Norfolk Power

IN BUSINESS TO SERVE.

February 25, 2008

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
26th Floor
Toronto, Ontario
Attn: Ms. Kirsten Walli
Board Secretary

Dear Ms. Walli

Re: OEB File No. EB-2007-0530: Norfolk Power Distribution Inc. Application to the Ontario Energy Board (the "OEB") for Electricity Distribution Rates and Charges as of May 1, 2008 – Responses to Interrogatories

Norfolk Power Distribution Inc. is pleased to advise the Board that we have submitted an electronic filing today, February 25, 2008, of all responses to interrogatories from Board staff and Intervenors.

If you have any questions, please contact the undersigned at 519-426-4440, extension 2264.

Yours truly,

Alvin E. Allim
Manager of Finance

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Board Staff Interrogatories
Norfolk Power Distribution Inc.
2008 Electricity Distribution
Rates Application EB-2007-0753

RATE BASE

1. Ref: Exhibit 2/ Tab 1/Schedule 1/Page 2/Line 4. Please confirm that the Norfolk Power Distribution Inc. ("Norfolk Power") definition description of Rate Base is arithmetically as below and consistent with the calculations of fixed assets as they relate to Capital Contributions and Grants of Exhibit 2/Tab 2/Schedule 1/Page 5:

   Rate Base = Gross Assets in Service – (Accumulated Depreciation + Contributed Capital) + Working Capital

Response:

Rate Base is arithmetically correct as below and consistent with the calculations of fixed assets as they relate to Capital Contributions and Grants.

	Gross Assets in Service	-	(	Accumulated Depreciation	+	Contributed Capital	)	+	Working Capital	=	**Rate Base**
2006 Actual	$59,766,670	-	(	$16,891,437	+	$5,353,674	)	+	$4,525,279	=	**$42,046,838**
2007 Bridge	$64,895,613	-	(	$19,018,458	+	$5,896,930	)	+	$4,817,458	=	**$44,797,683**
2008 Test	$72,209,974	-	(	$20,908,273	+	$6,096,930	)	+	$5,294,835	=	**$50,499,606**

2. Ref: General For the years 2002 to 2008 inclusive, please provide a table listing the following information (actual dollars where available, or expected, planned or projected dollars, or % where indicated):

I) Net income
II) Actual Return on the Equity portion of the regulated rate base (%)
III) Allowed Return on the Equity portion of the regulated rate base (%)
IV) Retained Earnings
V) Dividends to Shareholders
VI) Sustainment Capital Expenditures excluding smart meters
VII) Development Capital Expenditures excluding smart meters
VIII) Operations Capital Expenditures
IX) Smart meters Capital Expenditures
X) Other Capital Expenditures (identify)
XI) Total Capital Expenditures including and excluding smart meters
XII) Depreciation
XIII) Number of customer additions by class

Response: see below

	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Bridge	2008 Test
Net income (Loss)	($116,369)	($31,704)	$437,582	$422,606	$838,841	$447,361	$2,495,015
Actual Return on the Equity portion of the regulated rate base (%)	-0.50%	-0.14%	1.86%	1.78%	3.47%	1.82%	9.20%
Allowed Return on the Equity portion of the regulated rate base (%)	6.59%	6.59%	6.59%	9.88%	9.00%	9.00%	not defined
Retained Earnings	($167,017)	($248,721)	($11,139)	$111,467	$570,308	$1,017,669	$3,512,684
Dividends to Shareholders	$0	$50,000	$200,000	$300,000	$380,000	n/a	n/a
Sustainment Capital Expenditures excluding smart meters	n/a	n/a	$1,371,826	$2,003,600	$2,488,223	$1,551,200	$2,518,700
Development Capital Expenditures excluding smart meters	n/a	n/a	$5,962,235	$1,600,963	$1,844,604	$3,385,000	$2,785,900
Operations Capital Expenditures (note: included in sustainment)	$0	$0	$0	$0	$0	$0	$0
Smart meters Capital Expenditures	$0	$0	$0	$6,557	$25,185	$49,000	$4,061,000
*Other Capital Expenditures (identify - see details below)	$786,608	$903,108	$648,392	$459,775	$691,744	$637,000	$639,000
Total Capital Expenditures including smart meters	$5,917,050	$3,814,294	$7,982,453	$4,070,895	$5,049,756	$5,620,200	$10,189,600
Total Capital Expenditures excluding smart meters	$5,917,050	$3,814,294	$7,982,453	$4,064,338	$5,024,571	$5,573,200	$5,938,600
Depreciation;	$1,803,923	$1,922,200	$2,031,874	$2,186,437	$2,341,935	$2,523,899	$2,836,810
Number of customer additions by class:							
- Residential	15,187	15,444	15,686	15,905	16,121	16,363	16,607
- GS<50kW	2,180	2,132	2,120	2,107	2,100	2,078	2,058
- GS>50kW	149	160	161	159	163	165	166

*Other Capital Expenditures are as follows:

Land	$3,291	$64,382	$4,197	$5,700	$7,070	$25,000	$0
Buildings: Fixtures and Improvements	116,959	64,382	31,164	16,285	39,714	153,000	108,000
Leasehold Improvements	0	0	0	0	0	2,000	5,000
Office Furniture and Equipment	25,529	13,471	27,931	9,172	20,347	23,000	29,000
Computer Hardware	68,897	26,240	110,294	74,652	43,902	88,000	67,000
Computer Software	62,199	43,537	14,253	27,120	113,536	87,000	129,000
Transportation Equipment	255,291	419,959	230,666	94,586	345,936	95,000	95,000
Stores Equipment	8,829	1,083	9,213	16,153	9,828	4,000	5,000
Truck Tools and Equipment	44,601	41,945	40,288	25,825	51,154	33,000	32,000
Measurement and Testing Equipment	49,158	2,791	13,329	70,901	9,363	22,000	25,500
Communications Equipment	20,454	12,011	10,242	4,997	7,228	29,000	29,000
Miscellaneous Equipment	0	3,888	8,778	43,849	25,813	32,000	22,500
SCADA	131,400	209,419	148,037	70,535	17,853	44,000	92,000
	$786,608	$903,108	$648,392	$459,775	$691,744	$637,000	$639,000

3. Ref: Exhibit 2/ Tab1/

a. Ref: Rate Base Summary Table/Schedule 2/ Page 1

I) 2006 Year: Gross Assets: Please clarify why the Asset Value at Cost was different between the Board-approved $57,020,296 and the Actual of $54,412,996. Please elaborate on major additional projects undertaken, postponed or uncompleted; all with estimated and actual costs.

II) 2006 Year: Please clarify the reasons why the Accumulated Depreciation Actual of $16,891, 437 was different from the Board-approved $25,314,525. Please reconcile these differences in detail, and list any accounting entries and the reasons that contributed to this major difference in total Accumulated Depreciation.

b. Please confirm whether the depreciation policy changed during the period 2003 through 2007. If so please provide copies of the depreciation policies before and after any change.

Response:

a.

I) The 2006 EDR used an average of two year ends (i.e. 2003 – 2004) and only one half of the 2004 expenditures were allowed in the rate base. Also, assets that became fully depreciated were not accounted for in the 2006 EDR. This was not representative of the activity for 2005 and 2006. The only major project undertaken by Norfolk Power was the construction of a 115kV transformer station. The total cost upon completion at December 31, 2004, was $4,151,905, of which only half was in the 2006 Board Approved amount. Below is a reconciliation between the Board approved and 2006 Actual.

	2006 Board Approved	At Dec 31 2004	2005 Capital Additions	2006 Capital Additions	2005 & 2006 Adjustments	**At Dec 31 2006**
Land and Buildings	**$1,387,080**	$2,260,189	$6,452	$77,034	$0	**$2,343,675**
TS Primary Above 50	**1,527,739**	2,730,583	65,985	6,426	0	**2,802,994**
DS	**1,838,509**	1,874,142	436,062	78,143	0	**2,388,347**
Poles, Wires	**37,428,082**	38,516,968	2,194,070	2,677,734	(8,436,990)	**34,951,782**
Line Transformers	**7,746,968**	8,048,273	309,773	677,642	0	**9,035,688**
Services and Meters	**3,611,932**	3,759,191	563,598	805,659	0	**5,128,448**
General Plant	**1,875,786**	1,893,467	25,457	60,061	0	**1,978,985**
Equipment	**3,094,036**	3,264,259	256,311	449,322	(2,053,843)	**1,916,049**
IT Assets	**946,143**	1,008,417	101,772	157,438	(460,831)	**806,796**
CDM Assets	**209,034**	7,068	40,880	42,444	0	**90,392**
Other Distribution Assets	**414,838**	488,856	70,535	17,853	0	**577,244**
Contributions and Grants	**(3,059,852)**	(3,424,208)	(1,486,209)	(886,512)	0	**(5,796,929)**
TOTAL DISTRIBUTION ASSETS	**$57,020,296**	$60,427,205	$2,584,686	$4,163,244	($10,951,664)	**$56,223,471**
			Jan 1, 2006 Opening Balance			**52,602,521**
			Average reported as per 2008 EDR			**$54,412,996**

II) The 2006 EDR used an average of two year ends (i.e. 2003 – 2004) and only one half of the 2004 expenditures were allowed in the rate base. Also, assets that became fully depreciated were not accounted for in the 2006 EDR. This was not representative of the activity for 2005 and 2006. Below is a reconciliation between the Board approved and 2006 Actual.

	2006 Board Approved	At Dec 31 2004	2005 Depreciation	2006 Depreciation	2005 & 2006 Adjustments	**At Dec 31 2006**
Accumulated Depreciation	**($25,314,525)**	($24,214,689)	($2,186,437)	($2,341,935)	$10,951,664	**($17,791,397)**
			Jan 1, 2006 Opening Balance			**(15,991,478)**
			Average reported as per 2008 EDR			**($16,891,437)**

b. Norfolk Power Distribution Inc. depreciates all capital assets using the straight-line method. This is in accordance with GAAP and consistent with the Board's Accounting Procedures Handbook (APH). This method did not change during the period between 2003 to 2007.

4. Ref: Exhibit 2/Tab 2/ Schedule 2 (Gross Assets Table), and Schedule 4 (Accumulated Depreciation Table)

2006 Board Approved vs. 2006 Actual Please explain the major reason for the differences between 2006 Board-approved and 2006 Actual Gross Assets and Accumulated Depreciation figures (refer to some answers which may be given in responses to IR# 3 where appropriate). If the differences are affected by assets that were fully depreciated and written off please provide the following information about those assets:

I) the assets description
II) their gross asset value at cost
III) accumulated depreciation at the time of write off
IV) remaining depreciation taken at the time of write-off
V) Whether those written-off assets remain in service.

Response:

See above IR#3. Table below provides additional information.

Asset Description	Cost	Accumulated Depreciation	Remaining Depreciation at time of write-off (included in Accumulated Depreciation)	Still in Service Yes/No
Overhead - Poles, Towers and Equipment	$5,686,690	$5,686,690	$227,468	Yes
Overhead - Conductor and Devices	$2,750,300	$2,750,300	$110,012	Yes
Office Furniture and Equipment	$264,715	$264,715	$9,076	Yes
Computer Hardware	$398,232	$398,232	$13,779	No
Computer Software	$62,199	$62,199	$12,440	No
Transportation Equipment	$1,018,443	$1,018,443	$0	Yes
Stores Equipment	$81,132	$81,132	$2,524	Yes
Truck Tools and Equipment	$417,155	$417,155	$12,831	Yes

5. Ref: Exhibit 2/ Tab 2/ Schedule 1/ Page 5 – Continuity Statements Norfolk shows the following figures relating to net fixed asset values or rate base for the 2006 actual, 2007 bridge year, and 2008 test year: 2006 actual: $4.163 million 2007 bridge year: $5.62 million (an increase of 35% over 2006 actual) 2008 test year: $10.19 million (includes smart meters projects).

   Please provide the figures regarding 2006 Board Approved, 2006 actual, 2007 bridge year, in a table format, and include the following: I) variance analysis for 2006 actual vs. 2006 Board approved and the reasons for the increase or decreases II) variance analysis for 2007 vs. 2006 actual and the reasons for the increases.

Response:

2006 Board Approved VS 2006 Actual

Asset Account	2006 Board Approved	2006 Actual	Variance
Net Fixed Assets or Rate Base	$52,602,521	$56,765,764	$4,163,243

The 2006 Board approved amounts are based on an average generated by the 2006 EDR model of 2002 to 2004 data, not considering additions for 2005 and 2006. For 2006 actual, Norfolk Power Distribution Inc. had additions of $4,163,243 consisting of sustaining and developmental construction to the electrical distribution system, as well as replace and upgrade equipment and rebuilding existing substations.

2006 Actual VS 2007 Bridge

Asset Account	2006 Actual	2007 Bridge Year	Variance
Net Fixed Assets or Rate Base	$56,765,764	$62,385,964	$5,620,200

For 2007 Bridge, Norfolk Power Distribution Inc. forecasted additions of $5,620,200 consisting of:

- sustaining and developmental construction to the electrical distribution system
- rebuilding existing substations
- purchase of a mobile substation
- purchase of existing feeder lines from Hydro One
- replace and upgrade equipment

6. Ref: Exhibit 2/ Tab 3/ Schedule 3/ Capital Budget

a. General: Please list the projects started in 2006 and 2007 whose costs will carry over to 2008 respectively, in a table format, providing the figures for the total budgeted cost, committed costs, and the budget that will carry over to 2008.

b. General: Please file with the Board any existing Norfolk Power asset management plan, including method of prioritizing capital expenditures.

c. General: Please confirm that Norfolk Power has no projects for which a Leave to Construct under section 92 is required.

d. Ref: Exhibit 2/ Tab3/ Schedule 3/ Capital Budget Items/ Transformers

I) In the case of the Bloomsburg station, please list the project start date, the in-service date, the capacity in service at those dates, and the various carry-over costs year to year.

II) Sub –ref: Page 10. A capital cost of $120,000 is listed as a deposit for a new transformer. If the item is not in service in 2008, why is this classified as capital plant in rate base in 2008?

III) Please confirm the date when the capital expenditures for the Bloomsburg station were approved by the Board.

IV) Ref: Exhibit 2/ Tab 2/ Schedule 3 Pages 1, 4, Please provide a schedule giving a time line (2003 through 2008) and listing transformer projects (asset accounts 1815 and 1850), their cost, in-service dates and when the associated costs were included in rate base.

Response:

a. See below

Asset Account	**2007 Budget**	**2007 Committed Costs**	**Carryover**
Mobile Substation	$500,000	$227,000	$273,000

b. General: Norfolk Power does not have an asset management plan. But, Norfolk Power does prioritize its capital expenditures in the following manner:

- Importance of line
  - Stations
  - 27.6 kV-Three phase main feeders
  - Other 8kV feeders and radial feeders with large customers
  - radial feeders
- Age and reliability standards

c. General: Norfolk Power does not have any projects which require Leave to Construct under Section 92.

d.

I) In the case of the Bloomsburg station:

- the project start date – May 26, 2004
- the in-service date – In-service on February 1, 2005
- the capacity in service at those dates – 20MW

- Carryover from 2004 to 2005 was $42,324

II) Sub –ref: Page 10. The capital cost of $120,000 listed is for a deposit for a new transformer at the Bloomsburg TS. Since the item will not be in service in 2008 and is classified as capital plant in rate base for 2008, is an oversight by Norfolk Power. This item therefore, should be removed from the rate base.

III) The date when the capital expenditures for the Bloomsburg station were approved by the Board – March 23, 2005

IV) See Table Below

Account	Description	Project	Cost	In-Service date	Included in Rate Base
1815	Transformer Station Equipment	Bloomsburg TS	$837,398	2/1/2005	2006
1850	Line Transformers - O/H & U/G	Various	$383,867	2003	2006
			$602,609	2004	2006
			$309,773	2005	2008
			$677,642	2006	2008
			$745,000	2007	2008
			$876,000	2008	2008

Notes:

As per Article 410, 420 and 510 of the APH, transformers are capitalized when purchased and not held in inventory until installed.

7. Ref: Exhibit 2/Tab 3/Schedule 3/ Capital Budget by Project/ Customer Demand Projects

- Please provide profitability index calculations ("PI") for the Customer Demand Projects which are included in the capital cost $1,841,000.
- Please provide the average capital cost to connect a single residential customer in each of years 2002 through 2008.
- Please confirm that all the 2008 test year capital projects will be in service by the end of that test year. For those that will not, please estimate the value of capital projects that will not be placed in service in 2008.
- Please confirm whether or not the $200,000 capital contributions from these customers are included in the 2008 rate base.

Response:

- The Economic Evaluation Process indicates $200,000 would be required in capital contribution
-

	2002	2003	2004	2005	2006	2007	2008
Connection Cost (average) - Residential (Incl: labour, Trucking, Meter & Material)	N/A	N/A	$865.00	$884.00	$913.00	$925.00	$937.00

- All 2008 test year capital projects are expected to be completed and in service by the end of that year
- The $200,000 capital contributions are included in the rate base, which has the effect of reducing the rate base value See Exhibit 2/Tab 2/ Schedule 1/Page 5

8. Ref: Exhibit 2/ Tab 3/ Schedule 3/ page 5: Renewal Projects For the renewal projects, please provide:

a. A list of the 13 projects indicating their location.
b. A description of the work required.
c. The reason that the project is being undertaken.
d. Reliability data for those projects which are undertaken for reliability purposes, and indicate the reliability standard which the utility seeks to maintain.
e. Details of the procedures described under "Justification", including:
    I. Documentation of the procedures
    II. Nature of the Condition assessment process
    III. Identification of any pre-established set of criteria in categories including reliability, risk mitigation and financial impact.

Response:

a. to c. are below

Project Name	Project Description	Location	Justification
Replace depreciated Poles	Replace depreciated Poles	various in Norfolk County	Aged plant and pole testing results
Proactive Overhead transformer replacement program	Proactive Overhead transformer replacement program	various in Norfolk County	Aged plant, PCB testing and customer overload
Proactive Underground transformer replacement program	Proactive Underground transformer replacement program	various in Norfolk County	Aged plant, PCB testing and customer overload
Rehab Leamon St.	Rehabilitation of aged plant to current standards	Waterford	To ensure a reliable and safe distribution system to meet customer needs
Rehab Owen Woodhouse	Rehabilitation of aged plant to current standards	Simcoe	To ensure a reliable and safe distribution system to meet customer needs
Rehab Metcalf & Head St	Rehabilitation of aged plant to current standards	Simcoe	To ensure a reliable and safe distribution system to meet customer needs
College St	Rehabilitation of aged plant to current standards	Waterford	To ensure a reliable and safe distribution system to meet customer needs
Fair Grounds	Rehabilitation of aged plant to current standards	Simcoe	To ensure a reliable and safe distribution system to meet customer needs
Hillcrest rebuild	Rehabilitation of aged plant to current standards	Simcoe	To ensure a reliable and safe distribution system to meet customer needs
LIS, Reclosure and Lightning Arrestors	Replacement of damaged and/or inoperable equipment	various in Norfolk County	To ensure a reliable and safe distribution system to meet customer needs
DS Blueline U/G Egress	Rehabilitation of aged plant to current standards	Simcoe	To ensure a reliable and safe distribution system to meet customer needs
Miscellaneous Overhead Construction	Rehabilitation of aged plant to current standards	various in Norfolk County	To ensure a reliable and safe distribution system to meet customer needs
Miscellaneous Underground Construction	Rehabilitation of aged plant to current standards	various in Norfolk County	To ensure a reliable and safe distribution system to meet customer needs

d. For the 13 projects listed above, there are no reliability data to support these projects. However, Norfolk Power is undertaking the above projects because they have reached end-of-life usefulness. If rehabilitation is not performed, interruption to power supply could be caused by distribution plant failure (i.e. poles, equipment, conductor, etc.).

e. I. See response to VECC IR#9 (o)
   II. See response to VECC IR#9 (o)
   III. Norfolk Power's pre-established criteria is to replace/refurbish aged plant and equipment

9. Ref: Exhibit 2/ Tab 3/ Schedule 3/ Capital Budget by Project/ Stations MTS &MS Project

- Please provide a typical study justifying station capital upgrades resulting from reliability considerations.
- Please provide, in summary form, Norfolk Power's reliability statistics for EACH OF the years 2002 through 2007 inclusive.

Response:

- These projects are completed due to damaged or aged equipment in order to provide a safe and reliable power supply. Studies are not typically completed for these types of projects. Also, these projects will assist in the future reduction of system losses.
- See below

	2002	2003	2004	2005	2006
SERVICE QUALITY INDICATORS					
% Completed within approved time					
Low Voltage Connections	100%	100%	100%	100%	100%
High Voltage Connections	100%	0%	100%	0%	0%
Cable Locates	100%	100%	100%	0%	100%
Phone Calls	80%	86%	n/a	96%	97%
Annual Appointments	100%	100%	100%	100%	100%
Annual Written Response	89%	93%	n/a	86%	97%
Emergency Urban Response	98%	100%	100%	100%	100%
Emergency Rural Response	96%	100%	100%	100%	100%
Service Reliability Indices:					
Saidi-Annual	21.1	1.3	2.0	2.2	2.2
Saifi-Annual	0.0	1.3	3.8	2.2	2.2
Caidi-Annual	n/a	1.0	0.1	1.0	1.0

Note: 2007 SQI is not currently available

10. Ref: Exhibit 2/ Tab 3/Schedule 3/ Capitalization Policy
Please confirm that there has been no change in capitalization policy for Norfolk Power. If there has been a change please provide details.

Response:

Norfolk Power has not changed it's capitalization policy. It is consistent with the Board's Accounting Procedures Handbook (APH), Article 410.

11. Ref: Exhibit 2/ Working Capital/ Page 33/ Line 11 Electricity Supply Expense and 15% thereof for Working Capital: 2006 actual to 2008: Please advise how much of the rise in Power purchase cost (from $21,098,843 to $23,963,786) is due to increased purchased electricity unit price cost and how much is due to increased customer usage.

Response:

	2006 Actual		2007 Bridge		2008 Test
Cost of Power	$21,098,843	3%	$21,731,808	10%	$23,963,786

The 3% increase from 2006 to 2007 is a combination of 1.5% increased customer usage and 1.5% increase in electricity unit price.
The 10% increase from 2007 to 2008 is a combination of 8% % increased customer usage and 2.0% increase in electricity unit price. Customer usage will grow substantially due to addition of two major commercial customers to the Simcoe area.

RETAIL TRANSMISSION RATES (RTR)

12. Ref: Retail Transmission Rates (RTR)

The Wholesale Transmission Rate will decrease 28% effective November 1 2007.

I) For each rate class, please provide the revised RTR Network Service Rate that would be revenue neutral over the 12 month period beginning May 1, 2008. (The amount collected by the RTR – Network Service Rate for each rate class equals the amount paid for the Wholesale Transmission Rate.)

The Wholesale Connection Transmission Rate will decrease 18% and the Wholesale Transformation Connection Transmission Rate will increase 7% effective November 1 2007.

II) For each rate class, please provide the revised rate your RTR– Line and Transformation Connection Service Rate that would be revenue neutral over the 12 month period beginning May 1, 2008. (The amount collected by the RTR - Line and Transformation Connection Service Rate for each rate class equals the amount paid for the Wholesale Connection Transmission Rate and the Wholesale Transformation Connection Transmission Rate.)

Deferral and Variance Accounts 1584 & 1586

Utilities have been required to provide information on Account 1584 RSA NW and 1586 RSVA CN to the Board as part of the quarterly RRR filings. The Board may need confirmation of the actual balances in these accounts in order to set a rate rider for the RTS rates.

III) What are your current balances for Accounts 1584 RSA NW and 1586 RSVA CN?

IV) Please explain how your balances in Accounts 1584 RSA NW and 1586 RSVA CN have trended or fluctuated since January 1 2005.

V) Assuming your RTR – Network Service Rate for each rate class is revenue neutral, please provide the rate riders you would recommend beginning May 1 2008, and the duration in months for each rate rider, to reduce the balance in Account 1584 RSVA NW to a $0 balance. Please provide an explanation for the recommended duration of the rate riders.

VI) Assuming your RTR - Line and Transformation Connection Service Rate for each rate class is revenue neutral, please provide the rate riders you would recommend beginning May 1 2008, and the duration in months for each rate rider, to reduce the balance in Account 1586 RSVA CN to a $0 balance. Please provide an explanation for the recommended duration of the rate riders.

Response:

I. Exhibit 9/Tab 1/Schedule 3/Page 1 outlines the proposed RTR Network Service Rate for each rate class of Norfolk Power and the method used to determine the proposed rate. The method is based on revenue neutrality and assumes the wholesale transmission network rates will decrease by 18.3%.

II. Exhibit 9/Tab 1/Schedule 3/Page 1 outlines the proposed RTR Connection Service Rate for each rate class of Norfolk Power and the method used to determine the proposed rate. The method is based on revenue neutrality and assumes the wholesale transmission line connection rates will decrease by 28%; however, the wholesale transmission transformer connection rates will increase by 7.3%.

III. As outlined in Exhibit 5/Tab 1/Schedule 3/Page 1, the December 31, 2006 balance for account 1584 is $49,582 and for account 1586 is ($245,374). When interest to April 30, 2008 is included the balance for account 1584 is $52,872 and for account 1586 is ($258,706).

IV. See response to OEB IR #42

V. The proposed rate riders determined in Exhibit 5/Tab 1/Schedule 3/Page 1 are designed to recover Norfolk Power's December 31, 2006 deferral and variance account balances plus interest to April 30, 2008. The recovery of balances for accounts 1584 and 1586 are included in the rider. Norfolk Power proposed to recover the deferral and variance account balances over a three year period as this is expected period of rebasing. Norfolk Power plans to review the deferral and variance account balances at the time of the next rate rebasing application is prepared and develop a method of recovery for the actual balances at that time

VI. See response to V.

OPERATING COSTS

CORPORATE COST ALLOCATION

13. Ref: Exhibit 4 / Tab 2 / Schedule 4 / Page 1 Please confirm whether there are shared services between Norfolk Power Distribution Inc. and Norfolk Power Inc.

    Section 2.5 (Exhibit 4 Part D) of the Filing Requirements for Transmission and Distribution Applications states that Applicants are to file detailed description of the assumptions underlying the corporate cost allocation as well as provide documentation of the overall methodology and policy.

    Response:

    Shared services does not exist between Norfolk Power Distribution Inc. and Norfolk Power Inc.

14. Ref: Exhibit 4 / Tab 2 / Schedule 7 Re: The following tables: “Compensation (Total Salary and Wages ($))” and “Compensation (Total Benefits)”.

I. Please provide expanded versions of these tables showing test year data for 2008.

II. Please explain the variances, if any, between the 2008 and 2007 figures for employees compensation (total salary and wages), compensation (total benefits), and compensation (total incentives) for each employee type: Executive, Management, Non-unionized, and Unionized.

Response:

I. See below

Compensation (Total Salary and Wages ($)):

	2006 Board Approved	Average	2006 Actual	Average	2007 Bridge	Average	Variance	2008 Test	Average
Executive	$0	$95,892	$381,722	$95,430	$393,182	$98,296	4%	$410,764	$102,691
Management	$0	$59,014	$552,893	$61,433	$710,824	$64,260	4%	$741,876	$67,443
Non-Unionized	$0	$30,369	$168,553	$28,092	$180,980	$30,163	-67%	$59,456	$29,728
Unionized	$0	$46,948	$1,958,954	$54,415	$1,968,699	$54,686	-3%	$1,912,363	$53,121

Compensation (Total Benefits ($)):

	2006 Board Approved	Average	2006 Actual	Average	2007 Bridge	Average	Variance	2008 Test	Average
Executive	$0	$22,537	$86,318	$21,580	$97,852	$24,463	13%	$110,573	$27,643
Management	$0	$11,512	$124,214	$13,802	$173,958	$15,814	13%	$196,573	$17,870
Non-Unionized	$0	$3,371	$15,135	$2,523	$16,020	$2,670	6%	$16,981	$5,660
Unionized	$0	$13,102	$539,377	$14,983	$579,170	$16,088	8%	$625,504	$17,375

II. Compensation (Total Salary and Wages):

Executive & Management – a 4% increase from 2007 to 2008 is due to increase in wages for those staff on progression + 3% for cost of living adjustment (inflation).

Non-Unionized – a 67% reduction from 2007 to 2008 is due to elimination of certain contract and part-time employees.

Unionized – a 3% reduction from 2007 to 2008 is due to net of 3% for cost of living adjustment (inflation) and two positions on short-term disability.

15. Ref: Exhibit 4 / Tab 2 / Schedule 7

On Page 1, Norfolk Power provides a comparison of total salary and wages for 2006 and 2007. Please explain the 16% differential between the 2006 Board approved amount of $46,948 in average unionized compensation and the 2006 actual amount of $54,415.

Response:

- The 2006 EDR used the average of 2004 Wages. The following events perspired in 2005 and 2006 that was not provided for in the 2006 EDR:
  - (2) additional employees (Journeyman Lineman and P&C Technologist) were added to the staff complement. The wages for these (2) employees must be added to 2005 and 2006
  - Pay Equity was processed for certain union employees in 2005
  - Cost of living increases of 3% for 2005 and 2006, respectively
- Below is a reconciliation from the 2006 EDR approved average and 2006 Actual average

Wages used for 2006 Approved EDR average		**$1,596,237.66**
Cost Of living Adjustments - 2005 @ 3%		**47,887.13**
	Sub-total	**$1,644,124.79**
Cost Of living Adjustments - 2006 @ 3%		**49,323.74**
	Sub-total	**$1,693,448.53**
Wages for (2) additional employees - 2005		**111,632.55**
	Sub-total	**$1,805,081.08**
(2) additional employees hired in 2005 - 2006		**114,981.53**
	Subtotal	**$1,920,062.61**
Pay Equity		**38,892.33**
Actual for 2006	TOTAL	**$1,958,954.94**

2006 Board Approved = $1,596,237.66 / 34	**$46,948**
2006 Actual = $1,958,954.94 / 36	**$54,415**

16. Ref: Exhibit 4 / Tab 2 / Schedule 7

Page 1 provides a comparison of total benefits from 2006 to 2007.

- Please explain the 13% increase in average executive benefits, from $21,580 in 2006 to $24,463 in 2007.
- Please explain the 15% increase in average management benefits, from $13,802 in 2006 to $15,814 in 2007.

Response:

- The 13% increase in average Executive benefits is the result of:
    - Executive benefits are a function of gross wages. In 2007, average increase due from wages is 3%
    - As per the benefits carrier for Norfolk Power (Equitable Life of Canada), increases for benefits such as LTD, Dental, Extended Health, historically increase between 5% - 8% annually. Norfolk Power used 5% for the 2007 Bridge year. Also, some staff have shifted from single coverage to family coverage, which is substantially higher in cost
    - Norfolk Power also implemented a new benefit in 2006 for all staff. The incremental increase from 2006 to 2007 for Executives is approximately 2.0%
    - Incremental increase in other benefit costs (i.e. employer's share for OMERS, EI, CPP, WSIB) of approximately 3%
- The 15% increase in average management benefits is the same as mentioned above for Executive. The only difference is the staff complement for management had increased from 9 to 11, which represents an additional increase of approximately 2%.

17. Ref: Exhibit 4 / Tab 2 / Schedule 7

On Page 1, Norfolk Power provides a comparison of total benefits from 2006 to 2007.

- Please explain the 20% differential between the 2006 Board approved amount of $11,512 in average management benefits and the 2006 actual amount of $13,802.
- Please explain the 14% differential between the 2006 Board approved amount of $13,102 in unionized benefits and the 2006 actual amount of $14,983.

Response:

- See below

Benefits used for 2006 Approved EDR		**$115,120.00**
Cost Of living Adjustments - 2005 @ 3%		**3,453.60**
	Sub-total	**$118,573.60**
Cost Of living Adjustments - 2006 @ 3%		**3,557.21**
	Sub-total	**$122,130.81**
Less: Benefit for (1) less employee		**(11,512.00)**
	Sub-total	**$110,618.81**
New Benefit		**13,595.19**
	Subtotal	**$124,214.00**

2006 Board Approved = $115,120 / 10	**$11,512**
2006 Actual = $124, 214 / 9	**$13,802**

- See below

Benefits used for 2006 Approved EDR		**$445,468.00**
Cost Of living Adjustments - 2005 @ 3%		**13,364.04**
	Sub-total	**$458,832.04**
Cost Of living Adjustments - 2006 @ 3%		**13,764.96**
	Sub-total	**$472,597.00**
Add: Benefits for (2) additional employees		**26,204.00**
	Sub-total	**$498,801.00**
New Benefit		**40,576.00**
	Subtotal	**$539,377.00**

2006 Board Approved = $445,468 / 34	**$13,102**
2006 Actual = $539,377 / 36	**$14,983**

18. Ref: Exhibit 4 / Tab 2 / Schedule 7

On Page 1, Norfolk Power provides a breakdown of employee compensation from 2006 to 2007. Please confirm whether or not Norfolk Power has overtime compensation. If so, please provide a breakdown of overtime amounts for 2006, 2007 & 2008, including Historical Board Approved and Historical Actual.

Response:

Norfolk Power has overtime compensation. The following table presents the data for 2006 Board Approved, 2006 Actual, 2007 Bridge and 2008 Test.

	2006 Board Approved	**2006 Actual**	**2007 Bridge**	**2008 Test**
Overtime	$224,700	$174,337	$182,000	$185,000

19. Ref: Exhibit 4 / Tab 2 / Schedule 7

On Page 1, Norfolk Power provides a breakdown of employee compensation from 2006 to 2007. Please confirm whether or not Norfolk Power employs any staff on contract that are not listed in Exhibit 4/Tab 2/ Schedule 7 under “Part-time Equivalent”. If so, please provide a breakdown identifying the number of staff, their compensation, and their benefits for 2006 (including Historical Board Approved and Historical Actual), 2007 and 2008.

Response:

Norfolk Power included staff on contract under “Part-time Equivalent”.

20. Ref: Exhibit 4 / Tab 2 / Schedule 7

On Page 2, Norfolk Power indicates that total costs charged to O&M is not applicable to the utility. Please explain where total compensation costs were charged in 2006 and 2007 and where total costs will be charged in 2008.

Response:

This is an oversight by Norfolk Power. A revised Exhibit 4/Tab2/Schedule 7/Page 2 is provided below.

Total of Costs charged to O&M ($)):

	2006 Board Approved	Average	2006 Actual	Average	2007 Bridge	Average	2008 Test	Average
TOTAL	$0	$0	$1,531,061	$27,837	$1,724,453	$30,254	$1,655,963	$30,666

21. Ref: Exhibit 4 / Tab 2 / Schedule 7 Please provide details regarding:

I) the status of Norfolk Power's pension fund and all assumptions used in the analysis.
II) costs for the years 2006, 2007, and 2008.

Response:

Norfolk Power is a contributing member to the Ontario Municipal Employees Retirement System (OMERS). The costs for 2006 Actual, 2007 Bridge and 2008 Test is provided below.

	2006 Actual	**2007 Bridge**	**2008 Test**
OMERS Employer Contributions	$206,357	$228,380	$240,556

OM&A EXPENSES

22. Ref: General Question
    a. Please confirm whether Norfolk Power
        I. made any changes to it’s accounting policies in respect to capitalization of operation expenses
        II. made any significant changes to accounting estimates used in allocation of costs between operations and capital expenses post fiscal year end 2004.

    If any accounting policy changes or any significant changes in accounting estimates have been made post 2004 fiscal year end, please provide all supporting documentation and a full explanation highlighting the impact of the changes.

Response:

Norfolk Power did not change any accounting policies with respect to capitalization of operating expenses or accounting estimating used in allocation of costs between operations and capital expense.

23. Exhibit 4/ Tab 2/Schedule 1
Table 1 below was prepared to review Norfolk Power OM&A expenses. Note rounding differences may occur, but are immaterial to the questions below. This table removes, from the 2006 Board approved controllable expenses, the Low Voltage and Energy Conservation Expenses which allows a better comparison of Norfolk Power's controllable expenses over the reporting period.

Table 1

OM&A COSTS	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
Operation	757,522	1,073,025	1,197,000	1,207,774
Maintenance	747,613	641,406	925,000	933,326
Billing and Collections	856,868	814,191	944,000	952,497
Community Relations	24,718	24,169	28,000	28,252
Administrative and General Expenses	1,459,232	1,244,865	1,447,000	1,822,023
Total Controllable OM&A	3,845,953	3,797,656	4,541,000	4,943,872
Amortization Expenses	2,381,357	1,817,778	2,631,128	2,836,810
4750-LV Charges	371,652	231,386	371,652	371,652
5415-Energy Conservation	563	125,766	68,000	68,612
6105-Taxes Other Than Income Taxes	67,981	66,370	85,000	85,765
Total O M & A	6,667,506	6,038,956	7,696,780	8,306,711

Table 2 below was created to review Norfolk Power's OM&A forecasted expenses from the evidence provided at Exhibit 4/Tab 2/Schedule 1. Note rounding differences may occur, but are immaterial to the following questions. Board staff notes that Norfolk Power is forecasting increases to 2008 Controllable OM&A Expenses by $1,146,216, or 30.2% from Actual 2006.

OM&A COSTS	2006 Board Approved	Variance 2006/2006	2006 Actual	Variance 2007/2006	2007 Bridge	Variance 2008/2007	2008 Test	Variance 2008/2006
Operation	$757,522	$315,503	$1,073,025	$123,975	$1,197,000	$10,774	$1,207,774	$134,749
		8.20%		3.30%		0.20%		3.50%
Maintenance	747,613	-106,207	641,406	283,594	925,000	8,326	933,326	291,920
		-2.80%		7.50%		0.20%		7.70%
Billing and Collections	856,868	-42,677	814,191	129,809	944,000	8,497	952,497	138,306
		-1.10%		3.40%		0.20%		3.60%
Community Relations	24,718	-549	24,169	3,831	28,000	252	28,252	4,083
		0.00%		0.10%		0.00%		0.10%
Administrative and General Expenses	1,459,232	-214,367	1,244,865	202,135	1,447,000	375,023	1,822,023	577,158
Total Controllable OM&A		-5.60%		5.30%		8.30%		15.20%
	3,845,953	(48,297)	3,797,656	743,344	4,541,000	402,872	4,943,872	1,146,216
		-1.30%		19.60%		8.90%		30.20%

Table 3 below was created to review Norfolk Power's OM&A actual and forecasted expenses from the evidence provided in OM&A Cost

Table in Exhibit 4/ Tab 2/Schedule 2. Note rounding differences may occur, but are immaterial to the following questions.

