformer Station	13

Project Name

Transformer Station Capital (miscellaneous)

Location

Bloomsburg TS

Area

Simcoe

Proposed Year	Cost Estimate	Priority
2013	$50,000	High

Business Need

Provision for urgent station work identified from routine inspection.

Project scope

A provision for Station projects such as a backup inverter system including a UPS2 transfer switch and a modification to UPS1 with a transfer switch and resealing of station metering

Risk Analysis

Safety Risk

to be reviewed at project level

Reliability Risk

to be reviewed at project level

Environmental Risk

to be reviewed at project level

Overall Strategic Value

High - Projects are considered urgent if Safety, Reliability or Environmental Risk is determined to be high if the project is not completed

Department	Project Type	Record No.
Engineering	Stations	14

Project Name

Miscellaneous DS Equipment Upgrades

Location

Distribution Stations

Area

Various

Proposed Year	Cost Estimate	Priority
2013	$75,000	High

Business Need
Provision for urgent station work identified from routine inspection

Project scope
Complete urgent station work identified from routine inspection

Risk Analysis

Safety Risk

to be reviewed at project level

Reliability Risk

to be reviewed at project level

Environmental Risk

to be reviewed at project level

Overall Strategic Value
High - Projects are considered urgent if Safety, Reliability or Environmental Risk is determined to be high if the project is not completed

Department	Project Type	Record No.
Engineering	Renewal	15

Project Name

4.16kV to 27.6kV Conversion Phase 3- Distributing Station NP10 Waterford

Location

Brown St & Montclair Cres.

Area

Waterford

Proposed Year	Cost Estimate	Priority
2013	$650,000	High

Business Need

Conversion of the customer base supplied by the NP10 Distribution Station in the Waterford area would allow consideration for the decommissioning of NP10 DS and sale of the station assets and property. This would improve reliability and power quality for the service area. The NP10 distribution station is a single transformer station with no backup. Transformer failure would result in an extended outage (greater than 8 hrs) to 355 residential customers.

Project scope

4.16kV to 27.6kV Conversion of approximately 2000m of overhead primary, 50 poles and 12 transformers. This affects approximately 90 services in the areas of Brown St., Montclair Cres., Howard St., Harrison St., Baltic Circle and Normandy Court.

Risk Analysis

Safety Risk

Low

Reliability Risk

High – loss of station results in extended outages, project will improve power quality

Environmental Risk

Low

Overall Strategic Value

High - This project is phase 3 of a multi-phase project to convert the NP10 4.16kV distribution area to 27.6kV.

Department	Project Type	Record No.
Engineering	Renewal	16

Project Name

Pole Replacement Program - 2013

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2013	$480,000	High

Business Need

Priority pole replacements as determined from annual pole condition testing program and engineering department analysis of results.

Project scope

Provision for replacement of 80 priority poles and related transformers. Project cost and scope to be updated following 2012 pole testing and analysis.

Risk Analysis

Safety Risk

High - assets at or near end of life

Reliability Risk

Medium - possible risk of asset failures resulting in reduced reliability

Environmental Risk

Medium - possible risk of transformer pole failure resulting in oil spill less than 100L

Overall Strategic Value

High - annual pole replacement program

Department	Project Type	Record No.
Engineering	Renewal	17

Project Name

Miscellaneous Overhead and Underground Betterments

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2013	$485,000	High

Business Need

Provision for misc urgent capital distribution system work initiated by customer demand or identified from inspections or service calls; capital renewal of run to failure assets

Project scope

Complete capital renewal work and system upgrades as required.

Risk Analysis

Safety Risk

to be reviewed at project level

Reliability Risk

to be reviewed at project level

Environmental Risk

to be reviewed at project level

Overall Strategic Value

High - Projects are considered urgent if Safety, Reliability or Environmental Risk is determined to be high if the project is not completed

Department	Project Type	Record No.
Engineering	Renewal	18

Project Name

Simcoe 4.16 kV to 27.6 kV Conversion Phase 2

Location

Berkley Cres. & Cherry St.

Area

Simcoe

Proposed Year	Cost Estimate	Priority
2013	$1,500,000	Medium

Business Need

Conversion of Simcoe distribution system to reduce loading on aging stations, to improve safety, reliability, power quality and reduce system inventory. Upon completion of the conversion program Simcoe Municipal Stations (MS) 1, 2, 3, and 5 may be decommissioned.

Project scope

Phase 2 of the 4.16 kV to 27.6 kV conversion project in Simcoe. Rebuild consists of approx. 29 new poles, 3 O/H Transformers, 32 padmounted transformers, 800m O/H primary conductor, 7000m U/G primary cable, 1350m U/G secondary cable in the Berkley Cres. & Cherry St. areas. This project affects approximately 300 services.

Risk Analysis

Safety Risk

Medium – Aging assets nearing end of service life

Reliability Risk

High – Aging assets nearing end of service life, power quality (voltage) will improve

Environmental Risk

Low

Overall Strategic Value

Medium - Conversion Program

Department	Project Type	Record No.
Engineering	Regulatory	19

Project Name

Plant Relocation for Road Widening

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2013	$150,000	High

Business Need

Where road widening projects are required as a result of municipal infrastructure development, NPDI follows the Public Service Works on Highways Act, 1990 and related regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital for 50% of NPDI labour and vehicles.

Project scope

Adjustments to distribution system equipment as required due to road widening projects established by the Municipality.

Risk Analysis

Safety Risk

N/A

Reliability Risk

N/A

Environmental Risk

N/A

Overall Strategic Value

High - Municipally driven, partial cost recovery

Department	Project Type	Record No.
Engineering	Customer Demand	20

Project Name

Subdivision Development

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2013	$303,000	High

Business Need

NPDI is obligated under the DSC to provide and connect distribution systems for new subdivisions. Capital contributions are determined based on the economic evaluation methodology outlined in Appendix B of the DSC.

Project scope

Small line extensions and connections to new subdivisions as required.

Risk Analysis

Safety Risk

N/A

Reliability Risk

N/A

Environmental Risk

N/A

Overall Strategic Value

High - Customer demand driven

Department	Project Type	Record No.
Engineering	Customer Demand	21

Project Name

New Services and Service Upgrades

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2013	$446,000	High

Business Need

NPDI is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions for connection assets are charged for commercial / industrial services in accordance with NPDI's Conditions of Service.

Project scope

2013 Budget provides for approximately 100 new services, including 6 commercial / industrial services requiring three phase pad mount transformers, consistent with prior years

Risk Analysis

Safety Risk

N/A

Reliability Risk

N/A

Environmental Risk

N/A

Overall Strategic Value

High - Customer demand driven

Department	Project Type	Record No.
Engineering	Regulatory	22

Project Name

Long Term Load Transfers elimination program - 2013

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2013	$300,000	High

Business Need
Section 6.5.4 of the DSC requires that geographic distributors that serve customers through load transfer arrangements with physical distributors eliminate those load transfer arrangements by January 31, 2014. NPDI has established a 3 year plan to ensure compliance with the DSC

Project scope
Eliminate Long Term Load Transfers as per plan (Part 1)

Risk Analysis

Safety Risk

N/A

Reliability Risk

N/A

Environmental Risk

N/A

Overall Strategic Value
High - Regulatory requirement

Department	Project Type	Record No.
Engineering	Regulatory	23

Project Name

Norfolk TS primary metering upgrade

Location

Norfolk TS

Area

Simcoe

Proposed Year	Cost Estimate	Priority
2013	$175,000	High

Business Need

NPDI owned metering equipment at Norfolk TS must be upgraded to meet current primary metering requirements

Project scope

Replace metering equipment as required to meet new requirements. Includes CT's, PT's and Meters.

Risk Analysis

Safety Risk

N/A

Reliability Risk

N/A

Environmental Risk

N/A

Overall Strategic Value

High - Regulatory requirement

Department	Project Type	Record No.
Engineering	Other	24

Project Name

Fleet replacement plan - 2013

Location

NPDI

Area

Simcoe

Proposed Year	Cost Estimate	Priority
2013	$300,000	Med-High

Business Need
Fleet replacement as per plan – Line Truck (radial boom digger derrick) #42 (1992) is nearing end of life and requires replacement

Project scope
Purchase new Line Truck

Risk Analysis

Safety Risk

None - need is not safety related

Reliability Risk

High - not completing this project could substantially reduce productivity and increase vehicle maintenance costs

Environmental Risk

None - not completing this project would not affect the environment

Overall Strategic Value

Med-High - Annual fleet replacement plan

Department	Project Type	Record No.
Engineering	Other	25

Project Name

Fleet replacement plan - 2013

Location

NPDI

Area

Simcoe

Proposed Year	Cost Estimate	Priority
2013	$40,000	Med-High

Business Need

Fleet replacement as per plan. Pickup Truck #2 (1999) requires replacement as it is nearing end of life

Project scope

Purchase new pickup truck

Risk Analysis

Safety Risk

None - need is not safety related

Reliability Risk

High - not completing this project could substantially reduce productivity and increase vehicle maintenance costs

Environmental Risk

None - not completing this project would not affect the environment

Overall Strategic Value

Med-High - Annual fleet replacement plan

Department	Project Type	Record No.
Engineering	Transformer Station	26

Project Name

Transformer Station Capital (miscellaneous)

Location

Bloomsburg TS

Area

Simcoe

Proposed Year	Cost Estimate	Priority
2014	$50,000	High

Business Need
Provision for urgent station work identified from routine inspection

Project scope
Complete urgent station work identified from routine inspection

Risk Analysis

Safety Risk

to be reviewed at project level

Reliability Risk

to be reviewed at project level

Environmental Risk

to be reviewed at project level

Overall Strategic Value

High - Projects are considered urgent if Safety, Reliability or Environmental Risk is determined to be high if the project is not completed

Department	Project Type	Record No.
Engineering	Stations	27

Project Name

Miscellaneous DS Equipment Upgrades (miscellaneous)

Location

Distribution Stations

Area

Various

Proposed Year	Cost Estimate	Priority
2014	$75,000	High

Business Need
Provision for urgent station work identified from routine inspection.

Project scope
Complete urgent station work identified from routine inspection.

Risk Analysis

Safety Risk

to be reviewed at project level

Reliability Risk

to be reviewed at project level

Environmental Risk

to be reviewed at project level

Overall Strategic Value

High - Projects are considered urgent if Safety, Reliability or Environmental Risk is determined to be high if the project is not completed

Department	Project Type	Record No.
Engineering	Renewal	28

Project Name

Pole Replacement Program – 2014

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2014	$480,000	High

Business Need

Priority pole replacements as determined from annual pole condition testing program and engineering department analysis of results.

Project scope

Provision for replacement of 80 priority poles and related transformers. Project cost and scope to be updated following 2012 pole testing and analysis.

Risk Analysis

Safety Risk

High - assets at or near end of life

Reliability Risk

Medium - possible risk of asset failures resulting in reduced reliability

Environmental Risk

Medium - possible risk of transformer pole failure resulting in oil spill less than 100L

Overall Strategic Value

High - annual pole replacement program

Department	Project Type	Record No.
Engineering	Renewal	29

Project Name

Miscellaneous Overhead and Underground Betterments

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2014	$485,000	High

Business Need

Provision for misc urgent capital distribution system work initiated by customer demand or identified from inspections or service calls; capital renewal of run to failure assets

Project scope

Complete capital renewal work and system upgrades as required.

