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VT INCEPIT FIDELIS SIC PERMANET
Ontario

BY EMAIL

March 20, 2008

Ontario Energy Board
P.O. Box 2319
27th. Floor
2300 Yonge Street
Toronto ON M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: Norfolk Power Distribution Inc. – 2008 Electricity Distribution Rates
Board Staff Submission
Board File No. EB-2007-0753

Please find attached Board staff's submission for the above proceeding for distribution to the applicant and any intervenors.

Yours truly,

Original signed by

Adrian Pye
Case Manager

c. Mr. B. Randall, Norfolk Power Distribution Inc.
Intervenors.

Encl.

ONTARIO ENERGY BOARD

STAFF SUBMISSION

2008 ELECTRICITY DISTRIBUTION RATES

NORFOLK POWER DISTRIBUTION INC.

EB-2007-0753

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. The Applicant currently delivers electricity through a network of over 573 kilometers of overhead wires, through transformer stations, to approximately 18,500 customers in residential and general service classes. The Applicant asserts that a determining characteristic of the system is that it serves a large geographic area resulting in a large length of line per customer.

The Applicant submitted an application for 2008 electricity distribution rates on November 16, 2007. The application was based on a future 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”).

These submissions reflect observations and concerns which arise from Board staff’s review of the pre-filed evidence and interrogatory responses made by the utility, and are intended to assist the Ontario Energy Board (the “Board”) in evaluating NPDIs application and setting reasonable and just rates.

THE APPLICATION

NPDI has requested a revenue requirement of $12,800,352 to be recovered in new rates effective May 1, 2008. The revenue deficiency for 2008 has been calculated at $2,925,795.

OM&A

The Applicant’s Summary of Operating Costs is found at Exhibit 4, Tab 2, Schedule 1, Pages 1 through 6 of its application. The as-filed test year Total Controllable OM&A Expenses forecast is $4,943,872. This results in a 30%, or $1,146,216, increase compared to the 2006 actual level.

Discussion and Summary

Overall OM&A

Board staff notes that the 30% increase in controllable OM&A expenses that has been requested by NPDI for the 2008 test year, relative to the 2006 actual level, is one of the higher percentage increases requested to date by any of the utilities that have filed cost of service applications with the Board for 2008 rates.

Using the Summary as its base, Board staff created two different tables and asked interrogatories concerning each table to clarify the drivers of this increase. NPDI confirmed the accuracy of each of the tables through their response to Board Staff interrogatory response 23.

Table 1 summarizes the key components of NPDIs operating costs for the 2006 Board approved and actual, 2007 Bridge and 2008 Test years.

Table 2 highlights the significant sources of variance for controllable expenses.

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

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
		8.2%		3.3%		0.2%		3.5%
Maintenance	747,613	-106,207	641,406	283,594	925,000	8,326	933,326	291,920
		-2.8%		7.5%		0.2%		7.7%
Billing and Collections	856,868	-42,677	814,191	129,809	944,000	8,497	952,497	138,306
		-1.1%		3.4%		0.2%		3.6%
Community Relations	24,718	-549	24,169	3,831	28,000	252	28,252	4,083
		0.0%		0.1%		0.0%		0.1%
Administrative and General Expenses	1,459,232	-214,367	1,244,865	202,135	1,447,000	375,023	1,822,023	577,158
		-5.6%		5.3%		8.3%		15.2%
Total Controllable OM&A	3,845,953	-48,297	3,797,656	743,344	4,541,000	402,872	4,943,872	1,146,216
		-1.3%		19.6%		8.9%		30.2%
Amortization Expenses	2,381,357	-563,579	1,817,778	813,350	2,631,128	205,682	2,836,810	1,019,032
4750-LV Charges	371,652	-140,266	231,386	140,266	371,652	0	371,652	140,266
5415-Energy Conservation	563	125,203	125,766	-57,766	68,000	612	68,612	-57,154
6105-Taxes Other Than Income Taxes	67,981	-1,611	66,370	18,630	85,000	765	85,765	19,395
Total O M & A	6,667,506	-628,550	6,038,956	1,657,824	7,696,780	609,931	8,306,711	2,267,755
		-16.3%		43.7%		13.4%		37.6%