Table 3
O M & A Cost Drivers

	2006	2007	2008
Opening Balance - Jan 1	3,845,953	3,797,656	4,541,000
Trouble Calls - Overhead	105,366		
Trouble Calls - Underground	102,837		
Charges to previous accounts and overhead for IT Services	137,140		
PCB Testing not completed	-80,893		
Reallocation of IT Expenses	-169,362		
Scada Operation and IT Costs		121,141	
Smart Meter contra account			362,000
5315-Customer Billing	114,515	86,816	4,563
5320-Collecting	15,934	16,915	2,007
5330-Collection Charges	-49,300	18,318	-630
5335-Bad Debt Expense	-46,207	56,830	1,080
5615-General Administrative Salaries and Expenses	-169,362	60,245	4,086
5620-Office Supplies and Expenses	-34,617	19,343	1,494
5655-Regulatory Expenses	-32,375	67,116	855
Unexplained Difference	58,027	296,620	27,417
Closing Balance Dec 1	3,797,656	4,541,000	4,943,872

a. Please confirm that Norfolk Power agrees with the results presented in the three tables above. If Norfolk Power does not agree with one or more of the tables or the information contained in them please fully explain why not.
b. Please complete a Cost Drivers by Year analysis table similar to the Board Staff Table 3 above identifying the cost drivers (incremental expenses that affect common costs i.e. payroll increases) that make up the changes to Norfolk Power's annual controllable expenses. The objective of this request is to have Norfolk Power identify all significant expense cost drivers that reduce the "Unexplained Difference" to an amount no greater than plus or minus Norfolk Power's calculated OM&A materiality limits.

   Please include values that show the incremental changes to current employee salary and benefit increases from new staff changes and list these separately. You may report these values on a consolidated company basis as opposed to by department or USoA account similar to the O&M Wages and Benefits line where the values include multiple USoA amounts.

   Please ensure that each identified driver is followed with a detailed explanation and includes any additional information Norfolk Power believes is required. Examples include but are not limited to: "Trouble Calls – Overhead" would benefit from an explanation as to what precipitated this action, providing an explanation for "Charges to previous accounts and overhead for IT Services".

   Board staff have extracted drivers identified in the application for example purposes only but Norfolk Power is free to change the descriptions and values presented to provide a more meaningful document.

Some transactions entered may be one time charges, which may not be repeated in the following year. Please ensure that one time charges are identified.

c. Norfolk Power includes the incremental value of $67,166 for regulatory costs in 2007 and $855 in 2008 (see Table 3 above).
   I. Please provide an explanation for the increases in 2007 and 2008. Please fully explain the component costs of these expenses.
   II. Please explain why Norfolk Hydro expects to continue to incur these costs over the next two years while under 3rd generation IRM.
d. On Exhibit 4, Tab 2, Schedule 1, Page 4 Bad Debt Expense. Is shown increasing from $63,170 in 2006 Actual to $121,080 in 2008.
   I. Please provide details of the components (i.e. energy sales, work order recoveries etc.) that are included in Bad Debt Expenses.
   II. Please describe the methodology(s) employed by Norfolk Power to calculate the value for Bad Debt Expense.
   III. Please describe Norfolk Power's plan to manage the increase in Bad Debt Expenses.

Response:

a. Norfolk Power agrees with the results presented in the three tables above.
b. See revised Table 3 below with explanations to follow

Table 3

O M & A Cost Drivers	**2006 Actual**	**2007 Bridge**	**2008 Test**
Opening Balance - Jan 1	$3,845,953	$3,797,656	$4,541,000
5010-Load Dispatching		121,304	
5013-TS Buidlings and Fixtures Expense		7,296	
5014-TS Equipment		15,625	
5017-MS & DS Operating Supplies & Expenses		(7,496)	
5020-Overhead Distribution Operation		(7,726)	
Trouble Calls - Overhead	105,366	(21,931)	
5065-Meter Expense		28,278	
5095-O/H Lines and Feeders - Rental Paid		(2,990)	
5110-MS & DS Building Maintenance		65,303	
5112-TS Equipment Maintenance		28,443	
5114-MS & DS Equipment Maintenance		57,033	
5135-O/H Lines & Feeders - Right of Way		31,905	
5160-Transformer Maintenance		20,000	
Trouble Calls - Underground	102,837		
Charges to previous accounts and overhead for IT Services	137,140		
PCB Testing not completed	(80,893)		
Reallocation of IT Expenses	(169,362)		
Smart Meter contra account			362,000
5305-Billing & Collecting Supervision		3,309	
5310-Meter Reading		5,951	
5315-Customer Billing	114,515	116,138	4,563
5320-Collecting	15,934	17,342	2,007
5330-Collection Charges	(49,300)	(27,873)	(630)
5335-Bad Debt Expense	(46,207)	56,830	1,080
5605-Executive Salaries and Expenses		5,470	

5615-General Administrative Salaries and Expenses	(169,362)	59,669	4,086
5620-Office Supplies and Expenses	(34,617)	19,343	1,494
5655-Regulatory Expenses	(32,375)	67,119	855
5665-Miscellaneous General Expense		11,000	
5680-ESA Fees		6,000	
Unexplained Difference	58,027	68,002	27,417
Closing Balance Dec 31	$3,797,656	$4,541,000	$4,943,872

2006

Overhead and Underground Trouble Calls - New sub-account created as a subset of Account 5020 and 5040 to track "Trouble Calls" pertaining to the overhead distribution system for power outages experienced during regular and after hours. Before 2006, "Trouble Calls" were charged to various accounts, which made tracking these costs difficult. At the end of the year, this account is reviewed and where possible, a re-allocation is made to capital.

IT Services and Reallocation of IT Expenses: As of January 1, 2006, the IT function was treated as an overhead to all user accounts. Prior to this, IT expenses were an integral part of General Admin. A corresponding decrease should be evident in General Adminstration expenses.

PCB Testing not completed: Deferred to 2007 and 2008

5315-Customer Billing : includes share of IT Expenses

5320-Collecting : Includes share of IT expenses

5330-Collection Charges: Increased volume

5335-Bad Debt Expense: Actual was lower than anticipated

5615-General Administrative Salaries and Expenses: IT Expenses removed

5620-Office Supplies and Expenses: Stationary decreased by $3,597; postage reduced substantially by $22,932 because of more efficient use of mail; communications expense decreased by $5,582

5655-Regulatory Expenses : OEB fees substantially lower that Board approved and system programming changes lower than anticipated.

2007

5010-Load Dispatching: Contract Operator + new Operator in Training

5012-MS & DS Buidlings and Fixtures Expense :Decrease in costs to maintain stations

5013-TS Buidlings and Fixtures Expense : add labour for maintenance program + costs to add three data circuits

5014-TS Equipment: Increase in labour for routine calibration testing

5017-MS & DS Operating Supplies & Expenses: Decrease due to Less oil sampling testing required

5020-Overhead Distribution Operation: Training labour removed and charged to appropriate account

5065-Meter Expense: additional labour charged for supervision of meter operations

5095-O/H Lines and Feeders - Rental Paid: Less poles subject to pole attachment fees

5110-MS & DS Building Maintenance: Various substations require structural repairs and maintenance

5112-TS Equipment Maintenance: costs to repair leaking breaker, OEB mandated reverification

5114-MS & DS Equipment Maintenance: repair transformer oil leaks, PCB Testing and removal

5135-O/H Lines & Feeders - Right of Way: Forestry Audit

5160-Transformer Maintenance: PCB Testing

5305-Billing & Collecting Supervision : 3% increase in wages

5310-Meter Reading: 1% Growth + 3% Inflation

5315-Customer Billing : Increase allocation of IT of $51,666 + $64,472 increase in labour

5320-Collecting: Increase allocation of IT of $12,916 + $4,426 increase in labour

5605-Executive Salaries and Expenses: 3% Inflationary increase for labour

5615-General Administrative Salaries and Expenses: Increase in IT Allocation $15,198 + Increase in legal fees $10,296 for Collective Agreement bargaining and labour related + $9,641 increase in labour + $24,534 Other

5620-Office Supplies and Expenses : Includes $11,000 for Tower Rental Space for the radio system

5655-Regulatory Expenses: $16,457 for Cost Allocation Fees + $25,408 OEB Fees + system changes for OEB & IESO Market Compliance

5665-Miscellaneous General Expense: Increase in Governance costs

5680-ESA Fees: $2,000 increase in annual fee + $4,000 for ESA Audit

2008

Smart Meter contra account

5315-Customer Billing : 3% inflationary increase

5320-Collecting : 3% inflationary increase

5330-Collection Charges : immaterial

5335-Bad Debt Expense : Increase as per bad debt analysis

5615-General Administrative Salaries and Expenses: 3% inflationary increase

5620-Office Supplies and Expenses : increase in rental costs of Tower for radios

5655-Regulatory Expenses: Increase is immaterial. But it is due to expenses for consultant for the 2008 EDR Application

c. Norfolk Power includes the incremental value of $67,166 for regulatory costs in 2007 and $855 in 2008 (see Table 3 above).
   I. The overall increase from 2007 to 2008 of $855 is a coincidence. The component costs of these expenses are as follows:

	2007 Bridge	2008 Test
Regulatory Expenses - OEB Annual Fees; Cost Assessments	$66,500	$67,000
Regulatory Expenses - Non OEB (Rates, Cost Allocation, etc.)	28,500	28,855
	$95,000	$95,855

   II. Norfolk Power does not expect to continue to incur these costs over the next two years while under 3rd generation IRM.

d. On Exhibit 4, Tab 2, Schedule 1, Page 4 Bad Debt Expense. Is shown increasing from $63,170 in 2006 Actual to $121,080 in 2008.
   I. The components that are included in Bad Debt Expenses are sale of energy - all components i.e. WMS, CN, NW, etc. (SSS and Retailer)
   II. Norfolk Power uses actual uncollectible accounts to budget Bad Debt Expense. For example, at December 31, 2007, our billing system will generate a listing of all delinquent accounts as at December 31, 2006. This amount will be written-off to Bad Debt Expense for 2007.
   III. Norfolk Power's plan to manage the increase in Bad Debt Expenses are as follows:
      - Redefine existing policy for collecting deposits
      - Implement a more aggressive collection policy
      - Make use of SIDs or Load Limiters on delinquent accounts
      - Revise billing and payment cycle

24. Exhibit 4/ Tab 2/ Schedule 1

Please prepare a comprehensive listing of all operational costs by work unit for smart meter costs included in the 2008 budget. Include in this listing the work unit where the smart meter cost is accounted for in the budget, description of the activity and amount budgeted. In particular, please identify for each of the reported budget amounts whether Norfolk Power considers the cost to be a component of minimum functionality, or if the amount is incidental/incremental to minimum functionality. In addition, please provide the breakdown of the budget for operating vs. the capital expenditure for the smart meters.

Response: Please see table below

SMART METERS	2008	
	Capital	Operating
Repair of unsafe meter bases	$45,222.75	$0.00
Costs for Detailed Propagation Studies	$0.00	$0.00
Smart Meter Network Infrastructure		
AMCD Vendor 5	$2,480,025.60	$0.00
AMRC Including WAN Costs Vendor 5	$249,628.81	$32,989.06
AMCC Vendor 5	$171,032.35	$30,678.47
AMI Miscellaneous (Including Labour For Daily Ops) Vendor 5	$10,739.00	$108,150.00
Smart Meter Installation Process Vendor 4	$268,607.32	
Adaptor Installation Vendor 4	$1,128.30	
Workforce Management System Vendor 4	$18,021.00	
Capturing of GPS Coordinates Vendor 4	$1,261.47	
Imaging of All Old Meters Vendor 4	$8,229.59	
Delivery of Customer Notification Package Vendor 4	$7,869.17	
Meter Seals	$6,175.50	
Meter Rings	$87,486.25	
Meter Adaptors	$154,387.50	
Rent for Space for Meter Inventory and Scrapping Process	$50,000.00	
AMI Installation Operational Verification Tools (Temp MDM/R)		$86,457.00
Scrapping Process Separation Costs	$36,800.00	
Meter Scrapping/Recycling Process	-$20,585.00	
Staff Training and Department Integration	$15,000.00	
AMI Warranty Costs (1% Failure Rate)	$27,426.48	
Measurement Canada Re-Verification Accrual Account	$41,473.59	
AMI Inventory Costs (Meters to Replace Rever Meters)	$41,333.76	
Contingency at 5%	$185,063.17	$12,913.73
Section Sub Total	$3,886,326.61	$271,188.25
Total Smart Meter Assest Investment	$3,935,857.99	
Total Depreciation Amount Based On 15 Years Straight Line	$265,692.63	
Current Value of Sections Smart Meter Assets	$3,670,165.37	

BILLING / CUSTOMER SERVICE		
CIS Automated Meter Change Package	$25,085.00	
Smart Meter Customer Presentment Tools (Web, IVR)	$50,170.00	$0.00
Smart Meter Entity MDM/R (est Based On OEB 2005 Report)	$15,000.00	$86,457.00
Bill Print Modifications	$0.00	
Customer Education Packages	$41,170.00	
CIS TOU Modifications and MDM/R Integration	$15,000.00	
Staff Training and Department Integration	$0.00	
Contingency at 5%	$7,321.25	$4,322.85
Section Sub Total	$153,746.25	$90,779.85
Total Smart Meter Assest Investment	$153,746.25	
Total Depreciation Amount Based On 3 Years Straight Line	$30,749.25	
Current Value of Sections Smart Meter Assets	$122,997.00	
FINANCE / CORPORATE		
Consulting Services	$20,000.00	
Legal for AMI Contracts		
Legal for Installation Contract		
Legal for Old Meter Recycling Contract		
AMI Security Audits		$0.00
Contingency at 5%	$1,000.00	$0.00
Section Sub Total	$21,000.00	$0.00
Total Smart Meter Assest Investment	$77,700.00	
Total Depreciation Amount Based On 15 Years Straight Line	$8,960.00	
Current Value of Sections Smart Meter Assets	$68,740.00	
	2008	
	Capital	**Operating**
Totals	$4,061,072.86	$361,968.10

For all of the components of the Smart Meter budget above, Norfolk Power considers the cost to be of minimum functionality.

25. Ref: Exhibit 1 / Tab 3 / Schedule 1 – 2006 Audited Financial Statements

Please provide a complete copy of Norfolk Power's 2006 Audited Financial Statements, including all Notes to the Audited Financial Statements.

Response:

Please see the end of this report.

OPERATING REVENUE

26. Ref: Exhibit 3/ Tab 2/ Schedule 1/ page 1

In Schedule 1, page 1, Norfolk Power very briefly explains how it developed its 2008 load forecast. While parts of the explanation are missing, the Applicant appears to have used a similar approach to some other applicants. Hence, the approach used appears to be that the Applicant:

- determined the 2008 forecasted customer count for each customer class,
- determined the weather-normalized retail energy for each customer class for 2004,
- determined the 2004 retail normalized average use per customer (NAC) for each class by dividing each of these weather-normalized retail energy values by the number of customers/connections in each class existing in 2004,
- applied the 2004 NAC for each class to the 2008 Test Year without modification, and
- determined the 2008 Test Year energy forecast for each customer class by multiplying the applicable 2004 NAC for each class by the 2008 forecasted customer count in that class.

Please verify that the above is the essence of the Applicant's load forecasting methodology, and fully correct any errors in the above explanation.

Response:

The above description of the load forecast methodology for the normalized values is correct for the Residential and GS<50 kW classes. For the GS > 50 kW class, the 2004 NAC value was 16% lower than the 2006 average use per customer value. If the 2004 NAC was used for the GS > 50 kW class the distribution volumetric rate would have been 16% higher than the proposed distribution volumetric rate for this class and in Norfolk Power's view this would be unreasonable. Consequently, for the GS > 50 kW class, Norfolk Power decided to use the 2006 average use per customer value and adjusted it by the ratio of 2004 actual to normalized volumes as outlined in the 2004 Hydro One data used for the cost allocation study.

The non-weather sensitive classes such as Street Lighting, Sentinel Lights and Unmetered Scattered Load do use a normalized average use per customer.

27. Please provide the Hydro One report and any spreadsheets containing data supporting the calculations of the normalized historical load.

Response:

Please see table below

RUN # 2	Rate classes	Weather station used for normalization	Test Year
1	Residential	Windsor	2004
2	GS>50kW		
3	Street Lighting		
4	GS<50kW		
5	Sentinel Lighting		
6	USL		

Monthly kWh by class (with actual weather)		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
1	Residential	15,412,691	13,008,235	14,139,977	10,919,371	9,550,762	10,635,167	12,260,734	11,910,864	11,222,124	10,389,806	11,701,162	14,663,715	145,814,609
2	GS>50kW	12,258,276	12,243,192	12,557,962	11,507,339	12,233,407	12,164,404	12,426,403	11,955,311	12,214,696	12,570,017	13,055,429	12,287,712	147,474,148
3	Street Lighting	303,391	283,817	303,391	294,048	303,389	293,603	320,933	320,934	310,582	320,934	309,101	320,933	3,685,056
4	GS<50kW	6,337,803	5,996,177	6,125,921	5,318,336	5,027,089	5,283,817	5,872,733	6,321,028	5,761,987	5,537,025	5,572,150	6,052,728	69,206,795
5	Sentinel Lighting	27,244	27,105	27,091	26,951	26,994	26,944	27,725	25,954	26,382	26,658	26,202	26,334	321,582
6	USL	14,651	14,651	14,651	14,651	14,651	14,651	14,651	14,651	14,651	14,651	14,651	16,185	177,341

Monthly kWh by class (with normalized weather)		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
1	Residential	14,908,062	13,157,978	14,553,844	11,127,190	9,584,155	11,235,802	12,817,460	12,684,890	11,042,143	10,695,845	12,139,135	14,605,330	148,551,834
2	GS>50kW	12,129,701	12,281,346	12,663,412	11,560,289	12,241,539	12,293,788	12,546,328	12,122,045	12,173,695	12,647,993	13,167,021	12,272,836	148,099,993
3	Street Lighting	303,391	283,817	303,391	294,048	303,389	293,603	320,933	320,934	310,582	320,934	309,101	320,933	3,685,056
4	GS<50kW	6,211,631	6,033,618	6,229,400	5,370,297	5,036,844	5,522,510	6,093,977	6,628,627	5,698,811	5,613,544	5,681,657	6,038,130	70,159,045
5	Sentinel Lighting	27,244	27,105	27,091	26,951	26,994	26,944	27,725	25,954	26,382	26,658	26,202	26,334	321,582
6	USL	14,651	14,651	14,651	14,651	14,651	14,651	14,651	14,651	14,651	14,651	14,651	16,185	177,341

Residential class information		Equipment saturation
	Electric space heating	8%
	Electric water heating	16%
	Air conditioning	55%
	Baseload	100%

General service >50kW		2004 kWh (Actual)	2004 kWh (Weather Corrected)
	Weather sensitive load	57,259,714	57,885,559
	Non-weather sensitive load	90,214,434	90,214,434
	TOTAL	147,474,148	148,099,993

28. Ref: Ex 3/ Tab 2/Schedule 1/Page 2

Issue: In Schedule 1, page 2, the Applicant explains that it established the number of streetlights shown in the table on that page for the year 2006 by physically counting them. As a result, the number of streetlights shown in the table drops from 3,800 in 2005 to 3,050 in 2006.

Please fully explain the situation including:

a. The background that required such a large correction/change to be made, and
b. The Applicant's rationale for not apparently reflecting the correction/change in years prior to 2006.

Response:

Norfolk Power used an incomplete file when the street light numbers were reported in the application. From further investigation, the actual number for street lighting is in fact, 3,850 and not 3,050 as reported previously.

29. <u>Ref: 3/2/1/p2 and 3/2/2/p1</u>

Issue: In Schedule 1, page 2, the Applicant presents a table of Customer Forecast data. In Schedule 2, page 1, the Applicant presents a table of Normalized Volume Forecast data. There appears to be a significant difference in customer growth and load growth.

a. Please verify that the average annual increase in customers for the 2006-2008 period in Schedule 1, page 2 is about 0.1%,
b. Please verify that the average annual increase in load for the 2006-2008 period in Schedule 2, page 1 is about 2.2%, and
c. Please explain the physical changes in load utilization that the Applicant expects to see in the 2006-2008 period that rationalizes these forecasted changes.

Response:

a. In Schedule 1, page 2, the total number of customer in 2006 excluding connections is 18,384. The total number of customer in 2008 is 18,831. This represents a increase of 2.4% from 2006 to 2008 which is an annual average increase of 1.2%.

b. In Schedule 2, page 1 For those classes that have customers (i.e. Residential, GS < 50kW and GS > 50 kW) the total normalized kWh's in 2006 is 383,949,548. The total normalized kWhs in 2008 is 401,274,778 This represents a increase of 4.5% from 2006 to 2008 which is an annual average increase of 2.2%.

c. There is a higher annual average increase in kWhs compared to the increase in customer numbers since a new manufacturing plant was connected to the Norfolk Power system January 1, 2008. The plant is expected to use on average 916,150 kWhs per month. As a result, the kWhs associated with the plant are in for a full year in 2008 but are not in 2006.

30. Ref: 3/2/1/p1

Issue: In Schedule 1, page 1, the Applicant explains how it determined the 2004 retail normalized average use per customer (NAC) for each class and apparently used this value for other years also. This does not appear to adequately weather-normalize the energy usage in historical years and does not allow for the possible change in energy usage per customer over the 2002 – 2008 period due, for example, to Conservation and Demand Management. The minimal amount of weather normalization and the constant retail energy assumption could potentially lead to forecasting errors.

a. Please file a data table for the historical years 2002 to 2006 that shows:

I. the actual retail energy (kWh) for each customer class in each year,

II. the weather normalized retail energy (kWh) for each customer class in each year (where, for the customer classes that the Applicant has identified as weather sensitive, the weather normalization process should, as a minimum, involve the direct conversion of the actual load to the weather normalized load using a multiplier factor for that year and not rely on results for any other year),

III. the values of the weather conversion factors used,

IV. the customer count for each class in each year,

V. the retail normalized average use per customer for each class in each year based on the weather corrected kWh data in item ii. above, and

VI. as a footnote to the table, the source(s) of the weather correction factors.

b. Please file a data table for the 2002 to 2008 period:

I) utilizing the retail normalized average use per customer values for each class in each year obtained in a) v. above for the historical years 2002 to 2006,

II) including 2007 and 2008 projections for the retail normalized average use per customer values (where, for each of the weather-sensitive classes, this is based on trends in the data) for each class, and

III) for each of the weather-sensitive classes, describe in detail the trend analysis performed in ii. above.

c. Please file an updated version of the Schedule 2, page 1, Normalized Volume Forecast Table, utilizing the weather corrected data determined in b) above.

Response:

a.

i. The following table outlines the actual retail energy (kWh) for each customer class for 2002 to 2006.

Customer Class	2002	2003	2004	2005	2006
Residential	134,772,689	137,538,000	136,303,616	144,724,830	139,960,236
GS < 50 kW	65,267,007	64,851,585	65,494,939	66,635,465	63,242,003
GS > 50 kW	138,361,916	142,885,583	146,981,638	144,362,624	174,720,116
Sentinel Lights	304,353	309,564	303,660	306,916	342,469
Streetlights	2,793,818	3,461,352	3,497,643	3,409,153	3,060,430
USL	231,982	471,986	406,396	406,396	406,396
Total	341,731,765	349,518,070	352,987,892	359,845,384	381,731,650

ii. The following table outlines the weather normalized retail energy (kWh) for each customer class for 2002 to 2006. The classes that have classified as weather sensitive are the Residential, GS < 50 kW and GS > 50 kW.

Customer Class	2002	2003	2004	2005	2006
Residential	131,619,008	136,602,742	136,480,811	142,640,792	141,037,930
GS < 50 kW	63,739,759	64,410,594	65,580,082	65,675,914	63,728,966
GS > 50 kW	135,124,247	141,913,961	147,172,714	142,283,802	176,065,461
Sentinel Lights	304,353	309,564	303,660	306,916	342,469
Streetlights	2,793,818	3,461,352	3,497,643	3,409,153	3,060,430
USL	231,982	471,986	406,396	406,396	406,396
Total	333,813,167	347,170,199	353,441,306	354,722,974	384,641,652

iii. The values of the weather conversion factors are shown below

2002	2003	2004	2005	2006
97.66%	99.32%	100.13%	98.56%	100.77%

iv. The customer/connection count for each class for 2002 to 2006 is provided in the following table.

Customer Class	2002	2003	2004	2005	2006
Residential	15,197	15,385	15,640	15,905	16,123
GS < 50 kW	2,181	2,144	2,132	2,107	2,098
GS > 50 kW	150	166	160	159	163
Sentinel Lights	389	380	400	400	400
Streetlights	3,750	3,749	3,800	3,800	3,050
USL	50	51	51	51	51
Total	21,717	21,875	22,183	22,422	21,885

v. The retail normalized average use per customer for each class in each year based on the weather corrected kWh data in item ii. above, is outlined in the following table

Customer Class	2002	2003	2004	2005	2006
Residential	8,661	8,879	8,726	8,968	8,748
GS < 50 kW	29,225	30,042	30,760	31,170	30,376
GS > 50 kW	900,828	854,903	919,829	894,867	1,080,156
Sentinel Lights	782	815	759	767	856
Streetlights	745	923	920	897	1,003
USL	4,640	9,255	7,969	7,969	7,969

vi In order to prepare this application Norfolk Power and its advisors researched various weather normalization methods and concluded that there were limited resources available in the industry to prepare a cost effective weather normalization forecast which would reflect the characteristic of Norfolk Power. However, in order to prepare the recent cost allocation study Norfolk Power, retained Hydro One, as most other distributors in the province did, to weather normalize the 2004 volumes by rate class. From the documentation provided by Hydro One the following summaries the weather normalization process used in the cost allocation study.

"Weather correction is a statistical process designed to remove the impact of abnormal or extreme weather conditions from historical load data. Normal weather data is defined to be data that is based on the average weather conditions experienced over the last 31 years. A weather-normal load forecast is a forecast of load assuming normal weather conditions with a weather-corrected base year. The weather correction method is applicable to the total utility load as well as by rate class."

Hydro One was approached to conduct a weather normalized forecast for the 2008 test but the resources that were available to prepare the weather normalized information for the cost allocation study were no longer available. In addition, the IESO was approached to prepare a weather normalized forecast but they also did not have the resources. Other options were pursued but the cost of preparing the weather normalized forecast were unreasonable considering a simplistic approach could be produced in a cost effective manner.

In the view of Norfolk Power, the method of using the 2004 weather normalized data as base data in the application to produce the weather normal forecast for 2008 is the most reasonable approach considering the 2004 weather normalized values reflects 31 years of average weather conditions . In the view of Norfolk Power, at the time the application was prepared the only improvement that could have been made to the process would be to include 2005 and 2006 actual data in the 31 year average but it is expected this would not significantly change the 2004 weather normalized results and the cost to include 2005 and 2006 data would be outweighed by the benefits.

However, in order to respond to this interrogatory Norfolk Power reviewed the responses of Halton Hills Hydro to the interrogatories for their 2008 rebased rate application. In response to question 17 a iii, Halton Hills Hydro Responses to Second Round of OEB Staff Interrogatories, EB-2007-0696, dated December 21, 2007, Halton Hills Hydro used weather normalized data from the IESO website to develop weather conversion factors to address an interrogatory similar to this one. Norfolk Power has used these same factors to respond to this interrogatory. However, it is Norfolk Power view that using these factors to produce weather normalized data would be inferior to the method used in the application as it does not reflect specific rate class characteristic of Norfolk Power.

b) The following table outlines the weather corrected average kWh/Customer values for the years 2002 to 2008 for the rate classes that are weather sensitive.

Customer Class	2002	2003	2004	2005	2006	2007	2008
Residential	8,661	8,879	8,726	8,968	8,748	8,796	8,796
GS < 50 kW	29,225	30,042	30,760	31,170	30,376	30,315	30,315
GS > 50 kW	900,828	854,903	919,829	894,867	1,080,156	930,117	930,117

The method used to determine the values for 2007 and 2008 reflects the average for the years 2002 to 2006. The average was chosen as there did not appear to be a good trend line in the numbers.

c) The updated version of Schedule 2, page 1 is provided below.

REVISED NORMALIZED VOLUME FORECAST TABLE

Rate Classes	2006 Board Approved	2006 Actual Normalized	Variance form 2006 Board Approved	2006 Actual Normalized	2007 Bridge Normalized	Variance form 2006 Actual Normalized	2007 Bridge Normalized	2008 Test Normalized	Variance form 2007 Actual
Residential	138,382,016	141,824,768	3,442,752	141,824,768	143,937,541	2,112,773	143,937,541	146,081,789	2,144,248
General Service Less Than 50 kW	64,089,807	63,600,265	(489,542)	63,600,265	62,986,341	(613,924)	62,986,341	62,378,343	(607,998)
General Service 50 to 4,999 kW	146,755,138	151,609,040	4,853,902	151,609,040	153,356,274	1,747,234	153,356,274	165,445,509	12,089,235
Unmetered Scattered Load	371,668	406,396	34,728	406,396	406,396	-	406,396	406,396	-
Sentinel Lighting	314,278	342,469	28,191	342,469	342,469	-	342,469	342,469	-
Street Lighting	3,279,050	3,060,430	(218,620)	3,060,430	3,080,765	20,335	3,080,765	3,101,236	20,470
Total	353,191,957	360,843,368	7,651,411	360,843,368	364,109,786	3,266,418	364,109,786	377,755,742	13,645,956

Revenue Offsets and Specific Service Charges

31. Ref: Exhibit 3, Tab 1, Schedule 2, Page 1

    Please confirm whether the amount shown for Revenue Offsets for the 2008 test year is the same as 2007 bridge ($464,000). If this is not correct please provide the correct amount and reconcile these amounts with the information provided in Exhibit 3, Tab 1, Schedule 2, Page 1.

Response:

Confirmed

32. Ref: Exhibit 3, Tab 3, Schedule 2, Page 1

2006 Board Approved VS 2006 Actual

Revenue Account	2006 Board Approved	2006 Actual	Variance
4405-Income from Dividend	$ 122,178.00	$ 267,805	$ 145,627

Recovery of Regulatory Assets were calculated incorrectly in 2004 and 2005 as per yearend audit. Therefore, adjustments were required to bring recovery accounts to correct balance as at December 31, 2006.

Norfolk Power noted in its analysis on other Distribution Revenues that "Recovery of Regulatory Assets were calculated incorrectly in 2004 and 2005 as per yearend audit. Therefore, adjustments were required to bring recovery accounts to correct balance as at December 31, 2006."

Please provide a detailed explanation of:

a. The calculation of the adjustment;
b. The amount of the error;
c. When the adjustment was made and;
d. Why Norfolk Power. believes that account 4405 is the appropriate account in which to make the correction of the error.

2006 Actual VS 2007 Bridge

Asset Account	2006 Actual	2007 Bridge	Variance
4405-Income from Dividend	$ 267,805	$ 50,000	$(217,805)

Included in the 2007 Bridge year is interest revenue from bank account plus provision for carrying charges on regulatory asset balances. The adjustments from 2004 and 2005 have been excluded.

Please provide the sources of the Interest Income, specifically stating whether any of this interest relates to regulatory assets.

Response:

a) and b) are presented in the table below.
Norfolk Power had setup it's own account #4099, as a contra to account 1590, to track the recovery of regulatory assets as approved by the OEB. The difference below of $394,026.07 was debited to account 4099 and credited to account 1590. The interest (carrying charges), was credited to account 4405 and debited to the various sub-accounts of regulatory assets (i.e. Account 1580, 1584, 1586, 1588, etc.)

NORFOLK POWER DISTRIBUTION INC.
Reconciliation of Regulatory Asset Recovery
As of April 30, 2006

Rate Class	2004 Recovery as per OEB	Interest	Total 2004 Recovery as per OEB	2005 Recovery as per OEB	Interest	Total 2005 Recovery as per OEB	TOTAL Recovery as per OEB	Recovery as per Norfolk Power	DIFFERENCE
Residential	$381,935.53	$12,125.14	$394,060.67	$701,592.14	$24,424.88	$726,017.02	$1,120,077.70	$1,094,265.44	$25,812.26
General Service < 50kWh	176,630.13	5,780.56	182,410.69	310,449.57	11,089.34	321,538.91	503,949.60	$482,233.91	21,715.69
General Service > 50kWh	552,087.61	19,167.82	571,255.42	759,519.84	26,993.02	786,512.86	1,357,768.28	$1,018,765.29	339,002.99
Street Lighting	9,330.50	308.04	9,638.54	14,835.43	532.53	15,367.96	25,006.50	$19,066.97	5,939.53
Sentinel Lighting	813.53	27.14	840.67	1,323.70	47.78	1,371.48	2,212.15	$656.55	1,555.61
	$1,120,797.30	**$37,408.70**	**$1,158,206.00**	**$1,787,720.67**	**$63,087.56**	**$1,850,808.24**	**$3,009,014.23**	**$2,614,988.16**	**$394,026.07**

c) The adjustment was made at December 31, 2006

d) Account 4405 only contained the adjustments for carrying charges. The other side of the entry was to account 1590.

The sources of interest income are as follows:
- interest earned on bank accounts
- carrying charges from regulatory assets
- miscellaneous interest income

33. Ref: Exhibit 2, Tab 2, Schedule 1, Page 4
Please confirm whether the credit balance of $70,630 in Account 5330 is included in Specific Service Charges.

Response:

The credit balance of $70,630 in Account 5330 is included in Specific Service Charges.

LOSS FACTORS

34. References: Exhibit 4, Tab 2, Schedule 7, Page 3; Exhibit 4, Tab 2, Schedule 10, Page 1; Exhibit 1, Tab 1, Schedule 4, Page 2; Exhibit 1, Tab 1, Schedule 6, Page 2; Exhibit 1, Tab 2, Schedule 1, Page 1

    - The 1st reference provides a calculation of actual Distribution Loss Factors (DLF) for 2002 to 2006 and an average for the 5-year period (1.0588). This reference further provides the Supply Facilities Loss Factor (SFLF) of 1.0045 and Total Loss Factors (TLF) [corresponding to the 5-year average DLF for secondary and primary metered customers < 5,000 kW] of 1.0636 and 1.0529 respectively. Also provided are approved TLFs for 2007 for secondary and primary metered customers < 5,000 kW of 1.0560 and 1.0454 respectively.
    - The 2nd reference provides a narrative on distribution losses and a statement that Norfolk Power will not use loss factors resulting from the 5-year average DLF as proposed factors for 2008.
    - The 3rd reference provides the proposed TLFs for 2008 for secondary and primary metered customers < 5,000 kW of 1.0560 and 1.0454 respectively.
    - The 4th reference replicates approved 2007 and proposed 2008 TLFs.
    - The 5th reference describes Norfolk Power‘s situation as a partially embedded distributor served by the host distributors Hydro One Networks Inc. (HONI) and Haldimand County Hydro (HCH).

    a. Please provide an explanation of the 6% increase in the actual DLF from 2005 (5.39%) to 2006 (5.71%) as shown in the 1st reference.
    b. Please confirm that the underlying DLF corresponding to the proposed 2008 TLF (2nd and 3rd references) of 1.0560 is 1.0513 (TLF divided by SFLF).
    c. Please explain the rationale for proposing that the TLF for 2008 be a continuation of the approved TLF of 1.0560 for 2007 (2nd, 3rd and 4th references) rather than a lower value.
    d. Given that Norfolk Power is partially embedded in HONI and HCH distribution systems (5th reference), please confirm if the DLF values provided include losses that occur in the HONI and HCH distribution systems.
        I) If this is correct, please provide a breakdown of losses that occur in the Norfolk Power and HONI/HCH distribution systems.
        II) If this is not correct, please confirm how losses that occur in the HONI/HCH distribution systems are accounted for.

e. Please describe any steps that are contemplated to decrease Norfolk Power ‘s component of DLF during the test year (2008) and/or during a longer planning period.

Response:

a. Norfolk Power has calculated the DLF in accordance with the 2006 EDR. At this time, Norfolk Power does not have sufficient data to justify the 6% increase from 2005 to 2006.

b. Confirmed

c. The calculation in the first reference indicates the TLF should be 1.0636. In Norfolk Powers’ opinion this factor does not properly reflect the initiatives that have been undertaken to reduce losses as outlined in the second reference. However, at this time Norfolk Power does not have enough experience with these new initiatives to estimate how they will impact the TLF. Norfolk Power submits it would only be prudent to maintain the current TLF level until more experience is gained.

d. The DLF values provided do not include losses that occur in the HONI and HCH distribution systems
   i. Not applicable
   ii. The cost of the HONI and HCH losses are included in the charges from the IESO to Norfolk Power for commodity, rural rate protection and wholesale market service

e. Please see response to School Energy Coalition IR#1 and Vulnerable Energy Consumers Coalition IR#5 (b)

COST OF CAPITAL

35. Re: Exhibit 6 / Tab 1 / Schedule 2 – Short-term Debt

In the table shown under "Capital Structure", Norfolk Power has used a short-term debt rate (or "Cost Rate") of 4.77%.

The Board Report on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, issued December 20, 2006 (the "Board Report") states the following in section 2.2.2:

> **"The Board has determined that the deemed short-term debt rate will be calculated as the average of the 3-month bankers' acceptance rate plus a fixed spread of 25 basis points**. This is consistent with the Board's method for accounting interest rates (i.e. short-term carrying cost treatment) for variance and deferral accounts.
>
> The Board will use the 3-month bankers' acceptance rate as published on the Bank of Canada's website, for all business days of the same month as used for determining the deemed long-term debt rate and the ROE.
>
> For the purposes of distribution rate-setting, the deemed short-term debt rate will be updated whenever a cost of service rate application is filed. The deemed short-term debt rate will be applied to the deemed short-term debt component of a distributor's rate base. Further, consistent with updating of the ROE and deemed long-term rate, the deemed short-term debt rate will be updated using data available three full months in advance of the effective date of the rates." [Emphasis in original]

a. Please provide the derivation of the 4.77% short-term debt rate estimate showing the calculations, data used and identifying data sources.

b. Please confirm if Norfolk Power is proposing that the deemed short-term debt rate would be updated based on January 2008 Consensus Forecasts and Bank of Canada data, in accordance with the methodology documented in section 2.2.2 of Board Report. If Norfolk Power is not proposing that the methodology in the Board Report be followed, please provide Norfolk Power's reasons for varying from the methodology in the Board Report.

Response:

a. The application used data from the Bank of Canada's website at the time the Return on Capital was being prepared in June 2007. At that time, the average rate for the three-month bankers' acceptances was 4.52%, resulting in a deemed short-term debt rate of 4.52% + 25 basis points = 4.77%.

b. Norfolk Power expects the Board will adjust the proposed revenue requirement using a deemed short-term debt rate based on the date available three full months in advance of the effective date of new rates, as indicated in the Board report.

36. <u>Re: Exhibit 6 / Tab 1 / Schedule 1 and Exhibit 6 / Tab 1 / Schedule 5 –Return on Equity</u>

Norfolk Power states that it is requesting an equity return of 8.68% per the Board's formulaic approach as documented in Appendix B of the Board Report, with the final ROE for 2008 rate-setting purposes to be established based on January 2008 Consensus Forecasts and Bank of Canada data per the methodology in the Board Report. Please provide further information on the derivation of the 8.68% ROE shown in the table labelled "Return on Equity Calculation" in Exhibit 6 / Tab 1 / Schedule 5 showing the source data used, and identifying fully the data sources and date(s) of the data used.

Response:

On August 1, 2007, Board staff advised Norfolk Power's representative, Elenchus Research Associates that is calculation yielded an ROE of 8.68% based on the methodology described in the Board Report, the underlying details of the calculations were not communicated.

