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

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.

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.

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

a. 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).

b. 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.

5. Ref: Exhibit 2/ Tab 2/ Schedule 2/ 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

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. <u>Ref: Exhibit 2/ Tab3/ Schedule 3/ Capital Budget Items/ Transformers</u>

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) <u>Ref: Exhibit 2/ Tab 2/ Schedule 3 Pages 1, 4</u>, 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.

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

a. Please provide profitability index calculations (“PI”) for the Customer Demand Projects which are included in the capital cost $1,841,000.

b. Please provide the average capital cost to connect a single residential customer in each of years 2002 through 2008.

c. 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.

d. Please confirm whether or not the $200,000 capital contributions from these customers are included in the 2008 rate base.

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

   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.

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

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

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

11. <u>Ref: Exhibit 2/ Working Capital/ Page 33/ Line 11</u>
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.

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.

OPERATING COSTS

CORPORATE COST ALLOCATION

13. <u>Ref: Exhibit 4 / Tab 2 / Schedule 4 / Page 1</u>

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.

Please provide the documentation described above if the applicant confirmed that a shared services arrangement exists

EMPLOYEE COMPENSATION

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.

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.

16. Ref: Exhibit 4 / Tab 2 / Schedule 7
Page 1 provides a comparison of total benefits from 2006 to 2007.
    a. Please explain the 13% increase in average executive benefits, from $21,580 in 2006 to $24,463 in 2007.
    b. Please explain the 15% increase in average management benefits, from $13,802 in 2006 to $15,814 in 2007.

17. Ref: Exhibit 4 / Tab 2 / Schedule 7
On Page 1, Norfolk Power provides a comparison of total benefits from 2006 to 2007.

a. 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.

b. 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.

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.

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.

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.

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.

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.

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.

Table 2

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 8.2%	1,073,025	123,975 3.3%	1,197,000	10,774 0.2%	1,207,774	134,749 3.5%
Maintenance	747,613	-106,207 -2.8%	641,406	283,594 7.5%	925,000	8,326 0.2%	933,326	291,920 7.7%
Billing and Collections	856,868	-42,677 -1.1%	814,191	129,809 3.4%	944,000	8,497 0.2%	952,497	138,306 3.6%
Community Relations	24,718	-549 0.0%	24,169	3,831 0.1%	28,000	252 0.0%	28,252	4,083 0.1%
Administrative and General Expenses	1,459,232	-214,367 -5.6%	1,244,865	202,135 5.3%	1,447,000	375,023 8.3%	1,822,023	577,158 15.2%
Total Controllable OM&A	3,845,953	-48,297 -1.3%	3,797,656	743,344 19.6%	4,541,000	402,872 8.9%	4,943,872	1,146,216 30.2%

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.

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.

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.

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.

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

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.

29. Ref: 3/2/1/p2 and 3/2/2/p1

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.

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:

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

IV) 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),

V) the values of the weather conversion factors used,

VI) the customer count for each class in each year,

VII) 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

VIII) 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.

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.

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.

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.

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.

COST OF CAPITAL

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

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.

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.

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

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.

DEFERRAL AND VARIANCE ACCOUNTS

38. <u>Ref: Exhibit1/Tab1/Schedule8/Page2</u>

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.

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

Please provide the 2007 and 2008 pro forma balance sheets.

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.

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?

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.

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)?

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.

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?

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?

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.

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.

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.

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?

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.

l) If not, confirm if these amounts were applied to the smart meter capital variance account.

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.

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.

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.

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.

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.

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.

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.

Regulatory Cost Category	Ongoing or One-time Cost?	2006 Board Approved	2006 Actual	2007 (as of Dec 07)	% Change in 2007 vs. 2006	2008 Forecast	% Change in 2008 vs. 2007
OEB Annual Assessment							
OEB Hearing Assessments (applicant initiated)							
OEB Section 30 Costs (OEB initiated)							
Expert Witness cost for regulatory matters							
Legal costs for regulatory matters							
Consultants costs for regulatory matters							
Operating expenses associated with staff resources allocated to regulatory matters							
Operating expenses associated with other resources allocated to regulatory matters (please identify the resources)							
Other regulatory agency fees or assessments							
Any other costs for regulatory matters (please define)							

- End of Document -