In response to Board staff interrogatory 23, NPDI provided a cost driver review table to explain the increases in Total Controllable OM&A expenses identified above. Board staff note that the accounts shown in the table below account for the majority of this increase (over 85%):

Account	$ 2008/2006 Increase	% 2008/2006 Increase
5695 – Smart Meter OM&A Contra	362,000	N/A – 0 in 2006
5010 – Load Dispatching	123,841	69%
5315 – Customer Billing	91,379	22%
5114 – Mait. Of Dist. Stn Equip.	85,485	156%
5655 – Regulatory Expenses	67,971	244%
5110 – Mait. Of Build. & Fix. – Dist St.	64,368	828%
5615 – G & A – Sal. & Exp.	64,331	16%
5105 – Mait., Sup. & Eng.	62,350	135%
5335 – Bad Debt Expense	57,910	92%

<u>Smart Meter OM&A Contra</u>

Staff's submission on this cost driver is contained in the smart meter section of this submission.

<u>Load Dispatching</u>

The Applicant identifies the driver for this increase as “Contract Operator + New Operator in Training”. Staff’s submission on NPDIs employee compensation costs is contained in the following section.

<u>Customer Billing</u>

The Applicant identifies the driver as “Increase allocation of IT of $51,666 + $64,472 increase in labour.”

<u>Maintenance of Distribution Station Equipment</u>

The Applicant identifies “Repair transformer oil leaks, PCB testing and removal” as the driver for this increase.

<u>Regulatory Expenses</u>

The Applicant identifies in response to Board staff interrogatory 23.c that it has included in regulatory expenses for 2008 the amount of $28,855 of non-OEB costs which are unexplained. It remains unclear to Board staff if this amount will be required in future years. Board staff invites parties to provide comments on this issue in their respective submissions.

<u>Maintenance of Building & Fixtures – Distribution Station</u>

The Applicant identifies as the driver for this increase “Various substations require structural repairs and Maintenance.”

<u>General Administrative Salaries and Expenses</u>

The Applicant identifies as the driver for this increase for 2007 as “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” and for 2008: “3% inflationary increase.”

<u>Maintenance Supervision and Engineering</u>

The Applicant does not provide an explanation for the increase of $62,350 in this account in the 2008/2006 period.

Bad Debt Expense

The Applicant states that its bad debt expense, which has increased by 92% over the two-year period 2008/2006, is "as per bad debt analysis." The Applicant provides additional details on this increase in its response to Board staff interrogatory 23d and provides its plan to manage the increase in bad debt expense. However, the Applicant has not explained why such a large increase in the expense is necessary, especially given the measures it plans to undertake to improve collections.

Office Supplies and Expenses

The Applicant states that this increase for 2007 is due to "$11,000 for Tower Rental Space for the radio system" and for 2008 is due to "Increase in rental costs of Tower for radios."

Board staff notes that NPDI is proposing a 30% increase in its controllable OM&A costs, but NPDI has minimal or no explanation with respect to the key components of the increase. The Applicant is invited to clarify its justifications for these increases in its reply submission by referring to material in its 2008 EDR application already filed with the Board. Other parties to this proceeding are also invited to address the proposed increase in their submissions.

Increase in Compensation and Staffing

Board staff prepared Table 3 to summarize the information on labour costs provided in Exhibit 4/Tab 2/Schedule 7.

Table 3

	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
Compensation	$ 2,812,892	$ 3,062,122	$ 3,253,685	$ 3,124,459
Pension and Benefits	$ 677,704	$ 765,044	$ 867,000	$ 949,631
Incentive Pay	$ -	$ -	$ -	$ -
Total Compensation	$ 3,490,596	$ 3,827,166	$ 4,120,685	$ 4,074,090
Capitalized	$ -	$ 2,296,105	$ 2,396,232	$ 2,418,127
OM&A	$ -	$ 1,531,061	$ 1,724,453	$ 1,655,963
Total Compensation	$ 3,490,596	$ 3,827,166	$ 4,120,685	$ 4,074,090
Capitalized	-	60%	58%	59%
OM&A	-	40%	42%	41%

The Applicant's response to Board staff interrogatory 20 does not clarify where total compensation costs were charged in the 2006 Board approved year. Accordingly, Board staff has left these columns blank in the tables in this section.