37. <u>Re: Exhibit 6 / Tab 1 / Schedule 3 and Exhibit 6 / Tab 1 / Schedule 2 Long-Term Debt</u>

In Exhibit 6/Tab 1/Schedule 3 Norfolk Power lists its debt instruments, showing principal, carrying costs (interest rate), and calculated (interest) cost for each instrument, for each of the following years: i) 2006 Board-approved; ii) 2006 actual; iii) 2007 Bridge; and iv) 2008 Test.

At the bottom of page 4 of Exhibit 6 / Tab 1 / Schedule 2, Norfolk Power states:

> "The Applicant is planning to acquire additional third party long term debt in the amount of $2,000,000 in 2008 and therefore move closer to the Ontario Energy Board suggested [sic] rate of 53.33% debt and 46.67% equity."

This new loan appears to be shown in Exhibit 6 / Tab 1 / Schedule 3 as an Operating Loan under Short-Term debt for the 2008 test year and attracting a debt rate of 6.17%. In addition, two loans with TD-Canada Trust with principals of $1,500,000 and $2,000,000 are shown beginning in 2007 in Exhibit6/Tab 1/Schedule 3.

In the Board Report, the Board states, in section 2.2.1, the following policy for setting the debt rate:

> "For rate-making purposes, the Board considers it appropriate that further distinctions be made between affiliated debt and third party debt, and between new and existing debt.
>
> **The Board has determined that for embedded debt the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt.**
>
> **The Board has determined that the rate for new debt that is held by a third party will be the prudently negotiated contracted rate. This would include recognition of premiums and discounts.**
>
> **For new affiliated debt, the Board has determined that the allowed rate will be the lower of the contracted rate and the deemed long-term debt rate. This deemed long-term debt rate will be calculated as the Long Canada Bond Forecast plus an average spread with "A/BBB" rate corporate bond yields. The Long Canada** Bond Forecast is comprised of the 10-year Government of Canada bond yield forecast (Consensus Forecast) plus the actual spread between 10-year and 30-year bond yields observed in Bank of Canada data. The average spread with "A/BBB" rate corporate bond yields is calculated from the observed spread between Government of Canada

Bonds and "A/BBB" corporate bond yield data of the same term from Scotia Capital Inc., both available from the Bank of Canada.

For all variable-rate debt and for all affiliate debt that is callable on demand the Board will use the current deemed long-term debt rate. When setting distribution rates at rebasing these debt rates will be adjusted regardless of whether the applicant makes a request for the change." [Emphasis in original]

a. For each of the $1,500,000 and $2,000,000 long-term debt instruments shown beginning in the 2007 Bridge year, please provide:
   I) The calculation of the interest expense for each of 2007 and 2008;
   II) Information on when and for what purpose the loan was taken out;
   III) The length of the loan; and
   IV) Whether the interest rate is fixed, variable or renegotiable during the term of the loan. If the rate is variable or renegotiable, provide further information on the current rate or the conditions under which the rate would be renegotiable.
b. Please confirm that the new long-term debt documented in Exhibit 6 / Tab 1 / Schedule 2 is shown as the Operating Loan in Exhibit 6 / Tab 1 / Schedule 3, or else provide an explanation. Please explain why this is shown as short-term debt (i.e. what characteristics of the future loan suggest that it be treated as short-term debt). Please provide a derivation or other justification for the assumed rate of 6.17%.
c. Please explain why there is a calculated interest expense of $3,044 for 2008 but no principal for the long-term debt with the municipal shareholder, Haldimand County. Please provide a continuity schedule, by month, of principal and interest actual and forecasted payments on this loan for the period 2006 to 2008 inclusive.
d. Norfolk Power shows a "Cost Rate" of 6.70% for Long-term debt for the 2007 Bridge and 2008 Test Years in Exhibit 6 / Tab 1 /Schedule 2. Please provide a detailed derivation of this rate with respect to all debt instruments shown in Exhibit 6 / Tab 1 /Schedule 3 for the 2007 Bridge and 2008 Test Years.
e. Please demonstrate if and how the debt instruments that start in each of 2007 and 2008 new and/or renewed debt instruments, with respect to the proposed rate of 6.17% and other terms and conditions (fixed versus variable rate,

renegotiable, callable on demand) is reasonable and complies with the Board's policy for long-term debt rate treatment for rate-setting purposes as documented in section 2.2.1 of the Board Report.

Response:

a. For each of the $1,500,000 and $2,000,000 long-term debt instruments shown beginning in the 2007 Bridge year, please
provide:

I) See below

2007	Outstanding Principal	Interest Rate	Days Outstanding	Interest
Loan principal was borrowed Sept. 20, 2007	$1,500,000	6.17%	103 days	$26,117
Loan principal was borrowed Sept. 20, 2007	$2,000,000	6.17%	103 days	$34,822
2008				
Loan principal was borrowed Sept. 20, 2007	$1,468,000	6.17%	366 days	$90,576
Loan principal was borrowed Sept. 20, 2007	$1,957,000	6.17%	103 days	$34,074
	$1,957,000	6.17%	365 days	$120,747
			Difference	($120,747)
Note: Incorrect number of days outstanding was used in the 2008 EDR Model. Interest expenses should be $120,747, not $34,074				

II) The $1,500,000 loan was originally revolving 90-day short-term debt. Norfolk Power decided to re-finance this loan as long-term because of lower rate of borrowing was accepted. The $2,000,000 was approved by Norfolk Power's Board in the 2007 Budget for the purpose of financing the deficiency in capital spending.

III) The $1,500,000 loan has a 20-year amortization and the $2,000,000 loan has a 25-year amortization

IV) Both loans carry a fixed interest rate

b. Upon further investigation of the $2,000,000 classified as short-term debt in the 2008 EDR application, it should have been disclosed as long-term debt. The assumed rate of 6.17% was a negotiated rate with a 3rd party financial institution.

c. The $3,044 is not interest expense, but the final amortization amount of the debenture discount. Also, upon further investigation, interest expense of $19,926 was not disclosed in the 2008 EDR Model for the debenture debt to

Haldimand County. This debt however, becomes fully mature in 2008. Below is a continuity schedule of the debenture debt to Haldimand County

Norfolk Power Distribution Inc.
DEBENTURE - DEBT ANALYSIS
Held by Haldimand County

Principal:

Bylaw Number	Issue Date	Maturity Date	Terms	Issue Amount	Outstanding Principal	Principal Payments 2006	2007	2008
N/A	15-Dec-98	15-Dec-08	10 years	$3,000,000	$1,061,000	$339,000	$353,000	$369,000
TOTAL DEBT PRINCIPAL						**$339,000**	**$353,000**	**$369,000**

Interest:

Bylaw Number	Maturity Date	Terms	Rate	Issue Interest	Outstanding Amount	Interest Payments 2006	2007	2008
N/A	15-Dec-08	10 years	5.130%		$82,207	$40,186	$22,095	$19,926
DEBENTURE INTEREST						**$40,186**	**$22,095**	**$19,926**

		Amortization of Discount		
Amortization of Debt Discount:	$9,132	$3,044	$3,044	$3,044
		$3,044	**$3,044**	**$3,044**

Note: Principal and interest payments are made semi-annually, in equal amounts

d. Below is a detailed derivation of "Cost Rate" of 6.70%.

	Principle	2008 Carrying Costs	Calculated Cost	Cost of Long-Term Debt
Long-Term Debt				
TD-Canada Trust	$9,971,000	7.00%	$697,970	
TD-Canada Trust	3,257,000	6.02%	196,071	
TD-Canada Trust	1,468,000	6.17%	90,576	
Haldimand County			3,044	
	$14,696,000		$987,661	
Short-Term Debt				
Operating Loan - AVERAGE BALANCE	$562,842	6.17%	$34,727	
	$562,842		$34,727	
	$15,258,842		$1,022,388	6.70%

e. The debt instruments that start in each of 2007 and 2008 is reasonable and complies with the Board's policy for long-term debt rate treatment for rate-setting purposes as documented in section 2.2.1 of the Board Report because the debts are held by a third party

(TD-Canada Trust) and Norfolk Power has prudently negotiated the contracted rate.

DEFERRAL AND VARIANCE ACCOUNTS

38. Ref: Exhibit1/Tab1/Schedule8/Page2

Norfolk Power is requesting a deferral and variance account for capital works during the non-rebasing years to collect the revenue requirement costs associated with the cost of construction.

a. What is the regulatory precedent for the collection of these costs in this proposed deferral account?
b. What is the justification for this account?
c. What are the types of capital expenditures/revenue expenditures to be recorded in this account?
d. What are the journal entries to be recorded?
e. How will these capital expenditures be financed?
f. Does Norfolk Power plan to ask for its disposition? If so, when?
g. Upon disposition of this account, how does Norfolk Power plan to allocate this amount by rate class?
h. Norfolk Power has identified new capital spending for the 2008 test year. If Norfolk Power under-forecasts or over-forecasts the 2008 capital costs, should Norfolk Power be required to record the difference in this deferral account? If not, please explain the rationale for not doing this?
i. Norfolk Power stated that the revenue requirement costs associated with the costs of construction will be collected in this account. Please confirm that Norfolk Power will not record the total capital costs in this account but just the amounts related to the annual cost of service associated with the new assets (i.e. depreciation, return, PILs, etc.). If the latter, please provide an example showing all the relevant calculations and amounts. If the former, please confirm that Norfolk Power is proposing to recover the total capital costs outside of rate base in the future (i.e. via a future rate rider), and therefore these amounts will not be included in rate base in the future.

Response:

a) Norfolk Power is not aware of any regulatory precedent for the collection of these costs in this proposed deferral account.

b) In the OEB's Filing Requirements for Transmission and Distribution Applications dated November 14, 2006, Page 7, Section 2.0 Preamble Framework, last paragraph it states:

"For the distributors, recognizing that rebasing may occur every three years, a distributor may consider applying for deferral accounts for capital works during the non-rebasing years to collect the cost of construction."

Based on the above reference it is Norfolk Power's view the requested deferral is justified since it has been suggested in the filing requirements and it is a reasonable approach to address the cost associated with capital that occurs in a non-rebasing year.

c) Hydro One is planning to construct a new transmission line (A12N) in Norfolk County in 2008 and in service April 2009. This will allow for future economic development in Norfolk County as well as improved system reliability. The costs associated with a such a project will be recorded in this account

d) Debit to deferral variance account; credit to cash. Debit to carrying charges sub-account; credit to interest earned

e) The capital expenditures will be debt financed

f) It is Norfolk Power plan to dispose of this deferral account next time rates are rebased.

g) At this time, Norfolk Power plans to allocate this amount to each rate class based on the proportion of rate class distribution revenue. However, this may change at the time the proposal to dispose of the deferral account is developed as experience may indicate a better allocator would be more appropriate.

h) Norfolk Power expects to record any under-forecast or over-forecast of 2008 capital costs in this deferral account.

i) Norfolk Power will record the annual cost of service associated with the new assets in this account. The cost items to be included will be depreciation and return but not PILs as the process to calculate incremental PILs on incremental capital assets is difficult and could be very controversial at the time of disposition. Depreciation will be calculated as the approved deprecation rate times the new assets. The return will be the value of assets minus accumulated deprecation on the new assets times the approved rate of return.

39. Ref: Exhibit 1/Tab 3/Schedule 2/Page 6; Exhibit 1/Tab 3/Schedule 2/Page 12

Please provide the 2007 and 2008 pro forma balance sheets.

Response:

2007 pro forma balance sheet is provided below.

Group Description	Account Description	Total
1050-Current Assets	1005-Cash	0
	1010-Cash Advances and Working Funds	1,900
	1020-Interest Special Deposits	0
	1030-Dividend Special Deposits	0
	1040-Other Special Deposits	0
	1060-Term Deposits	0
	1070-Current Investments	0
	1100-Customer Accounts Receivable	4,284,571
	1102-Accounts Receivable - Services	0
	1104-Accounts Receivable - Recoverable Work	273,710
	1105-Accounts Receivable - Merchandise, Jobbing, etc.	831
	1110-Other Accounts Receivable	870,775
	1120-Accrued Utility Revenues	4,406,441
	1130-Accumulated Provision for Uncollectible Accounts--Credit	-120,000
	1140-Interest and Dividends Receivable	0
	1150-Rents Receivable	0
	1170-Notes Receivable	0
	1180-Prepayments	449,006
	1190-Miscellaneous Current and Accrued Assets	0
	1200-Accounts Receivable from Associated Companies	0
	1210-Notes Receivable from Associated Companies	0
1050-Current Assets Total		10,167,233
1100-Inventory	1305-Fuel Stock	0
	1330-Plant Materials and Operating Supplies	582,105
	1340-Merchandise	0
	1350-Other Materials and Supplies	0
1100-Inventory Total		582,105
1150-Non-Current Assets	1405-Long Term Investments in Non-Associated Companies	0
	1408-Long Term Receivable - Street Lighting Transfer	0
	1410-Other Special or Collateral Funds	0
	1415-Sinking Funds	0
	1425-Unamortized Debt Expense	6,367
	1445-Unamortized Discount on Long-Term Debt--Debit	0
	1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0
	1460-Other Non-Current Assets	0
	1465-O.M.E.R.S. Past Service Costs	0
	1470-Past Service Costs - Employee Future Benefits	0

	1475-Past Service Costs - Other Pension Plans	0
	1480-Portfolio Investments - Associated Companies	0
	1485-Investment in Associated Companies - Significant Influence	0
	1490-Investment in Subsidiary Companies	0
1150-Non-Current Assets Total		6,367
1200-Other Assets and Deferred Charges	1505-Unrecovered Plant and Regulatory Study Costs	0
	1508-Other Regulatory Assets	566,828
	1510-Preliminary Survey and Investigation Charges	0
	1515-Emission Allowance Inventory	0
	1516-Emission Allowances Withheld	0
	1518-RCVARetail	-31,512
	1520-Power Purchase Variance Account	0
	1525-Miscellaneous Deferred Debits	15,591
	1530-Deferred Losses from Disposition of Utility Plant	0
	1540-Unamortized Loss on Reacquired Debt	0
	1545-Development Charge Deposits/ Receivables	0
	1548-RCVASTR	46,465
	1550-LV Variance Account	8,650
	1555-Smart Meters Capital Variance Account	-38,086
	1560-Deferred Development Costs	0
	1562-Deferred Payments in Lieu of Taxes	370,440
	1563-Account 1563 - Deferred PILs Contra Account	-370,440
	1565-Conservation and Demand Management Expenditures and Recoveries	-386,534
	1566-CDM Contra Account	393,602
	1570-Qualifying Transition Costs	33
	1571-Pre-market Opening Energy Variance	0
	1572-Extraordinary Event Costs	0
	1574-Deferred Rate Impact Amounts	0
	1580-RSVAWMS	-14,148
	1582-RSVAONE-TIME	0
	1584-RSVANW	49,582
	1586-RSVACN	-245,374
	1588-RSVAPOWER	-602,139
	1590-Recovery of Regulatory Asset Balances	731,779
1200-Other Assets and Deferred Charges Total		494,735
1300-Intangible Plant	1605-Electric Plant in Service - Control Account	0
	1606-Organization	0
	1608-Franchises and Consents	0
	1610-Miscellaneous Intangible Plant	0
1300-Intangible Plant Total		0
1350-Not for distributor use	1615-Land	0
	1616-Land Rights	0
	1620-Buildings and Fixtures	0
	1630-Leasehold Improvements	0
	1635-Boiler Plant Equipment	0
	1640-Engines and Engine-Driven Generators	0

	1645-Turbogenerator Units	0
	1650-Reservoirs, Dams and Waterways	0
	1655-Water Wheels, Turbines and Generators	0
	1660-Roads, Railroads and Bridges	0
	1665-Fuel Holders, Producers and Accessories	0
	1670-Prime Movers	0
	1675-Generators	0
	1680-Accessory Electric Equipment	0
	1685-Miscellaneous Power Plant Equipment	0
	1705-Land	0
	1706-Land Rights	0
	1708-Buildings and Fixtures	0
	1710-Leasehold Improvements	0
	1715-Station Equipment	0
	1720-Towers and Fixtures	0
	1725-Poles and Fixtures	0
	1730-Overhead Conductors and Devices	0
	1735-Underground Conduit	0
	1740-Underground Conductors and Devices	0
	1745-Roads and Trails	0
1350-Not for distributor use Total		0
1450-Distribution Plant	1805-Land	380,064
	1806-Land Rights	301,911
	1808-Buildings and Fixtures	1,455,870
	1810-Leasehold Improvements	0
	1815-Transformer Station Equipment - Normally Primary above 50 kV	2,997,994
	1820-Distribution Station Equipment - Normally Primary below 50 kV	3,565,347
	1825-Storage Battery Equipment	0
	1830-Poles, Towers and Fixtures	17,566,729
	1835-Overhead Conductors and Devices	9,187,597
	1840-Underground Conduit	3,546,245
	1845-Underground Conductors and Devices	6,867,211
	1850-Line Transformers	9,780,687
	1855-Services	1,923,317
	1860-Meters	4,007,074
	1865-Other Installations on Customer's Premises	0
	1870-Leased Property on Customer Premises	0
	1875-Street Lighting and Signal Systems	0
1450-Distribution Plant Total		61,580,046
1500-General Plant	1905-Land	236,830
	1906-Land Rights	0
	1908-Buildings and Fixtures	2,100,788
	1910-Leasehold Improvements	6,177
	1915-Office Furniture and Equipment	134,706
	1920-Computer Equipment - Hardware	670,110
	1925-Computer Software	241,909

	1930-Transportation Equipment	1,395,157
	1935-Stores Equipment	39,068
	1940-Tools, Shop and Garage Equipment	245,866
	1945-Measurement and Testing Equipment	167,541
	1950-Power Operated Equipment	0
	1955-Communication Equipment	83,931
	1960-Miscellaneous Equipment	114,327
	1965-Water Heater Rental Units	0
	1970-Load Management Controls - Customer Premises	88,276
	1975-Load Management Controls - Utility Premises	0
	1980-System Supervisory Equipment	656,052
	1985-Sentinel Lighting Rental Units	0
	1990-Other Tangible Property	0
	1995-Contributions and Grants - Credit	-5,996,930
1500-General Plant Total		183,810
1550-Other Capital Assets	2005-Property Under Capital Leases	10,039
	2055-Construction Work in Progress--Electric	0
1550-Other Capital Assets Total		10,039
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	-20,244,214
	2120-Accumulated Amortization of Electric Utility Plant - Intangibles	-1,304
1600-Accumulated Amortization Total		-20,245,519
1650-Current Liabilities	2205-Accounts Payable	-9,461,846
	2208-Customer Credit Balances	-160,347
	2210-Current Portion of Customer Deposits	-42,200
	2215-Dividends Declared	0
	2220-Miscellaneous Current and Accrued Liabilities	-467,530
	2225-Notes and Loans Payable	0
	2240-Accounts Payable to Associated Companies	-554,851
	2242-Notes Payable to Associated Companies	0
	2250-Debt Retirement Charges(DRC) Payable	0
	2252-Transmission Charges Payable	0
	2254-Electrical Safety Authority Fees Payable	0
	2256-Independent Market Operator Fees and Penalties Payable	0
	2260-Current Portion of Long Term Debt	-353,000
	2262-Ontario Hydro Debt - Current Portion	0
	2264-Pensions and Employee Benefits - Current Portion	0
	2268-Accrued Interest on Long Term Debt	0
	2270-Matured Long Term Debt	-382,000
	2272-Matured Interest on Long Term Debt	0
	2285-Obligations Under Capital Leases--Current	0
	2290-Commodity Taxes	-843
	2292-Payroll Deductions / Expenses Payable	0
	2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	0
	2296-Future Income Taxes - Current	0
1650-Current Liabilities Total		-11,422,617
1700-Non-Current Liabilities	2305-Accumulated Provision for Injuries and Damages	0

	2306-Employee Future Benefits	-640,121
	2308-Other Pensions - Past Service Liability	0
	2310-Vested Sick Leave Liability	0
	2315-Accumulated Provision for Rate Refunds	0
	2320-Other Miscellaneous Non-Current Liabilities	-9,811
	2325-Obligations Under Capital Lease--Non-Current	-4,772
	2330-Development Charge Fund	0
	2335-Long Term Customer Deposits	-66,893
	2340-Collateral Funds Liability	0
	2345-Unamortized Premium on Long Term Debt	0
	2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
	2350-Future Income Tax - Non-Current	0
	2405-Other Regulatory Liabilities	0
	2410-Deferred Gains from Disposition of Utility Plant	0
	2415-Unamortized Gain on Reacquired Debt	0
	2425-Other Deferred Credits	0
	2435-Accrued Rate-Payer Benefit	0
1700-Non-Current Liabilities Total		-721,597
1800-Long-Term Debt	2505-Debentures Outstanding - Long Term Portion	-369,000
	2510-Debenture Advances	0
	2515-Reacquired Bonds	0
	2520-Other Long Term Debt	0
	2525-Term Bank Loans - Long Term Portion	-15,126,000
	2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
	2550-Advances from Associated Companies	0
1800-Long-Term Debt Total		-15,495,000
1850-Shareholders' Equity	3005-Common Shares Issued	-22,768,898
	3008-Preference Shares Issued	0
	3010-Contributed Surplus	-122,799
	3020-Donations Received	0
	3022-Development Charges Transferred to Equity	0
	3026-Capital Stock Held in Treasury	0
	3030-Miscellaneous Paid-In Capital	-708,000
	3035-Installments Received on Capital Stock	0
	3040-Appropriated Retained Earnings	0
	3045-Unappropriated Retained Earnings	-679,401
	3046-Balance Transferred From Income	-589,598
	3047-Appropriations of Retained Earnings - Current Period	0
	3048-Dividends Payable-Preference Shares	0
	3049-Dividends Payable-Common Shares	0
	3055-Adjustment to Retained Earnings	-270,907
	3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total		-25,139,603
Grand Total		-0

2008 pro forma balance sheet is provided below.

Group Description	Account Description	Total
1050-Current Assets	1005-Cash	0
	1010-Cash Advances and Working Funds	1,900
	1020-Interest Special Deposits	0
	1030-Dividend Special Deposits	0
	1040-Other Special Deposits	0
	1060-Term Deposits	0
	1070-Current Investments	0
	1100-Customer Accounts Receivable	4,284,571
	1102-Accounts Receivable - Services	0
	1104-Accounts Receivable - Recoverable Work	273,710
	1105-Accounts Receivable - Merchandise, Jobbing, etc.	831
	1110-Other Accounts Receivable	870,775
	1120-Accrued Utility Revenues	4,406,441
	1130-Accumulated Provision for Uncollectible Accounts--Credit	-120,000
	1140-Interest and Dividends Receivable	0
	1150-Rents Receivable	0
	1170-Notes Receivable	0
	1180-Prepayments	449,006
	1190-Miscellaneous Current and Accrued Assets	0
	1200-Accounts Receivable from Associated Companies	0
	1210-Notes Receivable from Associated Companies	0
1050-Current Assets Total		10,167,233
1100-Inventory	1305-Fuel Stock	0
	1330-Plant Materials and Operating Supplies	582,105
	1340-Merchandise	0
	1350-Other Materials and Supplies	0
1100-Inventory Total		582,105
1150-Non-Current Assets	1405-Long Term Investments in Non-Associated Companies	0
	1408-Long Term Receivable - Street Lighting Transfer	0
	1410-Other Special or Collateral Funds	0
	1415-Sinking Funds	0
	1425-Unamortized Debt Expense	6,367
	1445-Unamortized Discount on Long-Term Debt--Debit	0
	1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0
	1460-Other Non-Current Assets	0
	1465-O.M.E.R.S. Past Service Costs	0
	1470-Past Service Costs - Employee Future Benefits	0
	1475-Past Service Costs - Other Pension Plans	0
	1480-Portfolio Investments - Associated Companies	0
	1485-Investment in Associated Companies - Significant Influence	0
	1490-Investment in Subsidiary Companies	0
1150-Non-Current Assets Total		6,367
1200-Other Assets and Deferred Charges	1505-Unrecovered Plant and Regulatory Study Costs	0
	1508-Other Regulatory Assets	566,828
	1510-Preliminary Survey and Investigation Charges	0

	1515-Emission Allowance Inventory	0
	1516-Emission Allowances Withheld	0
	1518-RCVARetail	-31,512
	1520-Power Purchase Variance Account	0
	1525-Miscellaneous Deferred Debits	15,591
	1530-Deferred Losses from Disposition of Utility Plant	0
	1540-Unamortized Loss on Reacquired Debt	0
	1545-Development Charge Deposits/ Receivables	0
	1548-RCVASTR	46,465
	1550-LV Variance Account	8,650
	1555-Smart Meters Capital Variance Account	-38,086
	1560-Deferred Development Costs	0
	1562-Deferred Payments in Lieu of Taxes	370,440
	1563-Account 1563 - Deferred PILs Contra Account	-370,440
	1565-Conservation and Demand Management Expenditures and Recoveries	-386,534
	1566-CDM Contra Account	393,602
	1570-Qualifying Transition Costs	33
	1571-Pre-market Opening Energy Variance	0
	1572-Extraordinary Event Costs	0
	1574-Deferred Rate Impact Amounts	0
	1580-RSVAWMS	-14,148
	1582-RSVAONE-TIME	0
	1584-RSVANW	49,582
	1586-RSVACN	-245,374
	1588-RSVAPOWER	-602,139
	1590-Recovery of Regulatory Asset Balances	731,779
1200-Other Assets and Deferred Charges Total		494,735
1300-Intangible Plant	1605-Electric Plant in Service - Control Account	0
	1606-Organization	0
	1608-Franchises and Consents	0
	1610-Miscellaneous Intangible Plant	0
1300-Intangible Plant Total		0
1350-Not for distributor use	1615-Land	0
	1616-Land Rights	0
	1620-Buildings and Fixtures	0
	1630-Leasehold Improvements	0
	1635-Boiler Plant Equipment	0
	1640-Engines and Engine-Driven Generators	0
	1645-Turbogenerator Units	0
	1650-Reservoirs, Dams and Waterways	0
	1655-Water Wheels, Turbines and Generators	0
	1660-Roads, Railroads and Bridges	0
	1665-Fuel Holders, Producers and Accessories	0
	1670-Prime Movers	0
	1675-Generators	0
	1680-Accessory Electric Equipment	0

	1685-Miscellaneous Power Plant Equipment	0
	1705-Land	0
	1706-Land Rights	0
	1708-Buildings and Fixtures	0
	1710-Leasehold Improvements	0
	1715-Station Equipment	0
	1720-Towers and Fixtures	0
	1725-Poles and Fixtures	0
	1730-Overhead Conductors and Devices	0
	1735-Underground Conduit	0
	1740-Underground Conductors and Devices	0
	1745-Roads and Trails	0
1350-Not for distributor use Total		0
1450-Distribution Plant	1805-Land	380,064
	1806-Land Rights	302,911
	1808-Buildings and Fixtures	1,530,070
	1810-Leasehold Improvements	0
	1815-Transformer Station Equipment - Normally Primary above 50 kV	3,319,994
	1820-Distribution Station Equipment - Normally Primary below 50 kV	2,990,092
	1825-Storage Battery Equipment	0
	1830-Poles, Towers and Fixtures	18,697,529
	1835-Overhead Conductors and Devices	9,925,797
	1840-Underground Conduit	3,828,245
	1845-Underground Conductors and Devices	7,467,211
	1850-Line Transformers	10,656,687
	1855-Services	2,245,317
	1860-Meters	8,584,474
	1865-Other Installations on Customer's Premises	0
	1870-Leased Property on Customer Premises	0
	1875-Street Lighting and Signal Systems	0
1450-Distribution Plant Total		69,928,391
1500-General Plant	1905-Land	236,830
	1906-Land Rights	0
	1908-Buildings and Fixtures	2,209,188
	1910-Leasehold Improvements	11,177
	1915-Office Furniture and Equipment	163,706
	1920-Computer Equipment - Hardware	626,816
	1925-Computer Software	356,656
	1930-Transportation Equipment	1,490,157
	1935-Stores Equipment	44,068
	1940-Tools, Shop and Garage Equipment	277,866
	1945-Measurement and Testing Equipment	193,041
	1950-Power Operated Equipment	0
	1955-Communication Equipment	112,931
	1960-Miscellaneous Equipment	151,827
	1965-Water Heater Rental Units	0

	1970-Load Management Controls - Customer Premises	88,276
	1975-Load Management Controls - Utility Premises	0
	1980-System Supervisory Equipment	748,152
	1985-Sentinel Lighting Rental Units	0
	1990-Other Tangible Property	0
	1995-Contributions and Grants - Credit	-6,196,930
1500-General Plant Total		513,763
1550-Other Capital Assets	2005-Property Under Capital Leases	10,039
	2055-Construction Work in Progress--Electric	0
1550-Other Capital Assets Total		10,039
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	-21,569,723
	2120-Accumulated Amortization of Electric Utility Plant - Intangibles	-1,304
1600-Accumulated Amortization Total		-21,571,028
1650-Current Liabilities	2205-Accounts Payable	-13,266,094
	2208-Customer Credit Balances	-160,347
	2210-Current Portion of Customer Deposits	-42,200
	2215-Dividends Declared	0
	2220-Miscellaneous Current and Accrued Liabilities	-467,530
	2225-Notes and Loans Payable	0
	2240-Accounts Payable to Associated Companies	-554,851
	2242-Notes Payable to Associated Companies	0
	2250-Debt Retirement Charges(DRC) Payable	0
	2252-Transmission Charges Payable	0
	2254-Electrical Safety Authority Fees Payable	0
	2256-Independent Market Operator Fees and Penalties Payable	0
	2260-Current Portion of Long Term Debt	-353,000
	2262-Ontario Hydro Debt - Current Portion	0
	2264-Pensions and Employee Benefits - Current Portion	0
	2268-Accrued Interest on Long Term Debt	0
	2270-Matured Long Term Debt	-382,000
	2272-Matured Interest on Long Term Debt	0
	2285-Obligations Under Capital Leases--Current	0
	2290-Commodity Taxes	-843
	2292-Payroll Deductions / Expenses Payable	0
	2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	0
	2296-Future Income Taxes - Current	0
1650-Current Liabilities Total		-15,226,865
1700-Non-Current Liabilities	2305-Accumulated Provision for Injuries and Damages	0
	2306-Employee Future Benefits	-640,121
	2308-Other Pensions - Past Service Liability	0
	2310-Vested Sick Leave Liability	0
	2315-Accumulated Provision for Rate Refunds	0
	2320-Other Miscellaneous Non-Current Liabilities	-9,811
	2325-Obligations Under Capital Lease--Non-Current	-4,772
	2330-Development Charge Fund	0
	2335-Long Term Customer Deposits	-66,893

	2340-Collateral Funds Liability	0
	2345-Unamortized Premium on Long Term Debt	0
	2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
	2350-Future Income Tax - Non-Current	0
	2405-Other Regulatory Liabilities	0
	2410-Deferred Gains from Disposition of Utility Plant	0
	2415-Unamortized Gain on Reacquired Debt	0
	2425-Other Deferred Credits	0
	2435-Accrued Rate-Payer Benefit	0
1700-Non-Current Liabilities Total		-721,597
1800-Long-Term Debt	2505-Debentures Outstanding - Long Term Portion	-369,000
	2510-Debenture Advances	0
	2515-Reacquired Bonds	0
	2520-Other Long Term Debt	0
	2525-Term Bank Loans - Long Term Portion	-15,126,000
	2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
	2550-Advances from Associated Companies	0
1800-Long-Term Debt Total		-15,495,000
1850-Shareholders' Equity	3005-Common Shares Issued	-22,768,898
	3008-Preference Shares Issued	0
	3010-Contributed Surplus	-122,799
	3020-Donations Received	0
	3022-Development Charges Transferred to Equity	0
	3026-Capital Stock Held in Treasury	0
	3030-Miscellaneous Paid-In Capital	-708,000
	3035-Installments Received on Capital Stock	0
	3040-Appropriated Retained Earnings	0
	3045-Unappropriated Retained Earnings	-1,648,999
	3046-Balance Transferred From Income	-3,168,542
	3047-Appropriations of Retained Earnings - Current Period	0
	3048-Dividends Payable-Preference Shares	0
	3049-Dividends Payable-Common Shares	0
	3055-Adjustment to Retained Earnings	-270,907
	3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total		-28,688,145
Grand Total		-0

40. Ref: Exhibit 5/Tab 1/Schedule 1/Page 1

Describe the deferral and variance accounts of Account 1518, Retail Cost Variance Account - Retail and 1548, Retail Cost Variance Account – STR.

Response:

1518 Retail Cost Variance Account – Retail
Description: This account is used to record the net of:
i) revenues derived from the following services described in the Rates Handbook:
a) Establishing Service Agreements;
b) Distributor-Consolidated Billing
c) Retailer-Consolidated Billing; and
d) Split Billing

AND

ii) the costs (expenses) of entering into Service Agreements, and related contract administration, monitoring, and other expenses necessary to maintain the contract, as well as the incremental costs incurred to provide the services in (b) and (d) above, as applicable, and the avoided costs credit arising from Retailer- Consolidated Billing.

1548 Retail Cost Variance Account – STR
Description: This account is used to record the net of:
i) revenues derived from the Service Transaction Request services described in the Rates Handbook and charged by the distributor, as prescribed, in the form of a:
a) Request fee;
b) Processing fee;
c) Information Request fee;
d) Default fee; and
e) Other Associated Costs fee;

AND

ii) the incremental cost of labour, internal information system maintenance costs, and delivery costs related to the provision of the services associated with the above items.

41. Ref: Exhibit 5/Tab 1/Schedule 2/Page 1

What interest rates are being used to calculate the carrying charges for the deferral and variance accounts from January 1, 2005 to April 30, 2008?

Response:

The interest rates used to calculate the carrying charges for the deferral and variance accounts from January 1, 2005 to April 30, 2008 is 4.59%.

42. Ref: Exh5/Tab1/Sch2 and Exh5/Tab1/Sch3

Norfolk Power is applying for disposition of regulatory variance accounts as per schedule Exhibit 5/Tab1/Sch2/Pg1. The totals in the exhibit do not agree to totals reported to the Board as per.2.1.1 of the Reporting and Record Keeping Requirements for the period ending December 31, 2006. Please provide the information as shown in the attached Regulatory Assets Continuity Schedule and provide a further schedule reconciling the continuity schedule with the amounts requested for disposition on Exh5/Tab1/Sch2 and Exh5/Tab1/Sch3. Please note that forecasting principal transactions beyond December 31, 2006 and the accrued interest on these forecasted balances and including them in the attached continuity schedule is optional.

Response:

Please see schedules below

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Norfolk Power Distribution Inc.	**LICENCE NUMBER**	ED-2002-0521
NAME OF CONTACT	Alvin Allim	**DOCID NUMBER**	EB-2007-0753
E-mail Address	aallim@norfolkpower.on.ca		
VERSION NUMBER	v3.0	**PHONE NUMBER**	519-426-4440
Date	25-Feb-08	**(extension)**	2264

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

Account Description	Account Number	2005 Opening Principal Amounts as of Jan-1-05 [1]	Transactions (additions) during 2005, excluding interest and adjustments [6]	Transactions (reductions) during 2005, excluding interest and adjustments [6]	Adjustments during 2005 - instructed by Board [2]	Adjustments during 2005 - other [3]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec31-05	Closing Interest Amounts as of Dec-31-05
RSVA - Wholesale Market Service Charge	1580	658,702	378,049		-	-	1,036,751	109,885	55,857	165,742
RSVA - One-time Wholesale Market Service	1582	-	-		-	-	-	-	-	-
RSVA - Retail Transmission Network Charge	1584	(32,834)	40,154		-	-	7,320	6,715	(5,122)	1,593
RSVA - Retail Transmission Connection Charge	1586	(158,254)	(58,370)		-	-	(216,624)	(5,337)	(16,627)	(21,963)
Sub-Totals		467,613	359,833		-	-	827,446	111,264	34,108	145,371
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	22,330	29,210	-	-	-	51,540	-	-	-
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	-	-	-	-	-	-	-	-	-
Other Regulatory Assets - Sub-Account - Other [7]	1508	-	220,118	-	-	-	220,118	-	-	-
Other Regulatory Assets - Sub-Account - Other [7]	1508	-	-	-	-	-	-	-	-	-
Other Regulatory Assets - Sub-Account - Other [7]	1508	-	-	-	-	-	-	-	-	-
Retail Cost Variance Account - Retail	1518	(20,276)	(636)	-	-	-	(20,912)	-	-	-
Retail Cost Variance Account - STR	1548	24,389	22,343	-	-	-	46,731	-	-	-
Misc. Deferred Debits	1525	12,350	15,902	-	-	-	28,252	-	-	-
LV Variance Account	1550	-	-	-	-	-	-	-	-	-
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	-	-	-	-	-	-	-	-	-
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	-	-	-	-	-	-	-	-	-
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Me	1555	-	-	-	-	-	-	-	-	-
Smart Meter OM&A Variance	1556	-	-	-	-	-	-	-	-	-
Conservation and Demand Management Expenditures and Recoveries	1565	7,068	187,398	(484,167)	-	-	(289,701)	-	-	-
CDM Contra	1566	-	296,769	-	-	-	296,769	-	-	-
Qualifying Transition Costs [5]	1570	2,302,666	n/a	n/a	-	-	2,302,666	448,051	180,711	628,762
Pre-Market Opening Energy Variances Total [5]	1571	303,157	n/a	n/a	-	-	303,157	58,610	21,979	80,589
Extra-Ordinary Event Costs	1572	-	-	-	-	-	-	-	-	-
Deferred Rate Impact Amounts	1574	-	-	-	-	-	-	-	-	-
Other Deferred Credits	2425	-	-	-	-	-	-	-	-	-
Sub-Totals		2,651,684	771,103	(484,167)	-	-	2,938,620	506,661	202,690	709,351
Deferred Payments in Lieu of Taxes	1562				**see PILs reconciliation requested**					
2006 PILs & Taxes Variance	1592				**see PILs reconciliation requested**					
Sub-Totals					**see PILs reconciliation requested**					
Total		3,119,297	1,130,936	(484,167)	-	-	3,766,066	617,925	236,798	854,722
The following is not included in the total claim but is included on a memo basis:										
Deferred PILs Contra Account [8]	1563				**see PILs reconciliation requested**					
RSVA - Power (including Global Adjustment)	1588	1,085,498	(78,573)		-	-	1,006,925	110,017	86,257	196,274
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	-	(2,181,951)		-	-	(2,181,951)	-	-	-
Recovery of Regulatory Asset Balances	1590	(213,109)	71,036	(1,090,093)	-	-	(1,232,166)	(9,013)	(41,355)	(50,368)

[1] As per general ledger, if does not agree to Dec-31-04 balance filed in 2006 EDR then provide supplementary analysis
[2] Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, and etc.
[3] Provide supporting statement indicating nature of this adjustments and periods they relate to
[4] Not included in sub-total
[5] Closed April 30, 2002
[6] For RSVA accounts only, report the net additions to the account during the year. For all other accounts, record the additions and reductions separately.
[7] Please describe "other" components of 1508 and add more component lines if necessary.
[8] 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.
[9] Interest projected on December 31, 2006 closing principal balance.

