Norfolk Power

IN BUSINESS TO SERVE.

April 9, 2008

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

Re: OEB File No. EB-2007-0530
Norfolk Power Distribution Inc.
2008 Electricity Distribution Rate Application

Dear Ms. Walli,

Norfolk Power Distribution Inc. is pleased to advise the Board that we are filing our reply submission to submissions from Board staff and Intervenors, as per Procedural Order No. 3 dated February 28, 2008. We have included two paper copies and an electronic version filed through the Board's RESS.

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

Yours truly,

Alvin E. Allim
Manager of Finance

Norfolk Power

Norfolk Power Distribution Inc. Submission

2008 Electricity Distribution Rates

EB-2007-0530

April 9, 2008

INTRODUCTION

Norfolk Power Distribution Inc. ("NPDI" or the "Applicant") operates an electrical distribution system with a total service area of 693 square kilometers within the County of Norfolk. The sole shareholder of the Applicant is the County of Norfolk. Norfolk Power Distribution Inc. currently delivers electricity through a network of over 573 kilometers of overhead wires, through transformer stations and municipal substations, to approximately 18,500 customers in residential and general service classes. Norfolk Power Distribution Inc. asserts that a determining characteristic of the system is that it serves a large geographic area with a density of 33 customers/route kilometer.

Norfolk Power Distribution Inc. submitted an application for 2008 electricity distribution rates on November 16, 2007. The application was based on a forward test year cost of service methodology. On February 15, 2008 NPDI filed its response to interrogatories from Board staff and the two intervenors, the School Energy Coalition ("SEC") and Vulnerable Energy Consumers Coalition ("VECC").

NPDI has requested a revenue requirement of $12,800,352 (Figure 1.1 below), to be recovered in new rates effective May 1, 2008. This revenue requirement reflects a revenue deficiency for 2008 of $2,925,795.

Figure 1.1
Calculation of Base Revenue Requirement

OM&A Expenses	$5,098,246
Amortization Expenses	2,836,810
Total Distribution Expenses	$7,935,056
Regulated Return On Capital	3,811,769
PILs (with gross-up)	1,053,527
Service Revenue Requirement	**$12,800,352**
Less: Revenue Offsets	(464,000)
Base Revenue Requirement	**$12,336,352**
Less: Directly Allocated	(68,612)
Outstanding Base Revenue Requirement	**$12,267,740**

Through this Application, Norfolk Power Distribution Inc. seeks:

- To recover Revenue Deficiency arising from changes in OM&A, Amortization, Rate of Return and PILS
- To recover Deferral and Variance Account Balances
- To change Retail Transmission Rates
- To continue current Specific Service Charges
- Prepare for the implementation of Smart Meters
- Approval of just and reasonable distribution rates applied for in accordance with the Ontario Energy Board Filing Requirements for Distribution Rate Applications

The following submission addresses the various components of Norfolk Power Distribution Inc.'s application and responds to submissions from Board staff, VECC and SEC.

OPERATIONS, MAINTENANCE & ADMINISTRATION (OM&A)

The OM&A costs represent NPDI's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and Government direction. These costs also include providing services to customers connected to the NPDI's Distribution system, and to meet the service levels stipulated in the Standard Supply Service Code and the Retailer Settlement Code.

The proposed OM&A cost expenditures for the 2008 test year result from a business planning and work prioritization process that reflects risk-based decision making to ensure that the most appropriate, cost effective solutions are put in place.

Discussion and Submission

Board staff, VECC, and SEC each provided comments on the OM&A component of NPDI's rate application. In the Board staff Submission, various tables were prepared to assist in reviewing the OM&A costs. Board staff noted Regulatory Expenses, Maintenance Supervision/Engineering and Bad Debt Expense required further clarification. NPDI provides the following explanation for the increases:

- Regulatory Expenses – As per NPDI's response to Board IR #58, consultant and other costs were significantly higher in the 2007 Bridge and 2008 Test years due to regulatory obligations imposed by the OEB including: (1) Cost Allocation; and (2) the 2008 EDR Application. NPDI believes these are "one-time" costs and pertain to the above years respectively.
- Maintenance Supervision/Engineering - Historically, only line staff engaged directly in supervising the maintenance function were charged to Account 5105 – Maintenance Supervision and Engineering. To be consistent with the APH, Article 230, other labour (engineering and clerical) and related costs in the maintenance function are now included.
- Bad Debt Expense – Upon further review, the components that have increased bad debt expense are beyond the control of NPDI. These include, customers signed with retailers that become delinquent and subsequently are written-off, are not passed on to the retailers. Under the current rules from the Board, this expense is borne by NPDI. Also, over the past few years, NPDI has experienced a decline in the economy of Norfolk County, with losses in employment and general service less than 50kW (tobacco farming).