In response to Board staff interrogatory 10, NPDI confirmed that it has not made any changes to its capitalization policies or estimates. This is shown in the consistency of the above percentage splits from the 2006 historical year to the 2008 test year.

In comparing the distributor's labour costs to Total Controllable OM&A, Board staff notes that Labour is, on average, approximately 37% of operation costs as indicated in Table 4.

Table 4

		2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
OM&A Labour	A	$ -	$ 1,531,061	$ 1,724,453	$ 1,655,963
Total Controllable OM&A Expenses	B	$ 3,845,953	$ 3,797,656	$ 4,541,000	$ 4,943,872
Labour as a percent of OM&A	C = A / B	-	40.3%	38.0%	33.5%

Board staff prepared Table 5 to identify the final value of labour cost drivers to be used in the following cost driver analysis table.

Table 5

	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
OM&A	$ -	$ 1,531,061	$ 1,724,453	$ 1,655,963
Annual Labour Changes		$ -	$ 193,392	-$68,490
% Change		-	11.2%	-4.1%

From Table 5, the significant variance is the 11% increase in the 2007 bridge year. One of the key components of this increase is the two-year increase in average Executive and Management benefits of 13% and 15% respectively. In response to Board staff interrogatory 16, which asked the Applicant to explain this increase, NPDI stated that the increase was due to annual cost of living adjustments of 3% and increases in health care premiums of 5%. In 2006, NPDI implemented a new benefit plan which has also increased Executive and Management benefits by 2%. Furthermore, the shifting of some employees from single coverage to family coverage and the hiring of 2 management positions has further increased average Executive and Management benefits.

The second major component of this increase is total Management salary and wages, which have increased by 34% from 2006 to 2008. In response to Board staff interrogatory 14, which asked the Applicant to provide test year data for 2008 and to explain any variances between 2007 and 2008 amounts, NPDI stated that there has been a 4% increase for Executive and Management employees related to progression and a 3% cost of living adjustment for inflation.

Parties may wish to comment on the reasonableness of the 13% to 15% increase to Executive and Management benefits respectively from the 2007 bridge year and the 34% increase in Management salary and wages from 2006.

SHARED SERVICES

As outlined in Exhibit 1 Tab 2 Schedule 6 Page 2, 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

The Applicant's evidence is not clear as to the extent and nature of shared services. In Exhibit 4 Tab 2 Schedule 3 Page 1, which is entitled "Shared Services", NPDI states that it provides water reading and billing services, water heating billing services, sentinel light billing services and sentinel light maintenance services to its affiliate Norfolk Energy Inc., but provides no further information on these services. In response to VECC interrogatory 6, which asked whether either Norfolk Power Inc. or Norfolk Energy Inc. provide services to NPDI, the Applicant stated that neither of these affiliates provides such services. In response to Board staff interrogatory 13, the Applicant states that "Shared services does not exist between NPDI and Norfolk Power Inc." With reference to the evidence noted above in Exhibit 4, Board staff invites NPDI to clarify the arrangement between NPDI and Norfolk Power Inc.

RATE BASE

Background

The average rate base for 2008 is projected by the Applicant to be $50,449,606 compared with $44,797,683 for 2007 (up 12.6%, smart meters included) and with $42,046,838 for 2006 actual (a 2006-2007 inter year rise of 6.4%). The Applicant projects a 2008 capital expenditure level of $10,189,600 for 2008 (or $5,938,600 without smart meters). Table 1 provides the rate base comparisons and the capital expenditure comparisons for those years. Annual capital expenditures between 2002 through 2007 average about $5.4 million per year (calculated from response to Board Staff interrogatory 2).

Table 1:

	2006 (Actual)	2007	2008 - Projected
Capital Budget	$5,049,756	$5,620,200	$10,189,600 (or $5,938,600 without smart meters)
% of increase as compared to the prior year	-	+11.3%	+81.35% (or +5.7% without smart meters)
Rate Base (average)	$42,046,838	$44,797,683	$50,499,606 (or calculated as $48,374,106 without smart meters)
% of increase as compared to the prior year	-	+6.5%	12.7% (or +8.0% without smart meters)

Discussion and Submission

Board staff notes that the rate base aspects of the application (supplemented by some interrogatory responses) were essentially complete. However, 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.