Other Regulatory Assets - Sub-Account - Other [7] - Regulatory Asset Recovery Phase I & II for Hydro One

2006										
Opening Principal Amounts as of Jan-1-06	Transactions (additions) during 2006, excluding interest and adjustments [6]	Transactions (reductions) during 2006, excluding interest and adjustments [6]	Adjustments during 2006 - instructed by Board [2]	Adjustments during 2006 - other [3]	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec31-06	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Interest Amounts as of Dec-31-06
$ 1,036,751	$ (464,911)		$ -	$ -	$ (658,702)	$ (86,862)	$ 165,742	$ 80,531	$ (173,560)	$ 72,713
$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 7,320	$ 13,613		$ -	$ -	$ 32,834	$ 53,767	$ 1,593	$ (2,238)	$ (3,541)	$ (4,186)
$ (216,624)	$ (159,484)		$ -	$ -	$ 158,254	$ (217,854)	$ (21,963)	$ (26,190)	$ 20,635	$ (27,519)
$ 827,446	$ (610,781)		$ -	$ -	$ (467,613)	$ (250,948)	$ 145,371	$ 52,103	$ (156,466)	$ 41,008
$ 51,540	$ 41,976	$ -	$ -	$ -	$ (22,330)	$ 71,186	$ -	$ 4,981	$ (2,159)	$ 2,822
$ -	$ 178,459	$ -	$ -	$ -	$ (178,459)	$ -	$ -	$ 3,320	$ (3,320)	$ -
$ 220,118	$ 272,702	$ -	$ -	$ -	$ -	$ 492,820	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ (20,912)	$ -	$ (29,194)	$ -	$ -	$ 20,276	$ (29,830)	$ -	$ (3,643)	$ 1,960	$ (1,683)
$ 46,731	$ 21,289	$ -	$ -	$ -	$ (24,389)	$ 43,631	$ -	$ 5,191	$ (2,358)	$ 2,833
$ 28,252	$ -	$ (311)	$ -	$ -	$ (12,350)	$ 15,591	$ -	$ -	$ -	$ -
$ -	$ 8,377	$ -	$ -	$ -	$ -	$ 8,377	$ -	$ 273	$ -	$ 273
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ (38,086)	$ -	$ -	$ -	$ (38,086)	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ (289,701)	$ -	$ (96,833)	$ -	$ -	$ -	$ (386,534)	$ -	$ -	$ -	$ -
$ 296,769	$ 96,833	$ -	$ -	$ -	$ -	$ 393,602	$ -	$ -	$ -	$ -
$ 2,302,666	n/a	n/a	$ (1,224,646)	$ -	$ (1,078,020)	$ -	$ 628,762	$ 41,881	$ (670,643)	$ -
$ 303,157	n/a	n/a	$ -	$ -	$ (303,157)	$ -	$ 80,589	$ 7,327	$ (87,916)	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 2,938,620	$ 619,636	$ (164,424)	$ (1,224,646)	$ -	$ (1,598,429)	$ 570,757	$ 709,351	$ 59,329	$ (764,435)	$ ___4,245
					see PILs reconciliation requested					
					see PILs reconciliation requested					
					see PILs reconciliation requested					
$ 3,766,066	$ 8,855	$ (164,424)	$ (1,224,646)	$ -	$ (2,066,042)	$ 319,809	$ 854,722	$ 111,432	$ (920,902)	$ 45,253
					see PILs reconciliation requested					
$ 1,006,925	$ 135,701		$ -	$ -	$ (1,085,498)	$ 57,128	$ 196,274	$ 151,055	$ (214,949)	$ 132,380
$ (2,181,951)	$ 1,464,387		$ -	$ -	$ -	$ (717,564)	$ -	$ (74,083)	$ -	$ (74,083)
$ (1,232,166)	$ 3,892,089	$ (1,924,188)	$ -	$ -	$ -	$ 735,734	$ (50,368)	$ 19,817	$ -	$ (30,551)

Projected Interest on Dec 31 -06 balance from Jan 1, 2007 to Dec 31, 2007 [9]	Projected Interest on Dec 31 -06 balance from Jan 1, 2008 to April 30, 2008 [9]	Claim before Forecasted Transactions	Forecasted Transactions, Excluding Interest from Jan 1, 2007 to Dec 31, 2007	Forecasted Transactions, Excluding Interest from Jan 1, 2008 to April 30, 2008	Projected Interest from Jan 1, 2007 to April 30, 2008 on Forecasted Transx (Excl Interest) from Jan 1, 2007 to December 31, 2007	Projected Interest from Jan 1, 2008 to April 30, 2008 on Forecasted Transx (Excl Interest) from Jan 1, 2008 to April 30, 2008	Total Claim
$ (3,987)	$ (1,329)	$ (19,464)	$ -	$ -	$ -	$ -	$ (19,464)
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 2,468	$ 823	$ 52,872	$ -	$ -	$ -	$ -	$ 52,872
$ (10,000)	$ (3,333)	$ (258,706)	$ -	$ -	$ -	$ -	$ (258,706)
$ (11,519)	$ (3,840)	$ (225,298)	$ -	$ -	$ -	$ -	$ (225,298)
$ 3,267	$ 1,089	$ 78,365	$ -	$ -	$ -	$ -	$ 78,365
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 22,620	$ 7,540	$ 522,981	$ -	$ -	$ -	$ -	$ 522,981
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ (1,369)	$ (456)	$ (33,338)	$ -	$ -	$ -	$ -	$ (33,338)
$ 2,003	$ 668	$ 49,134	$ -	$ -	$ -	$ -	$ 49,134
$ 716	$ 239	$ 16,545	$ -	$ -	$ -	$ -	$ 16,545
$ 384	$ 128	$ 9,162	$ -	$ -	$ -	$ -	$ 9,162
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ (1,748)	$ (583)	$ (40,417)	$ -	$ -	$ -	$ -	$ (40,417)
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ (17,742)	$ (5,914)	$ (410,190)	$ -	$ -	$ -	$ -	$ (410,190)
$ 18,066	$ 6,022	$ 417,691	$ -	$ -	$ -	$ -	$ 417,691
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ 199,733	$ -	$ 4,950	$ 3,056	$ 207,739
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 26,198	$ 8,733	$ 609,932	$ 199,733	$ -	$ 4,950	$ 3,056	$ 817,671
		$ 370,440					$ 370,440
		$ (370,440)					$ (370,440)
		$ -					$ -
$ 14,679	$ 4,893	$ 384,634	$ 199,733	$ -	$ 4,950	$ 3,056	$ 592,373
		$ -					$ -
$ 2,622	$ 874	$ 193,004	$ -	$ -	$ -	$ -	$ 193,004
$ (32,936)	$ (10,979)	$ (835,562)	$ -	$ -	$ -	$ -	$ (835,562)
$ -	$ -	$ 705,184	$ -	$ -	$ -	$ -	$ 705,184

The following is a reconciliation between the continuity schedules from above, with the amounts requested for disposition on Exh5/Tab1/Sch2 and Exh5/Tab1/Sch3:

	Account Number	Claim as per Regulatory Asset Continuity Schedule		Claim as per 2008 EDR Application	Difference
Account Description					
RSVA - Wholesale Market Service Charge	1580	($19,464)		($19,464)	($0)
RSVA - One-time Wholesale Market Service	1582	0		0	0
RSVA - Retail Transmission Network Charge	1584	52,872		52,872	(0)
RSVA - Retail Transmission Connection Charge	1586	(258,706)		(258,706)	0
Sub-Totals		($225,298)		($225,298)	$0
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$78,365			
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	0			
Other Regulatory Assets - Sub-Account - Other [7]	1508	522,981			
Other Regulatory Assets - Sub-Account - Other [7]	1508	0			
Other Regulatory Assets - Sub-Account - Other [7]	1508	0	$601,346	$601,345	$1
Retail Cost Variance Account - Retail	1518	($33,338)		(33,338)	($0)
Retail Cost Variance Account - STR	1548	49,134		49,135	1
Misc. Deferred Debits	1525	16,545		16,545	0
LV Variance Account	1550	9,162		9,162	0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	0			
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	(40,417)			
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	0	(40,417)	(40,417)	0
Smart Meter OM&A Variance	1556	0		0	0
Conservation and Demand Management Expenditures and Recoveries	1565	(410,190)		(410,190)	0
CDM Contra	1566	417,691		417,691	(0)
Qualifying Transition Costs [5]	1570	0		2,011,316	(2,011,316)
Pre-Market Opening Energy Variances Total [5]	1571	0		0	0
Extra-Ordinary Event Costs	1572	207,739		207,739	0
Deferred Rate Impact Amounts	1574	0		0	0
Other Deferred Credits	2425	0		0	0
Sub-Totals		$817,671		$2,828,988	($2,011,314)
Deferred Payments in Lieu of Taxes	1562	$370,440		$393,111	($22,671)
2006 PILs & Taxes Variance	1592	(370,440)		(393,111)	22,671
Sub-Totals		$0		$0	$0
Total		$592,373		$2,603,689	($2,011,314)
The following is not included in the total claim but is included on a memo basis:					
Deferred PILs Contra Account [8]	1563	$0		$0	$0
RSVA - Power (including Global Adjustment)	1588	$193,004			
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	(835,562)	($642,558)	($642,558)	$0
Recovery of Regulatory Asset Balances	1590	$705,184			
	TOTAL CLAIM RECONCILED		**($635,158)**	**($635,158)**	**$0**

Note: The accounts that are shaded indicate those that Norfolk Power is seeking disposal from the 2008 EDR Application. Total disposal claimed as per 2008 EDR Application is $635,158 (ABOVE)

43. Ref: Exh5/Tab1/Sch2/P1

Norfolk Power is requesting disposition of account 1572 Extra-ordinary Event Losses of $207,739 as at April 30, 2008.

a. What was the extraordinary event that caused this expense?
b. When did this event occur?
c. Please explain in detail why this event satisfies each of the regulatory principles: causation, materiality, inability of management to control, and prudence?
d. Please provide a detailed breakdown, identifying the types of costs included in this account. Please provide supporting documentation.
e. Have the principal balances been independently verified?
f. Is there a reason why the Board should depart from past regulatory practice of disposing account balances other than at the end of a completed and verifiable fiscal year (e.g. December 31, 2006)?

Response:

a. See table below
b. See table below
c. See table below
d. See table below
e. The principal balances will be independently verified as part of the 2007 Yearend Audit
f. Since re-basing will not be done again until 2011, from a cash flow perspective, it is unreasonable to Norfolk Power and its customers to carry this asset for the next three years and add interest charges to the principal balance, for future recovery.

	Ice Storm January 2007	**Wind Storm June 2007**	
Event	Natural Disaster	Natural Disaster	
Description	Freezing rain and strong winds knocked down trees and overhead wires	Strong winds and lighting knocked down trees and overhead wires	
Total Customers without power	16,503	4,258	
Outside Assistance	Oakhill Tree Service	Oakhill Tree Service	
	K-Line Maintenance	K-Line Maintenance	
	Brant County Power	Brant County Power	
	Brantford Power	Tillsonburg Hydro	
Breakdown of Event Costs:			TOTAL CLAIM
Overtime labour - Internal	$18,799.65	$10,702.78	$29,502.43
Trucking	8,630.00	4,130.00	12,760.00
Outside Assitance	132,269.55	22,656.12	154,925.67
Accommodations & Meals	2,063.41	481.73	2,545.14
Interest (Carrying Charges)			14,118.00
	$161,762.61	$37,970.63	$213,851.24

Satisfying Criteria as per OEB:

Causation	Norfolk Power had no option other than to restore power in a timely manner	Norfolk Power had no option other than to restore power in a timely manner
Materiality	0.2% of Net Fixed Assets	0.2% of Net Fixed Assets
Prudence	most cost effective option	most cost effective option

44. Ref: Ex5/Tab1/Sch2/Pg1&2

a. Is Norfolk Power currently using account 1590?
b. If the answer to a. is no, why not?
c. If the answer to a. is yes, have previous 2006 EDR Board approved amounts for regulatory asset recovery been transferred to account 1590, as instructed in the Board's letter dated November 28, 2006 to LDCs? When did Norfolk Power do this transfer?
d. Please update Exhibit 5/Tab 1/Schedule 2 to reflect the appropriate transfers and include account 1590. Please also update Exhibit 5/Tab 1/Schedule 3 to reflect the appropriate transfers.
e. If transfers of 2006 EDR Board-approved amounts for regulatory asset recovery to 1590 have occurred please explain why Norfolk Power has a balance in account 1570 as at December 31, 2006. The account should have been closed once final approval was received in the 2006 EDR process.

Response:

a. Norfolk Power is currently using account 1590
b. Not applicable
c. Previous 2006 EDR Board approved amounts for regulatory asset recovery have been transferred to account 1590, as instructed in the Board's letter dated November 28, 2006 to LDCs. Norfolk Power did the transfer as part of the 2006 yearend process.
d. Please see response to Board IR#42
e. There is a contra-account (Account #2120 not disclosed) to Account #1570 (Qualifying Transition costs) of equal amount. The net is zero.

45. Ref: Ex5/Tab1/Sch2/Pg1 & 2

a. What is the composition of Account 1508?
b. Please clarify whether Norfolk Power is disposing of the following accounts and whether the costs in these accounts were approved for disposition in 2006 EDR.
   I) 1508
   II) 1525
   III) 1570
c. What is the total amount for disposition for all accounts that received approval in the 2006 EDR process?

Response:

a. The costs contained in Account #1508 are from Hydro One invoices for Phase I & II of their regulatory asset recovery as approved by the OEB. Norfolk Power did not apply for disposal of this account in order to mitigate the impact on total customer's bill.
b. Norfolk Power is not seeking approval to dispose the following accounts in the 2008 EDR application.
   I) 1508
   II) 1525
   III) 1570

   The above accounts were approved for disposition in the 2006 EDR.

c. Please see the schedule below taken from the approved 2006 EDR RAR.

NAME OF UTILITY	NOROLK POWER DISTRIBUTION INC.
NAME OF CONTACT	ALVIN ALLIM
E-mail Address	aallim@norfolkpower.on.ca
VERSION NUMBER	v2.0
Date	14-Sep-05

Regulatory Asset Accounts:	**Decision Ref.#**		**Amount**	**ALLOCATOR**
WMSC - Account 1580	2.0.35	$	832,261	kWh
One-Time WMSC - Account 1582	2.0.35	$	-	kWh
Network - Account 1584	2.0.35	$	(192,539)	kWh
Connection - Account 1586	2.0.35	$	1,266,976	kWh
Power - Account 1588	2.0.35	$	1,300,447	kWh
Subtotal - RSVA		$	3,207,146	
Other Regulatory Assets - Account 1508		$	72,709	Dx Revenue
Retail Cost Variance Account - Acct 1518		$	(22,236)	# of Customers
Retail Cost Variance Account (STR) Acct 1548		$	26,746	# of Customers
Rebate Cheques - Acct 1525	5.0.19	$	13,544	# cust. w/ Rebate Cheq
Hydro One's Environmental Costs - Acct 1525	5.0.25	$	27,516	Dx Revenue

Pre Market Opening Energy - Acct 1571	3.0.27	$ 391,073	kWh for Non TOU Cust.
Extraordinary Event Losses - Acct 1572		$ -	
Deferred Rate Impact Amounts - Acct 1574		$ -	
Other Deferred Credits - Acct 2425		$ -	
Transition Costs - Acct 1570	7.0.67	$ 1,078,020	# of Customers
Subtotal - Non RSVA		$ 1,587,371	
Total to be Recovered		$ 4,794,517	

Interim Transition Cost Recoveries (if applicable)	10.0.19		
Recoveries - Mar 1-02 to Mar 31-04		$ -	Actual
Recoveries - Mar 1-02 to Mar 31-04 (Interest)		$ -	
Recoveries - Apr 1-04 to Apr 30-06 (Interest)		$ -	
Recoveries - Interim Transition Costs - Total		$ -	
Reg. Assets Interim Recoveries:	10.0.19		
Phase 1 Recoveries - Apr 1-04 to Mar 31-05		$ 1,120,797	Actual
Phase 1 Recoveries - Apr 1-04 to Mar 31-05 (Interest)		$ 37,409	
Phase 1 Recoveries - Apr 1-05 to Apr 30-06 (Interest)		$ 88,029	
Phase 1 (1st Interim) Recoveries - Total		$ 1,246,235	
Phase 1 Recoveries - Apr 1-05 to Apr 30-06		$ 1,787,721	Estimate-Actual to Jun.05
Phase 1 Recoveries - Apr 1-05 to Apr 30-06 (Interest)		$ 63,088	
Phase 1 (2nd Interim) Recoveries - Total		$ 1,850,808	
Total Recoveries to April 30-06		$ 3,097,044	

Balance to be collected or refunded in the next 2 years	$ 1,697,473
Balance to be collected or refunded per year	$ 848,737

46. Ref: Ex2/Tab3/Sch3

a. Is Norfolk Power using the Board-prescribed interest rate, as per the Board's letter to LDCs dated November 28, 2006, for construction work in progress (CWIP) since May 1, 2006?
b. If not, what interest rate has Norfolk Power been using for CWIP?
c. If not using the Board-prescribed interest rates, what would the impact on rate base, revenue requirement, and CWIP be if Norfolk Power did use the prescribed interest rates?

Response:

a. Norfolk Power does not have construction work in progress.
b. Not Applicable
c. Not Applicable

CONSERVATION AND DEMAND MANAGEMENT

47. Ref: Exhibit 4/Tab 2/Schedule 2

Norfolk Power's application indicates a "2006 Board Approved" amount of $563, and a 2006 Actual" amount of $125,766 for Energy Conservation, which is variance of $125,203.

a. Please cite the Board decision where Norfolk Power received approval from the Board for the $563.
b. Please clarify whether Norfolk Power has sought, or is seeking, recovery of the overspending of $125,203 indicated in the application.

Response:

a. Please see the 2006 Approved EDR Model. The amount of $563 is not quoted in the Board's decision and order, dated April 26, 2006.

EDR 2006 MODEL (ver. 2.1)

NORFOLK POWER DISTRIBUTION INC.

ED-2002-0521 (RP-2005-0020, EB-2005-0396)

SEPTEMBER 14, 2005

5-4 CDM (Input)

	$
Trial Balance account 5415-Energy Conservation	563
Tier 1 Adjustment	0
Adjusted amount	563
Portion attributed to specific classes	

b. Norfolk Power has not sought and is not seeking, recovery of the over-spending of $125,203 indicated in the application.

48. Ref: Exhibit 1 /Tab 3/Schedule 2, Exhibit 2 /Tab 4/Schedule 1 and Exhibit 4 /Tab 2/ Schedule 1

Norfolk Power's application indicates an amount of $68,000 for Energy Conservation in the 2007 bridge year.

a. Please clarify whether this amount relates to amounts spent by Norfolk Power in 2007.
b. If yes, please cite the Board decision where Norfolk Power received approval from the Board for this CDM spending.
c. If yes, please provide a description of the activity or activities for which this amount was used.
d. If the $68,000 does not relate to CDM spending in 2007, please fully explain how and when these dollars were used.

Response:

a. At the time the 2008 EDR was prepared, this amount represented Norfolk Power's forecast for 2007.
b. This amount represents 3rd Tranche spending as approved previously by the Board.
c. If yes, please provide a description of the activity or activities for which this amount was used.

Customer Energy Conservation Information	**$20,000**
Staff Training for Conservation	**3,000**
Energy Audits for Major Customers	**20,000**
Compact Fluorescent Giveaway	**5,000**
Appliance Incentives	**20,000**

d. Not Applicable

49. Ref: Exhibit 1 /Tab 3/Schedule 2, Exhibit 2 /Tab 4/Schedule 1, Exhibit 4 /Tab 2/Schedule 1 and Exhibit 9 /Tab 1/Schedule 1

Norfolk Power's application indicates an amount of $68,612 for Energy Conservation in 2008.

a. Please provide a description of the activity or activities for which Norfolk Power is seeking this amount.

b. The Board's "Filing Requirements for Transmission and Distribution Applications", issued on November 14, 2006, outlines the information that is required when filing an application for CDM funding. Please provide the information required by section 6.2 of the Filing Requirements in relation to the amount requested for 2008.

Response:

a. See below

Customer Energy Conservation Information	**$20,000**
Staff Training for Conservation	**3,612**
Energy Audits for Major Customers	**20,000**
Compact Fluorescent Giveaway	**5,000**
Appliance Incentives	**20,000**

b. Norfolk Power did not request any incremental funding as outlined in Section 6.2 of the Filing Requirements. Spending in 2008 Test year is the residual amount remaining from the original 3rd Tranche funding.

PILS

50. Reference Exhibits: E4/T3/S2/P2-4

   a. Please explain why, for the Capital Cost Allowance (CCA) class 47, the 8% rate, which has been available for use since February 23, 2005 was not used in the 2006 tax returns.
   b. Please provide a table that reconciles capital additions to rate base with the additions to UCC tax classes for 2006, 2007 and 2008.
   c. Please provide a continuity table that shows the movement in construction work in progress for 2006, 2007 and 2008.
   d. Has Norfolk maximized the CCA deductions in its tax returns and in this application?

Response:

   a. Norfolk Power's annual tax returns are completed by external auditors as part of yearend procedures. Norfolk Power was unaware of the Capital Cost Allowance (CCA) class 47, 8% rate.
   b. Please see table below. The differences between Exhibit 4/Tab 3/Schedule 2 and the amounts for the Bridge and Test years are the exclusion of land and land rights and leasehold improvements. Although the rate base includes these amounts, the PILS calculation for CCA did not include the capital cost for these assets. Land and Land Rights should have been classified as Class 1 and Leasehold Improvements should have been Class 13.4.

2006	
2006 Actual Capital Additions, as per Exhibit 4/Tab 3/Schedule 2/Page 2	$5,049,756
2007 Actual Capital Additions	5,049,756
Discrepancy	$0
2007	
2007 Bridge Capital Additions, as per Exhibit 4/Tab 3/Schedule 2/Page 3	$5,594,200
2007 Bridge Capital Additions	5,622,200
Discrepancy	($28,000)
Add:	
Land and Land Rights	26,000
Leasehold Improvements	2,000
Discrepancy	$0
2008	
2007 Bridge Capital Additions, as per Exhibit 4/Tab 3/Schedule 2/Page 4	$10,188,600
2008 Test Capital Additions	10,189,600
	($1,000)

Add:	
Land and Land Rights	1,000
Discrepancy	$0

c. Not Applicable. Norfolk Power does not recognize construction work in progress.

d. For 2006 and 2007, Norfolk Power believes it did not maximize the CCA deductions in its tax returns. With the exception of excluding land and land rights, Norfolk Power believes it has maximized the CCA deductions in its tax return for the 2008 Test year application.

SMART METERS

51. Ref: Exhibit 2 /Tab 3 /Schedule 3

On page 12, Norfolk Power provides capital expenditure amounts of $25,185, $49,000 and $4,251,000 for 2006, 2007 and 2008 respectively in regards of “Smart Metering Program (2006 CDM Pilots)”.

a. Norfolk Power is not one of the thirteen licensed distributors authorized by Ontario Regulation 427/06 to conduct discretionary metering activities with respect to smart meters.
   I) In light of its “un-named” status, please explain under what authority Norfolk Power has decided to undertake smart meter activity in 2006, 2007 and 2008.
   II) Please indicate the associated number of smart meter installations for 2006, 2007 and 2008.
b. Please confirm whether Norfolk Power will incorporate the 2008 smart meter capital expenditure amount of $4,251,000 into its rate base and recover the associated rate of return through its proposed 2008 revenue requirement.
   I) If not, please confirm whether Norfolk Power is going to maintain its current Smart Meter Rate Adder of $0.26 per month per metered customer which was approved by the Board on April 12, 2007 in EB-2007-0560.
   II) If Norfolk Power is not intending to maintain the Smart Meter Rate Adder of $0.26, what is the amount of the Smart Meter Rate Adder that Norfolk Power is proposing for 2008. Please provide justification for the amount of this Smart Meter Rate Adder.
c. Please confirm whether Norfolk Power has incorporated the 2006 and 2007 smart meter capital expenditure amounts of $25,185 and $49,000 into its net fixed assets and thereby brought forward these amounts into 2008 net fixed assets. If not, confirm if these amounts were applied to the smart meter capital variance account.

Response:

The Total Smart Metering program for 2008 is $4,423,000, comprised of $4,061,000 Capital and $362,000 OM&A.

a. See below
   I) Please see letter from Ministry of Energy below
   II) 2006 – Nil; 2007 – Nil; 2008 – 18,021
b. Norfolk Power will incorporate the 2008 smart meter capital expenditure amount of $4,061,000 into its rate base and recover the associated rate of return through its proposed 2008 revenue requirement.
c. Norfolk Power has incorporated the 2006 and 2007 smart meter capital expenditure amounts of $25,185 and $49,000 into its net fixed assets and thereby brought forward these amounts into 2008 net fixed assets.

Ministry of Energy

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Ontario

Office of Consumer & Regulatory Affairs

December 21, 2007

Mr. Bernie Watts
Chief Executive Officer
London Hydro Inc.
111 Horton Street
P.O. Box 3060
London, ON, N6A 4J8

Dear ~~Mr. Watts~~, Bernie

I understand that London Hydro and a consortium of more than 20 additional local distribution companies (LDCs) are currently working diligently considering bids received from the now closed smart meter RFP. I want to personally congratulate London Hydro and consortium members on the hard work and collaboration that has resulted in a process that strives to ensure economies of scale, cost-effectiveness, and best value for customers. We are eager to see the results from this process to establish a second round of smart meter procurement in the province.

In our letter to London Hydro on July 25, 2007, the government reiterated its view that, wherever possible, individual procurements of the same product should be combined to capture any economic benefits from a common statement of work. This was also communicated in subsequent discussions between Ministry staff and London Hydro regarding the consideration of options for allowing LDCs outside of the consortium to participate in the procurement process.

As you are no doubt well aware, this procurement has attracted attention from LDCs across the province and several have expressed an interest in participating. I am appreciative of the work done by London Hydro to develop a participation process that offers non-consortium LDCs with an opportunity to investigate a suitable technology for their own customers. I understand that the participation guidelines ensure that the integrity of the procurement process (which will be monitored by London Hydro's fairness commissioner) will be maintained in the event of expanded LDC participation. The participation process also provides opportunities for both consortium and other LDCs to achieve greater cost-savings and volumetric discounts in those cases where the same bidder's technology is selected.

Following the successful completion of the RFP and Minister Phillips' approval, the Ministry will recommend to Cabinet an amendment to O. Reg. 427/06 to accommodate London Hydro and consortium members as well as any other LDCs outside the consortium that have chosen to participate in the process. As you know, the Ministry cannot bind Cabinet's decision making. As such, nothing in this letter shall be construed as obligating the Cabinet or the legislature of the Province of Ontario to approve or promulgate the proposed amending regulation.

Please accept my congratulations on your accomplishments to date on this initiative. I encourage you to continue the dedication you have shown thus far toward the successful implementation of smart metering for your customers.

Sincerely,

Rosalyn Lawrence

Rosalyn Lawrence
Assistant Deputy Minister
Consumer and Regulatory Affairs

cc:

Electricity Distributors Association

Niagara Erie Power Alliance

Cornerstone Hydro Electric Concepts Group

District 9

Whitby Hydro

52. Ref: Exhibit 2/ Tab2/ Schedule 3/ Capital Budget Items/Customer Metering

a. Please provide a breakdown of the OM&A and CAPEX budget expenditure for the proposed smart meters projects.
b. Please explain how Norfolk is proposing to recover the cost for both capital and OM&A expenses for its proposed smart meters program.
c. Please provide the rationale and a cost/benefit study justifying the proposed $4,251,000 Smart Metering program in test year 2008.

Response:

a. Please see below

SMART METERS	2008	
	Capital	Operating
Repair of unsafe meter bases	$45,222.75	$0.00
Costs for Detailed Propagation Studies	$0.00	$0.00
Smart Meter Network Infrastructure		
AMCD Vendor 5	$2,480,025.60	$0.00
AMRC Including WAN Costs Vendor 5	$249,628.81	$32,989.06
AMCC Vendor 5	$171,032.35	$30,678.47
AMI Miscellaneous (Including Labour For Daily Ops) Vendor 5	$10,739.00	$108,150.00
Smart Meter Installation Process Vendor 4	$268,607.32	
Adaptor Installation Vendor 4	$1,128.30	
Workforce Management System Vendor 4	$18,021.00	
Capturing of GPS Coordinates Vendor 4	$1,261.47	
Imaging of All Old Meters Vendor 4	$8,229.59	
Delivery of Customer Notification Package Vendor 4	$7,869.17	
Meter Seals	$6,175.50	
Meter Rings	$87,486.25	
Meter Adaptors	$154,387.50	
Rent for Space for Meter Inventory and Scrapping Process	$50,000.00	
AMI Installation Operational Verification Tools (Temp MDM/R)		$86,457.00
Scrapping Process Separation Costs	$36,800.00	
Meter Scrapping/Recycling Process	-$20,585.00	
Staff Training and Department Integration	$15,000.00	
AMI Warranty Costs (1% Failure Rate)	$27,426.48	
Measurement Canada Re-Verification Accrual Account	$41,473.59	
AMI Inventory Costs (Meters to Replace Rever Meters)	$41,333.76	
Contingency at 5%	$185,063.17	$12,913.73
Section Sub Total	$3,886,326.61	$271,188.25
Total Smart Meter Assest Investment	$3,935,857.99	
Total Depreciation Amount Based On 15 Years Straight Line	$265,692.63	
Current Value of Sections Smart Meter Assets	$3,670,165.37	

BILLING / CUSTOMER SERVICE		
CIS Automated Meter Change Package	$25,085.00	
Smart Meter Customer Presentment Tools (Web, IVR)	$50,170.00	$0.00
Smart Meter Entity MDM/R (est Based On OEB 2005 Report)	$15,000.00	$86,457.00
Bill Print Modifications	$0.00	
Customer Education Packages	$41,170.00	
CIS TOU Modifications and MDM/R Integration	$15,000.00	
Staff Training and Department Integration	$0.00	
Contingency at 5%	$7,321.25	$4,322.85
Section Sub Total	$153,746.25	$90,779.85
Total Smart Meter Assest Investment	$153,746.25	
Total Depreciation Amount Based On 3 Years Straight Line	$30,749.25	
Current Value of Sections Smart Meter Assets	$122,997.00	
FINANCE / CORPORATE		
Consulting Services	$20,000.00	
Legal for AMI Contracts		
Legal for Installation Contract		
Legal for Old Meter Recycling Contract		
AMI Security Audits		$0.00
Contingency at 5%	$1,000.00	$0.00
Section Sub Total	$21,000.00	$0.00
Total Smart Meter Assest Investment	$77,700.00	
Total Depreciation Amount Based On 15 Years Straight Line	$8,960.00	
Current Value of Sections Smart Meter Assets	$68,740.00	
	2008	
	Capital	**Operating**
Totals	$4,061,072.86	$361,968.10

b. Norfolk Power is proposing to recover the cost for capital through the rate base and OM&A expenses from the Revenue Requirement.
c. The Smart Metering program for 2008 is $4,423,000, comprised of $4,061,000 capital and $362,000 OM&A. Please see response to OEB IR #51 (a)(i), re: Letter from Ministry of Energy

COST ALLOCATION

Informational Filing

53. Ref: Exhibit 9

a. Please file the “rolled-up” version of Run 2 of the Informational filing EB-2007-0002. (The hard copy reply needs to include only the input tables (Sheet I3 – I8) and Sheets O1 and O2.)

In the Informational filing two of the Customer Allocators in Sheet E2 ‘Allocator Worksheet’ stand out as being quite different from other allocators. The allocators in question are CCON (Number of Connections) and CCB (Subtransmission Customer Base).

b. Please test the sensitivity of the cost allocation results in the Informational Filing model by over-writing the values of CCON and CCB with more typical amounts, eg. the same values as CCA (Total Number of Customers), and provide a copy of Sheet O1 ‘Revenue to Cost Summary Worksheet’ based on these alternative inputs.

Response:

a. The “rolled-up” version of Run 2 of the Informational filing EB-2007-0002 has been included in the electronic version of the responses to Board staff interrogatories. The hard copy reply only includes the input tables, Sheet I3 to I8 as well as Sheets O1 and O2.

b. A review of Sheet E4 TB Allocation Details of the informational filing indicates that allocators CCON and CCB are not used. As a result, changes to these alllocators will have no impact on the results.

Low Voltage Wheeling Cost

54. Ref: Exhibit 9 / Tab 1 / Schedule 1 / page 8
The total amount of Low Voltage cost proposed to be recovered in the test year is $371,652, the same amount as was approved for recovery in the 2006 EDR Decision. The Allocation Percentages for each class, shown in the first table on page 8, are different from the approved percentages, however.
    a. Please provide a table showing the annual class totals of Retail Transmission connection Revenue used to calculate the new Allocation Percentages, and stating what the applicable period is.
    b. Please provide information on the amount of cost incurred from or settlements with the host distributors for Low Voltage Wheeling during the same period as in part a).
    c. Please explain why the 2006 approved amount is proposed for 2008 recovery, as opposed to a more recent actual amount or a forecast amount reflecting the Applicant's load forecast.

Response:

a. The LV costs are being allocated using total retail transmission revenue including connection and network revenue. Norfolk Power understands that retail transmission connection revenue should have been used to allocated LV charges. Through the process of responding to this interrogatory it was discover the model used for the application used total retail transmission revenue as the allocator for LV costs. However, the allocation factors using the total retail transmission revenue and the retail transmission connection revenue are provided in the following table which shows there is very little difference between the two methods.

Rate Classification	LV Allocation Factor with total Retail Transmission Revenue	LV Allocation Factor with Retail Transmission Connection Revenue
Residential	41.55%	42.08%
GS < 50 kW	16.25%	16.30%
GS > 50 kW	41.33%	40.75%
Sentinel Lights	0.03%	0.03%
Streetlights	0.74%	0.74%
USL	0.10%	0.10%
Total	100%	100%

b. Analysis was performed recently on actual LV costs for 2007, which were $350,000. Norfolk Power anticipates these costs to increase in 2008 and as a result, the annual cost will be more representative of the 2006 EDR amount.

c. At the time the 2008 EDR was prepared, the LV cost information from the 2006 EDR was the best full year data available

RATE DESIGN

General Service 50 - 4999 kW

55. Ref: Exhibit 9 / Tab 1 / Schedule 1 / page 4, and Exhibit 9 / Tab 1 /Schedule 8 / page 11

The stated intention is to maintain the same fixed/variable proportions as in the current rates. However, in Schedule 8 it is apparent that the Monthly Service Charge would increase by 28.9% whereas the volumetric rate would increase by 21.4%.

a. Please explain why rate design for the GS> 50 class does not follow the general principle of maintaining the existing proportions.

Response:

a. In preparing the response to this interrogatory Norfolk Power discovered the proposed rates shown in the application had been transcribed incorrectly from Rates model. As a result, Norfolk Power has filed a revision to its application correcting the rates. The revised rates for the GS > 50 class will show the Monthly Service Charge increasing by 23.3% and the volumetric charge increasing by 46.0%. The higher increase in the volumetric charge reflects the collection of transformer allowance and low voltage charges being collected in the volumetric rate. However, these adjustments to the volumetric rate are made after the current fix/variable ratio is applied in the rate design. In other words, the increase in the volumetric charge for the GS > 50 class excluding the adjustments for transformer allowance and low voltage charges is 23.3%

Impacts

56. Ref: Exhibit 9 / Tab 1 / Schedule 8

a. Schedule 8 ends with impact calculations for the GS > 50 kW class but does not include calculations for the three remaining customer classes. Please provide impact calculations for Street Lights, Sentinel Lights, and Unmetered Scattered Load customers.
b. The heading of the final page of the Application is Schedule 10. However, there is no information provided for Schedule 10, nor for the implied Schedule 9. If there is information intended for these Schedules, please provide it.

Response:

a. See below
b. There is no schedule 10

Street Light

1 kW Consumption

25 kWh Consumption

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				0.71			1.77	1.06	149.8%	15.8%
Distribution	kW	1	2.40250	1.80	1	6.29280	4.72	2.92	161.9%	43.3%
Sub-Total				**2.51**			**6.49**	**3.98**	**158.5%**	**59.1%**
Regulatory Asset Recovery	kW	1	0.29310	0.22	1	1.17125	0.88	0.66	299.6%	9.8%
Retail Transmission - Network	kW	1	1.51410	1.19	1	1.48397	1.16	(0.02)	-2.0%	-0.4%
Retail Transmission - Line and Transformation Connection	kW	1	1.25880	0.99	1	0.94337	0.74	(0.25)	-25.1%	-3.7%
Wholesale Market Service	kWh	26	0.00520	0.14	26	0.00530	0.14	0.00	1.9%	0.0%
Rural Rate Protection Charge	kWh	26	0.00100	0.03	26	0.00100	0.03	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	25	0.00700	0.18	25	0.00700	0.18	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	26	0.05704	1.49	26	0.05704	1.49	0.00	0.0%	0.0%
Total Bill				**6.73**			**11.11**	**4.37**	**64.9%**	**64.9%**

Sentinel

0.75 kW Consumption

25 kWh Consumption

	Metric	2007 BILL			2008 BILL			IMPACT		
		Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				1.37			5.43	4.06	296.2%	27.2%
Distribution	kW	1	3.37790	2.53	1	13.67630	10.26	7.72	304.9%	51.7%
Sub-Total				**3.90**			**15.68**	**11.78**	**301.8%**	**78.9%**
Regulatory Asset Recovery	kW	1	9.29090	6.97	1	3.02257	2.27	(4.70)	-67.5%	-31.5%
Retail Transmission - Network	kW	1	1.52170	1.21	1	1.49149	1.18	(0.02)	-2.0%	-0.2%
Retail Transmission - Line and Transformation Connection	kW	1	1.28510	1.02	1	0.96309	0.76	(0.26)	-25.1%	-1.7%
Wholesale Market Service	kWh	26	0.00520	0.14	26	0.00530	0.14	0.00	1.9%	0.0%
Rural Rate Protection Charge	kWh	26	0.00100	0.03	26	0.00100	0.03	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	25	0.00700	0.18	25	0.00700	0.18	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	26	0.05704	1.51	26	0.05704	1.51	0.00	0.0%	0.0%
Total Bill				**14.94**			**21.74**	**6.80**	**45.5%**	**45.5%**

Sentinel

0.75 kW Consumption

50 kWh Consumption

	Metric	2007 BILL			2008 BILL			IMPACT		
		Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				1.37			5.43	4.06	296.2%	24.2%
Distribution	kW	1	3.37790	2.53	1	13.67630	10.26	7.72	304.9%	46.0%
Sub-Total				**3.90**			**15.68**	**11.78**	**301.8%**	**70.2%**
Regulatory Asset Recovery	kW	1	9.29090	6.97	1	3.02257	2.27	(4.70)	-67.5%	-28.0%
Retail Transmission - Network	kW	1	1.52170	1.21	1	1.49149	1.18	(0.02)	-2.0%	-0.1%
Retail Transmission - Line and Transformation Connection	kW	1	1.28510	1.02	1	0.96309	0.76	(0.26)	-25.1%	-1.5%
Wholesale Market Service	kWh	53	0.00520	0.27	53	0.00530	0.28	0.01	1.9%	0.0%

Rural Rate Protection Charge	kWh	53	0.00100	0.05	53	0.00100	0.05	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	50	0.00700	0.35	50	0.00700	0.35	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	53	0.05704	3.01	53	0.05704	3.01	0.00	0.0%	0.0%
Total Bill				**16.78**			**23.59**	**6.81**	**40.6%**	**40.6%**

Unmetered Scattered Load

		-	-	-
0	kW Consumption		-	-
500	kWh Consumption		-	-
-		-		

		2007 BILL			2008 BILL			IMPACT		
	Metric	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
Monthly Service Charge				20.75			29.17	8.42	40.6%	14.6%
Distribution	kW	0	0.01170	0.00	0	0.01740	0.00	0.00		0.0%
Sub-Total				**20.75**			**29.17**	**8.42**	**40.6%**	**14.6%**
Regulatory Asset Recovery	kW	0	0.00230	0.00	0	-0.00041	0.00	0.00		0.0%
Retail Transmission - Network	kW	0	0.00490	0.00	0	0.00482	0.00	0.00		0.0%
Retail Transmission - Line and Transformation Connection	kW	0	0.00410	0.00	0	0.00307	0.00	0.00		0.0%
Wholesale Market Service	kWh	528	0.00520	2.75	528	0.00530	2.80	0.05	1.9%	0.1%
Rural Rate Protection Charge	kWh	528	0.00100	0.53	528	0.00100	0.53	0.00	0.0%	0.0%
Debt Retirement Charge	kWh	500	0.00700	3.50	500	0.00700	3.50	0.00	0.0%	0.0%
Cost of Power Commodity	kWh	528	0.05704	30.12	528	0.05704	30.12	0.00	0.0%	0.0%
Total Bill				**57.64**			**66.11**	**8.47**	**14.7%**	**14.7%**

All classes

57. In addition to the previous interrogatories, please describe any adjustments that you would make to the proposed rates in order to implement the policies in the Board Report on the Application of Cost Allocation for Electricity Distributors, EB-2007-0667, November 28, 2007.