Board staff also noted that NPDI is proposing a 30% increase in its controllable OM&A and is seeking clarification to justify these increases. In response to Board IR#23, NPDI provided cost driver tables, by USoA, to explain the increases. Board staff, VECC and SEC, agreed the information contained in the tables was inadequate to be able to comment. NPDI is providing Tables 1.1, 1.2 and 1.3, to further explain the main cost drivers in OM&A.

Table 1.1

OM&A Cost Drivers - Notes to 2006	2006
Opening Balance	$3,845,953
Closing Balance	$3,797,656
Difference	**($48,297)**
Difference Comprised of:	
Increase Salary/Wage and benefits	$111,471
Staff additions - none	$0
Increase in Collection Charges	($49,300)
Fewer No. of Accounts Written Off/Lower Balances	($46,207)
PCB Testing of Transformers – deferred	($80,893)
Reduced # of bill re-prints & stuffs due to mail machine improvements	($22,932)
Eliminated Redundant Cell Phones & Phone Lines	($5,582)
Centralization of Stationery Ordering, Implementation of Better Controls	($4,854)
Increase in # of After-Hours Trouble Calls Taken	$35,000
Incremental Costs relating to May 2006 Blackout	$15,000
	($48,297)

Table 1.2

OM&A Cost Drivers - Notes to 2007	2007
Opening Balance	$3,797,656
Closing Balance	$4,541,000
Difference	**$743,344**
Difference Comprised of:	
Increase Salary/Wage and benefits	$183,464
Staff Additions: Mgmt Supervisors (2); Contract Control Room Operator; Operator in Training	$213,975
Forestry Audit	$31,905
Collective Agreement Bargaining – Consultant	$10,300
Additional PCB Testing of Transformers	$20,000
Increase in Station Maintenance Program	$150,800
Increase in Contract Meter Reading Costs	$6,000
Incremental Tower Rental Space for Radio System	$11,000
Increase in OEB Fees & Cost Allocation Study Costs	$41,900
Additional Consultant for Merge-Co Consultant	$11,000
Increase in ESA Fees & Cost of ESA Audit	$6,000
Unforeseen Bad Debt Expense	$57,000
	$743,344

Table 1.3

OM&A Cost Drivers - Notes to 2008	2008
Opening Balance	$4,541,000
Closing Balance	$4,943,872
Difference	**$402,872**
Difference Comprised of:	
Increase Salary/Wage and benefits	$122,872
Staff additions - none	$0
Smart Meter Implementation	$362,000
Increase in Collections Charges	($22,000)
Reduce Stations Maintenance Program	($60,000)
	$402,872

Another part of the OM&A discussion was Employee Compensation and Benefits. Board staff noted that NPDI has requested a 13% to 15% in OM&A labour costs from Executive and Management benefits [2007 to 2008] and invited submissions from intervenors on the reasonableness of the increase. However, Board staff did not identify any issues or concerns in relation to labour costs.

VECC in its submission, sections 4.1 and 4.7, made comments similar to those made by Board Staff. However, VECC proposed a $150,000 reduction in OM&A. In its submission, SEC provided comments on OM&A on pages 1-3. On page 3, SEC proposes a $300,000 decrease in OM&A costs.

Any reduction to the OM&A cost, as proposed by VECC and SEC, would be purely arbitrary in nature and jeopardize the ability of NPDI to provide safe and reliable distribution service to its customers. Neither VECC nor SEC have pointed to any evidence that would justify a reduction in the OM&A cost.

RATE BASE

Discussion and Submission

Board staff noted that there is no clear explanation of why the 2006 actual rate base was approximately $5.8 million or 18% higher than the Board approved 2006 rate base. NPDI directs Board staff to responses for IR#3a (i) & (ii) concerning this issue.