Risk Analysis

Safety Risk

to be reviewed at project level

Reliability Risk

to be reviewed at project level

Environmental Risk

to be reviewed at project level

Overall Strategic Value

High - Projects are considered urgent if Safety, Reliability or Environmental Risk is determined to be high if the project is not completed

Department	Project Type	Record No.
Engineering	Renewal	30

Project Name

Simcoe 4.16 kV to 27.6 kV Conversion Phase 3

Location

Kennedy Rd & Brock St.

Area

Simcoe

Proposed Year	Cost Estimate	Priority
2014	$1,500,000	Medium

Business Need

Conversion of Simcoe distribution system to reduce loading on aging stations, to improve safety, reliability, power quality and reduce system inventory. Upon completion of the conversion program Simcoe Municipal Stations (MS) 1, 2, 3, and 5 may be decommissioned.

Project scope

Phase 3 of the 4.16 kV to 27.6 kV conversion project in Simcoe. Rebuild consists of approx. 4 new poles, 45 padmounted transformers, 3500m U/G primary cable, 700m U/G secondary cable. This project affects approximately 325 services.

Risk Analysis

Safety Risk

Medium – Aging assets nearing end of service life

Reliability Risk

High – Aging assets nearing end of service life, power quality (voltage) will improve

Environmental Risk

Low

Overall Strategic Value

Medium - Conversion Program

Department	Project Type	Record No.
Engineering	Regulatory	31

Project Name

Plant Relocation for Road Widening

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2014	$150,000	High

Business Need

Where road widening projects are required as a result of municipal infrastructure development, NPDI follows the Public Service Works on Highways Act, 1990 and related regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital for 50% of NPDI labour and vehicles.

Project scope

Adjustments to distribution system equipment as required due to road widening projects established by the Municipality.

Risk Analysis

Safety Risk

N/A

Reliability Risk

N/A

Environmental Risk

N/A

Overall Strategic Value

High - Municipally driven, partial cost recovery

Department	Project Type	Record No.
Engineering	Customer Demand	32

Project Name

Subdivision Development

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2014	$303,000	High

Business Need

NPDI is obligated under the DSC to provide and connect distribution systems for new subdivisions. Capital contributions are determined based on the economic evaluation methodology outlined in Appendix B of the DSC.

Project scope

Small line extensions and connections to new subdivisions as required.

Risk Analysis

Safety Risk

N/A

Reliability Risk

N/A

Environmental Risk

N/A

Overall Strategic Value

High - Customer demand driven

Department	Project Type	Record No.
Engineering	Customer Demand	33

Project Name

New Services and Service Upgrades

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2014	$446,000	High

Business Need

NPDI is obligated under the DSC to provide and connect new services and upgrade existing services as required to meet customer demand. Capital contributions for connection assets are charged for commercial / industrial services in accordance with NPDI's Conditions of Service.

Project scope

2014 Budget provides for approximately 175 new services, including 6 commercial / industrial services requiring three phase pad mount transformers, consistent with prior years

Risk Analysis

Safety Risk

N/A

Reliability Risk

N/A

Environmental Risk

N/A

Overall Strategic Value

High - Customer demand driven

Department	Project Type	Record No.
Engineering	Renewal	34

Project Name

4.16 kV to 27.6 kV Conversion Phase 4 – Distribution Station NP10 Waterford

Location

Blueline Rd. & Thompson Rd.

Area

Waterford

Proposed Year	Cost Estimate	Priority
2014	$400,000	High

Business Need

Conversion of the customer base supplied by the NP10 Distribution Station in the Waterford area would allow consideration for the decommissioning of NP10 DS and sale of the station assets and property. This would improve reliability and power quality for the service area. The NP10 distribution station is a single transformer station with no backup. Transformer failure would result in an extended outage (greater than 8 hrs) to 355 residential customers.

Project scope

Removal of converted distribution assets and decommissioning of NP10 Station and preparation for sale of the property.

Risk Analysis

Safety Risk

Low

Reliability Risk

Low

Environmental Risk

High – Potential for Oil Spill >100L from station Transformer

Overall Strategic Value

High - This project is phase 4 of a multi-phase project to convert the NP10 4.16kV distribution area to 27.6kV and decommission the NP10 Station.

Department	Project Type	Record No.
Engineering	Renewal	35

Project Name

8kV to 27kV Conversion – Prospect St, Grand St Areas

Location

Prospect St, Grand St Areas

Area

Port Dover

Proposed Year	Cost Estimate	Priority
2014	$400,000	High

Business Need

The Port Dover area 8 kV distribution is supplied from 3 distribution stations. Conversion of various strategic areas will permit the eventual elimination of NPDI's NP12 distribution station. Pole lines which are deteriorated and at the end of their useful life have been targeted for conversion. The upgrade will reduce related maintenance costs in the area, improve system reliability due to the presence of new plant and eventually reduce line losses by eliminating 4 kV transformation.

Project scope

Replace approximately 30 poles, 8 transformers and approximately 1500m of primary and secondary conductors. This project affects approximately 150 services.

Risk Analysis

Safety Risk

High - assets at or near end of life

Reliability Risk

Medium - possible risk of asset failures resulting in reduced reliability

Environmental Risk

Medium - possible risk of transformer pole failure resulting in oil spill less than 100L

Overall Strategic Value

High

Department	Project Type	Record No.
Engineering	Regulatory	36

Project Name

Long Term Load Transfers elimination program - 2014

Location

Various

Area

Various

Proposed Year	Cost Estimate	Priority
2014	$500,000	High

Business Need

Section 6.5.4 of the DSC requires that geographic distributors that serve customers through load transfer arrangements with physical distributors eliminate those load transfer arrangements by January 31, 2014. NPDI has established a 3 year plan to ensure compliance with the DSC

Project scope

Eliminate Long Term Load Transfers as per plan (Part 2)

Risk Analysis

Safety Risk

N/A

Reliability Risk

N/A

Environmental Risk

N/A

Overall Strategic Value

High - Regulatory requirement

Department	Project Type	Record No.
Engineering	Other	37

Project Name

Fleet replacement plan - 2014

Location

NPDI

Area

Simcoe

Proposed Year	Cost Estimate	Priority
2014	$260,000	Med-High

Business Need

Fleet replacement as per plan. Line truck (Single Bucket Aerial Device) #53 (2002) requires replacement as it is nearing end of life.

Project scope

Purchase new Line Truck

Risk Analysis

Safety Risk

None - need is not safety related

Reliability Risk

High - not completing this project could substantially reduce productivity and increase vehicle maintenance costs

Environmental Risk

None - not completing this project would not affect the environment

Overall Strategic Value

Med-High - Annual fleet replacement plan

Department	Project Type	Record No.
Engineering	Other	38

Project Name

Fleet replacement plan - 2014

Location

NPDI

Area

Simcoe

Proposed Year	Cost Estimate	Priority
2014	$80,000	Med-High

Business Need

Fleet replacement as per plan. Pickup Truck #10 (2003) and Van #24 (2004) require replacement as they are nearing end of life.

Project scope

Purchase new pickup truck and van

Risk Analysis

Safety Risk

None - need is not safety related

Reliability Risk

High - not completing this project could substantially reduce productivity and increase vehicle maintenance costs

Environmental Risk

None - not completing this project would not affect the environment

Overall Strategic Value

Med-High - Annual fleet replacement plan

EXHIBIT 2

APPENDIX B

Cost of Power Calculation

2011 Load Foreacst	**kWh**	**kW**	**2010 %RPP**
Residential	147,157,598		85%
General Service < 50 kW	61,967,789		82%
General Service 50 to 4,999 kW	133,777,131	351,747	18%
Street Lighting	3,035,802	8,853	99%
Sentinel Lighting	329,411	858	100%
Unmetered Scattered Load	481,000		100%
Hydro One	30,955,199		0%
TOTAL	377,703,930	361,458	

Electricity - Commodity RPP	**2011**	**2011 Loss**			
Class per Load Forecast RPP	**Forecasted**	**Factor**	**2011**		
Residential	125,083,958	1.0567	132,176,219	$0.06938	$9,170,386
General Service < 50 kW	50,813,587	1.0567	53,694,717	$0.06938	$3,725,339
General Service 50 to 4,999 kW	24,079,884	1.0567	25,445,213	$0.06938	$1,765,389
Street Lighting	3,005,444	1.0567	3,175,853	$0.06938	$220,341
Sentinel Lighting	329,411	1.0567	348,089	$0.06938	$24,150
Unmetered Scattered Load	481,000	1.0567	508,273	$0.06938	$35,264
Hydro One	0	1.0567	0	$0.06938	$0
TOTAL	203,793,284		215,348,363		$14,940,869

Electricity - Commodity Non-RPP	**2011**	**2011 Loss**			
Class per Load Forecast	**Forecasted**	**Factor**	**2011**		
Residential	22,073,640	1.0567	23,325,215	$0.06438	$1,501,677
General Service < 50 kW	11,154,202	1.0567	11,786,645	$0.06438	$758,824
General Service 50 to 4,999 kW	109,697,247	1.0567	115,917,081	$0.06438	$7,462,742
Street Lighting	30,358	1.0567	32,079	$0.06438	$2,065
Sentinel Lighting	0	1.0567	0	$0.06438	$0
Unmetered Scattered Load	0	1.0567	0	$0.06438	$0
Hydro One	30,955,199	1.0567	32,710,359	$0.06438	$2,105,893
TOTAL	173,910,646		151,061,021		$11,831,201

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**	**2011**		
Residential		kWh	155,501,434	$0.0066	$1,026,309
General Service < 50 kW		kW	65,481,363	$0.0060	$392,888
General Service 50 to 4,999 kW		kW	351,747	$2.4432	$859,388
Street Lighting		kWh	8,853	$1.8427	$16,313
Sentinel Lighting		kW	858	$1.8520	$1,589
Unmetered Scattered Load		kW	508,273	$0.0060	$3,050
Hydro One		kWh	32,710,359		$0
TOTAL					$2,299,538

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**	**2011**		
Residential		kWh	155,501,434	$0.0041	$637,556
General Service < 50 kW		kW	65,481,363	$0.0036	$235,733
General Service 50 to 4,999 kW		kW	351,747	$1.4256	$501,451
Street Lighting		kWh	8,853	$1.1021	$9,757
Sentinel Lighting		kW	858	$1.1251	$965
Unmetered Scattered Load		kW	508,273	$0.0036	$1,830
Hydro One		kWh	32,710,359		$0
TOTAL					$1,387,291

Wholesale Market Service					
Class per Load Forecast			**2011**		
Residential			155,501,434	$0.0052	$808,607
General Service < 50 kW			65,481,363	$0.0052	$340,503
General Service 50 to 4,999 kW			141,362,294	$0.0052	$735,084
Street Lighting			3,207,932	$0.0052	$16,681
Sentinel Lighting			348,089	$0.0052	$1,810
Unmetered Scattered Load			508,273	$0.0052	$2,643
Hydro One			32,710,359	$0.0052	$170,094
TOTAL			399,119,743		$2,075,423

Rural Rate Assistance					
Class per Load Forecast			**2011**		
Residential			155,501,434	$0.0013	$202,152
General Service < 50 kW			65,481,363	$0.0013	$85,126
General Service 50 to 4,999 kW			141,362,294	$0.0013	$183,771
Street Lighting			3,207,932	$0.0013	$4,170
Sentinel Lighting			348,089	$0.0013	$453
Unmetered Scattered Load			508,273	$0.0013	$661
Hydro One			32,710,359	$0.0013	$42,523
TOTAL			399,119,743		$518,856