Response:

Norfolk Power has reviewed the Board Report on the Application of Cost Allocation for Electricity Distributors, EB-2007-0667, November 28, 2007 and to the best of Norfolk Power's knowledge the proposed rates in this application reflect the policies outlined in the report. Norfolk Power has taken steps to address those rate classes that have revenue/cost ratios that fall outside the acceptable range outlined in the report but has also attempted to not have unreasonable bill impacts in order to address the issue.

General Questions

58. General – Regulatory Costs

a. Please provide the breakdown for actual and forecast, where applicable, for the 2006 Board approved, 2006 actual, 2007 bridge year, and 2008 test year regarding the following regulatory costs and present it in the following table format:
b. Under “Ongoing or One-time Cost”, please identity and state if any of the regulatory costs are “One-time Cost” and not expected to be incurred by the applicant during the impending two year period when the applicant is subject to 3rd Generation IRM process or it is “Ongoing Cost” and will continue throughout the 3rd Generation of IRM process.
c. Please state the utility’s proposal on how it intends to recover the “One-time” costs as a part of its 2008 rate application.

Response:

a. Please see table below
b. Please see table below
c. As per the table below, Norfolk Power does not have any “One-time” costs as a part of its 2008 rate application.

REGULATORY COST CONTROL	On-Going or "One-Time" Cost ?	2006 Board Approved	2006 Actual	2007 (as of Dec 2007)	% Change in 2007 vs. 2006	2008 Forecast	% Change in 2008 vs. 2007
OEB Annual Assessment	On-Going	$55,000.00	$58,343.00	$65,000.00	11%	$65,000.00	0.00%
OEB Hearing Assessments (applicant initiated)	Not Applicable	$0.00	$0.00	$0.00	0%	$0.00	0.00%
OEB Section 30 Costs (OEB initiated)	On-Going	$0.00	$869.40	$1,500.00	73%	$2,000.00	33.33%
Expert Witness cost for regulatory matters	Not Applicable	$0.00	$0.00	$0.00	0%	$0.00	0%
Legal costs for regulatory matters	Not Applicable	$0.00	$0.00	$0.00	0%	$0.00	0%
Consultant's costs for regulatory matters	See explanation below[1]	$5,259.00	$5,098.77	$28,500.00	459%	$28,855.00	1.25%
Operating expenses associated with staff resources allocated to regulatory matters (please identify the resources)	Not Applicable	$0.00	$0.00	$0.00	0%	$0.00	0%
Other regulatory agency fees or assessments	Not Applicable	$0.00	$0.00	$0.00	0%	$0.00	0%
Any other costs for regulatory matters (please define)	Not Applicable	$0.00	$0.00	$0.00	0%	$0.00	0%

(1) Consultant's costs were significantly higher in 2007 and 2008 due to projects from the OEB such as (1) Cost Allocation; and (2) 2008 EDR Application.

Norfolk Power believes these costs will decrease significantly in 2009 and 2010.

Norfolk Power Distribution Inc. (Norfolk)
2008 Electricity Rate Application
Board File No. EB-2007-0753
VECC's Interrogatories

Question #1

Reference: i) Exhibit 1/Tab 1/Schedule 5, page 1

a) Please confirm that Norfolk is not proposing to change the levels for any of its existing Specific Service Charges. If it is, please identify which charges and the rationale for the change.
b) Please confirm that Norfolk is not proposing any new Specific Service Charges for 2008? If it is, please describe what they are, the rationale for employing a specific service charge and the basis for the rate.

Response:

a) This is to confirm that Norfolk is not proposing to change the levels for any of its existing Specific Service Charges.
b) This is to confirm that Norfolk is not proposing any new Specific Service Charges for 2008.

<u>Question #2</u>

Reference: i) Exhibit 1/Tab 1/Schedule 7, page 2

a) Please confirm that Norfolk is proposing to include the 2008 costs related to Smart Meters in the 2008 Rate Base and Distribution Base Revenue Requirement as opposed to recording them in the deferral/variance accounts (i.e., Accounts #1555 and 1556) established by the OEB for tracking smart meter related revenues and costs.

Response:

It is confirmed that Norfolk Power is proposing to include the 2008 costs related to Smart Meters in the 2008 Rate Base and Distribution Base Revenue Requirement as opposed to recording them in the deferral/variance accounts (i.e., Accounts #1555 and 1556) established by the OEB for tracking smart meter related revenues and costs.

<u>Question #3</u>

Reference: i) Exhibit 1/Tab 1/Schedule 8

a) Please provide an illustrative “accounting order” that shows how the “Future Capital Projects” deferral/variance account would work.
b) What information would Norfolk anticipate filing at the time of its next rebasing to justify clearance of the “Future Capital Projects” account?

Response:

a) The accounting order would be a debit to the “Future Capital Projects” deferral/variance account and credit to cash. Upon approval from the OEB, balance would be transferred from the “Future Capital Projects” deferral/variance account to an account established by the OEB for recovery.
b) At this time, Norfolk Power would plan to file the capital programs that would support the depreciation and return included in the deferral /variance account. Norfolk Power would also provide the calculation that supports the level of depreciation and return included in the account.

Question #4

Reference: i) Exhibit 1/Tab 1/Schedule 9

a) Please confirm that the "Distribution Revenue" reported under the first column (2008 Test Existing Rates) is based on forecast 2008 billing quantities and existing 2007 rates.
b) If the response to (a) is no, please redo the deficiency/sufficiency calculation using forecast 2008 billing quantities and 2007 rates.
c) Please provide a schedule that sets out the derivation of the 2008 revenues based on 2007 rates. In doing so, please provide for each class:
    - The forecast 2008 billing quantities
    - The 2007 rates
    - The revenues by customer class – broken down as between those attributable to volumetric vs. fixed monthly charges
    - The total revenues for each class
d) Please explain what the line item "Net Adjustments per 2008 PILs" is meant to reflect.
e) Please confirm that the $101,174 reported as "Property & Capital Taxes" represents just the cost of Capital Taxes. If not, how much of this is "Property Tax"?

Response:

a) This is to confirm that the "Distribution Revenue" reported under the first column (2008 Test Existing Rates) is based on forecast 2008 billing quantities and existing 2007 rates.
b) Not applicable
c)

	2008 Test - Projected				
	Customers (Year-End)	Projected Consumption (kWh)	Projected Consumption (KW)	2007 Fixed Rate	2007 Variable Rate
Residential	16,607	147,447,515	-	$18.48	$0.0169
General Service Less Than 50 kW	2,058	64,081,972	-	$41.74	$0.0117
General Service 50 to 4,999 kW	166	189,745,291	403,334	$219.76	$3.0175
Unmetered Scattered Load	51	406,396	-	$20.75	$0.0117
Sentinel Lighting	400	342,469	345	$1.37	$3.3779
Street Lighting	3,091	3,101,236	9,478	$0.71	$2.4025
TOTAL	22,372	405,124,879	413,157		

	Fixed	Variable	TOTAL INCLUDING RATE RIDERS	Rate Riders Transition Costs	Rate Riders Reg Assets	Rate Riders LV Charge	Rate Riders Smart Meters	Net Distribution Service Revenue
Residential	$3,682,757	$2,491,863	$6,174,620	$0	$0	($132,703)	($51,814)	$5,990,104
General Service Less Than 50 kW	1,030,657	749,759	1,780,416	0	0	(57,674)	(6,420)	1,716,322
General Service 50 to 4,999 kW	437,910	1,217,062	1,654,972	0	0	(168,029)	(518)	1,486,425
Unmetered Scattered Load	12,699	4,755	17,454	0	0	(366)	0	17,088
Sentinel Lighting	6,576	1,165	7,741	0	0	(90)	0	7,651
Street Lighting	26,332	22,770	49,103	0	0	(2,685)	0	46,418
Total	$5,196,932	$4,487,374	$9,684,306	$0	$0	($361,547)	($58,752)	$9,264,007

d) These are adjustments to accounting income to produce taxable income
e) This is to confirm that the $101,174 reported as "Property & Capital Taxes" represents "Ontario Capital Tax" only.

Question #5

Reference: i) Exhibit 1/Tab 1/Schedule 12
ii) Exhibit 1/Tab 1/Schedule 13

a) Please comment on the current status of the initiatives outlined by Norfolk in its Line Loss Reduction Plan (Reference (ii)).
b) Please describe any future planned work associated with these initiatives and cross reference where the costs are included in the current Application.

Response:

a) Please see response to School Energy Coalition IR#1
b) The following is a long range budget for future capital programs that will be undertaken to reduce line losses as per Norfolk Power's Line Loss Reduction Plan:

Capital Account	Description of Future Work Planned	2009	2010	2011	2012
MS & DS Equipment	Continue to upgrade, refurbish and replace aged equipment	$600,000	$500,000	$800,000	$400,000
TS Equipment	Add second transformer and switchgear	650,000	1,100,000	381,000	300,000
SCADA	Upgrade master station, add and upgrade equipment	70,000	70,000	70,000	70,000
Distribution System - Overhead	Voltage conversions	100,000	100,000	100,000	100,000

<u>Question #6</u>

Reference: i) Exhibit 1/Tab 2/Schedule 6

a) Do either Norfolk Power Inc. or Norfolk Energy Inc. provide services to Norfolk Power Distribution?
b) If the response to (a) is yes, please indicate what the services are and the charges for each of the services for 2006 (actual), 2007 and 2008.
c) If the response to (a) is yes, please indicate the basis of the charges for each service and where in the Application the "charges" are included as a cost in the 2008 revenue requirement.
d) If the response to (a) is yes, please provide copies of the relevant service agreements, as required under the Affiliate Relations Code.

Response:

a) Norfolk Power Inc. and Norfolk Energy Inc. do not provide services to Norfolk Power Distribution Inc.
b) Not applicable
c) Not Applicable
d) Not Applicable

<u>Question #7</u>

Reference: i) Exhibit 1/Tab 3/Schedule 1

a) Please provide the full 2006 audited statements, including the associated notes.

Response:

To be included at the end of this report.

Question #8

Reference: i) Exhibit 2/Tab 2/Schedules 1 & 2

a) Please provide a summary Schedule that shows just the capital spending and capital additions for each of the years 2006 (actual) through 2008 for each of the following asset categories:
   - Land and Buildings
   - TS Primary Above 50 kW
   - DS
   - Poles and Wires – Overhead
   - Underground
   - Line Transformers
   - Services and Meters
   - General Plant
   - IT Assets
   - Equipment
   - Other Distribution Assets
   - Total of all Asset Categories

   In the schedule please indicate which USoA accounts Norfolk associated with each category. In addition, please clarify whether the amounts reported by asset category are net of capital contributions.

Response:

Please refer to the table below. The amounts reported are not net of capital contributions.

	2006 ACTUAL	2007 BRIDGE	2008 TEST	Uniform System of Account
DISTRIBUTION PLANT				
Land and Land Rights	$69,964	$1,000	$1,000	1805; 1806
Transformer Station - Building & Fixtures	0	5,000	74,200	1808
Transformer Station Equipment	6,426	195,000	322,000	1815
Substation Equipment	78,143	1,177,000	811,500	1820
Distribution System - Overhead:				
Poles, Towers, & Equipment	771,544	651,000	1,130,800	1830
Conductor & Devices	680,066	854,000	738,200	1835
Distribution System - Underground:				
Conduit	483,267	280,000	282,000	1840
Conductor & Devices	742,857	431,000	600,000	1845
Transformation	677,642	745,000	876,000	1850
Services - Overhead and Underground	543,952	311,000	322,000	1855
Meters (includes Smart Meters)	261,707	459,200	4,577,400	1860
TOTAL DISTRIBUTION PLANT	$ 4,315,568	$ 5,109,200	$ 9,735,100	
GENERAL PLANT				
Land and Land Rights	$7,070	$25,000	$0	1905; 1906

Buildings: Fixtures & Improvements	44,213	153,000	108,400	1905
Leasehold Improvements	0	2,000	5,000	1910
Office Furniture and Equipment	20,347	23,000	29,000	1915
Computer Equipment - Hardware	43,902	88,000	67,000	1920
Computer Equipment - Software	113,536	87,000	129,000	1925
Transportation Equipment	345,936	95,000	95,000	1930
Stores Equipment	9,828	4,000	5,000	1935
Garage, Truck Tools and Stringing Equipment	51,154	33,000	32,000	1940
Measurement & Testing Equipment	9,363	22,000	25,500	1945
Communication Equipment	7,228	29,000	29,000	1955
Miscellaneous Equipment	25,813	32,000	37,500	1960
Load Control Equipment	7,954	76,000	0	1970
SCADA Equipment	22,659	44,000	92,100	1980
TOTAL GENERAL PLANT	$ 709,003	$ 713,000	$ 654,500	
Contributions in Aid of Construction	($886,512)	($200,000)	($200,000)	1995
TOTAL CAPITAL	$4,138,059	$5,622,200	$10,189,600	

<u>Question #9</u>

Reference: i) Exhibit 2/Tab 3/Schedule 3, pages 1-10

a) Please provide a schedule that sets out the capital spending for 2006 (Board Approved and Actual), 2007 and 2008 for each of the budget categories on page 1. Please clarify whether the values presented are net of capital contributions or not.
b) With respect to page 2, please reconcile the $5,673,900 figure in the first paragraph with the $5,157,500 set out in Table 1.
c) Please ensure the totals set out in Table 1 (page 1) reconcile with the totalized capital spending over all the asset accounts, as set out in response to VECC Question #8.
d) With respect to Customer Demand Projects, please confirm whether the $1,841 k spending is net of the estimated $200,000 in capital contributions.
e) Using the breakdown in Table 2 (page 3), please provide a schedule setting out the spending on Customer Demand Projects for the years 2006 (actual), 2007 and 2008. Please provide an explanation of the reasons (i.e., underlying drivers) for any year over year change in a spending in any of the categories that exceeds 5%.
f) Page 6 makes reference to a Table 1 which purportedly summarizes projected 2008 rebuilds and conversions expenditures. However there is no Table 1 provided below – please provide/clarify.
g) Table 4, (page 6) purports to set out individual projects exceeding $100,000. However, the table appears to summarize all Renewal spending – please clarify.
h) Using the breakdown in Table 4 (page 6), please provide a schedule setting out the spending on Renewal Projects for the years 2006 (actual), 2007 and 2008. Please provide an explanation of the reasons (i.e., underlying drivers) for any year over year change in a spending in any of the categories that exceeds 5%.
i) Please provide a schedule similar to Table 4 (page 6) that sets out the Renewal spending in 2006 (actual) and 2007. Please provide an explanation of any year over year (2006 to 2007 or 2007 to 2008) changes that are greater than 5%.
j) Please explain why a new feeder is needed for the Bloomsburg MTS and why the spending is required in 2008 as opposed to a later year. To provide additional supply requirements to the northeast portion of our service territory. This will also enhance the reliability of the system.
k) Please reconcile the $1,207,500 in spending on Stations referenced at the top of page 9 with the $1,134,000 figure at the bottom of the same page.
l) Please explain what gives rise to the “Deposit for new 115/27.6 kV transformer” and why the payment must be made in 2008.
m) Please provide a schedule setting out spending on Stations in 2006 (actual) and 2007.
n) Please give the reasons (i.e., underlying drivers) for any year over year change in Stations spending that exceeds 5%.
o) Has Norfolk performed any form of Asset Condition Assessment in order to determine areas of required spending for system renewal and their priority? If yes, please provide. If not, on what basis did Norfolk determine the 2008 Renewal capital spending projects it is undertaking?

Response:

a) The schedule below provides the capital spending for 2006 (Board Approved and Actual), 2007 and 2008 for each of the budget categories on page 1.

	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
Land	$292,462	$69,964	$0	$0
Land Rights	2,886	0	1,000	1,000
Buildings and Fixtures	1,450,870	0	5,000	74,200
Transformer Station Equipment - Normally Primary above 50 kV	2,405,687	6,426	195,000	322,000
Distribution Station Equipment - Normally Primary below 50 kV	71,266	78,143	1,177,000	811,500
Poles, Towers and Fixtures	769,785	771,544	651,000	1,130,800
Overhead Conductors and Devices	733,961	680,066	854,000	738,200
Underground Conduit	143,769	483,267	280,000	282,000
Underground Conductors and Devices	530,257	742,857	431,000	600,000
Line Transformers	602,609	677,642	745,000	876,000
Services	263,275	543,952	311,000	322,000
Meters	67,233	261,707	410,200	516,400
Land	0	$7,070	$25,000	$0
Buildings and Fixtures	31,164	44,213	153,000	108,400
Leasehold Improvements	4,197	0	2,000	5,000
Office Furniture and Equipment	27,931	20,347	23,000	29,000
Computer Equipment - Hardware	110,294	43,902	88,000	67,000
Computer Software	14,253	113,536	87,000	129,000
Transportation Equipment	230,666	345,936	95,000	95,000
Stores Equipment	9,213	9,828	4,000	5,000
Tools, Shop and Garage Equipment	40,288	51,154	33,000	32,000
Measurement and Testing Equipment	13,329	9,363	22,000	25,500
Communication Equipment	10,242	7,228	29,000	29,000
Miscellaneous Equipment	8,778	25,813	32,000	37,500
Load Management Controls - Customer Premises	0	7,954	76,000	0
System Supervisory Equipment	148,037	22,659	44,000	92,100
Contributions and Grants - Credit	(728,713)	($886,512)	(200,000)	(200,000)
	$7,253,740	$4,138,059	$5,573,200	$6,128,600

b) With respect to page 2, please see the reconciliation below for $5,673,900 figure in the first paragraph with the $5,157,500 set out in Table 1. The discrepancy was caused by exclusion of the cost of regular meter program, which was included in General Plant. The correct total is $5,673,900.

	2008 Test
Land	$0
Land Rights	1,000
Buildings and Fixtures	74,200
Transformer Station Equipment - Normally Primary above 50 kV	322,000
Distribution Station Equipment - Normally Primary below 50 kV	811,500
Poles, Towers and Fixtures	1,130,800
Overhead Conductors and Devices	738,200
Underground Conduit	282,000

Underground Conductors and Devices	600,000
Line Transformers	876,000
Services	322,000
Meters	516,400
Total Distribution Plant (see above)	$5,674,100
Total Distribution Plant as Exhibit 2/Tab 3/Schedule 3/Page 2	5,157,500
	$516,600
Add: Regular Meter Program	516,400
Difference (due to rounding)	$200

c) See b) above
d) With respect to Customer Demand Projects, the $1,841K spending is <u>not</u> net of the estimated $200,000 in capital contributions.
e) See below

Table 2

Project	**2006 Actual**	**Variance**	**2007 Bridge**	**Variance**	**2008 Test**
Customer Service Work - Residential and Commercial	$990,000	-12%	$875,000	3%	$905,000
Subdivision Development	525,600	5%	550,000	9%	600,000
Roadway Relocations	670		31,000	16%	36,000
Upstream and Enhancement Projects	0		291,000	3%	300,000
Total	**$1,516,270**		**$1,747,000**		**$1,841,000**

Subdivision Development: Increase in variance between 2006 and 2008 of 13% is the result of increased subsidivion activity in Simcoe and Port Dover.

Roadway Relocations: Variance between 2007 and 2008 of 16% is the result of construction work driven by Norfolk County

f) Sentence should be omitted.
g) Table 4, (page 6) summarizes all Renewal spending.
h) See below

Table 4

Project	**2006 Actual**	**Variance**	**2007 Bridge**	**Variance**	**2008 Test**
Wood pole replacement program	$92,712	117%	$201,000	19%	$240,000
Proactive overhead transformer replacement program	126,655	-32%	86,000	44%	124,000
Proactive underground transformer replacement program	212,000	-22%	165,000	2%	168,000
Overhead renewal	1,062,090	-25%	796,400	8%	863,000
Underground renewal	744,024	-76%	180,600	56%	282,000
Total	**$2,237,481**		**$1,429,000**		**$1,677,000**

<u>Explanation of Variances:</u>

Wood Pole Replacement Program: Variance between 2006 and 2007 of 117%, and; between 2007 and 2008 of 19%, were the result of increased number of poles that required replacements from survey

Proactive Overhead Transformer Replacement Program: Variance between 2007 and 2008 of 44% were the result of capital programs scheduled for 2007, that were deferred because of changes in priorities (shifting resources to more customer demand projects)

Underground Renewal: Variance between 2007 and 2008 of 56% were the result of capital programs scheduled for 2007, that were deferred because of changes in priorities (shifting resources to more customer demand projects)

Overhead Renewal: Variance between 2007 and 2008 of 8% were the result of replacing reclosers and regulators. To minimize the costs, Norfolk Power will be installing rebuilt units.

i) Please see h) above.
j) A new feeder is needed for the Bloomsburg MTS to provide additional supply requirements to the northeast portion of our service territory, which currently is experiencing a level of very high growth. This will also enhance the reliability of the system.
k) See table below. Norfolk Power at the time of the application, focused its attention on MTS & MS equipment. Therefore, the budgeted costs for buildings and fixtures was omitted. The correct total is $1,207,500.

Stations Total Cost as per Exhibit 2/Tab 3/Schedule 3/Page 9	$1,207,500
Stations Total Cost as per Exhibit 2/Tab 3/Schedule 3/Page 9	1,134,000
	$73,500
Add: Buildings and Fixtures	74,200
Difference (due to rounding)	($700)

l) As a condition to commit to the purchase, a "Deposit for new 115/27.6 kV transformer" is required.
m) Please provide a schedule setting out spending on Stations in 2006 (actual) and 2007. See below

	2006 Actual	**Variance**	**2007 Bridge**
Transformer Station Equipment - Normally Primary above 50 kV	$6,426	2935%	$195,000
Distribution Station Equipment - Normally Primary below 50 kV	78,143	1406%	1,177,000

n) The variance from 2006 to 2007 for the transformer station represents the deferred cost that was in dispute with Hydro One to connect the Bloomsburg TS.

The variance from 2006 to 2007 for distribution station equipment represents Norfolk Power's commitment to enhance the reliability of the system and in some cases, make certain station safe. Please see the details below.

Type of Project	2007 Bridge
D.S. - Waterford Blueline	
- structure upgrade for back-up transformer	$15,000
D.S. - Waterford Nichol St.	
- de-commissioning	20,000

M.S. #2 - Simcoe	
- station overhaul	175,000
M.S. #3 - Simcoe	
- rebuild circuit breaker	43,000
M.S. #5 - Simcoe	
- station overhaul	41,000
M.S. #1 - Port Dover	
- fence replacement / upgrade	25,000
M.S. #2 - Port Dover	
- fence replacement / upgrade	25,000
M.S. #2 - Delhi	
- fence replacement / upgrade and berm additions	13,000
M.S. #7 - Delhi	
- structures for containment	15,000
Special Projects	
- transformers & switchgear at Toyotetsu	425,000
Substation Backup Transformer	380,000
TOTAL DISTRIBUTION STATION EQUIPMENT	$1,177,000

o) The following forms of Asset Condition Assessment are performed by Norfolk Power in order determine the 2008 Renewal capital spending projects:

- Pole Testing program by qualified 3rd party contractor
- Field Assessment survey by qualified staff (i.e. Engineers and Technicians)

<u>Question #10</u>

Reference: i) Exhibit 2/Tab 3/Schedule 3, page 11-12

a) Please confirm whether the reference to “Customer Connections” in the title of Table 7 is correct.
b) On page 1 of this Schedule “General Plant” appears to be a separate spending category from Customer Meters. However, on page 11, Customer Meters appears to be a sub-category of General Plant. Please clarify. If General Plant is a separate spending category please provide the spending details for 2006 through 2008.
c) Please provide the total OEB 2006 approved spending for Customer Metering
d) Please explain the year over year changes in spending on Wholesale Meter Verification (2006 actual to 2007 to 2008).
e) Please explain why spending on Upgrade and Replacement Programs virtually doubles between 2006 and 2007.
f) Please provide details regarding the $4,251,000 spending on smart meters projected for 2008:
    - How many meters does this represent and what is the total cost for meter replacement?
    - What other capital costs apart from meters are reflected in this spending?
    - What is Norfolk’s overall Smart Metering Plan for the 2008-2010 period?
    - Has Norfolk received authorization (from the provincial government) to proceed with the procurement of Smart Meters? If so, please provide. If not, what is Norfolk’s understanding as to when such authorization will be provided?
    - On what basis (i.e., OEB policy or directive) has Norfolk decided that it is appropriate to include its Smart Meter related costs for 2008 in its distribution revenue requirement as opposed to tracking the revenue requirement impacts in a variance account and establishing an appropriate “rate adder”?
g) Please explain what the $25,185 and $49,000 spending in 2006 and 2007 on Smart Meters was for.
h) Please provide a schedule setting out what the impact on the 2008 revenue requirement is of the planned $4,251,000 capital spending on Smart Meters.

Response:

a) The reference to “Customer Connections” in the title of Table 7 should be “Customer Metering”.
b) Customer Meters should have been classified as part of Distribution Plant. Please see response to Question #8 above for spending details for 2006 through 2008 for General Plant.
c) The total OEB 2006 approved spending for Customer Metering is $67,223
d) Spending on Wholesale Meter Verification (2006 actual to 2007 to 2008) is necessary to comply with IESO Market rules to address Hydro One legacy installations.
e) The spending on Upgrade and Replacement Programs virtually doubles between 2006 and 2007 because it includes $30,000 to install a service for a new GS>50 kW customer and $22,000 to upgrade metering for an existing GS>50 kW customer.
f) The capital spending on Smart Meters is $4,061,000, and not $4,251,000 as reported in Exhibit 2/Tab 3/Schedule 3. This represents ***18,021 meters.***

- See below

SMART METERS	2008 Capital
Repair of unsafe meter bases	$45,222.75
Costs for Detailed Propagation Studies	$0.00
Smart Meter Network INPrastructure	
AMCD Vendor 5	$2,480,025.60
AMRC Including WAN Costs Vendor 5	$249,628.81
AMCC Vendor 5	$171,032.35
AMI Miscellaneous (Including Labour For Daily Ops) Vendor 5	$10,739.00
Smart Meter Installation Process Vendor 4	$268,607.32
Adaptor Installation Vendor 4	$1,128.30
Workforce Management System Vendor 4	$18,021.00
Capturing of GPS Coordinates Vendor 4	$1,261.47
Imaging of All Old Meters Vendor 4	$8,229.59
Delivery of Customer Notification Package Vendor 4	$7,869.17
Meter Seals	$6,175.50
Meter Rings	$87,486.25
Meter Adaptors	$154,387.50
Rent for Space for Meter Inventory and Scrapping Process	$50,000.00
AMI Installation Operational Verification Tools (Temp MDM/R)	
Scrapping Process Separation Costs	$36,800.00
Meter Scrapping/Recycling Process	-$20,585.00
Staff Training and Department Integration	$15,000.00
AMI Warranty Costs (1% Failure Rate)	$27,426.48
Measurement Canada Re-Verification Accrual Account	$41,473.59
AMI Inventory Costs (Meters to Replace Rever Meters)	$41,333.76
Contingency at 5%	$185,063.17
Section Sub Total	$3,886,326.61
Total Smart Meter Assest Investment	$3,935,857.99
Total Depreciation Amount Based On 15 Years Straight Line	$265,692.63
Current Value of Sections Smart Meter Assets	$3,670,165.37
BILLING / CUSTOMER SERVICE	
CIS Automated Meter Change Package	$25,085.00
Smart Meter Customer Presentment Tools (Web, IVR)	$50,170.00
Smart Meter Entity MDM/R (est Based On OEB 2005 Report)	$15,000.00
Bill Print Modifications	$0.00
Customer Education Packages	$41,170.00
CIS TOU Modifications and MDM/R Integration	$15,000.00

Staff Training and Department Integration	$0.00
Contingency at 5%	$7,321.25
Section Sub Total	$153,746.25
Total Smart Meter Assest Investment	$153,746.25
Total Depreciation Amount Based On 3 Years Straight Line	$30,749.25
Current Value of Sections Smart Meter Assets	$122,997.00
FINANCE / CORPORATE	
Consulting Services	$20,000.00
Legal for AMI Contracts	
Legal for Installation Contract	
Legal for Old Meter Recycling Contract	
AMI Security Audits	
Contingency at 5%	$1,000.00
Section Sub Total	$21,000.00
Total Smart Meter Assest Investment	$77,700.00
Total Depreciation Amount Based On 15 Years Straight Line	$8,960.00
Current Value of Sections Smart Meter Assets	$68,740.00
	2008
	Capital
Totals	$4,061,072.86

- See below

SMART METERS	2008		2009		2010	
	Capital	Operating	Capital	Operating	Capital	Operating
Repair of unsafe meter bases	$45,222.75	$0.00	$0.00	$0.00	$0.00	$0.00
Costs for Detailed Propagation Studies	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Smart Meter Network INPrastructure						
AMCD Vendor 5	$2,480,025.60	$0.00		$0.00		$0.00
AMRC Including WAN Costs Vendor 5	$249,628.81	$32,989.06		$33,067.81		$33,148.53
AMCC Vendor 5	$171,032.35	$30,678.47		$36,769.05		$37,271.90
AMI Miscellaneous (Including Labour For Daily Ops) Vendor 5	$10,739.00	$108,150.00		$110,831.25		$113,579.53
Smart Meter Installation Process Vendor 4	$268,607.32					
Adaptor Installation Vendor 4	$1,128.30					
Workforce Management System Vendor 4	$18,021.00					
Capturing of GPS Coordinates Vendor 4	$1,261.47					
Imaging of All Old Meters Vendor 4	$8,229.59					
Delivery of Customer Notification Package Vendor 4	$7,869.17					
Meter Seals	$6,175.50		$0.00			
Meter Rings	$87,486.25		$0.00			
Meter Adaptors	$154,387.50		$0.00			
Rent for Space for Meter Inventory and Scrapping Process	$50,000.00		$0.00			
AMI Installation Operational Verification Tools (Temp MDM/R)		$86,457.00		$86,457.00		$0.00
Scrapping Process Separation Costs	$36,800.00		$0.00			
Meter Scrapping/Recycling Process	-$20,585.00		$0.00			
Staff Training and Department Integration	$15,000.00		$3,000.00		$3,000.00	
AMI Warranty Costs (1% Failure Rate)	$27,426.48		$27,426.48		$27,426.48	
Measurement Canada Re-Verification Accrual Account	$41,473.59		$41,473.59		$41,473.59	
AMI Inventory Costs (Meters to Replace Rever Meters)	$41,333.76					
Contingency at 5%	$185,063.17	$12,913.73	$3,595.00	$13,356.26	$3,595.00	$9,200.00
Section Sub Total	$3,886,326.61	$271,188.25	$75,495.08	$280,481.37	$75,495.08	$193,199.96
Total Smart Meter Assest Investment	$3,935,857.99		$4,011,353.07		$4,086,848.15	

Total Depreciation Amount Based On 15 Years Straight Line	$265,692.63		$533,116.16		$805,572.71	
Current Value of Sections Smart Meter Assets	$3,670,165.37		$3,478,236.91		$3,281,275.44	
BILLING / CUSTOMER SERVICE						
CIS Automated Meter Change Package	$25,085.00					
Smart Meter Customer Presentment Tools (Web, IVR)	$50,170.00	$0.00	$0.00	$8,234.00	$0.00	$8,645.70
Smart Meter Entity MDM/R (est Based On OEB 2005 Report)	$15,000.00	$86,457.00	$0.00	$86,457.00	$0.00	$86,457.00
Bill Print Modifications	$0.00		$10,000.00		$0.00	
Customer Education Packages	$41,170.00		$41,170.00		$0.00	
CIS TOU Modifications and MDM/R Integration	$15,000.00		$10,000.00		$0.00	
Staff Training and Department Integration	$0.00		$15,000.00		$3,000.00	
Contingency at 5%	$7,321.25	$4,322.85	$3,808.50	$4,734.55	$150.00	$4,755.14
Section Sub Total	$153,746.25	$90,779.85	$79,978.50	$99,425.55	$3,150.00	$99,857.84
Total Smart Meter Assest Investment	$153,746.25		$233,724.75		$236,874.75	
Total Depreciation Amount Based On 3 Years Straight Line	$30,749.25		$77,494.20		$124,869.15	
Current Value of Sections Smart Meter Assets	$122,997.00		$156,230.55		$112,005.60	
FINANCE / CORPORATE						
Consulting Services	$20,000.00		$20,000.00			
Legal for AMI Contracts						
Legal for Installation Contract						
Legal for Old Meter Recycling Contract						
AMI Security Audits		$0.00		$20,000.00		$20,000.00
Contingency at 5%	$1,000.00	$0.00	$1,000.00	$1,000.00	$0.00	$1,000.00
Section Sub Total	$21,000.00	$0.00	$21,000.00	$21,000.00	$0.00	$21,000.00
Total Smart Meter Assest Investment	$77,700.00		$98,700.00		$98,700.00	
Total Depreciation Amount Based On 15 Years Straight Line	$8,960.00		$15,540.00		$22,120.00	
Current Value of Sections Smart Meter Assets	$68,740.00		$83,160.00		$76,580.00	

	2008		2009		2010	
	Capital	Operating	Capital	Operating	Capital	Operating
Totals	$4,061,072.86	$361,968.10	$176,473.58	$400,906.92	$78,645.08	$314,057.80

- Please see letter from the Ministry of Energy below. Norfolk Power is a member of the Niagara Erie Power Alliance (NEPA).

Ministry of Energy

880 Bay Street
3rd Floor
Toronto ON M7A 2C1

Tel: (416) 325-6544
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Ministère de l'Énergie

880, rue Bay
3e étage
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Ontario

Office of Consumer & Regulatory Affairs

December 21, 2007

Mr. Bernie Watts
Chief Executive Officer
London Hydro Inc.
111 Horton Street
P.O. Box 3060
London, ON, N6A 4J8

Dear Mr. ~~Watts~~, Bernie

I understand that London Hydro and a consortium of more than 20 additional local distribution companies (LDCs) are currently working diligently considering bids received from the now closed smart meter RFP. I want to personally congratulate London Hydro and consortium members on the hard work and collaboration that has resulted in a process that strives to ensure economies of scale, cost-effectiveness, and best value for customers. We are eager to see the results from this process to establish a second round of smart meter procurement in the province.

In our letter to London Hydro on July 25, 2007, the government reiterated its view that, wherever possible, individual procurements of the same product should be combined to capture any economic benefits from a common statement of work. This was also communicated in subsequent discussions between Ministry staff and London Hydro regarding the consideration of options for allowing LDCs outside of the consortium to participate in the procurement process.

As you are no doubt well aware, this procurement has attracted attention from LDCs across the province and several have expressed an interest in participating. I am appreciative of the work done by London Hydro to develop a participation process that offers non-consortium LDCs with an opportunity to investigate a suitable technology for their own customers. I understand that the participation guidelines ensure that the integrity of the procurement process (which will be monitored by London Hydro's fairness commissioner) will be maintained in the event of expanded LDC participation. The participation process also provides opportunities for both consortium and other LDCs to achieve greater cost-savings and volumetric discounts in those cases where the same bidder's technology is selected.

Following the successful completion of the RFP and Minister Phillips' approval, the Ministry will recommend to Cabinet an amendment to O. Reg. 427/06 to accommodate London Hydro and consortium members as well as any other LDCs outside the consortium that have chosen to participate in the process. As you know, the Ministry cannot bind Cabinet's decision making. As such, nothing in this letter shall be construed as obligating the Cabinet or the legislature of the Province of Ontario to approve or promulgate the proposed amending regulation.

Please accept my congratulations on your accomplishments to date on this initiative. I encourage you to continue the dedication you have shown thus far toward the successful implementation of smart metering for your customers.

Sincerely,

Rosalyn Lawrence

Rosalyn Lawrence
Assistant Deputy Minister
Consumer and Regulatory Affairs

cc:

Electricity Distributors Association

Niagara Erie Power Alliance

Cornerstone Hydro Electric Concepts Group

District 9

Whitby Hydro

- On what basis (i.e., OEB policy or directive) has Norfolk decided that it is appropriate to include its Smart Meter related costs for 2008 in its distribution revenue requirement as opposed to tracking the revenue requirement impacts in a variance account and establishing an appropriate “rate adder”? Norfolk Power has taken the position that Smart Meters are a capital investment which is an integral part of the distribution plant. As an investment in the distribution business, they are no different from poles, towers, transformers, etc., for which a “rate rider” is not applicable.

g) The $25,185 and $49,000 spending in 2006 and 2007 on Smart Meters was approved spending from the OEB as part of 3rd Tranche.

h) Please see response to SEC IR#8

<u>Question #11</u>

Reference: i) Exhibit 2/Tab 3/Schedule 3, pages 12-13

a) Please provide a schedule that sets out the capital spending on Computer Hardware and Software for the period 2006 (actual) to 2008. Please fully explain any year over year changes that are greater (+/-) than 5%.
b) For each of 2006, 2007 and 2008 please identify any major software systems that are either new or being replaced. In each case, explain why spending is required.