Board staff are also seeking clarification to justify renewal projects and are requesting reliability statistics for 2002 through 2007 as well as an example of a typical study justifying station capital upgrades resulting from reliability considerations. NPDI directs Board staff to discussion and submission for Capital Expenditures (pages 6 – 8) and Service Reliability Indices (page 9), contained in this document.

CAPITAL EXPENDITURES

The Capital Expenditures in this rate application represents NPDI's integrated approach to asset replacement and additions to ensure that NPDI continues to provide current and future customers with safe, reliable and cost effective distribution of electricity.

The table below lists the 2008 Capital Budget as found in response to VECC IR#8, summarized by project type.

	2008 TEST
DISTRIBUTION PLANT	
Land and Land Rights	$1,000
Transformer Station - Building & Fixtures	74,200
Transformer Station Equipment	322,000
Substation Equipment	811,500
Distribution System - Overhead:	
Poles, Towers, & Equipment	1,130,800
Conductor & Devices	738,200
Distribution System - Underground:	
Conduit	282,000
Conductor & Devices	600,000
Transformation	876,000
Services - Overhead and Underground	322,000
Meters (excludes Smart Meters)	516,400
TOTAL DISTRIBUTION PLANT	$ 5,674,100
GENERAL PLANT	
Land and Land Rights	$0
Buildings: Fixtures & Improvements	108,400
Leasehold Improvements	5,000
Office Furniture and Equipment	29,000
Computer Equipment - Hardware	67,000
Computer Equipment - Software	129,000
Transportation Equipment	95,000
Stores Equipment	5,000
Garage, Truck Tools and Stringing Equipment	32,000
Measurement & Testing Equipment	25,500
Communication Equipment	29,000
Miscellaneous Equipment	37,500
Load Control Equipment	0
SCADA Equipment	92,100
TOTAL GENERAL PLANT	$ 654,500
Contributions in Aid of Construction	($200,000)
TOTAL CAPITAL	$6,128,600

Discussion and Submission

In general, Board staff and all intervenors are satisfied with the proposed capital expenditures.

However, VECC submits that the total 2008 spending on Renewal and Customer Demand projects should be "capped" at $3.3 million (versus the $3.5 million proposed). Any reduction to the Renewal and Customer Demand projects, as proposed by VECC, would be purely arbitrary in nature and hinder the ability of NPDI to fulfill its obligations to customers.

Board staff has asked for further clarification as related to actual and target reliability, in order to identify trends that could justify increasing capital expenditure for renewal and station upgrades. Also, Board staff requested information on customer demand projects profitability calculations. NPDI's responses to Board IR#8 & #9 explains briefly, the rationale for renewal projects and station work. NPDI has stated that it does not have a "formal" procedure to assess trends and target reliability in order to justify capital expenditures. However, NPDI has a process in place (see Appendix A), to determine the priority of its capital projects from year to year. With respect to information on customer demand projects profitability calculations (contributed capital), the calculations are determined using Methodology and Assumptions for An Economic Evaluation. A summary of the calculations is provided below:

Project	# of Lots	Material Cost Installed by NPDI (incl. cable, transformers, hardware)	Cost before connection [balance of NPDI cost - labour to install cable, civil work (e.g. trenching, transformer vault)]	Less: Amount Already collected from Developer	Total Contributed Capital *(Cost to Developer)* for 2008
2008 Subdivision Activity					
Lynnriver Phase 2 Stage 1	57	$ 39,236.96	$ 36,254.14	$ -	$ 75,491.10
Lynnriver Phase 2 Stage 2	48	$ 47,178.19	$ 35,826.04	$ -	$ 83,004.23
****Somerset Phase 6**	44	$ 52,028.84	$ 23,360.28	$ (74,339.12)	$ 1,050.00
****Harvest View Court, Simcoe**	26	$ 20,299.86	$ 19,700.14	$ -	$ 40,000.00
Total Contributions					**$ 199,545.33**

*****Carryover from 2007***

Board staff, SEC and VECC all commented on the lack of a formal "Assessment of Asset Condition and Asset Management Plan".