	2011
4705-Power Purchased	$26,772,071
4708-Charges-WMS	$2,075,423
4714-Charges-NW	$2,299,538
4716-Charges-CN	$1,387,291
4730-Rural Rate Assistance	$518,856
4750-Low Voltage	$251,001

TOTAL	33,304,179

2012 Load Foreacst	kWh	kW	2010 %RPP
Residential	147,876,185		85%
General Service < 50 kW	61,468,712		82%
General Service 50 to 4,999 kW	132,412,296	348,158	18%
Street Lighting	2,986,427	8,709	99%
Sentinel Lighting	331,979	864	100%
Unmetered Scattered Load	467,056		100%
Hydro One	30,955,199		0%
TOTAL	376,497,854	357,731	

Electricity - Commodity RPP	**2012 Forecasted**	**2012 Loss Factor**			
Class per Load Forecast RPP				**2012**	
Residential	125,694,757	1.0550	132,607,969	$0.07298	$9,677,730
General Service < 50 kW	50,404,344	1.0550	53,176,583	$0.07298	$3,880,827
General Service 50 to 4,999 kW	23,834,213	1.0550	25,145,095	$0.07298	$1,835,089
Street Lighting	2,956,563	1.0550	3,119,174	$0.07298	$227,637
Sentinel Lighting	331,979	1.0550	350,238	$0.07298	$25,560
Unmetered Scattered Load	467,056	1.0550	492,744	$0.07298	$35,960
Hydro One	0	1.0550	0	$0.07298	$0
TOTAL	203,688,912		214,891,802		$15,682,804

Electricity - Commodity Non-RPP	**2012 Forecasted**	**2012 Loss Factor**			
Class per Load Forecast				**2012**	
Residential	22,181,428	1.0550	23,401,406	$0.06837	$1,599,954
General Service < 50 kW	11,064,368	1.0550	11,672,908	$0.06837	$798,077
General Service 50 to 4,999 kW	108,578,083	1.0550	114,549,877	$0.06837	$7,831,775
Street Lighting	29,864	1.0550	31,507	$0.06837	$2,154
Sentinel Lighting	0	1.0550	0	$0.06837	$0
Unmetered Scattered Load	0	1.0550	0	$0.06837	$0
Hydro One	30,955,199	1.0550	32,657,735	$0.06837	$2,232,809
TOTAL	172,808,942		149,655,699		$12,464,769

Transmission - Network		**Volume Metric**			
Class per Load Forecast				**2012**	
Residential		kWh	156,009,375	$0.0064	$998,460
General Service < 50 kW		kWh	64,849,491	$0.0058	$376,127
General Service 50 to 4,999 kW		kW	348,158	$2.3614	$822,140
Street Lighting		kW	8,709	$1.7810	$15,511
Sentinel Lighting		kW	864	$1.7900	$1,547
Unmetered Scattered Load		kWh	492,744	$0.0058	$2,858
Hydro One		kWh	32,657,735	$0.0058	$189,415
TOTAL					$2,406,057

Transmission - Connection		**Volume Metric**			
Class per Load Forecast				**2012**	
Residential		kWh	156,009,375	$0.0035	$546,033
General Service < 50 kW		kWh	64,849,491	$0.0031	$201,033
General Service 50 to 4,999 kW		kW	348,158	$1.2237	$426,041
Street Lighting		kW	8,709	$0.9460	$8,239
Sentinel Lighting		kW	864	$0.9658	$834
Unmetered Scattered Load		kWh	492,744	$0.0031	$1,528
Hydro One		kWh	32,657,735	$0.0031	$101,239
TOTAL					$1,284,947

Wholesale Market Service					
Class per Load Forecast				**2012**	
Residential			156,009,375	$0.0052	$811,249
General Service < 50 kW			64,849,491	$0.0052	$337,217
General Service 50 to 4,999 kW			139,694,972	$0.0052	$726,414
Street Lighting			3,150,680	$0.0052	$16,384
Sentinel Lighting			350,238	$0.0052	$1,821
Unmetered Scattered Load			492,744	$0.0052	$2,562
Hydro One			32,657,735	$0.0052	$169,820
TOTAL			397,205,236		$2,065,467

Rural Rate Assistance					
Class per Load Forecast				**2012**	
Residential			156,009,375	$0.0013	$202,812
General Service < 50 kW			64,849,491	$0.0013	$84,304
General Service 50 to 4,999 kW			139,694,972	$0.0013	$181,603
Street Lighting			3,150,680	$0.0013	$4,096
Sentinel Lighting			350,238	$0.0013	$455
Unmetered Scattered Load			492,744	$0.0013	$641
Hydro One			32,657,735	$0.0013	$42,455
TOTAL			397,205,236		$516,367

	2012
4705-Power Purchased	$28,147,573
4708-Charges-WMS	$2,065,467
4714-Charges-NW	$2,406,057
4716-Charges-CN	$1,284,947
4730-Rural Rate Assistance	$516,367
4750-Low Voltage	$296,427

TOTAL	34,716,838

EXHIBIT 2

APPENDIX C

Norfolk Green Energy Plan

Basic Green Energy Act Plan

Norfolk Power Distribution Inc.

July 8, 2011

1. Current Assessment

Norfolk Power Distribution Inc. (NPDI) is a small, Local Distribution Company (LDC), with a service area of approximately 693 square kilometres, including 144 square kilometres of high density urban area and 549 square kilometres of low density rural area. NPDI is responsible for providing all regulated electricity distribution services to over 19,000 residential and commercial customers.

This Basic Green Energy Act ("GEA") Plan has been prepared in accordance with the Ontario Energy Board's Filing Requirements (EB-2009-0397). The GEA Plan is based on current information and presents a five year perspective of NPDI's plans for its distribution system to connect and integration renewable generation facilities.

NPDI distributes power from the Bloomsburg (NPDI owned) and Norfolk (Hydro One owned) transformer stations at 27.6kV. NPDI also owns 12 Distribution Stations that supply customers at 8.32kV and 4.16kV.

To date, NPDI has connected 28 solar photovoltaic rooftop and non-rooftop renewable generator projects throughout its territory within both the urban and rural areas. The majority of MicroFIT connections/applications are for 10kW solar PV. Small FIT projects are typically 50kW or 100kW in size whereas mid-Size generation projects tend to be either 500kW or 10MW. Small and mid size generators have expressed interest in a few different technologies including Solar PV (rooftop and ground mounted), Wind (on-shore) and Biogas.

Currently, NPDI does not have capacity limitations on its feeders or at Bloomsburg MTS. NPDI has completed anti-islanding capacity analysis for connection of Micro-generation projects (see Table 1. below) and is continuing to monitor areas of high "generation to minimum load" ratio line sections for changes power quality. NPDI is also closely reviewing applications for small and mid-size generation projects through CIA's and capacity analysis. FIT Projects (>10kW) and feeder capacities are outlined in Table 2. below.

Norfolk County is of particular interest to renewable generators as the region plays favourably to wind technology with its proximity to Lake Erie, and to large, ground mounted solar generators as acreage with limited solar obstructions may be available. Potential circumstances that could limit renewable generation connections include anti-islanding measures on lightly loaded feeders, reverse power flow limitations, Transformer/Distribution Station thermal capacity and short circuit capacity.

Summary of Renewable Connection Projects Statistics

As of June 30, 2011, the following NPDI renewable generation statistics are available:

MicroFIT Applications to OPA: 155 (1506kW)
MicroFIT Contracts Issued by OPA: 25
MicroFIT Generator Requests to NPDI for Connection (from 01JAN2011): 72
MicroFIT NPDI Offers to Connect Issued (from 01JAN2011): 39
MicroFIT Generators Connected (from 01JAN2011): 12
FIT Applications (from the OPA FAME application): 14
FIT Generator Requests for CIA: 8
FIT CIA's completed: 6

The current forecast for 2011 MicroFIT projects are based on the following:

Estimated Number of Offers to Connect Issued: 100
Estimated Number of Generators Connected: 50 (based on 50% of number of offers to connect)
Estimated Basic Connection Charge per Generator Connection: $1,266
Estimated Expansion Cost per Connection (limited to 30% of Generator Connections): $5,180
Estimated Total Generator Connection Costs for 2011: $141,000

The current forecast for 2011 FIT projects (<=250kW) is based on the following:

Estimated Number of Generators Connected: 6
Estimated Basic Connection Charge per Generator Connection: $5,330
Estimated Expansion Cost per Connection: $2,330
Estimated Total Generator Connection Costs for 2011: $46,000

The current forecast for 2011 FIT projects (>250kW but <=10MW) is based on the following:

Estimated Number of Generators Connected: 2
Estimated Enhancement Cost: $122,000
Estimated Expansion Cost per Generator Connection: $33,000
Estimated Total Generator Connection Costs for 2011: $188,000

Table 1. MicroFIT Project Capacity and Feeder Anti-Islanding Limiting Capacity

Transformer Station[1]	Feeder[1]	Distribution Station[1]	Feeder[1]	Capacity (kW)	kW Connected	kW Proposed[2]
Bloomsburg MTS (NPDI)	M1			1181.82	-	10
		NP1	F1	94.46	-	-
			F2	79.67	-	10
		NP2	F1	70.64	-	-
			F2	91.62	-	-
	M2			577.1	10	10
		NP3	F3	123.13	-	-
			F4	96.92	-	-
		NP5	F1	81.34	-	-
			F2	65.64	-	-
			F4	128.88	-	-
	M3			625.33	10	20
		NP11	F1	121.95	-	-
			F2	70.24	-	-
		NP12	F1	101.17	-	3.5
			F2	41.70	-	-
		NP13	F1	61.48	-	-
	M4	-	-	-	-	-
	M5	-	-	-	-	-
	M6	-	-	-	-	-
Norfolk TS (HO)	22M1 (HO)	NP8 (NPDI)	F1	172.15	-	-
			F2	204.54	-	-
			F3	39.63	-	-
		NP9 (NPDI)	F1	100.35	-	-
			F2	46.92	-	-
	22M2 (HO)			-	-	10
	22M3 (HO)	St. Williams (HO)	F2	88.81*	-	10
	22M5 (NPDI)			262.70	30	10
		NP4	F1	100.23	40	10
			F2	261.71	10	30
		NP6	F1	160.40	-	-
			F2	113.25	-	-
			F3	81.91	10	-
	22M6 (HO/NPDI)			896.23*	20	130
		Waterford (HO)	F1	237.37*	39.5	60
			F2	112.32*	-	30
		Wilsonville (HO)	F1	23.98*	-	10
			F2	175.59*	57	50
		NP10 (NPDI)	F1	86.14	10	-
			F2	22.78	-	-

Notes :

1. Ownership of Station/Feeder denoted by NPDI (Norfolk Power Distribution Inc.) or HO (Hydro One) if not indicated ownership is as per next upstream asset.
2. Capacity only includes customers that have been sent an offer to connect.