Response:

	2006 ACTUAL	Variance	2007 BUDGET	Variance	2008 BUDGET
Computer Equipment - Hardware	$43,902	100%	$88,000	-24%	$67,000
Computer Equipment - Software	$113,536	-23%	$87,000	48%	$129,000

The variance between 2006 Actual and 2007 Budget for Computer Hardware of 100% was mainly due to a PC/Laptop/Monitor/Peripheral program to replace old and obsolete equipment. The variance between 2007 Bridge and 2008 Budget for Computer Hardware decreased by 24%. This is due to lower number of PC/Laptop/Monitor/Peripheral that need replacing.

The variance between 2006 Actual and 2007 Budget for Computer Software decreased by 23%. This is a result of two significant acquisitions in 2006. The first was the purchase of an Engineering/Project Accounting/Estimating program and second was purchase of licenses to upgrade from Microsoft Office 2000 to Microsoft Office 2003. The variance between 2007 Budget and 2008 Budget for Computer Software of 48% is due to an upgrade to the existing financial programs, which have been in service since 1994. The existing system lacks the reporting and analytical capabilities required for record keeping and reporting. These tasks are currently performed on a manual basis. The upgrade scheduled for 2008, will enable Norfolk Power to better accommodate the OEB filing and reporting requirements, as well as improve internal record keeping and analysis.

Question #12

Reference: i) Exhibit 2/Tab 3/Schedule 3, pages 14-15

a) Please provide a schedule that sets out capital spending on transportation and related equipment in 2006 (actual), 2007 and 2008. Please explain any year over year variations that exceed 5%.

Response:

	2006 ACTUAL	Variance	2007 BUDGET	Variance	2008 BUDGET
Transportation Equipment	$345,936	-73%	$95,000	0%	$95,000

Question #13

Reference: i) Exhibit 2/Tab 3/Schedule 3, page 16

a) Please explain the relatively low level of spending on SCADA in 2007 relative to 2006 or 2008.
b) The first paragraph under SCADA explains that the spending is related to replacing existing equipment. However, the justification suggests reliability will be enhanced. Please explain how reliability will be enhanced if the spending is simply to maintain existing systems.
c) With respect to Buildings and Fixtures – Service Centre, please explain the why the spending in 2007 and 2008 are both significantly higher than 2006 levels.

Response:

a) In 2006, equipment such as RTUs, radio antenna, etc., were budgeted for a number of MS & DS. The 2007 Budget figures represent the installation labour.
b) The replacement pertains to aged control equipment to current technology, which will maintain the existing level of reliability. But with the new technology, it is expected that reliability will be improved by more efficient processing of data.
c) The Service Centre for Norfolk Power is 25 years old. The budget spending in 2007 and 2008 represents renovations such as:
    - Roof restoration
    - Upgrade drainage system
    - Renovate men's locker room
    - HVAC & Lighting upgrades
    - Parking lot expansion
    - Office expansion

<u>Question #14</u>

Reference: i) Exhibit 2/Tab 3/Schedule 3, page 17

a) Does Norfolk capitalization policy include the capitalization of administration costs or over heads? If so, please explain how the amounts to be capitalized are determined.

Response:

Norfolk Power capitalizes overheads. These include Stores, Fringe, Vehicle and Equipment Rates and Engineering. These are described as follows:

<u>Fringe Rate</u>
A fringe labour rate is utilized which recovers non productive time costs, premium and non-premium based benefits. It will be applied to all direct labour hours charged to maintenance, capital, and work for others through timesheet reporting.

<u>Engineering Rate</u>
An Engineering burden is utilized which recovers the direct cost of the Engineering Department. It will be applied to distribution capital projects and work for others where applicable.

<u>Vehicle and Equipment Rates</u>
Vehicle and equipment burden rates is utilized to capture the full costs associated with usage (maintenance, fuel, license, insurance, depreciation). Individual rates will be developed for major vehicle classifications based on expected utilization. Charges to the three major work activities will be accomplished through vehicle timesheet reporting.

<u>Stores Rate</u>
A Supply Chain burden rate is utilized to charge all stock, non-stock, and outside services transactions to fully recover the costs charged to the Stores area.

Question #15

Reference: i) Exhibit 2/Tab 4/Schedule 1, page 4

a) Please explain the basis for the 2007 and 2008 forecast values for each of the cost of power components presented on page 4.
b) Please explain why the 2008 charges for Network and Connection do not decline in 2008, in light of the lower Wholesale Transmission rates approved by the OEB for 2008.
c) What was the average cost of power purchased (cents/kWh) used for the 2007 and 2008 projected Power Purchased values.

Response:

a) Please see response to Ontario Energy Board IR#11
b) The wholesale transmission rates approved by the OEB for 2008 were not reflected in the 2008 charges for network and connection. However, the wholesale transmission rates approved by the OEB for 2008 are reflected in the proposed retail transmission rates.

c) The average cost of power purchased (cents/kWh) used for the 2007 and 2008 projected Power Purchased values were $0.0564/kWh and $0.0592/kWh, respectively.

<u>Question #16</u>

Reference: i) Exhibit 3/Tab 1/Schedule 2, page 1
ii) Exhibit 1/Tab 1/Schedule 9, page 1

a) Please reconcile the Total Revenue figure of $12,653,802 in Reference (i) with the Total Revenue figure of $12,800,352 in Reference (i).

Response:

a) The Total Revenue figure of $12,800,352 is the correct amount and has been used to design the proposed rates. At the time of filing the application, there were some last minute changes made to the numbers in the rate model which were reflected in the proposed rates and Exhibit 3/Tab 1/Schedule 2, page 1 but the information in Exhibit 1/Tab 1/Schedule 9, page 1 did not get updated.

<u>Question #17</u>

Reference: i) Exhibit 3/Tab 1/Schedule 2

a) Please explain the decrease in Other Income and Deductions between 2006 (actual) and 2007.
b) Please explain where the SSS Admin revenues are captured in the Other Distribution Revenue figures shown.
c) Where are the revenues reported for the services Norfolk provides to its affiliates (per Exhibit 4/Tab 2/Schedule 3, page 1)?

Response:

a) A prior period adjustment involving regulatory assets for 2004 and 2005, as per yearend audit. As a result, the adjustment increased carrying charges significantly.
b) As per Article 490 from the APH, SSS Admin revenues are cleared out to the balance sheet on a monthly basis. As a result, the difference between the revenues and expenses are cleared to the balance sheet are recorded as a variance. As a result, the net is $0 on the Income Statement.
c) The revenues reported for the services Norfolk provides to its affiliates (per Exhibit 4/Tab 2/Schedule 3, page 1) are netted against the expenses. The overall effect is zero because Norfolk Power charges these services at cost.

Question #18

Reference: i) Exhibit 3/Tab 2/Schedule 1, page 2

a) Please provide a schedule that sets out for 2004:
   - Actual wholesale volumes (kWh) by customer class
   - Weather corrected wholesale volumes by customer class (as provided by HONI)
   - Weather corrected retail volumes by customer class (based on weather corrected wholesale volumes and class loss factors)
   - The number of customers by customer class
   - The normalized average use per customer (NAC) as used to determine the load forecast.

b) If the steps outlined in part (a) do not reflect the approach used by Norfolk in developing the load forecast please provide a schedule setting out the various computational steps used to develop Norfolk's load forecast.

Response:

a) The weather normalization process for Norfolk Power applied to those classes that were classified as weather sensitive which include the Residential, GS < 50 kW and GS > 50 kW classes. As a result the requested information for 2004 has been provided for these classes

Class	Actual Wholesale Volumes (kWh)	Weather Corrected Wholesale Volumes (kWh)	Weather Corrected Retail Volumes (kWh)	Number of Customers	Normalized Average Use Per Customer Used in Forecast
Residential	145,814,609	148,551,834	138,862,301	15,640	8,879
GS < 50 kW	69,206,795	70,159,045	66,396,116	2,132	31,143
GS > 50 kW	147,474,148	148,099,993	147,605,393	160	1,076,451

b) For the GS > 50 kW class, see response to OEB staff interrogatory 26 . The calculation of the normalized average use per customer used in the forecast is as follows.

2006 average use per customer	1,071,903
2004 weather corrected to actual factor	1.0042
Normalized average use per customer	1,076,451

Question #19

Reference: i) Exhibit 3/Tab 2/Schedule 3, page 1

a) Please explain how the residential weather normalized values were determined for 2006 and 2007.

b) Why are there no weather normalized values for 2005?

c) Why are the percentage differences between actual and weather normalized sales the same for 2006 and 2007? Presumably the weather was not the same in 2006 and 2007.

Response:

a) The 2004 normalized average use per customer (NAC) was applied to the number of customers for 2006 and 2007 to produce the residential weather normalized values for these two years.

b) This was an oversight by Norfolk Power. The normalized value for 2005 would be the 2005 number of customers (i.e. 15,905) times the 2004 NAC value of 8,879. This would produce a residential weather normalized values for this year of 141,215,147 kWh.

At the time the application was prepared the 2007 actual volumes were not know. As a result, Norfolk Power estimated the 2007 actual amount to be the actual usage per customer in 2006 applied to the 2007 customer. Since the 2004 residential NAC was used to determine the 2006 and 2007 weather normalized values and the same usage per customer was used to produce the actual values the percentage difference between actual and weather normalized sales is the same.

Question #20

Reference: i) Exhibit 4/Tab 1/Schedule 1, pages 1-2
ii) Exhibit 1/Tab 1/Schedule 9, page 1

a) Please reconcile the OM&A (including depreciation) figure of $8,306,708 reported in Reference (i) with the sum of the OM&A and Depreciation values ($7,935,056) reported in Reference (ii). Note – Property taxes may account for part of the difference but they appear to be less than $100,000.
b) Please reconcile the Income Tax & Capital Tax figure of $1,053,527 reported in Reference (i) with the Income Tax and the Income and Capital Tax values reported in Reference (ii).

Response:

a) Please see reconciliation below. The difference is $371,652, which is the amount for LV Charges not included in $7,935,056.

Total OM&A (including Depreciation) as per Ex 4/Tab 1/Schedule 1, Page 1	$8,306,708
Total OM&A (including Depreciation) as per Ex 1/Tab 1/Schedule 1, Page 1	7,935,056
Difference	$371,652
Add: LV Charges as per Ex 4/Tab 1/Schedule 1, Page 1	371,652
	$0

b) The Income Tax & Capital Tax figure of $1,053,527 is the correct amount and has been used to design the proposed rates. At the time of filing the application, there were some last minute changes made to the numbers in the rate model which were reflected in the proposed rates and Exhibit 4/Tab 1/Schedule 1, pages 1-2 but the information in Exhibit 1/Tab 1/Schedule 9, page 1 did not get updated.

Question #21

Reference: i) Exhibit 4/Tab 2/Schedule 1

a) Please explain what types of taxes are recorded in Account #6105 – Taxes Other Than Income Taxes.
b) The 2007 over 2006 increase in Account #5010 (Load Dispatching) is attributed to a change in the account which the operating cost of the SCADA system and IT overhead were reported.
    - Please provide a schedule that shows the 2006 through 2008 values for all the accounts affected by this change.
    - If the year over year change in the total for these accounts is greater than 5% please explain why.
c) Please confirm that, excluding Amortization Expense and LV Charges:
    - 2006 Actual OM&A is $3,989,789
    - 2008 OM&A is $5,098,246
    - 2008 OM&A (excluding Smart Meters) is $4,736,246
d) Please provide a high level explanation that identifies and quantifies the major drivers behind the 19% increase in OM&A as between 2006 and 2008, excluding Smart Meters (e.g., How much of the change is due to employee compensation? What factors led to the increase and how much does each account for?)
e) Please provide details regarding the $362,000 in OM&A spending on Smart Meters in 2008.

Response:

a) Account #6105 – Taxes Other Than Income Taxes, contains the expenses for property tax only.
b) Account #5010 (Load Dispatching) contains the costs to operate the control room. Also, a sub-account has been in place to record separately the costs associated with operating the SCADA system. The only change made in 2006 was the charge for IT overhead. See below for costing details.

	Control Room Operations Account 5010			SCADA System Operations Account 5011		
	2006 Actual	2007 Bridge	2008 Test	2006 Actual	2007 Bridge	2008 Test
Labour	$85,300	$155,075	$160,000	$0	$0	$0
Supplies/Material	2,524	3,400	0	0	0	0
Trucking	5,635	8,000	7,500	0	0	0
Outside Services	38,556	86,844	88,000	17,042	12,000	12,000
IT Overhead				29,802	35,000	35,000
	$132,015	$253,319	$255,500	$46,844	$47,000	$47,000

2006 Actual **$178,859**

2007 Bridge **$300,319**

2008 Test **$302,500**

Notes:

1. The increase in labour from 2006 to 2007 is due to hiring of a Control Room Operator in Training
2. The increase in outside services from 2006 to 2007 is due to to hiring of a contract Control Room Operator to assist in daily operations and train new hiree

c) Please confirm that, excluding Amortization Expense and LV Charges:
   - 2006 Actual OM&A is $3,989,789 - **CONFIRMED**
   - 2008 OM&A is $5,098,246 - **CONFIRMED**
   - 2008 OM&A (excluding Smart Meters) is $4,736,246 - **CONFIRMED**

d) Please see response to Ontario Energy Board IR#23

e) See below.

SMART METERS	2008 Operating
Repair of unsafe meter bases	$0.00
Costs for Detailed Propagation Studies	$0.00
Smart Meter Network INPrastructure	
AMCD Vendor 5	$0.00
AMRC Including WAN Costs Vendor 5	$32,989.06
AMCC Vendor 5	$30,678.47
AMI Miscellaneous (Including Labour For Daily Ops) Vendor 5	$108,150.00
Smart Meter Installation Process Vendor 4	
Adaptor Installation Vendor 4	
Workforce Management System Vendor 4	
Capturing of GPS Coordinates Vendor 4	
Imaging of All Old Meters Vendor 4	
Delivery of Customer Notification Package Vendor 4	
Meter Seals	
Meter Rings	
Meter Adaptors	
Rent for Space for Meter Inventory and Scrapping Process	
AMI Installation Operational Verification Tools (Temp MDM/R)	$86,457.00
Scrapping Process Separation Costs	
Meter Scrapping/Recycling Process	
Staff Training and Department Integration	
AMI Warranty Costs (1% Failure Rate)	
Measurement Canada Re-Verification Accrual Account	
AMI Inventory Costs (Meters to Replace Rever Meters)	
Contingency at 5%	$12,913.73
Section Sub Total	$271,188.25
Total Smart Meter Assest Investment	
Total Depreciation Amount Based On 15 Years Straight Line	

Current Value of Sections Smart Meter Assets	
BILLING / CUSTOMER SERVICE	
CIS Automated Meter Change Package	
Smart Meter Customer Presentment Tools (Web, IVR)	$0.00
Smart Meter Entity MDM/R (est Based On OEB 2005 Report)	$86,457.00
Bill Print Modifications	
Customer Education Packages	
CIS TOU Modifications and MDM/R Integration	
Staff Training and Department Integration	
Contingency at 5%	$4,322.85
Section Sub Total	$90,779.85
Total Smart Meter Assest Investment	
Total Depreciation Amount Based On 3 Years Straight Line	
Current Value of Sections Smart Meter Assets	
	2008
	Operating
Totals	$361,968.10

Question #22

Reference: i) Exhibit 4/Tab 2/Schedule 7

a) Please provide the 2008 values for: i) Total Salaries and Wages and ii) Total Benefits by employee group.

Response:

Compensation (Total Salary and Wages ($)):								
	2006 Board Approved	Average	2006 Actual	Average	2007 Bridge	Average	2008 Test	Average
Executive	$0	$95,892	$381,722	$95,430	$393,182	$98,296	$410,764	$102,691
Management	$0	$59,014	$552,893	$61,433	$710,824	$64,260	$741,876	$67,443
Non-Unionized	$0	$30,369	$168,553	$28,092	$180,980	$30,163	$59,456	$29,728
Unionized	$0	$46,948	$1,958,954	$54,415	$1,968,699	$54,686	$1,912,363	$53,121
Compensation (Total Benefits ($)):								
	2006 Board Approved	Average	2006 Actual	Average	2007 Bridge	Average	2008 Test	Average
Executive	$0	$22,537	$86,318	$21,580	$97,852	$24,463	$110,573	$27,643
Management	$0	$11,512	$124,214	$13,802	$173,958	$15,814	$196,573	$17,870
Non-Unionized	$0	$3,371	$15,135	$2,523	$16,020	$2,670	$16,981	$5,660
Unionized	$0	$13,102	$539,377	$14,983	$579,170	$16,088	$625,504	$17,375
Compensation (Total Incentives ($)):								
	2006 Board Approved	Average	2006 Actual	Average	2007 Bridge	Average	2008 Test	Average
Executive	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Management	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Non-Unionized	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Unionized	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total of Costs charged to O&M ($)): NOT APPLICABLE								
	2006 Board Approved	Average	2006 Actual	Average	2007 Bridge	Average	2008 Test	Average
TOTAL	$0	$0	$1,531,061	$27,837	$1,724,453	$30,254	$1,655,963	$30,666

<u>Question #23</u>

Reference: i) Exhibit 4/Tab 2/Schedule 7

a) On page 2, Norfolk indicates that it is proposing to use a line loss factor of 5.6% for 2008. Please clarify if this is the proposed Distribution Loss Factor for Secondary Metered customers or the Total Loss Factor for Secondary Metered customers.

Response:

The loss factor is the Total Loss Factor for Secondary Metered customers.

<u>Question #24</u>

Reference: i) Exhibit 4/Tab 3/Schedule 1

a) Does Norfolk agree that its Application should be updated to reflect the new federal corporate tax rates for 2008? If not, why not? If yes, please provide a revised PILs estimate for 2008.
b) The March 2007 federal budget introduced new CCA classes for computer equipment and buildings (after March 2007). Do any of Norfolk's capital additions in 2007 and 2008 qualify and, if so, please adjust the CCA calculation accordingly.
c) Is any of the planned smart meter investment for 2008 related to computer software or equipment? If so, how much and please confirm which CCA class(es) it has been assigned to.

Response:

a) Norfolk Power does not agree that its Application should be updated to reflect the new federal corporate tax rates for 2008. The difference between the rates is 1.0%, resulting in a change of $18,081. This is below the materiality threshold set by the OEB of 1.0% of Distribution Expenses (including depreciation).

	PILS Before revised rates	PILS - revised rates	Difference
Taxable Income	$1,808,092	$1,808,092	$0
Federal Tax Rate	20.50%	19.50%	-1.00%
Ontario Tax Rate	14.00%	14.00%	0.00%
Income Tax	**$623,792**	**$605,711**	**($18,081)**

b) The only additions that qualify are for Computer Equipment.
c) The planned smart meter investment for 2008 does have computer software or equipment in the amount of $276,287. These have been included in Class 47 as a pooled cost for metering.

Question #25

Reference: i) Exhibit 4/Tab 3/Schedule 2

a) Please reconcile (if necessary) the total 2008 capital additions figure provided in response to VECC Question #8 with the value ($10,188,600) reported on page 4 of Reference (i).

Response:

	2008 TEST
SUBTOTAL CAPITAL BUDGET	$6,128,600
Smart Meter	4,061,000
	$10,189,600
As per Exhibit 4/Tab 3/Schedule 2/Page 4	10,188,600
Difference	$1,000
Land not subject to CCA	(1,000)
	$0

<u>Question #26</u>

Reference: i) Exhibit 4/Tab 2/Schedule 1, page 6

a) Please provide a schedule that shows (for 2006-Board Approved through to 2008) and for each of the various asset classes:
    - The Gross Book Value (Year End)
    - The Depreciation Rate
    - The Annual Depreciation

    The total annual depreciation for each year should reconcile with the amortization expenses shown in Reference (i).

Response:

Please refer to the table on the following page.

The 2006 Board approved depreciation expense includes general plant. As per the 2006 EDR application, the model excluded this amount, which is a difference of $199,124. Also, the 2006 EDR model included amortization from Tier 1 Adjustments, which is not reflected below.

The 2007 Bridge year includes $107,229 carried over from 2006 Actual. This is an error in the model and should be removed from the calculation.

GROSS ASSET	Depreciation Rate	2006 Board Approved	2006 Board Depreciation	2006 Actual	2006 Actual Depreciation	2007 Bridge	2007 Bridge Depreciation	2008 Test	2008 Bridge Depreciation
1805-Land	not applicable	$163,869	$0	$380,064	$0	$380,064	$0	$380,064	$0
1806-Land Rights	not applicable	$298,716	$0	$300,911	$0	$301,911	$12,056	$302,911	$12,096
1808-Buildings and Fixtures	2.00%	$725,435	$0	$1,450,870	$29,017	$1,455,870	$29,067	$1,530,070	$29,859
1815-Transformer Station Equipment	2.50%	$1,527,739	$0	$2,802,994	$70,075	$2,997,994	$72,512	$3,319,994	$78,975
1820-Distribution Station Equipment	3.33%	$1,838,509	$73,110	$2,388,347	$88,174	$3,565,347	$99,129	$2,990,092	$109,148
1830-Poles, Towers and Fixtures	4.00%	$20,800,394	$650,849	$16,915,729	$707,534	$17,566,729	$689,649	$18,697,529	$725,285
1835-Overhead Conductors and Devices	4.00%	$9,581,701	$287,935	$8,333,597	$333,344	$9,187,597	$350,424	$9,925,797	$382,268
1840-Underground Conduit	4.00%	$2,276,260	$76,533	$3,266,245	$113,258	$3,546,245	$136,250	$3,828,245	$147,490
1845-Underground Conductors and Devices	4.00%	$4,769,728	$153,197	$6,436,211	$209,251	$6,867,211	$266,068	$7,467,211	$286,688
1850-Line Transformers	4.00%	$7,746,968	$399,788	$9,035,687	$439,285	$9,780,687	$376,327	$10,656,687	$408,747
1855-Services	4.00%	$561,499	$27,725	$1,612,317	$64,493	$1,923,317	$70,713	$2,245,317	$83,373
1860-Meters	4.00%	$3,050,433	$114,692	$3,547,874	$132,695	$4,007,074	$151,099	$8,584,474	$251,831
1905-Land	not applicable	$199,060	$0	$211,830	$0	$236,830	$0	$236,830	$0
1908-Buildings and Fixtures	4.00%	$1,873,688	$25,772	$1,947,788	$26,942	$2,100,788	$40,486	$2,209,188	$43,100
1910-Leasehold Improvements	as per term	$2,099	$245	$6,177	$640	$6,177	$0	$11,177	$0
1915-Office Furniture and Equipment	10.00%	$333,266	$28,247	$111,706	$11,204	$134,706	$12,321	$163,706	$14,921
1920-Computer Hardware	20.00%	$833,281	$76,452	$608,350	$100,163	$670,110	$127,846	$626,816	$129,693
1925-Computer Software	20.00%	$112,862	$23,998	$198,446	$52,129	$241,909	$44,035	$356,656	$59,857
1930-Transportation Equipment	**Note 1**	$2,027,745	$0	$1,300,157	$100,728	$1,395,157	$168,457	$1,490,157	$180,332
1935-Stores Equipment	10.00%	$95,650	$0	$35,068	$3,507	$39,068	$3,707	$44,068	$4,157
1940-Tools, Shop and Garage Equipment	10.00%	$532,899	$0	$212,866	$21,287	$245,866	$22,937	$277,866	$26,187
1945-Measurement and Testing Equipment	10.00%	$58,613	$6,528	$145,541	$14,554	$167,541	$15,654	$193,041	$18,029
1955-Communication Equipment	10.00%	$37,586	$4,271	$54,931	$5,493	$83,931	$13,886	$112,931	$19,686
1960-Miscellaneous Equipment	10.00%	$8,277	$1,267	$82,327	$8,233	$114,327	$9,833	$151,827	$13,308
1970-Load Management Controls	10.00%	$0	$0	$12,276	$0	$88,276	$5,028	$88,276	$8,828
1980-System Supervisory Equipment	6.67%	$414,838	$32,590	$612,052	$40,803	$656,052	$42,291	$748,152	$46,830
1995-Contributions and Grants - Credit	4.00%	($3,059,852)	($136,968)	($5,796,930)	($231,877)	($5,996,930)	($235,877)	($6,196,930)	($243,877)
2005-Property Under Capital Leases	as per term	$0	$0	$10,039	$1,004	$10,039	$0	$10,039	$0
TOTAL		$56,811,262	$1,846,231	$56,223,471	$2,341,935	$61,773,894	$2,523,898	$70,452,193	$2,836,811

Note 1:		
	Automobiles	25.00%
	Trucks under 3 tons	20.00%
	Trucks 3 tons and over	12.50%
	Work and Service Equipment	12.50%

Question #27

Reference: i) Exhibit 5/Tab 1/Schedule 1 & Schedule 2

a) Please confirm what the costs accrued in Account #1508 (Other Regulatory Assets) were specifically for. Why is Norfolk not applying for disposal of this account?
b) What is the difference between the costs Norfolk recorded in Account #1508 and those recorded in Account #1525? Why is Account #1525 not being disposed of at this time?
c) Does Account #1555 include any capital related costs for Smart Meters or just revenues from the Smart Meter rate adder?
d) Please explain why there is still a balance in Account #1570 (Qualifying Transition costs). Why is there no disposal of this account in the Application?
e) Please explain the nature of the costs being claimed in Account #1572 (Extra-Ordinary Event Losses). If this is a Z-factor application, please provide full explanation and explain how the event and costs meet the Board's guidelines.
f) Why is number of customers the appropriate "allocator" for the Account #1572 costs?
g) Why is a three year period considered appropriate for the disposition of the variance and deferral accounts?

Response:

a) and b) The costs accrued in Account #1508 (Other Regulatory Assets) and #1525 are from Hydro One invoices for Phase I & II of their Regulatory Asset Recovery as approved by the OEB. Norfolk Power did not apply for disposal of this account in order to mitigate the impact on customer's bill.

c) Account #1555 just includes revenues from the Smart Meter rate adder.
d) There is a contra-account (Account #2120 not disclosed) to Account #1570 (Qualifying Transition costs) of equal amount. The net is zero.
e) This is a Z-factor application. A full explanation is as follows:

	Ice Storm January 2007	**Wind Storm June 2007**	
Event	Natural Disaster	Natural Disaster	
Description	Freezing rain and strong winds knocked down trees and overhead wires	Strong winds and lighting knocked down trees and overhead wires	
Total Customers without power	16,503	4,258	
Outside Assistance	Oakhill Tree Service K-Line Maintenance Brant County Power Brantford Power	Oakhill Tree Service K-Line Maintenance Brant County Power Tillsonburg Hydro	
Breakdown of Event Costs:			TOTAL CLAIM
Overtime labour - Internal	$18,799.65	$10,702.78	$29,502.43
Trucking	8,630.00	4,130.00	12,760.00
Outside Assistance	132,269.55	22,656.12	154,925.67

Accommodations & Meals	2,063.41	481.73	2,545.14
Interest (Carrying Charges)			14,118.00
	$161,762.61	$37,970.63	$213,851.24

Satisfying Criteria as per OEB:

Causation	Norfolk Power had no option other than to restore power in a timely manner	Norfolk Power had no option other than to restore power in a timely manner
Materiality	0.2% of Net Fixed Assets	0.2% of Net Fixed Assets
Prudence	most cost effective option	most cost effective option

h) The number of customers is the appropriate “allocator” for the Account #1572 costs because these customers experienced interruptions, which is not tied to consumption or specific class.

i) The three year period is the period of rebasing.

Question #28

Reference: i) Exhibit 6/Tab 1/Schedule 3

a) Please reconcile the 2008 calculated cost ($34,074) of the second TD-Canada Trust LT Debt Issue with the principle amount and carrying cost (6.17%) reported.
b) Please reconcile the 2008 calculated cost ($34,727) of the Operating Load with the principle amount shown and the carrying cost (6.17%) reported.
c) Please provide a table setting out the derivation of the 6.7% cost of long term debt used for 2008.

Response:

a) See below

	Outstanding Principal	Interest Rate	Days Outstanding	Interest
Calculation provided as per Exhibit 6/Tab 1/Schedule 3	$1,957,000	6.17%	103 days	$34,074
Original Loan principal was $2,000,000, borrowed Sept. 20, 2007	$1,957,000	6.17%	365 days	$120,747
			Difference	($86,673)

Note: Incorrect number of days outstanding was used in the 2008 EDR Model. Interest expenses should be $120,747, not $34,074

b) See below

	Outstanding Principal	Interest Rate	Days Outstanding	Interest
Calculation provided as per Exhibit 6/Tab 1/Schedule 3	$2,000,000	6.17%	103 days	$34,727
(Loan borrowed Sept. 20, 2008)				
Note: 2008 EDR Model uses 366 days for 2008				

c) See below

	Principle	2008 Carrying Costs	Calculated Cost	Cost of Long-Term Debt
Long-Term Debt				
TD-Canada Trust	$9,971,000	7.00%	$697,970	
TD-Canada Trust	3,257,000	6.02%	196,071	
TD-Canada Trust	1,468,000	6.17%	90,576	
Haldimand County			3,044	
	$14,696,000		$987,661	
Short-Term Debt				
Operating Loan - AVERAGE BALANCE	$562,842	6.17%	$34,727	
	$562,842		$34,727	
	$15,258,842		$1,022,388	6.70%

<u>Question #29</u>

Reference: i) Exhibit 8/Tab 1/Schedule 2

a) Please provide a copy of the Cost Allocation informational filing that derives the revenue to cost ratios presented on page 2.
b) Please confirm whether the Cost Allocation informational filing included LV Charges (i.e., were LV charges included as a "cost" in the filing and did the rates used to determine revenues include an allowance for LV Charge recovery?).
c) Why is the proposed ratio for USL increased from less than 100% to more than 100%?
d) If there were no proposed changes to the revenue to cost ratios, what would have been the revenue proportion (page 3) by customer class. Please explain how this value is determined.
e) Please provide a detailed explanation showing how the proposed revenue to cost ratios on page 2 translate into the proposed revenue proportions on page 3.
f) The Cost Allocation informational filing allocated the amount of the Transformer Allowance to all customer classes. Please provide the revenue to cost ratios that would result if the filing had allocated the cost in the same manner as Norfolk proposes to do for 2008 (as set out at Exhibit 9/Tab 1/Schedule 1, page 7).

Response:

a) See response to OEB staff interrogatory 53 a.
b) The Cost Allocation informational filing excluded the cost and the revenue associated with LV charges.
c) Norfolk Power attempted to have the USL class revenue/cost as close as possible to 100% and was able to achieve a revenue/cost ratio of 100.7%. Since the 0.7% represent only $184 it was Norfolk Power's view the 100.7% was close enough to unity.
d) See column E in response to e) and this represent revenue at existing rates which is the 2007 rates applied to 2008 forecasted customers and volumes.
e) The following table outlines how the proposed revenue proportions translate into the proposed revenue/cost ratio.

Customer Classes	Cost Allocation Rev/Cost Ratio (A)	Revenue at 100% Rev/Cost Ratio (B)	Proportion of Revenue (C) = (B) / (Rev Req)	Revenue Allocation at Existing Rates (D)	Proportion of Revenue (E) = (D) / (Rev Req)	Proposed Rate Application Revenue Allocation (F)	Proposed Rate Application Revenue (G) = (F) * Rev Req	Proposed Revenue/Cost Ratio (((B) * (A)) - ((D) - (G))/(B)
Residential	103.8%	7,414,481	60.4%	7,821,792	63.8%	63.1%	7,737,264	102.6%
General Service Less Than 50 kW	96.0%	2,453,907	20.0%	2,255,368	18.4%	19.0%	2,330,871	99.1%
General Service 50 to 4,999 kW	102.5%	2,041,085	16.6%	2,096,461	17.1%	16.5%	2,021,724	98.8%
Street Lights	30.7%	256,274	2.1%	62,202	0.5%	1.0%	122,677	54.3%
Sentinel Lights	19.6%	76,083	0.6%	9,807	0.1%	0.3%	30,669	47.0%
Unmetered Scattered Load	98.5%	25,910	0.2%	22,110	0.2%	0.2%	24,535	100.7%
		12,267,740	**100.0%**	**12,267,740**	**100.0%**	**100.0%**	**12,267,740**	

f) The revenue to cost ratios that would result if the filing had allocated the cost in the same manner as Norfolk proposes to do for 2008

Rate Classification	Revenue to Cost Ratio
Residential	105.1%
GS < 50 kW	97.7%
GS > 50 kW	95.6%
Streetlights	31.5%
Sentinel Lights	20.1%
USL	97.8%

Question #30

Reference: i) Exhibit 9/Tab 1/Schedules 2 & 8

a) Based on a recent 12 consecutive months of actual billing data, please indicate the percentage of total residential customers that:
   - Consume less than 100 kWh per month
   - Consume 100 -> 250 kWh per month
   - Consume 250 -> 500 kWh per month
   - Consume 500 -> 750 kWh per month

Response:

- Consume less than 100 kWh per month – 6.47%
- Consume 100 -> 250 kWh per month – 10.90%
- Consume 250 -> 500 kWh per month – 28.78%
- Consume 500 -> 750 kWh per month – 25.38%

<u>Question #31</u>

Reference: i) Exhibit 9/Tab 1/Schedule 1, page 2

a) Please provide details regarding the $68,612 of spending on CDM proposed for 2008 including:
   - Whether this is part of the 3rd tranche spending or not
   - Details regarding the associated CDM programs
   - Are there any new programs where the TRC Screening has not been submitted to the OEB. If so, please provide the screening results consistent with the Board's TRC guide.
   - The rationale for the proposed allocation to customer classes.

Response:

a) Please provide details regarding the $68,612 of spending on CDM proposed for 2008 including:
   - In 2007 NPDI applied and was approved to extend our 3rd tranche funding window to end of March 2008
   - Details regarding the associated CDM programs

Customer Energy Conservation Information	**$20,000**
Staff Training for Conservation	**3,000**
Energy Audits for Major Customers	**20,000**
Compact Fluorescent Giveaway	**5,000**
Appliance Incentives	**20,000**

   - Yes. The program in question continues to be active and TRC results will not be available until March 2008.
   - The rationale for the proposed allocation to customer classes is based on the expected level of participation in the programs by rate class.

<u>Question #32</u>

Reference: i) General

a) Please provide copies of all Board Decisions pertaining to Norfolk's rates issued since December 31, 2004.

Response:

Please see attached.

Question #33

Reference: i) Exhibit 9/Tab 1/Schedule 1, page 3

a) The text indicates that the approved monthly fixed charges used to determine the fixed revenue proportion are "before the smart meter adder". However, the rates presented in the associated table appear to be the approved rates for 2007 including the smart meter adder. Please clarify.

b) Please confirm whether or not Norfolk's approved 2006 (and therefore 2007) rates included an adder/adjustment for LV costs.

c) Please re-do the calculation of the fixed revenue proportion by customer class based on a "fixed charge" that excludes any smart meter rate adder and treats LV cost consistent with how they were treated in the Cost Allocation informational filing (i.e., if LV costs were not included in the filing then the associated rate adder should be excluded from the determination of the fixed proportion of revenue by class).

Response:

a) The rates presented in the table are the approved rates for 2007 including the smart meter adder. The description above the table is incorrect.

b) Confirmed

c) In Norfolk Power's opinion the smart meter adder should remain in the fixed charge in order to determine the fixed portion of revenue. When the Board decided to include the smart meter adder in the monthly fixed charges, in Norfolk Power's view, this indicated that smart meter costs should be collected in the fixed charge. In this application, smart meter costs are in the rate base and in the revenue requirement. If Norfolk Power was to remove the smart meter adder from the monthly fixed charge there would be no costs associated with smart meters in the fixed revenue portion. Norfolk Power understands that not all smart meter costs will be included in the fixed charge when the smart meter adder is left in but at least a portion of the smart meter costs will be collected through the fixed charge.

In the Cost Allocation filings the LV costs were excluded. As a result the following table provides the fixed revenue proportion when LV costs are excluded from the volumetric rates.

Rate Class	**Fixed Revenue Proportion**
Residential	61.0%
GS<50kW	59.8%
GS>50kW	29.5%
Street Lights	56.7%
Sentinel Lights	86.0%
USL	74.3%

Question #34

Reference: i) Exhibit 9/Tab 1/Schedule 1, pages 8-9

a) Please explain how the proportion of retail transmission revenue collected from each class was determined. In particular, please indicate which year's billing quantities and retail transmission rates were used in the calculation.
b) How was the forecast LV cost of $371,652 established?
c) Please indicate which of the proposed customer/connection charges exceed the ceiling for the Monthly Service Charge as set out on page 12 of the Report of the Board dealing with Application of Cost Allocation for Electricity Distributors (November 28, 2007).

Response:

a) See response to OEB staff IR# 54 a
b) See response to OEB staff IR# 54 b and c
c) It is Norfolk Power's understanding of the Report of the Board dealing with Application of Cost Allocation for Electricity Distributors that a ceiling for the Monthly Service Charge has not been established. If this is not the case, Norfolk Power is will be more than willing to adhere to the Monthly Service Charge ceiling requirements of the OEB.

Question #35

Reference: i) Exhibit 9/Tab 1/Schedule 3, page 1

a) Please confirm that the Network Billings and Connection Billings columns on the page are the revenues Norfolk receives from the retail transmission charges to its customers.

Response:

a) Confirmed

EB-2007-0753

IN THE MATTER OF the Ontario Energy Board Act 1998, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an Application by Norfolk Power Distribution Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the distribution of electricity commencing May 1, 2008.

INTERROGATORIES
OF THE
SCHOOL ENERGY COALITION

1. Loss Factor
Ref a: Ex 1/T1/S5
Ref b: Ex 1/T1/S13

In Ref a, NPDI's total loss factor for secondary metered customers is 1.0560 in both 2007 & 2008.

In its letter to the OEB subsequent to the Decision and Order dated April 26, 2006, NPDI has listed details of strategies and line loss programs to reduce its line losses and has commented that its goal is to approach the 5% target reflecting a technically efficient distribution system for a large rural utility.

Please comment on the effectiveness of the various line loss programs mentioned in NPDI's letter.

Response:

Norfolk Power's line loss continue to be stable around the 5.5% - 5.6% range. The strategies undertaken to reduce line losses to 5.0% will be achieved over a period of five to ten years based on cost benefit analysis. The capital spending previously in 2004, 2005, 2006 and future years will assist in reducing line losses. As a result, it is difficult to comment on the effectiveness of the line loss program at this time as they are not completely in service.

2. Rate Base

a. Ref: Ex 2/T2/S3/pg1

	2006 Approved	2006 Actual	Variance
#1830-Poles, Towers and Fixtures	$20,800,394	$16,915,729	($3,884,665)
#1835-Overhead Conductors and Devices	$9,581,701	$8,333,597	($1,248,104)

NPDI has explained that for 2005 and 2006 actual, it had additions of $2,552,000 consisting of line conversions, upgrades, new construction and rebuilding existing distribution plant. An overhead distribution plan write-off was also mentioned in the Evidence.
Please provide further details explaining the less than expected spending for Account #1830 and #1835 in 2006 (separately provide the amount of the write-off).