In response to Board staff interrogatory 8, sections (d) and (e) in particular, NPDI provided no data on reliability performance, target reliability standards, risk criteria, and financial impact for those projects justified broadly as being undertaken for reliability improvement purposes. The Applicant is invited to clarify its justifications for renewal projects and direct staff to material already filed with the Board in its application, if any, in support of its submissions with respect to this issue.

Furthermore, with respect to Board staff interrogatory 9 requesting reliability statistics for 2002 through 2007 as well as an example of a typical study justifying station capital upgrades resulting from reliability considerations, the Applicant's submissions were non-responsive. The Applicant is invited to direct Board staff to material already filed with the Board in its application, if any, containing the requested statistics and study.

INCREASE IN 2008 CAPITAL EXPENDITURES

Background

The information provided in Table 2 below is based on NPDIs response to Board staff Interrogatory 2.

Table 2

	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 (%)							
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	68,807	26,240	110,204	74,652	43,002	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

This Table demonstrates that capital expenditures in 2008 are expected to be considerably higher than the historical values, not only because of the addition of the proposed smart meter program of $4.25 million, but also because of a $5.94 million capital program. The annual capital expenditure from 2002 through 2007 averages $5.41 million. Therefore the "regular" capital program projected for 2008 is 9.8% higher than the trailing 6 year average and 6.5% higher than 2007. Project costs areas where 2008 capital costs are expected to each exceed $1 million and where increases above 2007 levels are expected are: customer demand related projects (up 5.3%); facilities renewal (up 7.4%) and station work (up 26.5%). All figures were derived from Exhibit 2/ Tab 3/ Page 2/ Table 1.

Discussion and Submission

As discussed previously, Board staff interrogatory 8 and interrogatory 9 requested information on facilities renewal projects and station work, as related to actual and target reliability, in order to identify trends that could justify increasing capital expenditure for renewal and station upgrades. Insufficient information was provided to allow Board staff to determine if and how reliability indicators are used to develop and undertake capital projects and the reliability targets expected to be achieved as a result of these projects. The Applicant is invited to clarify its justification for such facilities renewal and direct Board staff to material already filed with the Board in its application, if any, in support of such clarifications.

Board staff interrogatory 7 requested information on customer demand projects, including Profitability Index ("PI") calculations, in order to assess the economic advantages, burdens or required capital contributions affecting the revenue requirement resulting from these mandatory connections. No PI calculations were provided and the Applicant is invited to direct Board staff to any material already filed with the Board in its application, if any, containing the requested information.

<u>Reductions to Rate Base</u>

In response to Board staff interrogatory 6 (ii) concerning the inclusion of a $120,000 deposit for a transformer to be purchased, but not expected to be in service in 2008, the Applicant agreed that this should be excluded from the 2008 rate base.

Smart Meters

The Applicant has included an amount of $4.25 million in its 2008 capital expenditure projection. Please refer to staff's submission on smart meters further in this submission.

Service Reliability Indices

Reliability data was supplied by NPDI in response to Board staff IR #9, which is reproduced in the following table:

Service Reliability Indicator	2002	2003	2004	2005	2006
Annual SAIDI	21.1	1.3	2.0	2.2	2.2
Annual SAIFI	0.0	1.3	3.8	2.2	2.2
Annual CAIDI	n/a	1.0	0.1	1.0	1.0

The Applicant reports a SAIDI of 21.1 hours for 2002 but states that the annual value for 2002 SAIFI is 0. Zero value for SAIFI cannot be a correct figure if NPDI experienced 21.1 customer hours of interruptions duration in 2002. Furthermore, the 2004 CAIDI figure also does not seem to be correct, as CAIDI is the ratio of SAIDI to SAIFI which yields a value of 0.52 rather than 0.1, based on figures supplied by NPDI. Board staff also notes that the SAIDI and SAIFI for 2003, 2005, and 2006 are the same and that the reliability indicators for 2005 and 2006 are also the same. Board staff invites the Applicant to clarify if the reliability performance indicators that it reported for the 2002-2006 period are correct, or if the Applicant has made methodological and/or calculation errors in deriving the values for these indicators.

Furthermore, NPDI did not confirm its 2008 reliability targets. The Applicant advises that the capital projects were undertaken because equipment was at end-of-life, and it might have been expected that this would be reflected in deteriorating reliability. The data provided is insufficient to evaluate whether NPDI applied an appropriate method that utilized reliability performance indicators for development, evaluation, and prioritization of 2008 capital projects. The Applicant and other parties are invited to comment on this matter in their submissions.