* Estimated minimum load of NPDI customers only (other LDC customer load data not included)

Table 2. Renewable Generation (>10kW) Projects and Feeder Capacity

Transformer Station[1]	Feeder[1]	Distribution Station[1]	Feeder[1]	Capacity (kVA)	kW Connected	kW Proposed[2]
Bloomsburg MTS (NPDI)	M1			6,624	-	-
		NP1	F1	748	-	-
			F2	748	-	-
		NP2	F1	748	-	-
			F2	748	-	-
	M2			6,624	-	-
		NP3	F3	748	-	-
			F4	748	-	-
		NP5	F1	499	-	-
			F2	748	-	-
			F4	748	-	-
	M3			6,624	-	100
		NP11	F1	1,497	-	-
			F2	1,497	-	-
		NP12	F1	1,497	-	-
			F2	1,497	-	-
		NP13	F1	1,497	-	-
	M4	-	-	-	-	-
	M5	-	-	-	-	-
	M6	-	-	-	-	-
Norfolk TS (HO)	22M1 (HO)			-	-	1000
		NP8 (NPDI)	F1	1,497	-	-
			F2	1,497	-	-
			F3	1,497	-	-
		NP9 (NPDI)	F1	1,497	-	-
			F2	1,497	-	-
	22M2 (HO)			-	-	-
	22M3 (HO)	St. Williams (HO)	F2	-	-	-
	22M5 (NPDI)			-	9100**	10150
		NP4	F1	1,497	-	-
			F2	1,497	-	-
		NP6	F1	1,497	-	-
			F2	1,497	-	-
			F3	1,497	-	-
	22M6 (HO/NPDI)			-	-	-
		Waterford (HO)	F1	-	-	-
			F2	-	-	-
		Wilsonville (HO)	F1	-	-	-
			F2	-	-	-
		NP10 (NPDI)	F1	748	-	100
			F2	748	-	-

Notes :

1. Ownership of Station/Feeder denoted by NPDI (Norfolk Power Distribution Inc.) or HO (Hydro One) if not indicated ownership is as per next upstream asset.
2. Capacity only includes customers that have engaged in the CIA process.

* Estimated minimum load of NPDI customers only (other LDC customer load data not included)

** Renewable Project not connected under the FIT Program.

2. Planned Evolution of the System to Accommodate Renewable Generation Connections

In planning for future connection of renewable generation projects, NPDI has met with interested potential generator customers, Norfolk County and other neighbouring Utilities (Hydro One and Haldimand County Hydro). Load growth in the NPDI territory is expected to be fairly small and remains one of the contributing factors for capacity limitations however peak system loads coincide with peak production from solar generation projects (the majority of renewable projects in the NPDI service territory are solar energy fuelled). The plan includes system expansions and enhancements necessary to safely connect renewable generators while maintaining power system quality expectations for existing load customers. NPDI is in the process of standardizing its approach to connecting renewable generators to streamline the practice through standardized application forms, cost assessments and technical requirements documentation. This will help identify and simplify the process for potential generators to improve cost estimation accuracy and reduce the time from conception to connection.

Summary of Forecasted Expenditures

Tables 3 and 4 below summarize the forecasted expenditure estimates including expansions and enabling costs as well as the quantity and size (in MW) for renewable generation connections anticipated over the five year period respectively. These are based on data from the OPA LDC Admin and FAME web applications as well as discussions and pre-fit consultations with potential generator customers.

Table 3. Summary of Projects Capital Expenditures

Projects – CapEx	2012	2013	2014	2015	2016
	Cost	Cost	Cost	Cost	Cost
Renewable Connections (≤10kW)	$141,000	$113,000	$85,000	$56,000	$28,000
Renewable Connections (>10kW to ≤250kW)	$46,000	$38,000	$38,000	$31,000	$23,000
Renewable Connections (>250kW)	$832,000	$461,000	$416,000	$90,000	$45,000
Gross Cost	**$1,019,000**	**$612,000**	**$539,000**	**$177,000**	**$96,000**
Net Generator Contribution	-$261,500	-$200,200	-$143,900	-$112,600	-$56,300
Net NPDI Cost	**$757,500**	**$411,800**	**$395,100**	**$64,400**	**$39,700**

Table 4. Quantity and Size (MW) of Renewable Generator Connections Anticipated

Projects	**2012**		**2013**		**2014**		**2015**		**2016**	
	#	**MW**	**#**	**MW**	**#**	**MW**	**#**	**MW**	**#**	**MW**
Renewable Connections (≤10kW)	50	0.5	40	0.4	30	0.3	20	0.2	10	0.1
Renewable Connections (>10kW to ≤250kW)	6	0.5	5	0.4	5	0.4	4	0.35	3	0.25
Renewable Connections (>250kW)	4	21	3	11	2	10.5	2	1	1	0.5
Total	**60**	**22**	**48**	**11.8**	**37**	**11.2**	**26**	**1.55**	**14**	**0.85**

EXHIBIT 2

APPENDIX D

OPA Letter of Comment

OPA Letter of Comment:

Norfolk Power Distribution Inc.

Basic Green Energy Act Plan

August 11, 2011

ONTARIO POWER AUTHORITY

Introduction

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

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

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

Norfolk Power Distribution Inc. Basic Green Energy Act Plan

On July 12, 2011, the OPA received a Basic GEA Plan from Norfolk Power Distribution Inc. ("NDPI"). The OPA has reviewed NDPI's Plan and has provided its comments below.

OPA FIT/microFIT Applications Received

NDPI's Plan identifies 14 FIT applications and 155 microFIT applications received as of June 30, 2011. These have been itemized in the Summary of Renewable Connection Projects Statistics starting on page 2 of the Plan.

To date, the OPA has received 32 capacity allocation exempt FIT applications, 3 capacity allocation required FIT applications and 159 microFIT applications to NDPI's system for a total of 33.59 MW of FIT applications and 1.546 MW of microFIT applications. At this time, 30 microFIT applications have been connected and 22 microFIT applications have been terminated (leaving a total of 1.0393 MW of microFIT applications to be connected).

Upstream Transmission Constraints

There are no currently known transmission constraints applicable to NDPI's system.

Economic Connection Test Results

There has been no Economic Connection Test performed to date.

Opportunities for Integrated Solutions

There are no known corresponding expansions among neighbouring LDCs that could be addressed through integrated transmission solutions at this time.

Conclusion

The OPA finds that the GEA Plan as filed is reasonably consistent with the OPA's information regarding renewable energy generation applications to date in terms of the number of microFIT applications received. However, the OPA notes that it has received some additional capacity allocation exempt FIT applications as noted above, which have not yet been posted on the FAME website.

The OPA appreciates the opportunity to comment on NDPI's Basic GEA Plan.

OVERVIEW OF OPERATING REVENUE:

This Exhibit provides the details of NPDI’s operating revenue for 2008 Actual, 2008 Board Approved, 2009 Actual, 2010 Actual, the 2011 Bridge Year and the 2012 Test Year. This Exhibit also provides a detailed variance analysis by rate class of the operating revenue components. Distribution revenue does not include revenue from commodity sales.

A summary of operating revenues is presented in Exhibit 3, Tab 1, Schedule 2.

Throughput Revenue:

Information related to NPDI’s throughput revenue includes details such as weather normalized forecasting methodology, normalized volume based on historical number of customers billed throughout the year and CDM adjustments and known economic conditions. Detailed variance analysis on the throughput revenue is set out in Exhibit 3, Tab 2, Schedule 1.

Other Revenue:

Other revenues include Late Payment Charges, Miscellaneous Service Revenues and Retail Services Revenues, to name a few. A summary of these operating revenues together with a materiality analysis of variances is presented in Exhibit 3, Tab 3, Schedules 1 and 2.

Table 1.1 SUMMARY OF OPERATING REVENUE

	2008 Board Approved	2008 Actual	Variance from 2008 Board Approved	2009 Actual	Variance from 2008 Actual	2010 Actual	Variance from 2009 Actual	2011 Bridge	Variance from 2010 Actual	2012 Test	Variance from 2011 Bridge
DISTRIBUTION REVENUE											
Residential	6,999,229	6,310,348	(688,881)	6,902,951	592,603	6,921,061	18,110	7,001,919	80,858	7,068,910	66,991
GS<50kW	2,106,142	1,839,471	(266,671)	2,114,481	275,010	2,042,648	(71,833)	2,057,500	14,852	2,044,594	(12,906)
GS>50kW	1,828,666	1,509,034	(319,632)	1,812,097	303,063	1,687,648	(124,449)	1,751,389	63,740	1,738,366	(13,023)
Streetlight	99,602	74,783	(24,819)	142,748	67,965	159,296	16,548	146,737	(12,559)	145,864	(873)
Sentinel Light	21,275	16,512	(4,763)	42,059	25,547	43,303	1,244	43,812	509	44,143	331
Unmetered Scattered Load	20,465		(20,465)			139	139	31,381	31,242	30,854	(526)
Embedded Distributor									$ -	$ -	$ -
Total	11,075,379	9,750,148	(1,325,231)	11,014,336	1,264,188	10,854,096	(160,240)	11,032,737	178,642	11,072,731	39,993
											$ -
OTHER DISTRIBUTION REVENUE											$ -
SSS Administration Charge*								57,742	57,742	57,909	167
Late Payment Charges	101,500	124,516	23,016	155,219	30,703	86,593	(68,626)	138,000	51,407	138,000	$ -
Specific Service Charges	243,800	95,702	(148,098)	89,927	(5,775)	101,896	11,969	88,000	(13,896)	88,000	$ -
Other Distribution Revenue	10,000	90,227	80,227	96,051	5,824	97,285	1,234	97,500	215	97,500	$ -
Other Income and Expenses	108,700	117,626	8,926	75,164	(42,462)	132,795	57,631	147,454	14,659	95,880	(51,574)
Total	464,000	428,071	(35,929)	416,361	(11,710)	418,569	2,208	528,696	110,127	477,289	(51,407)
											$ -
Grand Total	11,539,379	10,178,219	(1,361,160)	11,430,697	1,252,478	11,272,665	(158,032)	11,561,433	288,769	11,550,020	(11,414)

VARIANCE ANALYSIS ON OPERATING REVENUE:

NPDI's 2012 distribution revenue has been calculated using its most recently approved rates. In particular, delivery rates are based on the rate order from NPDI's 2011 IRM application, EB-2011-0049 dated May 6 2011. As noted above, distribution revenue does not include commodity-related revenue.

A summary of normalized operating revenues is presented in Exhibit 3, Tab 1, Schedule 2.

2008 Board Approved:

NPDI's 2008 Board Approved operating revenue was forecast to be $11,539,379 as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $11,075,379 of total revenues. Other operating revenue (net) accounts for the remaining revenue of $464,000.

2008 Actual:

NPDI's operating revenue in fiscal 2008 was $10,178,219 as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $9,750,148 or 95.8% of total revenues. Other operating revenue (net), accounts for the remaining revenue of $428,071.

Comparison to 2008 Board Approved:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $1,361,160 lower than the 2008 Board Approved level forecasted. The distribution revenue accounted for $1,325,231of this difference. This is primarily a result of late implementation of rates. Although rates were made effective July 1 2008, the new rates were not implemented until September 1st. Also 2008 consumption was lower than the forecast approved in the 2008 rate application.

2009 Actual:

NPDI's operating revenue in fiscal 2009 was $11,430,697, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totaled $11,014,336 or 96.4% of total revenues. Other operating revenue (net), accounts for the remaining revenue of $416,361.

Comparison to 2008 Actual*:*

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $1,264,188 higher than the 2008 actual operating revenue. This increase of $1,264,188 resulted from increased distribution rates for the entire year, including a foregone distribution rate rider for the period January through April. The decrease in other revenue of $(11,710) is immaterial.

2010 Actual:

NPDI's operating revenue in fiscal 2010 was $11,272,665, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $10,854,096 or 96.3% of total revenues. Other operating revenue accounts for the remaining revenue of $418,569.