Response:

For capital accounts such as 1830 and 1835, the 2006 EDR used the average of the two year ends (i.e. 2003 – 2004). This meant only one half of the expenditures were allowed in the rate base. Also, assets that became fully depreciated were not accounted for in the 2006 EDR. This was not representative of the activity for 2005 and 2006. Table below shows the details of the actual expenditures for 2005 and 2006 as well as the write-off amounts separately.

	2006 Board Approved	At Dec 31 2004	2005 Capital Additions	2006 Capital Additions	Write-offs	At Dec 31 2006
Overhead Disribution System						
Poles, Towers and Equipment	$20,800,394	$21,185,287	$645,588	$771,544	($5,686,690)	$16,915,729
Conductors and Devices	9,581,701	9,948,681	455,150	680,066	(2,750,300)	8,333,597
TOTAL DISTRIBUTION ASSETS	$30,382,095	$31,133,968	$1,100,738	$1,451,610	($8,436,990)	$25,249,326

b. Ref: Ex 2/T2/S3/pg3

	2006 Approved	2006 Actual	Variance
#1930-Transportation Equipment	$2,027,745	$1,300,157	($727,588)

NPDI has explained that for 2005 and 2006 actual, it had additions of $441,000 consisting of new passenger vehicle and pick-up truck. Fully depreciated vehicles were written off in 2006.

Please provide further details explaining the less than expected spending for Account #1930 (separately provide amount of the write-off).

Response:

For capital accounts such as 1930, the 2006 EDR used the average of the two year ends (i.e. 2003 – 2004). This meant only one half of the expenditures were allowed in the rate base. Also, assets that became fully depreciated were not accounted for in the 2006 EDR. This was not representative of the activity for 2005 and 2006. Table below shows the details of the actual expenditures for 2005 and 2006 as well as the write-off amounts separately.

	2006 Board Approved	At Dec 31 2004	2005 Capital Additions	2006 Capital Additions	Write-offs	At Dec 31 2006
Transportation Equipment	$2,027,745	$2,143,078	$94,586	$345,936	($1,283,443)	$1,300,157

c. Ref: Ex 2/T2/S3/pg3

	2006 Approved	2006 Actual	Variance
#1940-Tools, Shop and Garage Equipment	$532,899	$212,866	($320,033)

NPDI has explained that for 2005 and 2006 actual, it had additions of $77,000 consisting of tools and equipment. Fully depreciated tools and equipment were written off in 2006.

Please provide further details explaining the less than expected spending for Account #1940 (separately provide amount of the write-off).

Response:

For capital accounts such as 1940, the 2006 EDR used the average of the two year ends (i.e. 2003 – 2004). This meant only one half of the expenditures were allowed in the rate base. Also, assets that became fully depreciated were not accounted for in the 2006 EDR. This was not representative of the activity for 2005 and 2006. Table below shows the details of the actual expenditures for 2005 and 2006 as well as the write-off amounts separately.

	2006 Board Approved	At Dec 31 2004	2005 Capital Additions	2006 Capital Additions	Write-offs	At Dec 31 2006
Garage Tools and Equipment	$532,899	$553,043	$22,825	$51,154	($414,155)	$212,866

d. Ref: Ex 2/T2/S3/pg4

2006 Actual vs. 2007 Bridge variances, for Account # 1820, #1830, #1835, #1840, #1845, #1850, #1855, #1860.

NPDI has stated that the variance for the above-mentioned accounts is the result of "several projects planned for 2007".

Please provide more details explaining the variances, for instance, type of projects, project start and end date, project costs and benefits.

Response:

DISTRIBUTION PLANT			
Substation Equipment			
D.S. - Waterford Blueline			
- structure upgrade for back-up transformer		$ 15,000	
D.S. - Waterford Nichol St.			
- de-commissioning		20,000	
M.S. #2 - Simcoe			
- station overhaul	$ 150,000		
- fence replacement / upgrade	25,000		
		175,000	
M.S. #3 - Simcoe			
- rebuild circuit breaker		43,000	
M.S. #5 - Simcoe			
- rebuild circuit breakers	$ 30,000		
- replace windows	3,000		
- replace roof	8,000		
		41,000	
M.S. #1 - Port Dover			
- fence replacement / upgrade		$ 25,000	
M.S. #2 - Port Dover			
- fence replacement / upgrade		25,000	
M.S. #2 - Delhi			
- fence replacement / upgrade and berm additions		13,000	
M.S. #7 - Delhi			
- structures for containment		15,000	
Special Projects			
- transformers for Toyotetseu (8 units including spares)	$ 300,000		
- switchgear for Toyotetseu	100,000		
- structures for containment	25,000		
		425,000	
Substation Backup Transformer		380,000	
			1,177,000

Distribution System - Overhead		
Poles, Towers, & Equipment		
Replace Depreciated Poles	$ 100,000	
Plant Relocation for Street Alterations	20,000	
Major Capital Projects	442,000	
Minor Capital Projects	89,000	
		$ 651,000
Conductor & Devices		
Plant Relocation for Street Alterations	$ 30,000	
Major Capital Projects	688,000	
Minor Capital Projects	136,000	
		854,000
Distribution System - Underground		
Conduit		
Residential Underground System	$ 245,000	
Major Capital Projects	35,000	
		280,000
Conductor & Devices		
Residential Underground System	$ 355,000	
Major Capital Projects	42,000	
Minor Capital Projects	14,000	
Unforseen	20,000	
		431,000
Transformers		
Purchase and Installation - Overhead	$ 390,000	
Purchase and Installation - Underground	355,000	**745,000**
Services		
Residential Services - Overhead	$ 65,000	
Industrial and Commercial Services - Overhead	60,000	
Residential Services - Underground	131,000	
Industrial and Commercial Services - Underground	55,000	
		311,000
Meters		
Single Phase Meters	$ 26,000	
Demand Meters	78,700	
Wholesale Metering Points	97,000	
Load Limiters	3,500	
Meter Reverification Program	205,000	
Smart Meters (from C&DM)	49,000	
		459,200

All capital projects are scheduled to start and be completed by the end of the 2007 fiscal year. Projects were planned in 2007 to accommodate load growth, enhance system reliability and safety and help reduce line losses. The following are highlights:

- Increase the distribution voltage in the Villa Nova area to 27.6KV, which will help reduce related line losses and eliminate the low voltage transformation facilities in the area.

- Replace depreciated overhead distribution lines, transformers and reclosers and build new lines for system expansion.

- Norfolk Power has strategically decided to retain our low voltage municipal transformer stations in lieu of aggressive voltage conversion. Our strategy recognizes this as a lower cost option compared to the related cost of replacing or upgrading distribution lines. *(We do however insulate to the higher voltage for use in future as required).* Retention of our municipal substations minimizes the impact on customers of power outages as the extent of an outage is minimized and we have the infrastructure to reroute supply as needed.

- In 2007 we plan to rebuild the transformer and switchgear at MS 2 and purchase a used substation transformer. This will provide backup in case one of our existing municipal substations fail.

- Replace or rebuild depreciated underground infrastructure (system reliability)

- Replace or upgrade depreciated fencing at substations (safety issues)

e. Ref: Ex 2/T2/S3/pg4

Account # 1815: 2008 test year vs. 2007 bridge year variance is $322,000. NPDI has stated that this is due to a deposit for a second 115KV transformer to be installed.

Fund set aside for the future installation of the transformer should be recorded as a reclassification of the current asset rather than an addition to the gross capital asset. Please justify NPDI's treatment.

Response:

The 2008 test year vs. 2007 bridge year variance is $322,000. Of this amount, $120,000 is for a deposit for a second 115KV transformer to be installed at the Bloomsburg TS. The remainder of the difference is for other capital work planned at Bloomsburg TS such as:

- ambient temperature sensor
- transformer fans
- standby transfer switch
- standby generator
- cable terminators
- lightning arrestors
- locate & identify feeder cables inside station

The capital cost of $120,000 listed for a deposit for a new transformer at the Bloomsburg TS should be removed from the rate base, since the item will not be in service in 2008.

f. Ref: Ex 2/T2/S3/pg4

Account #1820: 2008 test year vs. 2007 bridge year variance is ($575,255).

NPDI has stated that the variance is the net result of several projects planned for 2008 and the write-off of fully depreciated assets.

Please provide the amount of the write-off and the projects separately, and provide details on the projects (for instance, type of project, start and end date, project costs and benefits).

Response:

D.S. - Waterford Blueline			
- structure upgrade for back-up transformer	$ 16,500		
- fence and grounding rehab, civil modifications	38,400		
- secondary pole modification to raise feeder	27,500		
		$ 82,400	
D.S. - Waterford Nichol St.			
- environmental assessment		5,500	
D.S. - Simcoe Blueline			
- replace (3) single-phase transformers w ith one transformer		200,000	
M.S. #1 - Simcoe			
- CT termination & design change		5,500	
M.S. #2 - Simcoe			
- MUS civil egress modifications		11,000	
M.S. #3 - Simcoe			
- last spare breaker	$ 12,100		
- transformer fan replacement spare	500		
- sw itchgear control rehab / cleanup of control system	30,800		
		43,400	
M.S. #5 - Simcoe			
- last on-site spare breaker	$ 12,100		
- HVAC (temperature operated fans/louvres)	2,200		
- exterior brick repair	8,800		
- exterior and interior drainage	5,500		
- ground bus sw itchear modifications	3,300		
		31,900	
M.S. #6 - Simcoe			
- fence & grounding rehab		22,000	
M.S. #7 - Simcoe			
- decommission 2/3 of station		33,000	
M.S. #1 - Port Dover			
- replace station cap & pin insulators w ith station post insulators	$ 27,500		
- metalclad evaluation	3,300		
		30,800	
M.S. #2 - Port Dover			
- transformer overhaul (off-site) pending inspection details		54,900	
M.S. #3 - Port Dover			
- fence & grounding rehab		18,700	
Special Projects			
- mobile unit substation		272,400	
Total MS & DS Capital for 2008			**$ 811,500**
Less: Write-off of fully depreciated assets			**(1,386,755)**
			$ (575,255)

g. Ref: Ex 2/T2/S3/pg4

Account #1820, #1830, #1835, #1840, #1845, #1850, #1855, #1860.

The figures listed under column “2007 Bridge” and “2008 Test” are actually 2006 Actual and 2007 Bridge year amounts.

Please update the table using the correct data and provide detailed explanations on all material variances. For project related variances, please list type of project, project start and end date, project costs and benefits in the explanation.

Response:

Norfolk Power apologizes for this oversight. Below is an updated table with the correct amounts.

Asset Account	2007 Bridge	2008 Test	Variance
1820-Distribution Station Equipment	$3,565,347	$2,990,092	($575,255)
1830-Poles, Towers and Fixtures	$17,566,729	$18,697,529	$1,130,800
1835-Overhead Conductors and Devices	$9,187,597	$9,925,797	$738,200
1840-Underground Conduit	$3,546,245	$3,828,245	$282,000
1845-Underground Conductors and Devices	$6,867,211	$7,467,211	$600,000
1850-Line Transformers	$9,780,687	$10,656,687	$876,000
1855-Services	$1,923,317	$2,245,317	$322,000
1860-Meters	$4,007,074	$8,584,474	$4,577,400

Please see response to Ref: Ex 2/T2/S3/pg4 above for variance in Asset Account 1820. All other are provided below.

<u>Distribution System – Overhead</u>

Poles, Towers, & Equipment – Account 1830

Replace Depreciated Poles	$ 224,500		
Plant Relocation for Street Alterations		16,800	
Major Capital Projects		542,000	
Minor Capital Projects		347,500	
			$1,130,800

Conductor & Devices – Account 1835

Plant Relocation for Street Alterations	$ 17,400		
Major Capital Projects	440,400		
Minor Capital Projects		280,400	
			$738,200

<u>Distribution System - Underground</u>

Conduit – Account 1840

Residential Underground System $ 240,000

Major Capital Projects	24,000	
Minor Capital Projects	18,000	
		$282,000
Conductor & Devices – Account 1845		
Residential Underground System	$ 360,000	
Major Capital Projects	132,000	
Minor Capital Projects	108,000	
		$600,000
Transformers – Account 1850		
Purchase and Installation - Overhead	$ 359,000	
Purchase and Installation - Underground	517,000	
		$876,000
Services – Account 1855		
Residential Services - Overhead	$ 55,300	
Industrial and Commercial Services - Overhead	32,400	
Residential Services - Underground	174,200	
Industrial and Commercial Services - Underground	60,100	
		$322,000
Meters – Account 1860		
Single Phase Meters	$ 26,000	
Demand Meters	78,500	
Wholesale Metering Points	100,000	
Load Limiters	5,000	
Meter Re-verification Program	99,000	
Other Metering Programs	207,900	
Smart Meter Program	4,061,000	
		$ 4,577,400

All capital projects are scheduled to start and be completed by the end of the 2008 fiscal year. Projects were planned in 2008 to accommodate load growth, enhance system reliability and safety and help reduce line losses. The following are highlights:

- Norfolk Power is in the process to add a second transformer at Bloomsburg TS. Attempts to acquire a "re-conditioned" unit were unsuccessful, leading us to develop specifications towards the purchase of a new unit. Delivery times for a new unit vary from two to three years hence our capital investment will vary accordingly. In 2008, we expect to make a down-payment of $120,000 with the balance due upon delivery.

- In anticipation of the upgrade of the Hydro One A1N 115kV circuit, improvements are required within the Bloomsburg TS structure to accommodate new switching equipment. This upgrade to the station will allow us to switch between the two circuit feeds using remotely operated gear. System reliability will be improved for all customers fed from this station.

- Norfolk Power has strategically decided to retain our 8 kV municipal transformer stations in lieu of aggressive voltage conversions to 27.6kV. Our strategy recognizes this as a prudent option compared to the related cost of upgrading entire distribution feeders. As part of this strategy, we are required to improve the protection and control, upgrade fencing and refurbish station egress as necessary.

- The purchase of a back-up mobile substation transformer had been initiated in 2007. This multi-voltage unit is necessary to have available in the event that one of our existing substations fail. Outage durations will be minimized with the availability of the mobile unit. Potential outage scenarios become hours instead of days.

- Replace depreciated overhead distribution lines and extend existing lines to meet customer growth requirements.

3. Capital Budget

a. Ref: Ex 2/T3/S3/pg2/Table 1

Please confirm that column "2006 Budget" in Table 1 "Distribution Plant Capital 2006-2008 Total by Type" refers to 2006 actual rather than 2006 budget.

Response:

The Column "2006 Budget" in Table 1 "Distribution Plant Capital 2006-2008 Total by Type" refers to 2006 Budget, not 2006 Actual.

b. Ref: Ex2/T3/S3

	2006 Budget	2007 Budget	2008 Budget
Distribution Plant			
Customer Service Work-Residential & Commercial			*905,000*
Subdivision Development			*600,000*
Roadway Relocations			*36,000*
Upsteam and Enhancement Projects			*300,000*
Customer Demand	1,948,000	1,747,000	1,841,000
Wood Pole Replacement			*240,000*
Proactive overhead transformer replacement			*124,000*
proactive underground transformer replacement			*168,000*
overhead renewal			*863,000*
underground renewal			*282,000*
Renewal	1,593,000	1,429,000	1,677,000
Capacity	-	520,000	432,000
Stations	165,000	954,000	1,207,000
Subtotal	**3,706,000**	**4,650,000**	**5,157,000**
Customer Connections			
Meter Verification and Asset Mgmt	111,634	99,000	99,000
Wholesale Meter	84,320	97,000	100,000
IESO Compliance Meter Upgrade	52,336	104,500	104,500
Smart Metering	25,185	49,000	4,251,000
Other Projects under $100K	13,416	3,500	22,900
Subtotal	**286,891**	**353,000**	**4,577,400**
Computer Hardware			
Computer Software			
Vehicle and Related Equipment Replacement			
Vehicles	323,000	90,000	80,000
Equipment and Tools	15,000	5,000	15,000
Subtotal	**338,000**	**95,000**	**95,000**
Tools and Equipment			
Tools and Garage Equipment	49,500	33,000	32,000
Measurement and Testing Equipment	25,400	22,000	25,500
Misc. Equipment	33,000	17,000	22,500
Subtotal	**107,900**	**72,000**	**80,000**
SCADA	**102,500**	**44,000**	**92,000**
Buildings and Fixtures	**20,000**	**167,000**	**108,400**

Total Capital Budget	**4,561,291**	**5,381,000**	**10,109,800**

Data in the table above was extracted from Ex 2/T3/S3/pg2-16.

The Applicant has stated (Ex2/T3/S3/pg1) that its overall capital budget for 2008 is $6,245,800 reflecting an increase of $529,800 over 2007.

a.) Please provide the figures for Computer Hardware and Computer Software, update the table and confirm the total capital budget amount for both 2007 & 2008.

b.) Please confirm that no projects will be added to rate base before they are commercially in service.

Response:

Norfolk Power needs to address three issues:

1. Norfolk Power had stated (Ex2/T3/S3/pg1) that it's overall capital budget for 2008 is $6,245,800 reflecting an increase of $529,800 over 2007. The numbers were from an earlier budget and was not updated in the narrative. However, the numbers used in the 2008 EDR Model are accurate. Below is a calculation of the difference.

Capital Budget As reported in Exhibit2/Tab 3/Schedule 3/Page 1	$6,245,800
Capital Budget Revised	6,128,600
Difference	($117,200)

2. The overall capital budget should have included Smart Meters
3. Including Smart Meters, the overall Capital Budget for 2008 is $10,189,600, not $6,245,800 and reflecting an increase of $4,567,400 over 2007

   a) Please see table below for revised numbers and including Smart Meters.

	2006 BUDGET	2007 BRIDGE	2008 TEST
DISTRIBUTION PLANT			
Land and Land Rights	$8,000	$1,000	$1,000
Transformer Station - Building & Fixtures	0	5,000	74,200
Transformer Station Equipment	35,000	195,000	322,000
Substation Equipment	130,000	1,177,000	811,500
Distribution System - Overhead:			
Poles, Towers, & Equipment	814,000	651,000	1,130,800
Conductor & Devices	760,000	854,000	738,200
Distribution System - Underground:			
Conduit	507,000	280,000	282,000
Conductor & Devices	751,000	431,000	600,000

Transformation	424,000	745,000	876,000
Services - Overhead and Underground	277,000	311,000	322,000
Meters (excludes Smart Meters)	220,000	410,200	516,400
TOTAL DISTRIBUTION PLANT	$ 3,926,000	$ 5,060,200	$ 5,674,100
GENERAL PLANT			
Land and Land Rights	$15,000	$25,000	$0
Buildings: Fixtures & Improvements	20,000	153,000	108,400
Leasehold Improvements	0	2,000	5,000
Office Furniture and Equipment	20,000	23,000	29,000
Computer Equipment - Hardware	51,000	88,000	67,000
Computer Equipment - Software	186,000	87,000	129,000
Transportation Equipment	338,000	95,000	95,000
Stores Equipment	5,000	4,000	5,000
Garage, Truck Tools and Stringing Equipment	49,000	33,000	32,000
Measurement & Testing Equipment	25,000	22,000	25,500
Communication Equipment	48,000	29,000	29,000
Miscellaneous Equipment	33,000	32,000	37,500
Load Control Equipment	0	76,000	0
SCADA Equipment	103,000	44,000	92,100
TOTAL GENERAL PLANT	$ 893,000	$ 713,000	$ 654,500
Contributions in Aid of Construction	$0	($200,000)	($200,000)
SUBTOTAL CAPITAL BUDGET	$4,819,000	$5,573,200	$6,128,600
Smart Meter	0	49,000	4,061,000
TOTAL CAPITAL BUDGET	**$4,819,000**	**$5,622,200**	**$10,189,600**

b) Norfolk Power's intent is all projects will be started, completed and in service on or before December 31, 2008.

4. OM&A Costs – Materiality Analysis
Ref: Ex 4/T2/S2/pg1

For Account # 5020 and Account # 5040, NPDI's 2006 actual spending was higher than 2006 approved level. The Applicant has explained that these accounts were reviewed at year-end and a re-allocation was made to capital.

a. Re-allocation to the capital accounts should lead to a decrease in OM&A spending. Please explain.

b. Please explain whether the re-allocation to the capital accounts reflects any change in NPDI's capitalization policy.

Response:

a. As per Ref: Ex 4/T2/S2/pg1, the wording is, "at the end of the year, this account is reviewed and **where** possible, a re-allocation is made to capital." This means a re-allocation may or may not occur.

b. No Change

5. Wages and Salaries
Ref: Ex 4/T2/S7

It appears that NPDI has not charged any wages and salaries costs to OM&A. Please confirm and explain.

Response:

This is an oversight by Norfolk Power. Below is an updated table.

Total of Costs charged to O&M ($)):

	2006 Board Approved	Average	2006 Actual	Average	2007 Bridge	Average	2008 Test	Average
TOTAL	$0	$0	$1,531,061	$27,837	$1,724,453	$30,254	$1,655,963	$30,666

6. **Deferral and Variance Accounts**
   Ref a: Ex 5/T1/S2/pg5
   Ref b: Ex 3/T2/S1/pg5

   The sum of the selected deferral and variance accounts to be disposed of should be assigned to the proper allocator.

   In Ref a, Table “Test Year Forecast”, the number of customers shown in column “# Customers” does not correspond to the numbers presented in column “Test Year Normalized Forecast 2008” in Ex 3/T2/S1/pg5.

# Customers	Ref a: Ex 5/T1/S2/pg5	Ref b: Ex 3/T2/S1/pg5
GS>50	170	166
Small Scattered Load	48	51
Street Lighting	3892	3091

The correct customer numbers are those provided in Ex 3/T2/S1/pg5. When these numbers are used the deferral and variance account adders only changes for Sentinel Lights and Streetlights. For Sentinel Lights it moves from 3.0226 $/kW to 3.1560 $/kW and for Street Lights it moves from 1.1713 $/kW to 0.9100 $/kW.

7. New Deferral Account

NPDI has requested approval to establish a deferral/variance account on May 1, 2008 for capital works during non-rebasing years to collect revenue requirement costs associated with the cost of construction. (Ex 1/T1/S8)

Revenues for non-rebasing years will be based on the 3rd Generation Incentive Regulation Mechanism ("3GIRM). Please explain why NPDI requires a revenue requirement adjustment during non-rebasing years that is in addition to that produced by the 3GIRM process.

Response:

Hydro One is planning to construct a new transmission line (A12N) in Norfolk County in 2008 and in service April 2009. This will allow for future economic development in Norfolk County as well as improved system reliability. As per the Transmission System Code, Section 3.5, the estimated contributed capital from Norfolk Power is estimated to be in the range $3M.

It is unclear at this time to Norfolk Power how such a capital program will be addressed in the 3rd Generation IRM. As a result, Norfolk Power is requesting a deferral/variance account for capital works during non-rebasing years. This account will at least track costs associated with programs such as the new transmission line for possible disposition in the next rebasing rate application.

8. **Smart Meters**

What portion of NPDI's revenue deficiency is due to smart meter expenditures? In answering that question, so please isolate:

- the impact on OM&A (2008 versus 2007, and 2008 versus 2006)
- the impact on rate base and cost of capital;
- the impact on depreciation and amortization.

Response:

- See below

	With Smart Meters	Without Smart Meters	Difference and Impact on Revenue Deficiency
OM&A Expenses	$5,012,481	$4,650,481	($362,000)
Amortization Expenses	2,836,810	2,755,590	(81,220)
Regulated Return On Capital	3,811,769	$3,657,471	(154,298)
PILs (with gross-up)	1,053,527	$996,885	(56,642)
Service Revenue Requirement	12,800,352	$12,146,193	(654,159)

MILLARD, ROUSE AND 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, 2006 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 the company as at December 31, 2006 and the results of its operations and cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Millard, Rouse and Rosebrugh LLP

CHARTERED ACCOUNTANTS

March 23, 2007
Simcoe, Ontario

Norfolk Power Distribution Inc.

BALANCE SHEET
AS AT DECEMBER 31, 2006

- ASSETS -

	2006	2005
Current Assets		
Bank	**$0**	$514,262
Accounts Receivable - Energy Customers	**4,150,404**	2,229,311
Accounts Receivable - Other	**1,232,671**	3,643,266
Unbilled Energy Receivable	**4,333,253**	4,497,240
Inventory	**582,105**	497,895
Prepaid Expenses	**449,005**	409,615
Total Current Assets	**$10,747,438**	$11,791,589
Property, Plant and Equipment *[Note 4]*		
Property, Plant and Equipment	**$66,902,337**	$62,739,825
Accumulated Depreciation	**(28,470,262)**	(26,128,781)
Total Property, Plant and Equipment	**$38,432,075**	$36,611,044
Other Assets		
Unamortized Debenture Discount	**$6,367**	$9,551
Smart Meter Funding	**(38,086)**	0
Deferred Transition Costs *[Note 5]*	**0**	790,799
Regulatory Assets *[Note 6]*	**(714,754)**	687,950
Recovery of Regulatory Asset Balances *[Note 6]*	**731,778**	(1,282,534)
Hydro One Charges *[Note 7]*	**508,729**	172,900
Conservation & Demand Management *[Note 8]*	**7,068**	7,068
Other	**0**	49,583
Total Other Assets	**$501,102**	$435,317
Total Assets	**$49,680,615**	$48,837,950

- LIABILITIES AND SHAREHOLDER'S EQUITY -

	2006	2005
Current Liabilities		
Overdraft *[Note 10a]*	**$1,027,238**	$0
Bank Loans *[Note 10b]*	**1,500,000**	1,500,000
Accounts Payable & Accrued Liabilities	**6,895,397**	6,909,548
Due to Associated Companies *[Note 9]*	**554,851**	527,770
Corporate Tax Payable	**49,138**	61,600
Current portion of:		
Consumer Deposits	**42,200**	40,100
Capital Lease Obligation *[Note 12]*	**3,545**	3,162
Bank Loan *[Note 10c]*	**382,000**	357,000
Debenture Debt *[Note 11]*	**353,000**	339,000
Total Current Liabilities	**$10,807,369**	$9,738,180
Long-Term Liabilities		
Consumer Deposits	**$66,893**	$56,914
Post Employment Benefits	**640,121**	596,920
Capital Lease Obligation (Net of Current Portion) *[Note 12]*	**1,227**	4,772
Bank Loans (Net of Current Portion) *[Note 10c]*	**13,626,000**	14,008,000
Debentures (Net of Current Portion) *[Note 11]*	**369,000**	722,000
Total Long-term Liabilities	**$14,703,241**	$15,388,606
Total Liabilities	**$25,510,610**	$25,126,786
Shareholders' Equity		
Share Capital *[Notes 1 and 13]*	**$22,768,898**	$22,768,898
Contributed Capital	**830,799**	830,799
Retained Earnings	**570,308**	111,467
Total Shareholders' Equity	**$24,170,005**	$23,711,164
Total Liabilities & Shareholders' Equity	**$49,680,615**	$48,837,950

Norfolk Power Distribution Inc.

STATEMENT OF RETAINED EARNINGS
FOR THE YEAR ENDED DECEMBER 31, 2006

	2006	2005
Retained Earnings, beginning balance	**$111,467**	($11,139)
Net Income	**838,841**	422,606
Cash dividends declared	**(380,000)**	(300,000)
Retained Earnings, ending balance	**$570,308**	$111,467

STATEMENT OF OPERATIONS
FOR THE YEAR ENDED DECEMBER 31, 2006

	2006	2005
REVENUE		
Sale of Energy	**$26,098,639**	$26,667,590
Power Purchased	**26,098,639**	26,667,590
GROSS MARGIN	**$0**	$0
OTHER REVENUE		
Distribution Services Revenue *[Schedule 1]*	**$9,531,873**	$9,173,910
Regulatory Asset Recovery	**(1,650,040)**	(1,019,057)
Other Operating Revenues *[Schedule 2]*	**266,749**	207,875
Other Income/Deductions *[Schedule 3]*	**58,661**	133,257
Investment Income (Loss)	**267,804**	300,983
	$8,475,047	$8,796,968
EXPENSES		
Distribution System - Operation and Maintenance *[Schedule 4]*	**$1,836,006**	$1,451,384
Billing and Collecting *[Schedule 5]*	**877,360**	854,529
Community Relations *[Schedule 6]*	**149,934**	160,602
Administrative and General Expense *[Schedule 7]*	**1,251,722**	1,475,528
Depreciation - net Contributed Capital Amortization Credit	**2,063,117**	2,050,401
Amortization of Organization and Qualified Transition Costs *[Note 17]*	**(245,340)**	790,799
Interest	**1,202,462**	1,093,685
	$7,135,261	$7,876,928
Income before provision for payments in lieu of corporate taxes	**$1,339,786**	$920,040
Provision for payments in lieu of corporate taxes *[Note 14]*	**500,945**	497,434
Net Income	**$838,841**	$422,606

Norfolk Power Distribution Inc.

STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2006

	2006	2005
OPERATING ACTIVITIES		
Net Income	**$838,841**	$422,606
Add (Deduct) charges to operations not requiring a current cash payment:		
Gross Depreciation - Net of Contributed Capital Amortization Credit	**2,341,935**	2,186,437
Amortization of Qualified Transition Costs	**(245,340)**	790,799
Net Loss (Gain) on Disposal of Property, Plant and Equipment	**28**	(18,113)
Changes in Working Capital Amount:		
(Increase) Decrease in Accounts Receivable - Energy Customers	**(1,921,093)**	717,871
Decrease (Increase) in Accounts Receivable - Other	**2,410,595**	(874,426)
Decrease (Increase) in Unbilled Energy Receivable	**163,987**	(2,738,921)
(Increase) in Inventory	**(84,210)**	(41,241)
(Increase) in Prepaid Expenses	**(39,390)**	(144,481)
Decrease in Energy Variance and Carrying Charges	**860,750**	2,713,523
(Increase) in Hydro One Charges	**(335,829)**	(172,900)
Decrease in Unamortized Debenture Discount	**3,184**	3,184
Decrease (Increase) in Miscellaneous Deferred Debits and Other	**591,537**	(189,159)
(Decrease) Increase in Accounts Payable and Accrued Liabilities	**(14,151)**	269,772
Increase in amounts Due to Associated Companies	**27,081**	436,924
Corporate Taxes (Receivable)/Payable/	**(12,462)**	370,707
	$4,585,463	$3,732,582
INVESTING ACTIVITIES		
Property, Plant and Equipment Additions	**($5,049,756)**	($4,070,895)
Deferred Transition Costs	**1,036,139**	(180,711)
Recovery of Regulatory Asset Balances	**(2,014,312)**	0
Proceeds on Disposition of Property, Plant and Equipment	**250**	77,212
	($6,027,679)	($4,174,394)
FINANCING ACTIVITIES		
Smart Meter Funding	**$38,086**	$0
Capital Lease Obligations	**(3,162)**	7,934
Increase (Decrease) in Customer Deposits	**12,079**	(34,030)
Increase in Bank Loan	**0**	1,500,000
Repayment of Bank Loan	**(357,000)**	(335,000)
Repayment of Debentures	**(339,000)**	(317,000)
Contributions in Aid of Construction	**886,512**	1,486,209
Increase in Post Employment Benefits	**43,201**	41,620
Dividends Paid	**(380,000)**	(300,000)
	($99,284)	$2,049,733
Net (Decrease) Increase in Cash	**($1,541,500)**	$1,607,921
Bank, beginning balance	**514,262**	(1,093,659)
Bank (Overdraft), ending balance	**($1,027,238)**	$514,262
Supplementary Information:		
Interest Expense	**$1,202,462**	$1,093,685
Interest Revenue	**267,804**	300,983

NOTES TO FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

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 bi-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 value 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 was allocated to the wholly owned subsidiaries as follows:

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

NOTES TO FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

2. ACCOUNTING POLICIES

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles [GAAP], as amended by principles specifically prescribed by the Ontario Energy Board [the OEB] for rate regulated businesses in the "*Accounting Procedures Handbook for Electric Distribution Utilities*". The following reflect the significant accounting policies:

Basis of Accounting

These financial statements have been prepared using the accrual basis of accounting. The accrual basis of accounting recognizes revenue as it becomes available and measurable. Expenses are recognized as they are incurred and measurable as a result of the receipt of goods and services and the creation of a legal obligation to pay.

Inventory

Inventory consists of repair parts, supplies and material held for future capital expansion, operation and maintenance activities and are valued at lower of cost and replacement value. Cost is determined using the weighted average method.

Property, Plant and Equipment and Depreciation

Property, plant and equipment are valued at acquisition cost less accumulated depreciation. Property, plant and equipment acquired from predecessor commissions are recorded at their respective cost and accumulated depreciation amounts. Gains or losses at retirement or disposition are credited or charged to other income in the year of acquisition or disposition.

Depreciation 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 Equipment	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 depreciation is recorded in the year of acquisition and none in the year of disposal.

NOTES TO FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

2. ACCOUNTING POLICIES cont'd

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 depreciation of the related property, plant and equipment.

Pension Plan

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 pension plan which operates as the Ontario Municipal Employees Retirement Fund and provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees and by the investment earnings of the fund.

Post-Employment Benefits

Post Employment benefits provided by Norfolk Power Inc. and its' subsidiary companies include medical and life insurance benefits. These plans provide benefits to certain employees when they are no longer providing active service. The Post-Employment benefits expense is recognized in the period in which the employees render the services.

Post Employment benefits are recorded on an accrual basis. The accrued benefit obligations and current service costs are calculated using the projected benefits method prorated on service and based on assumptions that reflect management's best estimate. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period.

Customer Deposits

Customer deposits are cash collections from customers to guarantee the payment of energy bills. Deposits expected to be refunded to customers within the next fiscal period are classified as a current liability.

Revenue Recognition

Distribution services revenue is recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year.

Rental revenue and other service fees are recognized as the service is performed.

NOTES TO FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

2. ACCOUNTING POLICIES cont'd

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

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 relation to its regulated business using the taxes payable method as directed by the OEB.

Use of Estimates

The preparation of periodic financial statements sometimes requires management to make certain estimates and assumptions that affect reported amounts. In these instances, since precise determination is dependent on future events, actual results could differ from those estimates.

3. RATE SETTING AND INDUSTRY REGULATION

The Ontario Energy Board Act (1998) [the Act] gave the Ontario Energy Board [OEB] increased powers and responsibilities to regulate the electricity industry on 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 fulfill 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 powers 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.

NOTES TO FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

3. RATE SETTING AND INDUSTRY REGULATION cont'd

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 6 and 7.

4. PROPERTY, PLANT & EQUIPMENT

	Cost	Accumulated Depreciation	2006 Net	2005 Net
Distribution Plant				
Land Rights and Easements	$680,975	$0	$680,975	$611,012
Transformer Station Building	1,450,870	58,035	1,392,835	1,421,853
Transformer Station Equipment	2,802,994	139,989	2,663,005	2,726,653
Distribution Station Equipment	2,388,347	1,404,503	983,844	993,875
Poles, Towers and Fixtures	22,602,419	9,718,033	12,884,386	12,820,375
Overhead Conductor and Devices	11,083,897	4,182,713	6,901,184	6,554,462
Underground Conduit	3,266,245	991,737	2,274,508	1,904,500
Underground Conductors and Devices	6,436,211	2,006,189	4,430,022	3,896,415
Transformers	9,035,687	4,693,576	4,342,111	4,103,754
Overhead and Underground Services	1,612,317	165,267	1,447,050	967,590
Meters	3,547,874	1,788,658	1,759,216	1,605,020
	$64,907,836	$25,148,700	$39,759,136	$37,605,509
General Plant				
Land and Easements	$211,830	$0	$211,830	$204,760
Buildings and Fixtures	1,947,788	715,729	1,232,059	1,216,768
Leasehold Improvements - Hunt St	6,177	1,304	4,873	3,532
Office Furniture and Equipment	376,421	304,335	72,086	63,140
Computer Equipment	1,267,228	875,055	392,173	387,107
Vehicles	2,318,600	1,407,527	911,073	665,865
Stores Equipment	116,200	90,949	25,251	18,929
Equipment Under Capital Lease	10,039	2,008	8,031	9,035
Garage Tools and Equipment	630,022	484,033	145,989	116,122
Measurement and Testing Equipment	145,541	44,810	100,731	105,923
Communication Equipment	54,931	19,826	35,105	33,371
Miscellaneous Equipment	82,327	15,539	66,788	49,207
Load Management Controls	12,276	0	12,276	4,323
SCADA System	612,051	144,167	467,884	486,027
	$7,791,431	$4,105,282	$3,686,149	$3,364,109
	$72,699,267	$29,253,982	$43,445,285	$40,969,618
Contributions in Aid of Construction	(5,796,930)	(783,720)	(5,013,210)	(4,358,574)
	$66,902,337	$28,470,262	$38,432,075	$36,611,044

NOTES TO FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

5. DEFERRED TRANSITION COSTS

	2006	2005
Deferred Organization Costs	**$1,895,289**	$2,931,428
Accumulated Amortization	**(1,895,289)**	(2,140,629)
	$0	$790,799

Deferred transition costs represent the incremental recoverable costs of preparing for the open electricity market.

6. REGULATORY ASSETS (LIABILITIES)

	2006	2005
Retail Services and Service Transaction Requests Variances	**$14,952**	$25,819
Pre-Market Opeining Energy Variance (Incl. Carrying Charges)	**0**	383,746
Low Voltage (LV) Variance	**8,650**	0
Other Regulatory Assets - OEB Cost Assess. & Other Reg. Assets Carrying Charges	**74,008**	51,540
OMERS Pension Deferral Account	**0**	178,459
Retail Settlement Variance Accounts (inclues carrying charges):		
Wholesale Market Services	**(14,148)**	1,202,492
Transmission Network Services	**109,009**	28,492
Transmission Connection Services	**(797,926)**	(560,405)
Bloomsburg Transformation Connection Charge	**492,840**	356,559
Power	**189,508**	1,203,199
Global Adjustment	**(791,647)**	(2,181,951)
	($714,754)	$687,950

Recovery of Regulatory Asset Balances:		
Recovery of Regulatory Asset Balances	**$7,689**	($1,232,166)
Recovery of Regulatory Asset Balances - Carrying Charges	**(30,551)**	(50,368)
Recovery of Transition Costs	**728,045**	0
Transition Costs - Carrying Charges	**26,595**	0
	$731,778	($1,282,534)

NOTES TO FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

6. REGULATORY ASSETS(LIABILITIES) cont'd

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. HYDRO ONE CHARGES

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.

	2006	2005
Hydro One Deferred L.V. Costs	**$492,820**	$220,118
Hydro One Secondary Env.	**15,591**	7,087
Hydro One Market Ready	**34**	15
Hydro One Network Charge	**(59,428)**	(19,578)
Hydro One Connection Charge	**59,712**	(34,742)
	$508,729	$172,900

8. CONSERVATION & DEMAND MANAGEMENT

Includes costs of conservation and demand management activities 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.