<u>Asset Management Plan</u>

In response to Board staff interrogatory 6, NPDI advised that it does not have an asset management plan, but it provided a listing of the prioritizing for deployment of capital expenditure. The Applicant indicated that reliability standards are one of the criteria, but it did not expand on how it utilizes the reliability indicators in prioritizing capital expenditures. The Applicant also advised in its response to VECC interrogatory 9(o) that it makes use of equipment assessments by a 3rd party contractor as well as its own engineers and technicians. No further information on these assessments was provided. Parties may wish to comment on whether or not the Applicant should develop a formal asset management plan.

COST OF CAPITAL

Background

With respect to the Cost of Capital, NPDIs application, as clarified and corrected on the record, and subject to Board staff's comments on the capital structure and long-term debt below, complies with the Board's guidelines for Cost of Capital for the purposes of electricity distribution rate-setting.

The Board has documented its guideline Cost of Capital methodology in the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Board Report"), issued December 20, 2006. The Board Report is a guideline, but departures from the methodology in the Board Report are expected to be adequately supported.

The Applicant has provided its proposed Cost of Capital in Exhibit 6, which is summarized in the table below:

Cost of Capital Parameter	NPDIs Proposal
Capital Structure	53.3% debt (composed of 49.3% long-term debt and 4.0% short-term debt) and 46.7% equity.
Short-Term Debt	4.77%, to be updated in accordance with section 2.2.2 of the Board Report.
Long-Term Debt	6.70%, as the weighted average of all of The Applicant's long-term debt instruments in 2008. Clarification on The Applicant's long-term debt and the derivation of this rate was sought, as is discussed below.
Return on Equity	8.68%, but to be updated in accordance with the methodology in Appendix B of the Board Report.
Return on Preference Shares	Not applicable
Weighted Average Cost of Capital	7.55% as proposed, but subject to change as the short-term debt rate and ROE are updated per the Board Report at the time of the Board's Decision.

The Applicant's approach to cost of capital appears generally to be consistent with the Board Report. Board staff submits that NPDIs proposal, subject to Board staff's comments on capital structure and long-term debt which follow, is consistent with the Cost of Capital methodology in the Board Report.

Discussion and Submission

Capital Structure

The Applicant is proposing to comply with the guidelines in the Board Report and to transition to the general deemed capital structure of 60% debt and 40% equity for rate-making purposes. For 2008 this means that NPDIs 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.

While NPDI has rounded these percentages to two decimal places in its Application, Board staff understands that NPDI is proposing to adhere to the guidelines in the Board

Report. Staff invite NPDI to confirm in its reply submission whether or not it is proposing to use the percentages in the Board Report as documented above.

Long-term Debt Rate

The Applicant proposed in Exhibit 6 Tab 1 Schedule 1 and Schedule 3 that the long-term debt rate for 2008 should be 6.70%. Details on its debt instruments were documented in Exhibit 6 Tab 1 Schedule 3. However, the information presented was unclear, and interrogatories from both Board staff and VECC sought clarification.

Board staff is satisfied with the interrogatory responses NPDI provided that the rates of all of its debt instruments are consistent with the guidelines in section 2.2.1 of the Board Report. While Board staff understands the derivation of the proposed long-term debt rate of 6.70%, as provided in the responses to Board staff interrogatory 37 d) and VECC interrogatory 28 c), it is not clear that this accurately depicts NPDIs cost of long-term debt. In response to Board staff interrogatory 27 b), NPDI acknowledged that "the $2,000,000 loan classified as short-term debt "should have been disclosed as long-term debt."

However, in the response to Board staff interrogatory 37 d), the Operating Loan is portrayed as having an average balance of $562,842. Board staff invites NPDI to confirm if the Operating Loan shown is the $2,000,000, and if so, to reconcile the $2,000,000 principal and the $562,842 average balance. It is also unclear what NPDI is proposing with respect to the treatment of the amortization amount and the interest on the debenture maturing in 2008, as discussed in the response to Board staff interrogatory 37 c). The $3,044 amortization cost is included in the calculation of the 6.70% long-term debt rate but the interest expense is not.