Comparison to 2009 Actual:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue was $ (158,032) lower than the actual year level in fiscal 2009. The difference in distribution revenue of $160,240 is mostly attributable to the fact 2009 had four months of increased distribution rates, carried forward from the 2008 COS rate application. In addition customer numbers in the GS<50kW has declined slightly as has the number of kW billed in the GS>50kW class due to declining economic activity.

2011 Bridge Year:

NPDI's operating revenue is forecast to be $11,561,433 in fiscal 2011, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $11,032,737 or 95.5% of total revenue. Other operating revenue accounts for the remaining $528,696.

Comparison to 2010 Actual:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue is expected to be $284,769 above the actual year level in 2010. The portion of the increase pertaining to distribution revenues is $178,642, of which approximately $81,000 relates to residential customers and $63,500 relates to GS>50kW customers. The remaining $110,127 increase relates to other operating revenues.

2012 Test Year:

NPDI's operating revenue is forecast to be $11,550,020 in fiscal 2012, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $11,072,731 or 95.9% of total revenue. Other operating revenue accounts for the remaining $477,289.

Comparison to 2011 Bridge:

As shown in Exhibit 3, Tab 1, Schedule 2, the total operating revenue for 2012 is expected to be ($11,414) below the forecasted Bridge Year 2011. Although overall distribution revenues are expected to increase by approximately $40,000 over 2011, other revenues are expected to decrease by approximately $51,000. The decrease relates to "other income and expenses" which will be discussed further in Exhibit 3, Tab 2, Schedule 2.

WEATHER NORMALIZED LOAD AND CUSTOMER/CONNECTION FORECAST

The purpose of this evidence is to present the process used by Norfolk Power to prepare the weather normalized load and customer/connection forecast used to design the proposed 2012 electricity distribution rates.

In summary, Norfolk Power has used the same regression analysis methodology previously used by a number of distributors in their cost of service rate applications to determine a prediction model. With regard to the overall process of load forecasting, Norfolk Power submits that conducting a regression analysis on historical electricity purchases to produce an equation that will predict purchases is appropriate. Norfolk Power has the data for the amount of electricity (in kWh) purchased from the IESO for use by Norfolk Powers customers. With a regression analysis, these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The results of the regression analysis produce an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for Norfolk Power for the Bridge Year and the Test Year which is converted to billed kWh by rate class. A detailed explanation of the process is provided later in this evidence.

During proceedings related to the 2009 and 2010 cost of service applications for a number of other distributors, intervenors expressed concerns with the load forecasting process that was proposed at the time by those distributors. For the 2009 cost of service applications, intervenors suggested the regression analysis should be conducted on an individual rate class basis and the regression analysis would be based on monthly billed kWh by rate class. Norfolk Power submits that conducting a regression analysis which relates the monthly billed kWh of a class to other monthly variables is problematic. The monthly billed amount does not reflect the amount consumed in the month. Rather, it reflects the amount billed. The amount billed is based on billing cycle meter reading schedules whose reading dates vary and typically are not at month end. The amount billed could include consumption from the prior month or even earlier. Using a regression analysis to relate rate class billing data to a variable such as heating degree days does not appear to be reasonable, since the resulting regression model would attempt to relate heating degree days in a month to the amount billed in the month, not the amount consumed. In Norfolk Powers view, variables such as heating degree days impact the amount consumed and not the amount billed. It is possible to estimate the amount consumed in a month based on the amount billed, but until smart meters are fully deployed this would only be an estimate. This would reduce the accuracy of a regression model that is based on monthly billing data.

In addition, Norfolk Power understands that a number of 2010 cost of service applicants attempted to conduct the regression analysis on a rate class basis but were unsuccessful in achieving reasonable results that could be used in the load forecasting process. Conducting the regression analysis on purchases provides better results since a higher level of historical data increases the accuracy of the regression analysis.

Norfolk Power understands that to a certain degree the process of developing a load forecast for a cost of service rate application is an evolving science for electricity distributors in the province. During the review of 2010 cost of service applications, Board staff and intervenors expressed concern that the regression analysis assigned coefficients to some variable that were counter intuitive. For example, the customer variable would have a negative coefficient assigned to it which meant as the number of customers increased the energy forecast decreased. 2010 applicants explained that this was related to the recent Conservation and Demand Management (“CDM”) savings in the utility but in the view of Board staff and intervenors this was not a sufficient explanation. Further, the regression analysis indicated that some of the variables used in the load forecasting formula were not statistically significant and should not have been included in the equation. Norfolk Power has attempted to address these concerns in the load forecast used in this Application. However, Norfolk Power expects to include additional improvements to the load forecasting methodology in future cost of service rate applications by: i) taking into consideration data provided by smart meters; and ii) evaluating how others will conduct load forecasts in future cost of service rate applications. Based on the OEB’s approval of this methodology in previous applications, and based on the discussion that follows, Norfolk

Power submits that its load forecasting methodology is reasonable at this time for the purposes of this Application.

The following provides the material to support the weather normalized load forecast used by Norfolk Power in this Application.

Table 2.1 - Summary of Load and Customer/Connection Forecast

Year	Billed (GWh)	Growth (GWh)	Percent Change	Customer/ Connection Count	Growth	Percent Change (%)
Billed Energy (GWh) and Customer Count / Connections						
2008 Board Approved	405.1			22,373		
2003 Actual	349.0			21,774		
2004 Actual	352.6	3.5	1.0%	21,963	189.0	0.9%
2005 Actual	360.0	7.4	2.1%	22,229	266.0	1.2%
2006 Actual	349.3	(10.6)	(3.0%)	22,493	264.5	1.2%
2007 Actual	351.9	2.6	0.7%	22,734	240.5	1.1%
2008 Actual	345.9	(5.9)	(1.7%)	22,954	220.0	1.0%
2009 Actual	336.9	(9.0)	(2.6%)	23,104	150.5	0.7%
2010 Acutal	338.6	1.7	0.5%	23,188	84.0	0.4%
2011 Normalized Bridge Year	**346.6**	**7.9**	**2.3%**	**23,401**	**212.8**	**0.9%**
2012 Normalized Test Year	**345.4**	**(1.2)**	**(0.3%)**	**23,616**	**215.6**	**0.9%**

Notes:

2003 to 2010 are weather actual, while 2011 and 2012 are weather normalized. Norfolk Power does not have a process to adjust weather actual data to a weather normal basis. However, based on the process outlined in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and used in this Application.

Total Customers and Connections are on a mid-year basis and streetlight, sentinel lights and unmetered loads are measured as connections.

Actual and forecasted billed amounts and numbers of customers are shown in Table 2.2 and customer usage is shown in Table 2.3, on a rate class basis.

Table 2.2 - Billed Energy and Number of Customers / Connections by Rate Class

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Total
Billed Energy (GWh)							
2008 Board Approved	147.4	64.1	189.8	3.1	0.3	0.4	405.1
2003 Actual	137.5	64.2	142.9	3.5	0.3	0.6	349.0
2004 Actual	136.3	65.0	147.0	3.5	0.3	0.5	352.6
2005 Actual	144.7	66.6	144.4	3.4	0.3	0.5	360.0
2006 Actual	140.0	63.2	142.2	3.1	0.3	0.5	349.3
2007 Actual	142.5	65.1	140.3	3.1	0.3	0.5	351.9
2008 Actual	140.6	63.6	137.8	3.1	0.3	0.5	345.9
2009 Actual	139.4	60.5	133.1	3.1	0.3	0.5	336.9
2010 Acutal	141.9	60.5	132.0	3.4	0.4	0.5	338.6
2011 Normalized Bridge Year	**147.3**	**62.0**	**133.0**	**3.4**	**0.4**	**0.5**	**346.6**
2012 Normalized Test Year	**148.1**	**61.5**	**131.5**	**3.4**	**0.4**	**0.5**	**345.4**
Number of Customers/Connections							
2008 Board Approved	16,607	2,058	166	3,091	400	51	22,373
2003 Actual	15,299	2,084	159	3,775	378	79	21,774
2004 Actual	15,513	2,059	163	3,775	374	80	21,963
2005 Actual	15,773	2,040	160	3,797	380	80	22,229
2006 Actual	16,014	2,025	161	3,819	397	78	22,493
2007 Actual	16,250	2,021	165	3,819	402	77	22,734
2008 Actual	16,462	2,036	164	3,819	396	77	22,954
2009 Actual	16,600	2,037	166	3,819	406	77	23,104
2010 Acutal	16,711	2,017	166	3,819	400	77	23,188
2011 Normalized Bridge Year	**16,923**	**2,007**	**166**	**3,825**	**403**	**76**	**23,401**
2012 Normalized Test Year	**17,138**	**1,998**	**167**	**3,832**	**406**	**76**	**23,616**

Table 2.3 - Annual Usage per Customer/Connection by Rate Class

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Energy Usage per Customer/Connection (kWh per customer/connection)						
2008 Board Approved	8,876	31,147	1,143,373	1,003	750	7,843
2003 Actual	8,990	30,834	898,651	917	819	7,704
2004 Actual	8,787	31,552	901,728	927	812	6,849
2005 Actual	9,176	32,664	905,095	898	808	6,756
2006 Actual	8,740	31,238	883,145	801	864	6,859
2007 Actual	8,772	32,205	853,030	802	839	6,828
2008 Actual	8,544	31,238	840,174	805	839	6,578
2009 Actual	8,395	29,721	804,265	808	818	6,444
2010 Acutal	8,489	29,999	797,457	895	905	6,475
2011 Normalized Bridge Year	**8,705**	**30,893**	**798,863**	**892**	**918**	**6,317**
2012 Normalized Test Year	**8,640**	**30,793**	**785,648**	**889**	**932**	**6,162**
Annual Growth Rate in Usage per Customer/Connection						
2008 Board Approved v 2008 Actual	3.9%	(0.3%)	36.1%	24.6%	(10.7%)	19.2%
2003 Actual						
2004 Actual	(2.3%)	2.3%	0.3%	1.0%	(0.9%)	(11.1%)
2005 Actual	4.4%	3.5%	0.4%	(3.1%)	(0.5%)	(1.4%)
2006 Actual	(4.8%)	(4.4%)	(2.4%)	(10.7%)	6.9%	1.5%
2007 Actual	0.4%	3.1%	(3.4%)	0.0%	(2.9%)	(0.5%)
2008 Actual	(2.6%)	(3.0%)	(1.5%)	0.4%	0.1%	(3.7%)
2009 Actual	(1.7%)	(4.9%)	(4.3%)	0.4%	(2.6%)	(2.0%)
2010 Acutal	**1.1%**	**0.9%**	**(0.8%)**	**10.8%**	**10.7%**	**0.5%**
2011 Normalized Bridge Year	**2.5%**	**3.0%**	**0.2%**	**(0.3%)**	**1.4%**	**(2.5%)**
2012 Normalized Test Year	**(0.7%)**	**(0.3%)**	**(1.7%)**	**(0.3%)**	**1.4%**	**(2.5%)**

LOAD FORECAST AND METHODOLOGY

Norfolk Power weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates historical load, weather, calendar related events, economic activity and CDM savings. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. The forecast of customers by rate class is determined using a geometric mean analysis. For those rate classes that use kW for the distribution volumetric billing determinant, an adjustment factor is applied to class energy forecast based on the historical relationship between kW and kWh.

A detailed explanation of the load forecasting process follows.