Assessment of Asset Condition and Asset Management Plan

NPDI believes it has a prudent and effective asset management plan in place. The flow chart shown in Appendix A shows the decision making process in relation to Asset Management. This approach enables the business planning and budget process to accurately reflect infrastructure requirements on a priority basis.

Factors for Prioritizing Renewal Projects

In conjunction with the process from Appendix A, NPDI also reviews the following factors for identifying Renewal Projects:

- Age of the plant (i.e. in excess of 40 years)
- Condition of insulation on open bus secondary
- Small conductors (i.e. #4 ACSR and #6 Copper)
- Non-Standard construction (Safety issues)
- Condition of hardware (i.e. crossarms, guys, anchors, etc.)
- Condition of protective devices (i.e. fuse holders, arrestors, etc.)

Please note, the more factors that exist, the higher the priority is given to the project

SERVICE RELIABILITY INDICES

NPDI has conducted a detailed and prudent review of operating and capital expenditures, as set out in this rate application. The Service Reliability indices have a direct correlation to the proposed OM&A and Capital Expenditures proposed by NPDI. It is submitted that the rates proposed by NPDI are just and reasonable and are designed to ensure Service Reliability will be maintained and enhanced.

Discussion and Submission

Board staff seeks clarification on the accuracy of the reliability performance indicators reported for the 2002-2006 period. Furthermore, Board staff have asked for clarification of the correlation and impact of its 2008 capital expenditure projects with the performance targets.

VECC and SEC in their respective Submissions, had no comments related to this issue.

Upon further review of the Service Reliability Indices reported in Board staff IR #9, NPDI had made methodological and/or calculation errors in deriving the values for these indicators. Furthermore, NPDI had not reported service reliability indices for 2007 due to availability.

These errors have been corrected and a revised table is provided below, which includes 2007:

Service Reliability Indicator (SRI)	2002	2003	2004	2005	2006	2007
Annual SAIDI	*21.090	1.285	1.957	2.244	2.949	*5.066
Annual SAIFI	2.120	1.330	3.405	2.238	4.451	1.891
Annual CAIDI	9.948	0.966	0.575	1.003	0.663	2.679

**Note: includes Ice and Wind Storm*

NPDI has made a conscientious effort to include capital projects in this rate application in order to maintain or enhance NPDI's current Service Reliability Indicators of SAIDI, SAIFI and CAIDI. In particular, NPDI has concentrated its efforts to reduce SAIFI, which it believes is the SRI that provides its customers assurance of a dependable distribution system. As a result, NPDI's 2008 target for SAIFI will be consistent with the 2007 level and NPDI expects to lower SAIDI in 2008 and future years.

SHARED SERVICES

NPDI is owned by Norfolk Power Inc., a holding corporation owned by Norfolk County, which is its sole shareholder. The holding company also owns Norfolk Energy Inc.

Discussion and Submission

Board staff seeks clarification on the arrangement between NPDI and Norfolk Power Inc.

VECC and SEC in their respective Submissions, had no comments related to this issue.

Norfolk Power Inc. charges NPDI and Norfolk Energy Inc. an annual management fee (cost based) to fund its' operating and governance expenditures.

With respect to services rendered to Norfolk Power Inc. from NPDI, the activities performed are limited to accounting and finance. Staff of NPDI produce quarterly and annual financial statements on behalf of Norfolk Power Inc. These costs are considered immaterial to the overall operation of NPDI.

A shared services arrangement does not exist between Norfolk Power Inc. and NPDI.

PAYMENTS IN LIEU OF TAXES

Discussion and Submission

VECC and SEC believe the change in federal corporate income tax should be reflected in NPDI's PILS allowance. Also, VECC submits that NPDI's CCA calculations for 2008 should be updated to reflect the fact that there are computer equipment/software investments taking place in that year.

Board staff had no comments related to this issue.

NPDI will make the necessary adjustments to reflect CCA calculations for computer equipment/software investments and will recalculate Payment in Lieu of Taxes with the most recent tax legislation at the time final rates are determined.