Board staff observe that NPDI is consistent with the Board Report with respect to the rate for each debt instrument individually. However it is not clear that the proposed long-term debt rate of 6.70% accurately reflects the weighted average cost of debt for NPDI in 2008. Board staff invites NPDI to clarify the matter in its reply argument and direct Board staff to material already filed with the Board in its application, if any, in support of such clarification.

LOAD FORECASTING

Background

In Exhibit 3 of the Application, the development of the Applicant's customer count and load forecasts are discussed. Using a simple trend growth, the historical number of customers is projected based on 2002-2006 data (for most classes) to obtain both Bridge Year (2007) and Test Year (2008) customer counts by class. The kWh forecast – and the kW forecast for appropriate classes – is presented by customer class. Variance analyses are presented in support of the forecasts.

The Applicant provided additional information in response to Board staff and VECC forecasting interrogatories.

Discussion and Submission

<u>Methodology and Model</u>

The Applicant explained that as a result of the limited amount of data available, the slow growth and consistent trend in customer numbers in its service territory over the past five years, it had chosen to use a simple trend growth to determine the customer count forecast. The tabular data presented generally substantiated the Applicant's description of its customer growth. While various numbers of Street Lighting connections were reported in the application (Exhibit 3/Tab 2/Schedule 1/Page 2) and in the response to Board Staff interrogatory 28, the 2007 and 2008 forecasted values seemed reasonable.

Turning to its kWh volume forecasts, the Applicant explained that for its weather sensitive load, it first developed the normalized average use per customer ("NAC") by customer class; the NAC value by class was based on the 2004 load values that had been weather-normalized for the Applicant by Hydro One. The Applicant provided no explanation in Exhibit 3 as to how the 2004-based NAC was utilized to determine the 2007 Bridge Year and 2008 Test Year kWh and kW forecasts. The Applicant confirmed in response to Board staff interrogatory 26, that the 2004-based NAC was extrapolated into the future and the extrapolated value was adopted as the basis for the 2007 and 2008 customer count forecasts. The kWh loads for 2007 and 2008 were determined by multiplying the NAC by the number of forecasted customers. The Applicant confirmed this methodology as it relates to the GS > 50 kW class as well.

Board staff observes that the methodology chosen utilizes only a single year of weather-normalized historical load to determine the future load. Assuming that the NAC value remains constant over a number of years may not be a robust assumption. The effect of the constant assumption could be to over-estimate the weather sensitive load by a few percent and correspondingly underestimate the required rates.

The Applicant presented its kW forecast for those customer classes that use this charge determinant. No rationale is presented for the determination of these values.

<u>Weather Normalization</u>

The Applicant noted that Hydro One carried out the weather normalization that was performed, albeit only for the year 2004. It is not clear whether Hydro One used the weather normalization method approved by the Board in the Distribution Cost Allocation Review (EB-2005-0317) and Hydro One's own 2006 Distribution Rate case (RP-2005-0020/EB-2005-0378). The Applicant may wish to clarify this issue in its reply submission.

<u>Results</u>

The Applicant's forecast shows a 0.1% annual average growth in customer numbers from 2006 to the 2008 Test Year. This compares with an average annual customer growth of 0.2% during the 2002 to 2006 period. Board staff observes that forecast growth in customer numbers is fairly consistent with what one might expect based on the input data.

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.

LOW VOLTAGE

Background

The Applicant is partially embedded, and receives electricity through two host distributors, Hydro One Distribution and Haldimand County Hydro. The application includes $371,652 for the forecast Low Voltage ("LV") charges by the host distributors. While the actual cost in 2007 was $350,000 the previous year was a higher amount, and NPDI anticipates that the cost will return to the earlier higher level. (Response to Board staff interrogatory 54(b)).

The cost of LV service is included as a rate adder. (Response to VECC interrogatory 33(b)). The adder is based on an allocation to the classes proportional to total Retail Transmission Service revenues. (Response to Board staff interrogatory 54 (a))

Discussion and Submission

Staff notes that the forecast costs are consistent with the previously approved amounts. Staff notes that one of the host distributors, Hydro One, has an application currently with the Board that includes lower rates for the service currently called Shared Lines, EB-2007-0681. The final reconciliation, if the forecast is too high or low, is captured in a variance account.