Purchased KWh Load Forecast

An equation to predict total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days); calendar variables (days in month, seasonal) and the local economic activity in the Haldimand-Norfolk area. The regression model uses monthly kWh and monthly values of independent variables from January 2003 to December 2010 to determine the monthly regression coefficients. This provides 96 monthly data points - this represents a reasonable data set for use in a regression analysis. Based on the recent global activity surrounding climate change, historical weather data is showing that there is a warming of the global climate system. In this regard, Norfolk Power submits that it is appropriate to review the impact of weather since 2003 on the energy usage and then determine the average weather conditions from January 2003 to December 2010 which would be applied in the forecasting process to determine a weather normalized forecast. However, in accordance with the OEB’s Filing Requirements, Norfolk Power has also provided a sensitivity analysis showing the impact on the 2011 forecast of purchases assuming weather normal conditions are based on a 10-year average and a 20-year trend of weather data.

The multifactor regression model has determined drivers of year-over-year changes in Norfolk Powers load growth; these include weather, “calendar” factors and local unemployment data. These factors are captured within the multifactor regression model.

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days (i.e. a measure of summer heat) are modeled.

The second main factor determining energy use in the monthly model can be classified as “calendar factors”. For example, the number of days in a particular month will impact energy use. The modeling of purchased energy uses number of days in the month and a “flag” variable to capture the typically lower usage in the spring months.

In the case of Norfolk Power, the remaining factor that impacts energy use is local unemployment. This data was found to be statistically relevant to the load forecast. For 2012, Norfolk Power has assumed a forecasted unemployment rate as the average for the actual unemployment rate for the period 2003 to 2010.

The following outlines the prediction model used by Norfolk Power to predict weather normal purchases for 2011 and 2012:

Norfolk Powers Monthly Predicted kWh Purchases

= Heating Degree Days * 9,579
+ Cooling Degree Days * 63,505
+ Number of Days in the Month * 627,772
+ Spring Fall Flag * (1,281,788)

+ Unemployment * (22,227,132)
+ Intercept of 9,092,511

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

The sources of data for the various data points are:

a) Environment Canada website for monthly heating degree day and cooling degree information. Weather data from the Delhi Weather Station was used.

b) The calendar provided information related to number of days in the month and the spring flag.

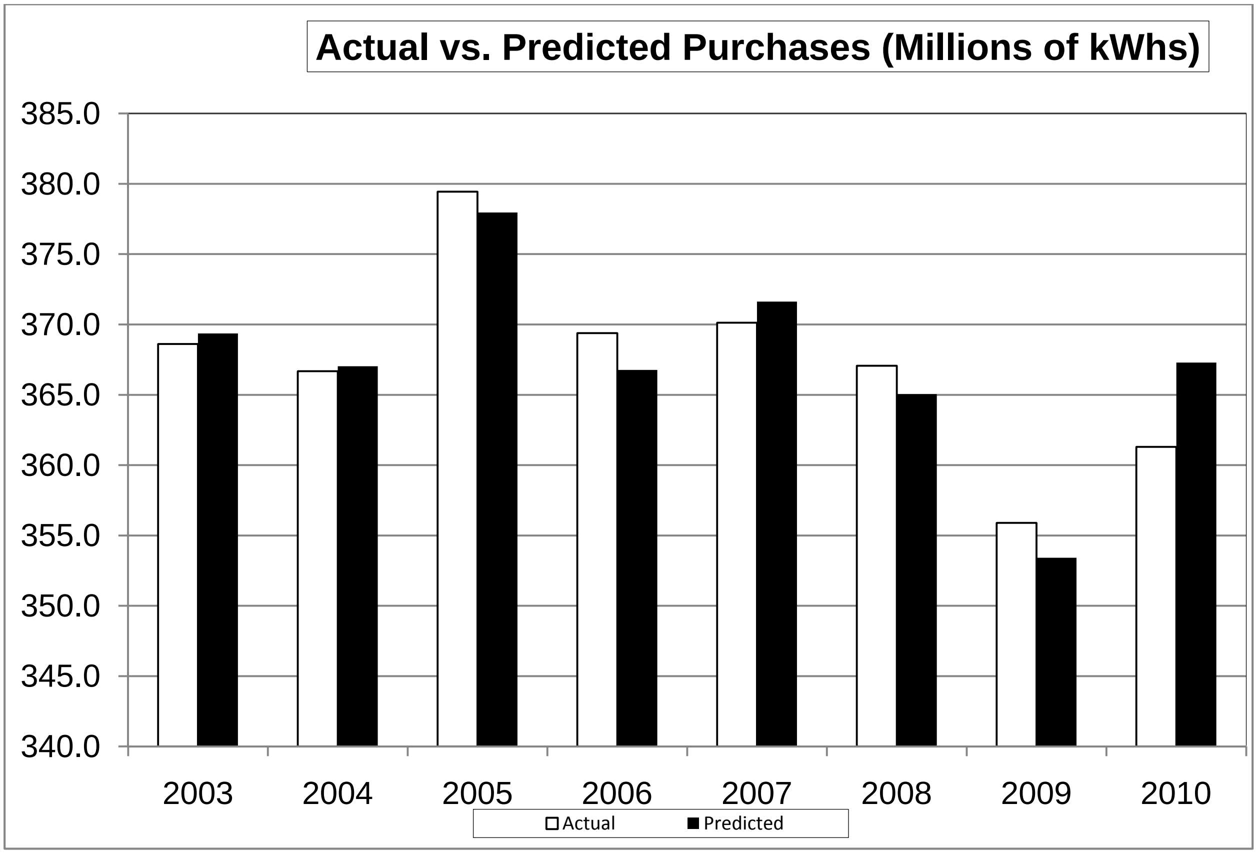
c) The local unemployment data for the Haldimand-Norfolk Health Unit was obtained from Statistics Canada's website through the CANSIM tool.

The prediction formula has the following statistical results:

Table 2.4 - Statistcial Results

Statistic	Value
R Square	84.6%
Adjusted R Square	83.8%
F Test	99.2
T-stats by Coefficient	
Intercept	2.3
Heating Degree Days	18.0
Cooling Degree Days	15.5
Number of Days in Month	4.8
Spring Flag	(5.1)
Unemployment	(3.5)

Norfolk Power is concerned with the R Square and Adjusted R Square results. Attempts to improve these results by adding additional variables such as Customers, Ontario Real GDP Monthly %, Ontario Tobacco Cash Activity and Number of Peak Hours, however, did not improve the results of the regression analysis. When the annual results of the above prediction formula compared to the actual annual purchases from 2003 to 2010 are reviewed, which are shown in the chart below, the resulting prediction equation appears to be reasonable.



The following table outlines the data that supports the above chart. In addition, the predicted total system purchases for Norfolk Power are provided for 2011 and 2012. In addition, values for 2011 are provided with a 10 year average and a 20 year trend assumption for weather normalization.

Table 2.5 - Total System Purchases Excluding Large Use

Year	Actual	Predicted	% Difference
Purchased Energy (GWh)			
2003	368.6	369.4	0.2%
2004	366.7	367.0	0.1%
2005	379.4	378.0	(0.4%)
2006	369.4	366.8	(0.7%)
2007	370.1	371.6	0.4%
2008	367.1	365.0	(0.5%)
2009	355.9	353.4	(0.7%)
2010	361.3	367.3	1.7%
2011 Normalized Bridge Year		**365.8**	
2012 Normalized Test Year		**364.5**	
2011 Weather Normal - 10 year average		**365.4**	
2011 Weather Normal - 20 year trend		**364.7**	

The weather normalized amount for 2012 is determined by using 2012 dependent variables in the prediction formula on a monthly basis together with the average monthly heating degree days and cooling degree days that occurred from January 2003 to December 2010 (i.e. eight years). The 2012 weather normalized 10 year average value represents the average heating degree days and cooling degree days that occurred from January 2001 to December 2010. The 2012 weather normalized 20 year trend value reflects the trend in monthly heating degree days and cooling degree days that occurred from January 1991 to December 2010.

The weather normal eight year average has been used as the purchased forecast in this Application for the purposes of determining a billed kWh load forecast which is used to design rates. The eight year average has been used as this is consistent with the period of time over which the regression analysis was conducted.

With regards to the impact of CDM, Norfolk Power has achieved CDM results since 2005 which are reflected in the actual historical purchased values from 2005 to 2010. Since the historical purchased values are used in the regression analysis the resulting prediction equations used for the forecast reflects a level of CDM savings. However, to fulfill the directive issued by the Minister of Energy & Infrastructure to the Ontario Energy Board on April 23, 2010, Norfolk

Power submits significant CDM savings from 2011 to 2014 will need to be achieved in order to meet the four year target of 15.68 GWhs set out in EB-2010-0215/EB-2010-0216, released by the OEB on November 12, 2010. The prediction equation will not reflect this level of savings since it is not included in the historical data supporting the equation. As a result, for 2011 a manual adjustment of 1.57 GWh, reflecting 10% of the four year target and a 2012 adjustment of 3.14 GWh reflecting 20% of the four year target, is made to the purchased forecast resulting from the prediction formula.

Billed KWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a historical loss factor of 5.55% reflecting the years over which the regression analysis was conducted.

With this average loss factor the total weather normalized billed energy will be 346.6 GWh for 2011 (i.e. 365.8/1.0555) and 345.3 GWh for 2012 (i.e. 364.5/1.0555).

Billed KWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in the following table.

Table 2.6 - Historical Customer/Connection Data

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	TOTAL
Number of Customers/Connections							
2003	15,299	2,084	159	3,775	378	79	21,774
2004	15,513	2,059	163	3,775	374	80	21,963
2005	15,773	2,040	160	3,797	380	80	22,229
2006	16,014	2,025	161	3,819	397	78	22,493
2007	16,250	2,021	165	3,819	402	77	22,734
2008	16,462	2,036	164	3,819	396	77	22,954
2009	16,600	2,037	166	3,819	406	77	23,104
2010	16,711	2,017	166	3,819	400	77	23,188

From the historical customer/connection data the growth rates in customers/ connections can be evaluated. The growth rates are provided in the following table. The geometric mean growth rate in number of customers is also provided. The geometric mean approach provides the average growth rate from 2003 to 2010.

Table 2.7 - Growth Rate in Customer/Connections

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Growth Rate in Customers/Connections						
2003						
2004	1.4%	(1.2%)	2.5%	0.0%	(1.1%)	0.6%
2005	1.7%	(0.9%)	(2.1%)	0.6%	1.6%	0.0%
2006	1.5%	(0.8%)	0.9%	0.6%	4.3%	(1.9%)
2007	1.5%	(0.2%)	2.2%	0.0%	1.4%	(1.3%)
2008	1.3%	0.7%	(0.3%)	0.0%	(1.5%)	0.0%
2009	0.8%	0.1%	0.9%	0.0%	2.4%	0.0%
2010	0.7%	(1.0%)	0.0%	0.0%	(1.5%)	(0.6%)
Geometric Mean	**1.3%**	**(0.5%)**	**0.6%**	**0.2%**	**0.8%**	**(0.5%)**

The resulting geometric mean is applied to the 2010 customer/connection numbers to determine the forecast of customer/connections in 2011 and 2012. Table 2.8 outlines the forecast of customers by rate class for 2011 and 2012.

Table 2.8 - Customer/Connection Forecast

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	TOTAL
Forecast Number of Customers/Connections							
2011	**16,923**	**2,007**	**166**	**3,825**	**403**	**76**	**23,401**
2012	**17,138**	**1,998**	**167**	**3,832**	**406**	**76**	**23,616**

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. The following table provides the average annual usage per customer by rate class from 2003 to 2010.