CONSERVATION AND DEMAND MANAGEMENT

Discussion and Submission

Board staff is seeking clarification whether:

1. NPDI will spend the $68,612 past the Board approved extension of March 31, 2008; and
2. The $68,612, which NPDI identified as Third Tranche funding, and thus already included in rates, is captured in NPDI's 2008 revenue requirement

All Third Tranche funds will be spent by March 31, 2008 in accordance with the Board decision dated August 23, 2007 (EB-2007-0690). Also upon further investigation, the $68,612, which NPDI identified as Third Tranche funding, is already included in previous rates, as per Board File No. RP-2005-0013/EB-2005-0056.

NPDI will make the necessary adjustments at the time final rates are determined, to exclude the $68,612 from Community Relations account 5415 – Energy Conservation, from the 2008 Electricity Distribution Rates.

LOAD FORECAST

Discussion and Submission

Board staff have submitted that:

> *"The Applicant's forecast shows a 2.2% annual average kWh load growth from 2006 to the 2008 Test Year. This compares with an average annual kWh load growth of 2.9% during the 2002 to 2006 period. Given the historical relationship between customer growth and kWh growth, the forecasted kWh growth is not inconsistent."*

NPDI agrees that on a weather normalized basis the forecast does show a 2.2% annual average kWh load growth from 2006 to the 2008 Test year. On an actual weather basis the average annual kWh load growth during the 2002 to 2006 period is 2.9%. NPDI suggests the weather normalization process is causing the two different growth rates. However, when the 2008 total kWh normalized forecast of 405,124,879 kWhs is compared to the actual 2006 kWhs sold of 381,731,650 the growth rate over two years is 6.1% which is a 3.0% annual growth rate.

When NPDI was preparing the rate application it reviewed the normalized forecast for 2007 and 2008 and compared it to the actual 2006 amount to determine the reasonableness of the forecast. NPDI determined the annual growth rate was 3.0% per year which was consistent with the growth rate from 2002 to 2006. As a result, NPDI believes the forecast is reasonable and no further adjustment should be made.

In response to VECC's submission regarding the GS >50 kW for 2007, the method used to forecast the weather normalized amount for this class produced a higher forecast than it would have been if the 2004 NAC was used. The 2004 NAC for this class is 922,534 kWh/customer. The NAC used for the GS > 50 kW class forecast was 1,076,451 kWh/customer. This NAC is 16.7% higher than the 2004 value and represents the 2006 actual kWh/customer multiply by 1.0042. The 1.0042 factor is the 2004 weather normalized amount for the GS >50 kW class divided by the actual amount for 2004. In Norfolk Power's view this forecast appears to be more reasonable based on recent experience. Reverting to the 2004 value would mean the proposed volumetric rates for the GS >50 kW class would increase by 16.7%.

REVENUE TO COST RATIOS AND COST ALLOCATION

Discussion and Submission

NPDI agrees with Board staff's submission on Revenue to Cost Ratios. The gap for Street Lighting between current ratio and the lower end of the target range has been reduced by 60% The gap for Sentinel Lighting has been reduced by 54%. NPDI submits this is a reasonable movement in the revenue to cost ratios for this application considering the bill impacts. NPDI also submits it would be unreasonable to move to a full 100% revenue to cost ratio for Street Lighting at this time as suggested by SEC as the bill impacts would be alarming.

With regards to the VECC submission on cost allocation, NPDI agrees that when the cost of the transformer allowance has been allocated directly to the GS > 50 kW class the resulting revenue to cost ratio would have been below 100% As a result, NPDI submits that all revenues derived from adjusting the revenue to cost ratios for Street Lighting, Sentinel Lighting and USL should be applied to the Residential Class.

The following outlines the rationale for $7,414,481 being consistent with a 100% revenue to cost for the Residential Class. In the cost allocation model the costs assigned to the Residential Class represented 60.68% of the total revenue requirement before adjustment for Revenue Offsets. This also represents what the revenue would be at a 100% revenue to cost ratio. In this application the total revenue requirement is $12,800,353 and 60.68% of this number is $7,767,449 However the total revenue requirement includes Revenue Offsets and CDM amounts. In the cost allocation model, the Residential class was assigned 67.75% of the Revenue Offsets and when this is applied to the Revenue Offsets in this application of $464,000 the result is $314,356. The CDM assigned to Residential class in this application is $38,612. Consequently, the base Residential revenue requirement which represent a 100% revenue to cost ratio is $7,767,449 minus $314,356 minus $38,612 which is $7,414,481.