The amounts allocated to each class are very close to what they would be if allocated with Retail Transmission Connection Service rates alone, which was the allocator used for the currently approved adder.

REVENUE TO COST RATIOS

Background

The Applicant proposes to change the proportion of distribution revenue from the respective classes, increasing the proportion from classes where the Informational Filing indicated a revenue to cost ratio less than 100% and decreasing the proportion from classes with a ratio above 100%. (Response to VECC Interrogatory 29(e)) The result of this re-balancing can be seen in the following table, by comparing columns 1 and 2. For ease of reference, the Board's target ranges are shown in column 3.

NPDI Revenue to Cost Ratios

%	Informational Filing Run 2 Col 1	Application: Exhibit 8 / Tab 1 / Schedule 2 / p. 2 Col 2	Board Target Ranges Col 3
Customer Class			
Residential	103.8	102.6	85 – 115
GS < 50 kW	96.0	99.1	80 – 120
GS 50 - 4999 kW	102.5	98.8	80 – 180
Street Lights	30.7	54.3	70 – 120
Sentinel Lights	19.6	47.0	70 – 120
USL	98.5	100.7	80 -- 120

Discussion

Board staff notes that two classes have proposed ratios that remain outside the Board's respective target ranges, both on the low side. Rebalancing the class revenues further, such that all classes would be within the target ranges would imply a decrease in rates to one or both of the classes that are within range but have ratios above 100%.

Board staff notes also that the re-balancing took the ratio for Unmetered Scattered Load past the neutral point. NPDI has pointed out that the over-correction is quite small in absolute terms (Response to VECC interrogatory 29(c)).

The Applicant proposes to raise 1.0% of its total revenue requirement from Streetlighting, compared to 0.5% at present. The result of this is that the revenue to cost ratio is increased from 30.7% to 54.3%, which closes the gap between the current ratio and the closer end of the target range by approximately 60%. The total bill impact on Streetlighting is calculated by NPDI to be 64.9% (Response to Board staff interrogatory 56(a)).

Similarly, NPDI proposes to raise 0.3% of its total revenue requirement from Sentinel Lighting, compared to 0.1% at present. The result of this is that the revenue to cost ratio is increased from 19.6% to 47.0%, which closes the gap between the current ratio and the closer end of the target range by approximately 54%. The total bill impact on Streetlighting is calculated by NPDI to be 40 - 45% (Response to Board staff interrogatory 56(a)).

RATE DESIGN

Background

The Informational Filing (EB-2007-0002) showed that NPDIs 2006 approved Monthly Service Charge was above the ceiling amount calculated by the model for all three of NPDIs main customer classes. The Applicant proposed to keep the proportions of revenue derived from fixed charges and volumetric charges unchanged from the status quo. In other words, the proposed increase to the monthly service charge and to the volumetric charge is identical within each class, though differing across classes per the re-balancing discussed in the previous section.

Discussion and Submission

The difference between the approved monthly fixed rate and the ceiling of the range in the Informational Filing is substantial for the two General Service classes: $41.37 compared to $25.41 for the GS<50 kW class, and $217.80 compared to $58.27 for the GS > 50 kW class. As the Applicant is maintaining the status quo proportions within each class, and the proportions across classes is changing by no more than 3%,it is likely that the gap between the proposed monthly service charge and the ceiling of the range is approximately the same (in percentage terms) as in the Information filing.

The matter is currently being studied by the Board in consultation with the industry and stakeholders (EB-2007-0031). The proposed rates essentially represent the status quo with respect to cost causation.

RETAIL TRANSMISSION SERVICE RATES

Background

The Applicant is a partially embedded distributor. It has filed detailed information on its transmission costs from all of its sources of delivery (IESO, Hydro One and Haldimand County Hydro) for the period May 2006 to September 2007 (Exhibit 9 /Tab 1 /Schedule 3).

Along with the detailed history, NPDI has provided an estimate of the IESO cost component at the wholesale rates that are approved to apply during the test year. Hydro One, one of the host distributors, has applied for changes in its Retail Transmission Service Charges (EB-2007-0681, Exhibit G1 /Tab 6 /Schedule 1 /Table 2 /ST Class), but the effect of any change to the Hydro One rates that would apply to NPDI has not been included in the cost estimate.