Table 2.9 - Historical Annual Usage per Customer

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Annual kWh Usage Per Customer/Connection						
2003	8,990	30,834	898,651	917	819	7,704
2004	8,787	31,552	901,728	927	812	6,849
2005	9,176	32,664	905,095	898	808	6,756
2006	8,740	31,238	883,145	801	864	6,859
2007	8,772	32,205	853,030	802	839	6,828
2008	8,544	31,238	840,174	805	839	6,578
2009	8,395	29,721	804,265	808	818	6,444
2010	8,489	29,999	797,457	895	905	6,475

As can been seen from the above table usage per customer/connection generally declines after 2005. Norfolk Power believes that this decline is partially due to the CDM programs initiated in 2005 and onward.

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed. That information is provided in the following table. The geometric mean growth rate has also been shown.

Table 2.10 - Growth Rate in Usage Per Customer/Connection

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Growth Rate in Customer/Connection						
2003						
2004	(2.3%)	2.3%	0.3%	1.0%	(0.9%)	(11.1%)
2005	4.4%	3.5%	0.4%	(3.1%)	(0.5%)	(1.4%)
2006	(4.8%)	(4.4%)	(2.4%)	(10.7%)	6.9%	1.5%
2007	0.4%	3.1%	(3.4%)	0.0%	(2.9%)	(0.5%)
2008	(2.6%)	(3.0%)	(1.5%)	0.4%	0.1%	(3.7%)
2009	(1.7%)	(4.9%)	(4.3%)	0.4%	(2.6%)	(2.0%)
2010	1.1%	0.9%	(0.8%)	10.8%	10.7%	0.5%
Geometric Mean	**(0.8%)**	**(0.4%)**	**(1.7%)**	**(0.3%)**	**1.4%**	**(2.5%)**

For the forecast of usage per customer/connection the historical geometric mean was applied to the 2010 usage and the resulting usage forecast is as follows:

Table 2.11 - Forecast Annual kWh Usage per Customer/Connection

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Forecast Annual kWh Usage per Customers/Connection						
2011	8,420	29,881	783,962	892	918	6,317
2012	8,351	29,764	770,696	889	932	6,162

With the preceding information the non-normalized weather billed energy forecast can be determined by applying the forecast numbers of customers/connections from Table 2.8 by the forecast of annual usage per customer/connection from Table 2.11. The resulting non-normalized weather billed energy forecast is shown in the following table.

Table 2.12 - Non-Normalized Weather Billed Energy Forecast

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Total
NON-normalized Weather Billed Energy Forecast (GWh)							
2011 (Not Normalized)	142.5	60.0	130.5	3.4	0.4	0.5	337.2
2012 (Not Normalized)	143.1	59.5	129.0	3.4	0.4	0.5	335.9

The non-normalized weather billed energy forecast has been determined but this needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 346.6 GWh for 2011 and 345.3 GWh for 2012.

The difference between the non-normalized and normalized forecast adjustments is 9.4 GWh in 2011 (i.e. 346.6 – 337.2) and 9.4 GWh in 2012 (i.e. 345.3 – 335.9). The difference is assumed to be associated with moving the forecast from a non-normalized to a weather normal basis and this amount will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for Norfolk Power for the cost allocation study, which has been used to support this Application, it was determined that the weather sensitivity by rate classes is as follows:

Table 2.13 - Weather Sensitivity by Rate Class

Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Weather Sensitivity					
70%	70%	39%	0%	0%	0%

For the General Service 50 to 4999 kW class the weather sensitivity amount of 39% was provided in the weather normalization work completed by Hydro One. For the Residential and General Service < 50 kW classes, it is has been previously assumed in 2009 and 2010 cost of service applications that these two classes are 100% weather sensitive. Intervenors expressed concern with this assumption and have suggested that 100% weather sensitivity is not appropriate. Norfolk Power agrees with this position but also submits that the weather sensitivity for the Residential and General Service < 50 kW classes should be higher than the General Service 50 to 4,999 kW class. As a result, Norfolk Power has assumed the weather sensitivity for the Residential and General Service < 50 kW classes to be mid-way between 100% and 39%, or 70%.

The difference between the non-normalized and normalized forecast of 9.4 GWh in 2011 and 9.4 GWh in 2012 has been assigned on a *pro rata* basis to each rate class based on the above level of weather sensitivity. The following table outlines how the weather sensitive rate classes have been adjusted to align the non-normalized forecast with the normalized forecast.

Table 2.14 - Alignment of Non-normal to Weather Normal Forecast

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Total
Non-normalized Weather Billed Energy Forecast (GWh)							
2011 Non-Normalized Bridge	142.5	60.0	130.5	3.4	0.4	0.5	337.2
2012 Non-Normalized Test	143.1	59.5	129.0	3.4	0.4	0.5	335.9
Adjustment for Weather (GWh)							
2011	4.8	2.0	2.5	0.0	0.0	0.0	9.3
2012	4.9	2.1	2.5	0.0	0.0	0.0	9.5
Weather Normalized Billed Energy Forecast (GWh)							
2011 Normalized Test	147.3	62.0	133.0	3.4	0.4	0.5	346.6
2012 Normalized Test	148.1	61.5	131.5	3.4	0.4	0.5	345.4

Billed KW Load Forecast

There are three rate classes that charge volumetric distribution on per kW basis. These include General Service 50 to 4999 kW, Sentinel Lighting and Street Lighting. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWhs and applying the average ratio to the forecasted kWh to produce the required kW.

The following table outlines the annual demand units by applicable rate class.

Table 2.15 - Historical Annual kW per Applicable Rate Class

Year	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	TOTAL
Billed Annual kW				
2003	381,565	9,351	0	390,915
2004	389,408	9,351	0	398,758
2005	375,257	9,351	0	384,608
2006	371,943	9,351	0	381,293
2007	367,949	9,351	0	377,299
2008	366,108	9,351	750	376,208
2009	354,307	9,351	919	364,576
2010	342,702	9,351	910	352,963

The following table illustrates the historical ratio of kW/kWh as well as the average ratio for 2003 to 2010.

Table 2.16 - Historical kW/KWh Ratio per Applicable Rate Class

Year	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting
Ratio of kW to kWh			
2003	0.2670%	0.2701%	0.0000%
2004	0.2649%	0.2673%	0.0000%
2005	0.2599%	0.2743%	0.0000%
2006	0.2616%	0.3055%	0.0000%
2007	0.2622%	0.3055%	0.0000%
2008	0.2657%	0.3042%	0.2256%
2009	0.2662%	0.3030%	0.2772%
2010	0.2597%	0.2735%	0.2516%
Average 2003 to 2010	**0.2634%**	**0.2879%**	**0.2515%**

The average ratio was applied to the weather normalized billed energy forecast in Table 2.14 to provide the forecast of kW by rate class as shown below. The following Table 2.17 outlines the forecast of kW for the applicable rate classes.

Table 2.17 - kW Forecast by Applicable Rate Class

Year	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Total
Predicted Billed kW				
2011 Normalized Bridge Year	**350,257**	**9,827**	**930**	**361,014**
2012 Normalized Test Year	**346,440**	**9,810**	**951**	**357,201**

Table 2.18 on the following page provides a summary of the billing determinants by rate class that are used to develop the proposed rates. Norfolk Power is a host distributor to Hydro One which means Norfolk Power charges Hydro One for an embedded distributor service. In order to determine the rates to be charged to Hydro One for distribution service Norfolk Power has assumed the 2012 forecast level of usage will be the same as 2010 actual.

Table 2.18 - Summary of Forecast

	2008	2009	2010	2011 Weather Normalized Bridge	2012 Weather Normalized Test
ACTUAL AND PREDICTED KWH PURCHASES					
Actual kWh Purchases	367,061,928	355,895,069	361,293,097		
Predicted kWh Purchases before CDM adjustment	365,046,593	353,413,873	367,288,597	365,779,810	364,517,433
% Difference of actual and predicted purchases	(0.5%)	(0.7%)	1.7%		
BILLING DETERMINANTS BY CLASS					
Residential					
Customers	16,462	16,600	16,711	16,923	17,138
kWh	140,646,761	139,365,167	141,859,487	147,314,024	148,067,203
General Service < 50 kW					
Customers	2,036	2,037	2,017	2,007	1,998
kWh	63,584,606	60,541,483	60,492,342	62,006,121	61,517,376
General Service 50 to 4,999 kW					
Customers	164	166	166	166	
kWh	137,788,570	133,105,833	131,979,063	132,970,679	131,521,846
kW	366,108	354,307	342,702	350,257	346,440
Street Lighting					
Customers	3,819	3,819	3,819	3,825	3,832
kWh	3,073,986	3,085,993	3,418,963	3,412,950	3,406,947
kW	9,351	9,351	9,351	9,827	9,810
Sentinel Lighting					
Customers	396	406	400	403	406
kWh	332,424	331,566	361,714	369,849	378,167
kW	750	919	910	930	951
Unmetered Scattered Load					
Customers	77	77	77	76	76
kWh	506,505	496,200	495,360	481,000	467,056
Total Excl Hydro One					
Customer/Connections	22,954	23,104	23,188	23,401	23,449
kWh	345,932,852	336,926,242	338,606,929	346,554,623	345,358,596
kW from applicable classes	376,208	364,576	352,963	361,014	357,201
Hydro One					
Customers	5	5	5	5	5
kWh	30,437,632	27,284,178	31,899,332	31,899,332	31,899,332
Total					
Customer/Connections	**22,959**	**23,109**	**23,193**	**23,406**	**23,621**
kWh	**376,370,484**	**364,210,420**	**370,506,261**	**378,453,955**	**377,257,928**
kW from applicable classes	**376,208**	**364,576**	**352,963**	**361,014**	**357,201**