RATE DESIGN

Discussion and Submission

NPDI agrees with Board staff that the proposed rates essentially represent the status quo with respect to cost causation. The matter of distribution rate design is currently being studied by the Board in consultation with the industry and stakeholders (EB-2007-0031). It is NPDI view that it would not be reasonable to move current fixed/variable split until the Board has completed this consultation.

In addition, as outlined in response to VECC 34 c), it is NPDI'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. This position is supported in the recent OEB Decisions on 2008 cost of service rates for Barrie Hydro, Hydro 2000, Halton Hills Hydro and Oshawa PUC Network as it appears to NPDI that the Board did not stipulate a ceiling on the monthly service charge.

RETAIL TRANSMISSION RATES

Discussion and Submission

At the time of preparing the application, NPDI attempted to adjust its Retail Transmission Rates with the best information it had available. NPDI agrees with Board staff that further changes should be made to reflect the cost of transmission that Hydro One expects to charge NPDI. In addition, as suggested by VECC changes to the working capital allowance should be made to reflect the lower transmission charges from the IESO and Hydro One.

DEFERRAL AND VARIANCE ACCOUNTS

Discussion and Submission

NPDI has requested rate riders for all customer classes to dispose of its Deferral and Variance account balance as forecasted in the application.

Board Staff provided comments on the Deferral and Variance Accounts calculated by NPDI and seeks clarification on the following issues:

1. Accounting for variance accounts in general and specific comments regarding accounts 1508, 1525, 1586 and 1590
2. Request for New Deferral Account
3. Carrying Charges
4. Treatment of Account 1572

VECC and SEC in their respective Submissions, had similar comments related to this issue.

Deferral and Variance Accounts

NPDI accounts for Deferral and Variance accounts in a manner that is consistent with the rules and guidelines specified in the Board's Accounting Procedures Handbook. This is further confirmed by unqualified opinions from previous yearend audits.

NPDI has applied for 2008 rates on a forward test year basis and has forecast its Deferral and Variance accounts in the same manner. While forecasting of principal and interest on Deferral and Variance accounts has not been implemented in the electricity utility sector, NPDI believes that this is the appropriate means to dispose of these balances. If the proposed Deferral and Variance account rate (over)/under recovers, then it is held in the variance account for disposition at the time of the next rate application.

NPDI has correctly calculated the amounts of the Deferral and Variance accounts as presented in the 2008 EDR Application. Differences highlighted by Board staff can be easily reconciled and corrected by a journal entry, if required.

Treatment of Carrying Charges

NPDI used the interest rate of 4.59% to calculate carrying charges for the deferral and variance account balances as at December 31, 2006. At the time of filing the 2008 EDR application, the prescribed interest rate was 4.59%. NPDI believes this rate was fair and reasonable, given the fact that the prescribed rate of interest for the last quarter of 2007 and first quarter of 2008, was 5.14%.

Treatment of Account 1572

Board Staff provided the following comments on the Treatment of Account 1572 calculated by NPDI:

1. For expenses incurred, the total expenses on a per event basis must be at least 0.2% of total distribution expenses before taxes. Capital costs will be considered material if, on a per event basis, they are at least 0.2% of net fixed assets. On a per event basis, the $161,763 January storm costs represent 0.42% of net fixed assets, while the $37,971 June storm costs represents 0.10% of net fixed assets. Therefore, under this principal, the June storm does not meet the materiality threshold.
2. There has been no independent verification of the costs claimed. The usual practice for disposing of variance and deferral accounts in the electricity sector is to use the most up-to-date audited balances, as supported by audited financial statements
3. NPDI did not provide any information in its reply to Board staff IR#43 that the damage inflicted on their systems by these two extraordinary events is genuinely incremental to its experience or reasonable expectations.

VECC and SEC in their respective Submissions, had similar comments related to this issue.

NPDI provides for storm damage in its annual O&M budget and is based on historical data. Storms in Norfolk County are typically created by wind and ice, causing minor system outages and customer interruptions, for which NPDI has the internal resources to respond and restore power on a timely basis. The two storms NPDI is requesting recovery were not typical because the damage was excessive and NPDI required outside assistance to restore power. NPDI believes it has demonstrated that the costs meet the four eligibility criteria established in of the 2000 Electricity Distribution Rate Handbook and the guidelines of the APH Article 480. The criteria are: causation, materiality, inability of management to control and prudence.