	2006	2005
C & DM Expenditures	**$194,466**	$194,466
Revenue from 3rd Tranche Recovery	**(581,000)**	(484,167)
CDM Contra Account	**393,602**	296,769
	$7,068	$7,068

NOTES TO FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

9. RELATED PARTY TRANSACTIONS

Transactions with associated companies are conducted within the normal course of business at fair market value of the services provided. Transactions between associated companies and year-end accounts receivable and accounts payable are eliminated for consolidation purposes.

As at December 31, 2006, the following transactions occurred between associated companies:

a) Norfolk Power Distributions Inc. paid operating expenses and income tax installments as follows:
   - $743,761 on behalf of Norfolk Energy Inc.
   - $109,403 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 $295,763.

c) Norfolk Power Distribution Inc. received revenue accruing to Norfolk Energy Inc. amounting to $1,135,048.

Balances owing at December 31, 2006, have no set repayment terms.

Norfolk Power Inc. owes Norfolk Power Distribution Inc.	$49,235
Norfolk Power Distribution Inc. owes Norfolk Energy Inc.	(604,086)
	($554,851)

10. 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.

NOTES TO FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

10. BANK INDEBTEDNESS cont'd

b) Bank Loans

	2006	2005
The total is comprised of $1,500,000 ISDA swap at 4.44% interest plus B/A stamping fees at 0.75%. Payable on Demand on a quarterly basis. The loan is secured by certain distribution assets as per the General Security Agreement.	**$1,500,000**	$1,500,000

c) Bank Loans

	2006	2005
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.	**$10,358,000**	$10,535,000
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.	**3,650,000**	3,830,000
	$14,008,000	$14,365,000
Less: Current Portion	**(382,000)**	(357,000)
Long Term Portion	**$13,626,000**	$14,008,000

Future principal payments are as follows:

2006	**$0**	$357,000
2007	**382,000**	382,000
2008	**399,000**	399,000
2009	**436,000**	436,000
2010	**464,000**	464,000
Future Principal Repayments	**12,327,000**	12,327,000
	$14,008,000	$14,365,000

NOTES TO FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

11. DEBENTURES

	2006	2005
Debenture bearing interest rates varying from 5.2% to 5.4% per annum over the term of the debenture and repayable in annual installments of principal plus semi-annual interest payments. The debenture is secured by certain distribution system assets.	**$722,000**	$1,061,000
Less: Current Portion	**(353,000)**	(339,000)
	$369,000	$722,000

Future principal payments are as follows:

2006	**$0**	$339,000
2007	**353,000**	353,000
2008	**369,000**	369,000
	$722,000	$1,061,000

12. CAPITAL LEASE OBLIGATION

	2006	2005
Capital lease is repayable in equal monthly installments of principal and interest and is due May 2008. The lease is secured by the leased vehicle.	**$4,772**	$7,934
Less: Current Portion	**(3,545)**	(3,162)
	$1,227	$4,772

13. 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.

Authorized:	**2006**		2005	
Unlimited Number of Common Shares				
	#	**$**	**#**	**$**
Issued:				
Common Shares	1,000	$22,768,898	1,000	$22,768,898

NOTES TO FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

14. 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:

	2006	2005
Income Tax	**$482,135**	$378,404
Provincial Capital Tax	**100,000**	105,200
Prior Year (Over)/Under Provision	**(81,190)**	13,830
	$500,945	$497,434

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:

	2006	2005
Future Benefit of Taxable Differences	**$802,360**	$645,055

15. FINANCIAL INSTRUMENTS

Financial instruments consist of cash, accounts receivable, accounts payable, bank loans and debentures.

a) **Fair Value**
Cash, accounts receivable and accounts payable are all short-term in nature and as such, their carrying values approximate fair value.

b) **Credit Risk**
Sales are made on credit and are subject to normal industry credit risks. Adequate provision has been made for any anticipated write-offs or uncollectible amounts.

c) **Interest Rate Risk**
The company’s overdraft bears interest at prime. The company is exposed to interest rate risk arising from fluctuations in prime rates.

The company’s bank loans and debentures bear interest at a fixed rate. Accordingly, there is no risk of exposure to interest rate fluctuations.

NOTES TO FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2006

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, 2006 the Company provided prudential support in the form of bank letters of credit of $1,871,058.

17. AMORTIZATION OF QUALIFIED TRANSITION COSTS

Deferred transition costs were supposed to be amortized for tax purposes over a four-year period commencing in 2003. During the 2006 EDR process, the OEB approved a minimum review to recover $1,078,020 through the distribution rates over the next two years. As such, deferred transition costs were over amortized by $245,340, which now has to be added back to this year's net income.

QUALIFYING TRANSITION COSTS		$2,302,666
Add:		
Carrying Charges from Jan 1/02 to Dec 31/02		$127,932
Carrying Charges from Jan 1/03 to Dec 31/03		166,943
Carrying Charges from Jan 1/04 to Dec 31/04		153,176
Carrying Charges from Jan 1/05 to Dec 31/05		180,710
Carrying Charges from Jan 1/06 to Apr 30/06		41,881
		$2,973,309
Less:		
OEB approved recovery through 2006 EDR		(1,078,020)
Amount Eligible for write-off		**$1,895,289**
Actual Amortization:		
	2003	$649,385
	2004	700,444
	2005	790,799
		$2,140,629
(Over)/Under Write-off		**($245,340)**

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 defenses 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 Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge.

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. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDCs’ situation may be distinguishable from that of Consumers Gas.

No determination of the portion of these payments which may have constituted interest at an impermissible rate has been made.

19. COMPARATIVE AMOUNTS

Certain amounts on the balance sheet as at December 31, 2005 have been reclassified to agree to the method of presentation adopted for the current year.

Norfolk Power Distribution Inc.

FINANCIAL STATEMENT SCHEDULES
FOR THE YEAR ENDED DECEMBER 31, 2006

	2006	2005
Schedule 1 - Distribution Services Revenue		
Residential	**$5,919,903**	$5,234,018
Street Lighting	**54,196**	52,596
Sentinel Lighting	**9,104**	6,170
General Service < 50KW	**1,792,867**	1,700,875
General Service > 50KW	**1,509,538**	1,668,499
Electric Services Incidental to Energy Sales	**136,281**	155,193
Unbilled Energy Receivable	**109,984**	356,559
	$9,531,873	$9,173,910
Schedule 2 - Other Operating Revenues		
Pole Rentals	**$82,705**	$68,727
Building & Property Rentals	**9,900**	7,200
Late Payment Charges	**101,469**	96,133
Miscellaneous Operating Revenue	**72,675**	35,815
	$266,749	$207,875
Schedule 3 - Other Income/Deductions		
Net (Loss) Gain on Disposal of Capital Assets	**($28)**	$18,113
Miscellaneous Non-Operating Revenue	**58,689**	115,144
	$58,661	$133,257
Schedule 4 - Distribution System - Operation and Maintenance		
Supervision	**$193,150**	$194,213
Meter Operations	**170,566**	143,234
Miscellaneous Operation Expense	**346,808**	222,755
Rent Paid	**36,090**	33,319
Storm Damage	**97,012**	54,667
Distribution Stations	**193,548**	111,662
Overhead Distribution System and Services Mtce	**355,865**	294,365
Tree Trimming	**233,095**	214,427
Underground Distribution System and Services Mtce	**120,465**	82,772
Transformers	**65,173**	79,620
Meter Maintenance	**24,234**	20,350
	$1,836,006	$1,451,384

Norfolk Power Distribution Inc.

FINANCIAL STATEMENT SCHEDULES
FOR THE YEAR ENDED DECEMBER 31, 2006

	2006	2005
Schedule 5 - Billing and Collecting		
Supervision	**$110,289**	$95,675
Meter Reading	**304,049**	322,396
Customer Billings	**663,895**	564,229
Collections	**325,615**	263,768
Collection Charges	**(135,874)**	(71,162)
Bad Debt Expense	**63,170**	85,965
Miscellaneous	**10,897**	7,333
Allocated to Norfolk Energy Inc.	**(464,681)**	(413,675)
	$877,360	$854,529
Schedule 6 - Community Relations		
Community Relations Sundry	**$10,831**	$12,983
Energy Conservation	**125,766**	127,676
Community Safety Program	**5,225**	11,214
Miscellaneous Customer Service	**8,112**	8,729
	$149,934	$160,602
Schedule 7 - Administrative and General Expense		
Executive/Management Salaries and Expenses	**$154,530**	$147,114
General Administration Salaries and Expenses	**393,755**	631,045
Office Supplies and Expense	**146,657**	153,773
Outside Services Employed	**76,097**	81,182
Property Insurance	**25,968**	27,462
Liability Insurance and Provision for Fines	**39,962**	39,009
Post Employment Benefits	**43,201**	41,620
Regulatory Expenses - OEB Fees	**23,135**	26,041
Market Readiness	**4,749**	33,706
Advertising	**4,215**	5,115
Miscellaneous General Expense	**75,676**	66,840
Maintenance of General Plant - Buildings and Fixtures	**185,553**	137,729
Electrical Safety Autority Fees (E.S.A.)	**8,197**	8,247
Property Tax	**66,370**	69,919
Donations	**3,657**	6,726
	$1,251,722	$1,475,528

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Ontario

March 15, 2004

Fred Druyf
President & CEO
Norfolk Power Distribution Inc.
P.O. Box 588
70 Victoria Street
Simcoe ON
N3Y 7N6

Dear Mr. Druyf:

Re: **Distribution Rate Application**
Board Decision and Order and Interim Rate Schedule

Attached is the Board's Decision and Order and Interim Rate Schedule with respect to your company's distribution rate application regarding the partial recovery of Regulatory Assets.

Yours truly,

P. O'Dell

Peter H. O'Dell
Assistant Secretary

cc. Intervenors of record

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

RP-2004-0074
EB-2004-0060

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

AND IN THE MATTER OF an Application by Norfolk Power Distribution Inc. for an order or orders approving or fixing just and reasonable rates.

BEFORE: Bob Betts
Presiding Member

Paul Vlahos
Member

DECISION AND ORDER

On January 15, 2004 the Ontario Energy Board ("the Board") issued filing guidelines to all electricity distribution utilities for distribution rate adjustments related to the recovery of Regulatory Assets, to be effective March 1, 2004 and implemented on April 1, 2004.

The Applicant filed an application for such adjustment. Notice of the proceeding was published on February 5, 2004 in major newspapers in the province.

While the Board had originally intended to approve the disposal of RSVA amounts on a final basis, on analysis of the applications by distributors and the reporting of RSVA amounts in these applications, the Board has now determined that all rate changes should be interim. In the Board's view, it would be premature to set these rates final based on the quality of the data contained in many of the applications and the fact that the audit sampling process by the Board has not been completed.

The Board received some interventions in these proceedings, mainly concerned with Phase Two of the process. The only intervenor to make specific submissions on Phase One of the proceeding was the School Energy Coalition, ("SEC") who objected to any interim increase in rates over and above the RSVA amounts on the basis that appropriate evidence had not been filed on these amounts. The Board is not convinced by SEC's arguments and sees no reason that Phase One cannot proceed. Phase One only contemplates partial recovery on an interim basis at this time. In Phase Two, the Board will review all applications to ensure that only prudent and reasonably incurred costs are recovered over the four year period mandated by the Minister.

In light of the above, the Board finds that it is in the public interest to order as follows.

THE BOARD ORDERS THAT:

1) The rate schedule attached is approved on an interim basis, effective March 1, 2004, to be implemented on April 1, 2004. All other rates currently in effect that are not shown on the attached schedule remain in force. If the Applicant's billing system is not capable of prorating to accommodate the April 1, 2004 implementation date, the new rates shall be implemented with the first billing cycle for electricity taken or considered to have been taken from April 1, 2004.

2) The Applicant shall notify its customers of the rate changes by including the brochure provided by the Board through a different process, no later than with the first customer bill reflecting the new rates, and provide to the Board samples of any other notices sent by the Applicant to its customers with respect to the rate changes. The Board expects the Applicant to provide notice to all customers about the rate changes, no later than with the first bill reflecting the new rates.

DATED at Toronto, March 15, 2004

ONTARIO ENERGY BOARD

P. O'Dell

Peter H. O'Dell
Assistant Secretary

RP-2004-0074
EB-2004-0060

Interim Rates
Norfolk Power Distribution
Schedule of Changed Distribution Rates and Charges
Effective Date: March 1, 2004
Implementation Date: April 1, 2004

RESIDENTIAL

Monthly Service Charge	(per month)	$16.91
Distribution Volumetric Rate	(per kWh)	$0.0110

GENERAL SERVICE < 50 KW

Monthly Service Charge	(per month)	$38.31
Distribution Volumetric Rate	(per kWh)	$0.0086

GENERAL SERVICE > 50 KW (Non Time of Use)

Monthly Service Charge	(per month)	$204.85
Distribution Volumetric Rate	(per kW)	$2.8987

SENTINEL LIGHTS (Non Time of Use)

Monthly Service Charge	(per connection)	$1.23
Distribution Volumetric Rate	(per kW)	$2.2350

STREET LIGHTING (Non Time of Use)

Monthly Service Charge	(per connection)	$0.65
Distribution Volumetric Rate	(per kW)	$2.0898

UNMETERED SCATTERED LOAD

Monthly Service Charge	(per month)	$38.31
Distribution Volumetric Rate	(per kWh)	$0.0086

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Ontario

March 23, 2005

BY PRIORITY POST

Fred Druyf
President & CEO
Norfolk Power Distribution Inc.
P.O. Box 588
70 Victoria Street
Simcoe ON
N3Y 7N6

Dear Mr. Druyf:

Re: 2005 Electricity Distribution Rates
Board Decision and Order
<u>Board File No. RP-2005-0013\EB-2005-0056</u>

The Board has now issued its Decision and Order for the above referenced proceeding and a copy is enclosed

Yours truly,

P. O'Dell

Peter H. O'Dell
Assistant Board Secretary

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

RP-2005-0013
EB-2005-0056

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

AND IN THE MATTER OF an Application by **Norfolk Power Distribution Inc.** for an order or orders approving or fixing just and reasonable rates.

BEFORE: Gordon Kaiser
Vice Chair and Presiding Member

Paul Vlahos
Member

Pamela Nowina
Member

DECISION AND ORDER

Background and Application

In November 2003 the Ontario government announced that it would permit local distribution companies to apply to the Board for the next installment of their allowable return on equity beginning March 1, 2005. The Government also indicated that the Board's approval would be conditional on a financial commitment to reinvest in conservation and demand management initiatives, an amount equal to one year's incremental returns.

Also in November 2003, the Government announced, in conjunction with the introduction of Bill 4, the *Ontario Energy Board Amendment Act, (Electricity Pricing), 2003*, that electricity distributors could start recovering Regulatory Assets in their rates, beginning March 1, 2004, over a four year period.

In February and March, 2004, the Board approved the applications of distributors to recover 25% of their December 31, 2002 Regulatory Asset balances (or additional amounts for rate stability) in their distribution rates on an interim basis effective March 1, 2004 and implemented on April 1, 2004.

On December 20, 2004 the Board issued filing guidelines to all electricity distribution utilities for the April 1, 2005 distribution rate adjustments. The guidelines allowed the applicants to recover three types of costs. These costs concern (i) the rate recovery of the third tranche of the allowable return on equity (Market Adjusted Revenue Requirement or "MARR"), (ii) the 2005 proxy allowance for payments in lieu of taxes ("PILs") and (iii) a second installment of the recovery of Regulatory Assets.

A generic Notice of the proceeding was published on January 25, 2005 in major newspapers in the province, which provided a 14 day period for submissions from interested parties. On February 4, 2005, the Board issued Procedural Order No. 1, providing for an extension for submissions until February 16, 2005 and also providing for reply submissions from applicants and other parties.

The Applicant filed an application for adjustments to their rates for the following amounts:

MARR: $ 581,000
2005 PILs Proxy: $ 1,048,196
Regulatory Assets Second Tranche: $ 1,531,499

The Applicant also applied for recovery of amounts outside of the guidelines. Specifically, the Applicant requested a PILs proxy that was not consistent with the Board's guidelines.

Submissions

The Board received one submission which addressed the 2005 rate setting process in general. This submission was made by School Energy Coalition (SEC). SEC objected to the guideline which caused the recovery of the 2005 PILs proxy to be reflected only on the variable charge. SEC was also concerned that monthly service charges and overall distribution charges varied significantly between utilities across the province. SEC also raised concerns regarding the consistency of, and access to, information on the applications as filed by the utilities.

Reply submissions to SEC's general submissions were received from the Coalition of Large Distributors, the Electricity Distributors Association, Hydro One Networks, and the LDC Coalition (a group of 7 distributors). These parties generally argued against the recommendations put forward by SEC, by and large indicating that the Board's existing processes for 2006 and 2007 have been planned to address these issues going forward and that these issues should not be added to the 2005 rates adjustment process.

The Applicant was not specifically named in any of these submissions.

The full record of the proceeding is available for review at the Board's offices.

Board Findings

The Board first addresses the general submission of SEC. While SEC raises important issues regarding electricity distribution rates, the Board has put in place a process which will address most of the issues raised by SEC on a comprehensive basis with coordinated cost of service, cost allocation and cost of capital studies for all distributors in 2006, 2007 and 2008. The Board does agree that unless there are compelling reasons to diverge from the Board's original filing guidelines for the 2005 distribution rate adjustment process, distributors should follow the guidelines in their applications.

At this time, the Board will approve only the portion of the application that conforms to the guidelines as the generic notice published informed customers and the public of only the changes contemplated in the guidelines. The Applicant may wish to apply for other specific changes to rates in a separate application.

As a result, the Board has made adjustments to the amounts applied for resulting in the following approved amounts:

MARR: $ 581,000
2005 PILs Proxy: $ 1,055,036
Regulatory Assets Second Tranche: $ 1,531,499

Subject to these adjustments, the Board finds that the application conforms with earlier decisions of the Board (including approval for the Applicant's Conservation and Demand Management plan), directives and guidelines.

The Board will issue a separate decision on cost awards.

THE BOARD ORDERS THAT:

1) The rate schedule attached as Appendix "A" is approved effective March 1, 2005, to be implemented on April 1, 2005. All other rates currently in effect that are not shown on the attached schedule remain in force. If the Applicant's billing system is not capable of prorating to accommodate the April 1, 2005 implementation date, the new rates shall be implemented with the first billing cycle for electricity consumed or estimated to have been consumed after April 1, 2005.

2) The Applicant shall notify its customers of the rate changes, no later than with the first bill reflecting the new rates and include the brochure provided by the Board.

DATED at Toronto, March 23, 2005
ONTARIO ENERGY BOARD

Peter H. O'Dell
Assistant Board Secretary

Appendix "A"

RP-2005-0013
EB-2005-0056

March 23, 2005

ONTARIO ENERGY BOARD

Norfolk Power Distribution Inc.
Schedule of Changed Distribution Rates and Charges
Effective Date: March 1, 2005
Implementation Date: April 1, 2005

RP-2005-0013
EB-2005-0056

RESIDENTIAL

Monthly Service Charge	(per month)	$15.43
Distribution Volumetric Rate	(per kWh)	$0.0180

GENERAL SERVICE < 50 KW

Monthly Service Charge	(per month)	$34.96
Distribution Volumetric Rate	(per kWh)	$0.0134

GENERAL SERVICE > 50 KW (Non Time of Use)

Monthly Service Charge	(per month)	$186.96
Distribution Volumetric Rate	(per kW)	$3.7577

SENTINEL LIGHTS (Non Time of Use)

Monthly Service Charge	(per connection)	$1.12
Distribution Volumetric Rate	(per kW)	$3.7676

STREET LIGHTING (Non Time of Use)

Monthly Service Charge	(per connection)	$0.59
Distribution Volumetric Rate	(per kW)	$2.9261

Unmetered Scattered Loads

Billed at General Service < 50 kW rates

Monthly Service Charge	(per month)	$34.96
Distribution Volumetric Rate	(per kWh)	$0.0134

The rates on this schedule include an interim recovery of Regulatory Assets.

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

Ontario

RP-2005-0020
EB-2005-0396

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

AND IN THE MATTER OF 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, 2006.

BEFORE: Paul Vlahos
Presiding Member

Bob Betts
Member

DECISION AND ORDER

Norfolk Power Distribution Inc. ("Norfolk Power" or the "Applicant") is a licensed distributor providing electrical service to consumers within its defined service area. Norfolk Power filed an application (the "Application") with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other matters, to be effective May 1, 2006.

Norfolk Power is one of over 90 electricity distributors in Ontario that are regulated by the Board. To streamline the process for the approval of distribution rates and charges for these distributors, the Board developed and issued the 2006 Electricity Distribution Rate Handbook (the "Handbook") and complementary spreadsheet-based models. These materials were developed after extensive public consultation with distributors, customer groups, public and environmental interest groups, and other interested parties. The Handbook contains requirements and guidelines for filing an application. The models determine the amounts to be included for the payments in lieu of taxes ("PILs") and calculate rates based on historical financial and other information entered by the distributor.

Also included in this process was a methodology and model for the final recovery of regulatory assets flowing from the Board's decision dated December 9, 2004 on the Review and Recovery of Regulatory Assets – Phase 2 for Toronto Hydro, London Hydro, Enersource Hydro Mississauga and Hydro One Networks Inc. ("Hydro One"). In Chapter 10 of the decision, the Board outlined a Phase 2 process for the remaining distributors. By letter of July 12, 2005, the Board provided guidance and a spreadsheet-based model to the distributors for the inclusion of this recovery as part of their 2006 distribution rate applications.

As a distributor that is embedded in Hydro One Network's low voltage system, the Applicant has included the recovery of certain Regulatory Assets that have been allocated by Hydro One Networks. The amount claimed by the Applicant was provided by Hydro One Networks as a reasonable approximation of the actual amount that Hydro One Networks will assess the Applicant. To the degree that the amount differs from the actual amount approved for Hydro One Networks in another proceeding (RP-2005-0020/EB-2005-0378), this difference will be reconciled at the end of the Regulatory Asset recovery period, as set out in the Phase II regulatory assets decision issued on December 9, 2004 (RP-2004-0064/RP-2004-0069/RP-2004-0100/RP-2004-0117/RP-2004-0118).

In its preliminary review of the 2006 rate applications received from the distributors, the Board identified several issues that appeared to be common to many or all of the distributors. As a result, the Board held a hearing (EB-2005-0529) to consider these issues (the "Generic Issues Proceeding") and released its decision (the "Generic Decision") on March 21, 2006. The rulings flowing from that Generic Decision apply to this Application, except to the extent noted in this Decision. The Board notes that pursuant to ss. 21 (6.1) of the *Ontario Energy Board Act, 1998*, and to the extent that it is pertinent to this Application, the evidentiary record of the Generic Issues Proceeding is part of the evidentiary record upon which the Board is basing this Decision.

In December 2001, the Board authorized the establishment of deferral accounts by the distributors related to the payments that the distributors make to the Ministry of Finance in lieu of taxes. The Board is required, under its enabling legislation, to make an order with respect to non-commodity deferral accounts once every twelve months. The Board has considered the information available with respect to these accounts and orders that the amounts recorded in the accounts will not be reflected in rates as part of the Rate Order that will result from this Decision. The Board will continue to monitor the accounts with a view to clearing them when appropriate.

Public notice of the rate Application made by Norfolk Power was given through newspaper publication in its service area. The evidence filed was made available to the public. Interested parties intervened in the proceeding. The evidence in the Application was tested through written interrogatories from Board staff and intervenors, and intervenors and Norfolk Power had the opportunity to file written argument. While the Board has considered the entire record in this proceeding, it has made reference in this Decision only to such evidence and argument as is necessary to provide context to its findings.

Norfolk Power has requested an amount of $10,621,538 as revenue to be recovered through distribution rates and charges. Included in this amount is a debit of $848,737 for the recovery of regulatory assets. Except where noted in this Decision, the Board finds that Norfolk Power has filed its Application in accordance with the Handbook and the guidelines for the recovery of regulatory assets.

Notwithstanding Norfolk Power's general compliance with the Handbook and associated models, in considering this Application the Board reviewed the following matters in detail:

- Low Voltage Rates;
- Rate Mitigation Proposal;
- Loss Factors;
- Deeming of Transmission Assets; and
- Consequences of the Generic Decision (EB-2005-0529).

Low Voltage Rates

Norfolk Power requested in its Application recovery of ongoing Low Voltage ("LV") charges that Hydro One Networks and Haldimand County Hydro Inc will be levying on Norfolk Power for Low Voltage wheeling distribution services provided to Norfolk Power. The Board notes that Hydro One Networks applied for an LV rate of $0.63/kW in its 2006 rate application RP-2005-0020/EB-2005-0378, and the Board has approved this rate. Haldimand County Hydro Inc has also applied for and has been granted Board approval of an LV wheeling rate to serve Norfolk Power.

The Board is of the view that the LV adjustment that Norfolk Power has included in its Application is insufficient to recover its expected LV charges in 2006, as this amount does not reflect the updated rates for Hydro One Networks and Haldimand County Hydro Inc. Although the Generic Decision provides that embedded distributors are to track differences between LV costs charged by the host distributor(s) and corresponding revenues recovered from ratepayers, the Board seeks to minimize systematic sources of variance. The Board is of the view that Norfolk Power's rates should reflect the LV rates authorized by the Board for the host distributors. Accordingly, the Board has revised the amount for LV charge recovery in Norfolk Power's revenue requirement.

Rate Mitigation Proposal

Norfolk Power's Application proposed a reduced return on equity (ROE) of 5.3%, compared to the original proposal which requested an ROE of 9.0%. Norfolk Power proposed that the revenue requirement reduction associated with the lower ROE be targeted to the residential class in order to reduce the rate increases for that class from 4.5% to 3.4%, while leaving the impacts to other classes unchanged.

The Vulnerable Energy Consumers Coalition submitted that Norfolk Power's mitigation plan was reasonable.

The Board acknowledges Norfolk Power's efforts to mitigate bill impacts. However, in the Board's view, two factors weigh against acceptance all the elements of the proposal.

First, the proposal effectively streams a discount to a selected class of customers. While it is true that rate impacts for other classes would not be affected directly by the proposal, an opportunity cost for those classes is necessarily involved. Furthermore, the conceptual basis of a class-differentiated ROE is not supported by the Handbook and has not been thoroughly tested in evidence by active or potential intervenors. Since a class-differentiated ROE represents a significant departure from historical Board practice, the Board views such testing as necessary.

Second, if viewed from the perspective of cost allocation, the proposal can be seen as pre-empting the results of the imminent cost allocation exercise. The Board is prepared to accept changes in the inter-class allocation of costs, but requires a sound basis in analysis and evidence to do so. That basis does not exist in the evidence before the Board.

Therefore, while the Board will accept Norfolk Power's proposed reduction in ROE, the Board finds that the reduction in revenue requirement will be applied to all classes through the existing cost allocation methodology embodied in the model.

Loss Factors

Norfolk Power has proposed a reduction in its distribution Loss Factor from 5.78% to 5.6%, following the methodology set out in the Handbook.

The proposed reduction is consistent with the Handbook requirements and the Board will accept it.

The Board notes that the RP-2004-0188 Report of the Board dated May 11, 2005 stated that any distributor whose 3-year average of distribution losses is higher than 5 percent will be required to report on those losses and provide an action plan as to how the distributor intends to reduce the level of losses. No plan was proposed. Therefore, the Board directs Norfolk Power to file an action plan within 90 days detailing how it intends to reduce the level of losses.

Deeming of a Transmission Asset

To meet growing local demand, reduce losses, and provide a reliable and secure supply of electricity, Norfolk Power constructed a 115 kV Transformer Station (the “TS”) which had an in-service date in 2004.

In this Application, Norfolk Power has requested that the TS be deemed to be a distribution asset.

Some assets operated by a distributor may be classified as part of a transmission system according to the definition of “transmission system” in the *Ontario Energy Board Act, 1998*. The Board has the power, under section 84 of the Act, to determine that transmission system assets are part of a distribution system, and can therefore treat them as distribution assets for the purpose of setting distribution rates. As stated above, Norfolk Power has requested the TS asset completed in 2004 be deemed to be a distribution asset in its rate base.

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.

Consequences of the Generic Decision on this Application

The Generic Decision contains findings relevant to funding for smart meters for electricity distributors. The Applicant did not file a specific smart meter investment plan or request approval of any associated amount in revenue requirement. Absent a specific plan or discrete revenue requirement, the Generic Decision provides that $0.30 per residential customer per month be reflected in the Applicant's revenue requirement. The Board finds that this increase in the revenue requirement amount will be allocated equally to all metered customers and recovered through their monthly service charge. This increment is reflected in the approved monthly service charges contained in the Tariff of Rates and Charges appended to this Decision. Pursuant to the Generic Decision, a variance account will be established, the details of which will be communicated in due course.

Resulting Revenue Requirement

As a result of the Board's determinations on these issues, the Board has adjusted the revenue requirement to be recovered through distribution rates and charges to $10,685,794, including a debit amount of $848,737 for the recovery of Regulatory Assets.

In its letter of December 20, 2004 to electricity distributors, the Board indicated that it would consider the disposition of the 2005 OEB dues recorded in Account 1508 in this proceeding. However, given that the final 2005 OEB dues are not available because of the difference in fiscal years for the Board and the distributors, and given that the model used to develop the Application does not incorporate this provision, the Board will review and dispose of the 2005 OEB dues at a later time.

Cost Awards

This Application is one of a number of applications before the Board dealing with 2006 rates chargeable by distributors. Intervenors may be parties to multiple applications and, if eligible, their costs associated with a specific distributor may not be separable. Therefore, for these applications, the matter of intervenor cost awards will be addressed by the Board at a later date, upon the conclusion of the current rate applications. If an intervenor that is eligible to recover its costs is able to uniquely identify its costs associated with this Application, it must file its cost claim within 10 days from the receipt of this Decision.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix “A” of this Order is approved, effective May 1, 2006, for electricity consumed or estimated to have been consumed on and after May 1, 2006. The application of the revised distribution rates shall be prorated to May 1, 2006. If Norfolk Power Distribution Inc.’s billing system is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors shall be implemented upon the first subsequent billing for each billing cycle.

2. The Tariff of Rates and Charges set out in Appendix “A” of this Order supersedes all previous distribution rate schedules approved by the Ontario Energy Board for Norfolk Power Distribution Inc., and is final in all respects.

3. Norfolk Power Distribution Inc. shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, April 26, 2006.

ONTARIO ENERGY BOARD

P. O'Dell

Peter H. O'Dell
Assistant Board Secretary

Appendix “A”

RP-2005-0020
EB-2005-0396

April 26, 2006

ONTARIO ENERGY BOARD

Norfolk Power Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

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

RP-2005-0020
EB-2005-0396

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders 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, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2006 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2006 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2006 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification applies to low voltage connection assets that operate at 750 volts or less and supply electrical energy to residential customers where such energy is used exclusively in separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex, or quadruplex house, with residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less Than 50 kW
This classification applies to low voltage connection assets that operate at 750 volts or less and supply electricity to general service customers whose monthly average peak demand during a calendar year is less than, or forecast by NPDI to be less than, 50 kW.

General Service 50 to 4,999 kW
This classification applies to general service customers with a monthly average peak demand during a calendar year equal to or greater than, or forecast by NPDI to be equal to or greater than, 50 kW but less than 5,000 kW.

Unmetered Scattered Load
This classification applies to low voltage connection assets that operate at 750 volts or less and supply electricity to general service customers whose monthly average peak demand during a calendar year is less than, or forecast by NPDI to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load.

Sentinel Lighting
This classification refers to lighting customers, other than street lighting customers, controlled by photo cells. The daily consumption for these customers will be based on the calculated connected load times the required night time or lighting times established in the approved OEB street lighting/sentinel lighting load shape template.

Street Lighting
This classification refers to roadway lighting customers such as the Norfolk County, Ministry of Transportation and private roadway lighting, controlled by photo cells. The daily consumption for these customers will be based on the calculated connected load times the required night time or lighting times established in the approved OEB street lighting load shape template.

Norfolk Power Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

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

RP-2005-0020
EB-2005-0396

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	18.32
Distribution Volumetric Rate	$/kWh	0.0167
Regulatory Asset Recovery	$/kWh	0.0046
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service Less Than 50 kW

Service Charge	$	41.37
Distribution Volumetric Rate	$/kWh	0.0116
Regulatory Asset Recovery	$/kWh	0.0023
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	217.80
Distribution Volumetric Rate	$/kW	2.9906
Regulatory Asset Recovery	$/kW	0.1217
Retail Transmission Rate – Network Service Rate	$/kW	2.0076
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6283
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	20.56
Distribution Volumetric Rate	$/kWh	0.0116
Regulatory Asset Recovery	$/kWh	0.0023
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	1.36
Distribution Volumetric Rate	$/kW	3.3478
Regulatory Asset Recovery	$/kW	9.2909
Retail Transmission Rate – Network Service Rate	$/kW	1.5217
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2851
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

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

RP-2005-0020
EB-2005-0396

Street Lighting

Service Charge (per connection)	$	0.70
Distribution Volumetric Rate	$/kW	2.3811
Regulatory Asset Recovery	$/kW	0.2931
Retail Transmission Rate – Network Service Rate	$/kW	1.5141
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2588
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Specific Service Charges

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
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special meter reads	$	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
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0560
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0454
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

EB-2007-0560

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

AND IN THE MATTER OF an application by Norfolk Power Distribution Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2007.

BEFORE: Paul Sommerville
Presiding Member

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION AND ORDER

Norfolk Power Distribution Inc. ("Norfolk Power") is a licensed distributor providing electrical service to consumers within its licensed service area. Norfolk Power filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2007.

Norfolk Power is one of 85 electricity distributors in Ontario that are regulated by the Board. To streamline the process for the approval of distribution rates and charges for these distributors, the Board issued its *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Report") on December 20, 2006. The Report contained the relevant guidelines for 2007 rate adjustments ("the guidelines") for distributors applying for rates only on the basis of the cost of capital and 2nd generation incentive regulation mechanism policies set out in the Report.

Public notice of Norfolk Power's rate application was given through newspaper publication in Norfolk Power's service area. The evidence filed as part of the rate application was made available to the public. Both Norfolk Power and interested parties had the opportunity to file written submissions in relation to the rate application. The Board received no submissions. While the Board has considered the entire record in this rate application, it has made reference only to such evidence as is necessary to provide context to its findings.

Norfolk Power's rate application was filed on the basis of the guidelines. In fixing new rates and charges for Norfolk Power, the Board has applied the policies described in the Report.

After confirming the accuracy of the 2006 rate tariff and accompanying materials submitted in the rate application, the Board applied its approved price cap index adjustment to distribution rates (fixed and variable) uniformly across all customer classes. The price cap index is calculated as a price escalator less an X-factor of 1.0%, intended to represent input price and productivity trends. Based on the final 2006 data published by Statistics Canada, the Board has established the price escalator to be 1.9%. The resulting price cap index adjustment is therefore 0.9%.

The price cap index adjustment was not applied to the following components of the rates:

- the specific service charges;
- the regulatory asset recovery rate rider; and
- the smart meter rate adder (an amount in the fixed components of the rates associated with smart meter cost recovery).

Norfolk Power requested an amount for smart meter costs. The Board has approved an amount of $0.26 per month per metered customer. Norfolk Power's variance accounts for smart meter program implementation costs, previously authorized by the Board, are continued. It is the Board's understanding that Norfolk Power will not be undertaking any smart metering activity (i.e. discretionary metering activity) in 2007. The amount collected through the smart meter rate adder will be booked into the existing variance accounts, and retained in those accounts, to help fund future smart meter activity. As the notice of this application indicated, the Board will be holding a combined proceeding to consider, among other things, appropriate recovery of smart meter costs.

The Board has made the necessary adjustments to Norfolk Power's filed 2006 Tariff of Rates and Charges to produce a new Tariff of Rates and Charges to be effective May 1, 2007. The Board finds the rates and charges in the Tariff of Rates and Charges attached as Appendix A to this decision to be just and reasonable.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix A of this order is approved, effective May 1, 2007, for electricity consumed or estimated to have been consumed on and after May 1, 2007.

2. The Tariff of Rates and Charges set out in Appendix A of this order supersedes all previous distribution rate schedules approved by the Ontario Energy Board for Norfolk Power, and is final in all respects.

3. Norfolk Power shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, April 12, 2007.

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary

Appendix A

THE TARIFF OF RATES AND CHARGES

EB-2007-0560

April 12, 2007

ONTARIO ENERGY BOARD

Norfolk Power Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

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

EB-2007-0560

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders 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, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2007 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification applies to low voltage connection assets that operate at 750 volts or less and supply electrical energy to residential customers where such energy is used exclusively in separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex, or quadruplex house, with residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less Than 50 kW
This classification applies to low voltage connection assets that operate at 750 volts or less and supply electricity to general service customers whose monthly average peak demand during a calendar year is less than, or forecast by NPDI to be less than, 50 kW.

General Service 50 to 4,999 kW
This classification applies to general service customers with a monthly average peak demand during a calendar year equal to or greater than, or forecast by NPDI to be equal to or greater than, 50 kW but less than 5,000 kW.

Unmetered Scattered Load
This classification applies to low voltage connection assets that operate at 750 volts or less and supply electricity to general service customers whose monthly average peak demand during a calendar year is less than, or forecast by NPDI to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load.

Sentinel Lighting
This classification refers to lighting customers, other than street lighting customers, controlled by photo cells. The daily consumption for these customers will be based on the calculated connected load times the required night time or lighting times established in the approved OEB street lighting/sentinel lighting load shape template.

Street Lighting
This classification refers to roadway lighting customers such as the Norfolk County, Ministry of Transportation and private roadway lighting, controlled by photo cells. The daily consumption for these customers will be based on the calculated connected load times the required night time or lighting times established in the approved OEB street lighting load shape template.

MONTHLY RATES AND CHARGES

Norfolk Power Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

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

EB-2007-0560

Residential

Service Charge	$	18.48
Distribution Volumetric Rate	$/kWh	0.0169
Regulatory Asset Recovery	$/kWh	0.0046
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	41.74
Distribution Volumetric Rate	$/kWh	0.0117
Regulatory Asset Recovery	$/kWh	0.0023
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	219.76
Distribution Volumetric Rate	$/kW	3.0175
Regulatory Asset Recovery	$/kW	0.1217
Retail Transmission Rate – Network Service Rate	$/kW	2.0076
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6283
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	20.75
Distribution Volumetric Rate	$/kWh	0.0117
Regulatory Asset Recovery	$/kWh	0.0023
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	1.37
Distribution Volumetric Rate	$/kW	3.3779
Regulatory Asset Recovery	$/kW	9.2909
Retail Transmission Rate – Network Service Rate	$/kW	1.5217
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2851
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Norfolk Power Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

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

EB-2007-0560

Service Charge (per connection)	$	0.71
Distribution Volumetric Rate	$/kW	2.4025
Regulatory Asset Recovery	$/kW	0.2931
Retail Transmission Rate – Network Service Rate	$/kW	1.5141
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2588
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

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
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special meter reads	$	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
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0560
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0454
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A