Appendix A – Monthly Data Used for Regression Analysis

	Original Purchase	H1 Purchases	Purchased with removal of H1 starting Nov 2005	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Spring Flag	Unemployment
Jan-03	32,965,044		32,965,044	810	0	31	0	7.1%
Feb-03	32,869,944		32,869,944	708	0	28	0	7.1%
Mar-03	28,824,007		28,824,007	587	0	31	1	7.1%
Apr-03	30,618,154		30,618,154	358	1	30	1	7.1%
May-03	25,654,909		25,654,909	174	0	31	1	7.1%
Jun-03	29,578,846		29,578,846	42	41	30	0	7.1%
Jul-03	32,623,851		32,623,851	2	83	31	0	7.0%
Aug-03	31,883,486		31,883,486	7	101	31	0	6.9%
Sep-03	27,798,910		27,798,910	66	13	30	0	6.8%
Oct-03	30,580,434		30,580,434	288	0	31	0	6.7%
Nov-03	30,761,583		30,761,583	377	0	30	0	6.6%
Dec-03	34,457,161		34,457,161	579	0	31	0	6.6%
Jan-04	34,354,060		34,354,060	846	0	31	0	6.5%
Feb-04	31,573,180		31,573,180	644	0	29	0	6.4%
Mar-04	33,169,000		33,169,000	504	0	31	1	6.3%
Apr-04	28,080,880		28,080,880	311	0	30	1	6.2%
May-04	27,156,110		27,156,110	132	14	31	1	6.1%
Jun-04	28,418,580		28,418,580	55	36	30	0	6.0%
Jul-04	30,923,170		30,923,170	2	69	31	0	6.1%
Aug-04	30,561,230		30,561,230	26	47	31	0	6.2%
Sep-04	29,537,940		29,537,940	46	26	30	0	6.2%
Oct-04	28,859,090		28,859,090	227	0	31	0	6.3%
Nov-04	30,678,700		30,678,700	380	0	30	0	6.4%
Dec-04	33,367,610		33,367,610	626	0	31	0	6.5%
Jan-05	35,509,730		35,509,730	777	0	31	0	6.5%
Feb-05	31,189,460		31,189,460	650	0	28	0	6.6%
Mar-05	33,152,890		33,152,890	639	0	31	1	6.7%
Apr-05	28,441,440		28,441,440	327	0	30	1	6.8%
May-05	27,281,950		27,281,950	212	0	31	1	6.8%
Jun-05	32,693,550		32,693,550	17	119	30	0	6.9%
Jul-05	35,563,070		35,563,070	2	130	31	0	6.9%
Aug-05	34,129,440		34,129,440	6	94	31	0	6.9%
Sep-05	29,718,670		29,718,670	32	24	30	0	6.9%
Oct-05	29,538,680		29,538,680	226	6	31	0	6.9%
Nov-05	31,266,630	2,809,844	28,456,786	391	0	30	0	6.9%
Dec-05	36,748,220	2,979,998	33,768,222	693	0	31	0	6.9%
Jan-06	36,001,110	2,614,309	33,386,801	547	0	31	0	6.8%
Feb-06	33,685,710	2,403,415	31,282,295	597	0	28	0	6.8%
Mar-06	35,394,580	2,430,181	32,964,399	542	0	31	1	6.8%
Apr-06	30,055,940	2,061,230	27,994,710	303	0	30	1	6.8%
May-06	29,171,120	2,120,697	27,050,423	162	22	31	1	6.8%
Jun-06	31,806,160	2,296,974	29,509,186	28	44	30	0	6.8%
Jul-06	37,632,030	2,952,411	34,679,619	4	136	31	0	6.8%
Aug-06	36,686,220	3,946,631	32,739,589	7	66	31	0	6.8%
Sep-06	31,884,060	4,302,011	27,582,049	101	3	30	0	6.7%
Oct-06	32,780,030	3,026,376	29,753,654	299	0	31	0	6.7%
Nov-06	33,778,150	2,881,260	30,896,890	397	0	30	0	6.7%
Dec-06	34,232,840	2,683,886	31,548,954	491	0	31	0	6.7%

Monthly Data Used for Regression Analysis (cont'd)

Jan-07	35,688,590	2,667,514	33,021,076	651	0	31	0	6.6%
Feb-07	35,489,010	2,660,489	32,828,521	751	0	28	0	6.6%
Mar-07	34,179,250	2,525,255	31,653,995	536	0	31	1	6.6%
Apr-07	30,453,750	2,217,684	28,236,066	377	0	30	1	6.6%
May-07	29,790,490	2,135,671	27,654,819	141	26	31	1	6.5%
Jun-07	33,430,400	2,509,429	30,920,971	23	74	30	0	6.5%
Jul-07	34,365,020	2,676,297	31,688,723	13	67	31	0	6.6%
Aug-07	36,980,810	3,809,828	33,170,982	12	81	31	0	6.8%
Sep-07	32,991,440	3,600,106	29,391,334	73	27	30	0	6.9%
Oct-07	32,291,130	2,732,776	29,558,354	156	16	31	0	7.0%
Nov-07	32,215,240	2,768,394	29,446,846	469	0	30	0	7.2%
Dec-07	35,248,140	2,693,907	32,554,233	643	0	31	0	7.3%
Jan-08	36,073,590	2,568,452	33,505,138	631	0	31	0	7.4%
Feb-08	34,907,090	2,481,387	32,425,703	678	0	29	0	7.6%
Mar-08	35,108,550	2,477,327	32,631,223	616	0	31	1	7.7%
Apr-08	29,555,380	1,994,367	27,561,013	279	0	30	1	7.8%
May-08	29,072,170	2,009,175	27,062,995	211	0	31	1	8.0%
Jun-08	32,114,150	2,259,563	29,854,587	22	64	30	0	8.1%
Jul-08	36,385,980	2,651,005	33,734,975	3	98	31	0	8.3%
Aug-08	34,121,280	2,908,498	31,212,782	20	45	31	0	8.5%
Sep-08	31,648,600	2,994,994	28,653,606	65	21	30	0	8.7%
Oct-08	30,965,600	2,689,984	28,275,616	295	0	31	0	8.9%
Nov-08	32,376,540	2,669,212	29,707,328	461	0	30	0	9.1%
Dec-08	35,170,630	2,733,668	32,436,962	650	0	31	0	9.3%
Jan-09	37,829,820	2,824,706	35,005,114	850	0	31	0	9.5%
Feb-09	32,640,640	2,331,201	30,309,439	612	0	28	0	9.7%
Mar-09	33,288,800	2,342,297	30,946,503	536	0	31	1	9.9%
Apr-09	29,095,780	2,045,149	27,050,631	316	3	30	1	10.1%
May-09	27,988,623	1,632,569	26,356,054	150	2	31	1	10.3%
Jun-09	29,616,438	1,696,941	27,919,497	46	34	30	0	10.5%
Jul-09	31,050,115	1,865,199	29,184,916	25	25	31	0	10.7%
Aug-09	34,661,654	2,365,588	32,296,066	20	73	31	0	10.9%
Sep-09	30,118,600	2,361,671	27,756,929	73	14	30	0	11.1%
Oct-09	30,715,615	2,627,162	28,088,453	307	0	31	0	11.3%
Nov-09	31,534,823	2,575,981	28,958,842	366	0	30	0	11.5%
Dec-09	34,638,338	2,615,714	32,022,624	634	0	31	0	11.7%
Jan-10	35,757,337	2,574,638	33,182,699	723	0	31	0	11.6%
Feb-10	31,890,293	2,259,258	29,631,035	634	0	28	0	11.4%
Mar-10	31,870,318	2,160,417	29,709,902	461	0	31	1	11.3%
Apr-10	27,540,533	1,838,134	25,702,400	242	0	30	1	11.1%
May-10	29,878,942	1,706,054	28,172,889	129	32	31	1	11.0%
Jun-10	31,983,882	2,120,246	29,863,636	21	59	30	0	8.7%
Jul-10	37,817,256	2,858,814	34,958,443	6	129	31	0	8.6%
Aug-10	38,392,409	4,158,261	34,234,148	8	120	31	0	8.4%
Sep-10	32,058,700	4,041,059	28,017,641	91	25	30	0	8.3%
Oct-10	30,815,433	2,838,596	27,976,837	251	0	31	0	8.1%
Nov-10	31,257,106	2,662,654	28,594,452	385	0	30	0	8.0%
Dec-10	33,930,219	2,681,203	31,249,016	710	0	31	0	7.8%

SUMMARY OF OTHER DISTRIBUTION REVENUE:

Table 3.1 – Summary of Other Operating Revenue

USoA Account	Account Description	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
4080	SSS Administration Charge				57,742	57,909
4082	Retail Services Revenue		745	450	800	800
4084	Service Transaction Requests		639	1,178	700	700
4210	Rent from Electric Property	90,227	94,667	95,657	96,000	96,000
4225	Late Payment Charges	124,516	155,219	86,593	138,000	138,000
4235	Miscellaneous Service Revenues	95,702	89,927	101,896	88,000	88,000
4315	Revenues from Electric Plant Leased to Others				23,880	23,880
4234	Special Purpose Charge			89,447	57,574	
4325	Revenues from Merchandise, Jobbing, Etc.	8,329	1,709	893	2,000	2,000
4355	Gain on Disposition of Utility and Other Property	9,100	10,030	1,469		
4360	Loss of Disposition of Utility and Other Property			(4,606)	(6,000)	
4375	Revenues from Non-Utility Operations	289,027	780,314	483,697	780,314	780,314
4380	Expenses of Non-Utility Operations	(275,348)	(791,115)	(496,521)	(780,314)	(780,314)
4385	Non-Utility Rental Income	700	1,500			
4390	Miscellaneous Non-Operating Income	67,569	91,121	45,718	58,000	58,000
4398	Foreign Exchange Gains and Losses, Including Amortization		(21,903)	23		
4405	Interest and Dividend Income (exclude interest on reg assets)	18,249	3,508	12,676	12,000	12,000
Total		**428,071**	**416,361**	**418,569**	**528,696**	**477,289**
SSS Administration Charge					57,742	57,909
Specific Service Charges		95,702	89,927	101,896	88,000	88,000
Late Payment Charges		124,516	155,219	86,593	138,000	138,000
Other Distribution Revenues		90,227	96,051	97,285	97,500	97,500
Other Income and Expenses		117,626	75,164	132,795	147,454	95,880
Total Other Operating Revenue		**428,071**	**416,361**	**418,569**	**528,696**	**477,289**

VARIANCE ANALYSIS ON OTHER OPEATING REVENUE:

Preamble:

The Materiality threshold used to analyze Other Operating Revenue in accordance with the Filing Requirements is 0.5% of distribution revenue requirement for a distributor with a distribution revenue requirement greater than $10 million and less than or equal to $200 million. Norfolk's 2012 revenue requirement is $12,745,918, resulting in a revenue requirement of $63,730. To allow for the most detailed review of materiality on Other Operating Revenue, Norfolk has explanations for variances exceeding $50,000.

2009 Actual to 2008 Actual:

NPDI's other operating income in fiscal 2009 was Board Approved other operating revenue was forecast to be $416,316 as shown in Exhibit 3, Tab 3, Schedule 1. NPDI's other operating revenue in fiscal 2008 was $428,071 as shown in Exhibit 3, Tab 3, Schedule 1. The variance was primarily a result of a decline of $(11,710) resulting from the decreases in Interest Revenues ($14,741), Jobbers Revenues ($6,620), Non-Utility Revenues ($24,480), offset by increases in Late Payment Charges $30,703, Miscellaneous Non-Operating Income $23,552 and Foreign Exchange Loss ($21,903).

2010 Actual Comparison to 2009 Actual:

NPDI's 2010 other operating revenue was $418,570, as shown in Exhibit 3, Tab 3, Schedule 1. The variance from 2009 was an overall increase of $2,208 due to the Special Purpose Recovery $89,447 , offset by decreases in Late Payment Charges ($68,625) and other immaterial decreases.

2011 Bridge Year Comparison to 2010 Actual:

As shown in Exhibit 3, Tab 3, Schedule 1, total other operating revenue for 2011 is forecasted at $528,696. The amount forecasted is $110,127 higher than the 2010 actual other operating revenue. The increase is largely due to increases in Late Payment Charges of $51,406, increase in the SSS Administration Charge $57,742 (for 2008 through 2010 the SSS Administration

Charge had been included in the respective Distribution Revenue customer class) and a charge of approximately $24,000 to Norfolk Energy Inc. (an affiliated company) for dark fibre leasing in 2011 (due to construction of a dark fibre line in 2010 by NPDI to service its SCADA system). These increases are offset by a decrease in Special Purpose Recovery of ($31,873). Please note that the Special Purpose Charge has been fully recovered as of April 30, 2011.

2012 Test Year Comparison to 2011 Bridge Year:

Norfolk Power's other operating revenue is forecast to be $477,289, as shown in Exhibit 3, Tab 3, Schedule 1. The amount forecasted for 2012 is $(51,407) lower than the 2011 Bridge Year. The decrease is due mainly to the decrease in Special Purpose Recovery of ($57,574) offset by other immaterial increases.