At the time the 2008 EDR application was prepared, NPDI was under the understanding that both storms would be combined to meet the Board's materiality threshold. Based on the information provided by Board staff, NPDI agrees that the storm costs from June 2007 should be excluded from Account 1572 recovery.

NPDI understands the Board's position that the usual practice for disposing of variance and deferral accounts in the electricity sector is to use the most up-to-date audited balances, as supported by audited financial statements. NPDI is pleased to inform Board staff that the 2007 audit has been performed and NPDI has received an unqualified opinion on its financial statements.

Request for New Deferral Accounts

Future Capital Projects Deferral Account

NPDI requested the approval of the new deferral account for capital works during the non-rebasing years as suggested in the Board's *Filing Requirements for Transmission and Distribution Applications*, issued November 14, 2006, Chapter 2, Section 2.0 Preamble, Page 7, the last paragraph in the section 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"*

It was NPDI's understanding that in order to address the lost revenue requirement that occurs on capital investments placed in service in non-rebasing years the OEB was suggesting in the filing requirements that a distributor may apply for a deferral account for capital works during the non-rebasing years.

NPDI understands this deferral account is analogous to including a capital investment factor in an IRM year. NPDI also understands that a capital investment "Z factor" approach has been suggested in the Staff Discussion Paper on 3rd Generation Incentive Regulation for Ontario Electricity Distributors dated February 28, 2008. However, as stated in the staff submission:

> "*The mechanistic calculation for 3rd Generation IRM has not been finalized, as it is currently before the Board, and may include a capital component."*

It is NPDI's position that as of the date of this submission, the Board has not approved the capital component in the 3rd Generation IRM and it is only prudent for Norfolk Power to request the establishment of new deferral account for capital works during the non-rebasing years.

VECC and SEC have both submitted that there is no justification to allow NPDI to address any over/under forecasting of 2008 capital costs with this capital works deferral account. Norfolk Power would like to point out that our response to 38 h) was based on the working of question which is as stated:

38 (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?

It would appear to NPDI that this question suggested it would be preferable to NPDI to include any under-forecasts or over-forecasts of the 2008 capital costs in this deferral account as there was only a need to provide a rationale for not doing this. A rationale for doing it was not required. As a result, NPDI assumed the Board would look more favourable on establishing this deferral account if the under-forecasts or over-forecasts of the 2008 capital cost was included in the capital work deferral account and thus responded to 38 h) in the affirmative.

LINE LOSSES

Discussion and Submission

In order to prepare this reply submission, NPDI has once again revisited how losses are handled particularly in the case of an embedded distributor. NPDI has found that this topic is confusing with many in the industry but has attempted to explain its position based on the information currently known. NPDI believes the DLF includes the losses from Hydro One Networks Inc. (“HONI”) and Haldimand County Hydro (“HCH”). In simple terms, the DLF is the factor that results from dividing the wholesale kWhs by the retail kWhs. The retail kWhs is the billed amount which is the easy part of the equation. However in the case of wholesale kWhs this includes the wholesale kWhs purchased directly from the IESO for those points where that are directly connected to the transmission grid. It also includes the amount purchased from the IESO that moves through HONI and HCH.

For the amount that moves through HONI and HCH, the IESO measures the kWh at the boundary of HONI and NPDI as well as the boundary of HCH and NPDI. The IESO takes this amount and uplifts for losses on HONI and HCH and then includes the resulting amount in the wholesale kWhs for NPDI. Based on this, it is NPDI’s understanding that the wholesale kWhs includes directly connected kWhs but also kWhs at the point HONI and HCH are directly connected to the transmission grid. This means losses on HONI and HCH are included in the wholesale kWhs. When this amount is divided by the retail kWhs, the losses on the HONI and HCH system are included in the resulting factor.

LOW VOLTAGE

Discussion and Submission

At the time of preparing the application, NPDI attempted to adjust its Low Voltage charges with the best information it had available. NPDI agrees with Board staff that a final reconciliation should be made to reflect the Hydro One application EB-2007-0681, currently with the Board when final rates are determined.

COST OF CAPITAL

Discussion and Submission

Capital Structure

NPDI agrees with Board staff that the deemed capital structure for rate-making purposes will be 53.3% debt, composed of 49.7% long-term debt and 4.0% short-term debt, and 46.7% equity, as presented in the Board Report.

Long-term Debt Rate

Board staff is seeking clarification on a number of issues:

1. classification of the $2 million operating loan as long-term debt
2. Debenture to Haldimand County, which matures in 2008, interest expense was excluded.

At the time the application was prepared, NPDI was in negotiation with TD-Canada Trust. The loan has since been approved as long-term debt. With respect to the debenture from Haldimand County, NPDI discovered the interest expense was erroneously excluded from the calculation in the 2008 EDR model. In response to cost of debt, the information has been revised in the table below.

Board staff, VECC and SEC have asked for clarification with respect to the weighted average cost of debt of 6.70% for NPDI in 2008. In preparing this submission NPDI has reviewed the debt cost that support the 6.70% and discovered an error was made in the calculation. NPDI has revised the calculation and the updated weighted average cost of debt is 6.10% for NPDI in 2008 as shown in the following table.

	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 - Interest Expense included	388,421	5.13%	19,926	
Haldimand County - Amortization of Debt Discount			3,044	
Operating Loan - Reclassified	2,000,000	6.17%	34,822	
	$17,084,421		$1,042,409	
Short-Term Debt				
None	$0	0.00%	$0	
	$0		$0	
	$17,084,421		$1,042,409	6.10%

SMART METERS

Discussion and Submission

Board staff seeks comments on the following issues:

- NPDI's proposal to incorporate the smart meter capital expenditure amount of $4,061,000 [the components of which according to NPDI meets the "minimum functionality" criteria] into rate base and the associated return & depreciation into its revenue requirement is acceptable, when it could recover its smart meter costs by continuing its current rate adder of $0.26;

- NPDI's proposed smart meter OM&A cost of $362,000 [the components of which according to NPDI meets the "minimum functionality" criteria] is acceptable;

- Disposal of the credit balance of $40,417 in the smart meter deferral account by deducting it from the 2008 smart meter revenue requirement.

VECC had similar comments related to this issue and SEC took the position that Smart Meter expenditures should continue to be recorded in the appropriate deferral account and recovered through a rate adder.

While NPDI is not a utility named in the EB-2007-0063 proceeding, NPDI supports the direction of the Ministry of Energy with respect to the implementation of the Smart Meter program. Recognizing that NPDI has not yet received approval to proceed with Smart Meter deployment, NPDI agrees with VECC and SEC that the Board should approve a Smart Meter Rate adder and continue to use the related deferral/variance accounts for 2008.

Also, NPDI agrees with VECC in their final response #7.7, which states:

the setting of appropriate Smart Meter rate adder should be a two step process. First, the correct rate adder should be established assuming all Norfolk's smart meters are deployed in 2008. Then, this value should be discounted to recognize the uncertainty associated with Norfolk actually being authorized and able to complete deployment of its smart meters by the end of 2008. As to the appropriate "discount factor" while it is a matter of judgement VECC submits that the rate adder should be set at somewhere between 50% and 75% of the annual cost associated with full deployment in 2008.

In the event that NPDI is allowed to undertake Smart Meter activities in 2008, NPDI agrees with Board staff that the credit balance of $40,417 in the smart meter deferral account, be deducted from the 2008 Smart Meter revenue requirement.

Summary of Submission

NPDI's 2008 EDR application proposes a 2008 Revenue requirement of $12,800,352, from which just and reasonable distribution rates have been calculated. The application is supported by a substantial record that includes pre-filed evidence and responses to interrogatories.

NPDI has focussed its submission primarily on those issues identified by Board staff and the Intervenors, and has provided additional information where requested. NPDI is under the assumption that all other aspects of the application that have not been addressed in their submissions are acceptable for the purposes of setting rates.

NPDI is seeking Board approval of the rates as applied for, subject to the changes that NPDI has proposed or agreed to in this submission.

All of which is respectfully submitted,

(original signed)

Alvin E. Allim
Manager of Finance

APPENDIX A

NORFOLK POWER DISTRIBUTION INC.
ASSET MANAGEMENT FLOW CHART