The same schedule in Exhibit 9 includes information on NPDIs billing revenues. It shows that Network costs and revenues were nearly equal, but that Connection revenues exceeded the cost by a margin of about 25%. The Applicants pro forma balance sheet shows an anticipated positive balance in the Network-related variance account 1584, at $49,582, and a negative balance in the Connection-related variance account 1586, at ($245,374). (Response to Board staff interrogatory 39)

Discussion and Submission

Board staff notes that the proposed Retail Transmission Network Service Rates are designed to correct for the forecast slight over-collection of Network cost that would occur if the retail rates were left unchanged. Similarly, the proposed Retail Transmission Connection Service Rates are designed to correct for the substantial over-collection of Connection costs that would occur in the absence of an adjustment. The proposed Network retail rate to each class is equal to 98% of the existing approved Network rate, presumably because the forecast Network cost would be 98% of the forecast revenue at existing rates. The proposed Connection retail rate for each class is 75% of the existing rate for the same reason.

Board staff notes that the price factors in the forecast of wholesale costs have not been adjusted for the electricity to be delivered through either of the host distributors. This is a valid assumption for the delivery through Haldimand County Hydro. It is more questionable for the delivery through Hydro One, as Hydro One has an application currently with the Board that would change the cost of transmission to NPDI.

Approval of new rates for Hydro One in its role as a host distributor would have a downward effect on about 1/3 of NPDIs wholesale cost of Network service, and on close to 1/2 of its wholesale cost of Connection service. The effect would be comparable to the adjustment that NPDI has made for the changes already approved by the Board for the rates charged by the IESO.

DEFERRAL AND VARIANCE ACCOUNTS

Background

The applicant is proposing to:

- Continue to use deferral and variance accounts
- Establish a new deferral account for future use
- Clear the balances of certain deferral and variance accounts to the accounts of the customers.

<u>Request for Disposition</u>

The Applicant is requesting that the following accounts and balances as per Exhibit 5, Tab 1, Schedule 3 and the response to Board staff interrogatory 42 be cleared for disposition as of December 31, 2006 balances plus interest to April 30, 2008. Account 1572 is an exception as it includes forecasted principal balances beyond December 31, 2006.

> 1518 RCVA – Retail, ($33,338)
> 1548 RCVA – STR, $49,135
> 1550 LV Variance, $9,162
> 1572 Extra–ordinary Event Losses, $207,739 (includes forecasted principal balances)
> 1580 RSVA – Wholesale Market Service Charge, ($19,464)

1584 RSVA – Retail Transmission Network Charges, $52,872
1586 RSVA – Retail Transmission Connection Charges, ($258,706)
1588 RSVA – Power, ($642,558)

Total: ($635,158)

The applicant's proposal is to collect these amounts from ratepayers over 3 years beginning May 1, 2008 via rate riders as per Exhibit 5/Tab 1/Schedule 3.

Discussion and Submission

Continuation of Deferral and Variance Accounts

The Board has already approved and defined, through the Accounting Procedures Handbook ("APH") and associated letters, the period and functionality of deferral and variance accounts in the electricity distribution sector. Therefore, it is not necessary for the applicant to request permission to continue using open deferral and variance accounts as per the APH.

Request for New Deferral Account

Future Capital Projects Deferral Account

The Applicant is requesting to establish a deferral/variance account on May 1, 2008 for capital works during the non-rebasing years to collect the revenue requirement costs associated with the cost of construction. It will record the cost of service associated with the new assets and will include depreciation and return but not Payments in Lieu of Taxes ("PILs").

Capital investment is necessary to keep the business a going concern and to maintain necessary reliability. Accordingly, a reasonable level of capital investment can be characterized as both prudent and outside management's ability to control.

Rate base does impact revenue requirement, satisfying causality. The Applicant did not provide the total expected costs or calculations in its response to Board staff interrogatory 38, so materiality cannot be determined.

Board staff notes that the request to establish this deferral account is analogous to including a capital investment factor in an IRM year. The mechanistic calculation for 3rd Generation IRM has not been finalized, as it is currently before the Board, and may include a capital component.

Board staff seeks comments as to whether NPDI has sufficiently justified the need for a new account. It would be helpful for parties to comment on the new account proposed and provide reasons.

Treatment of 1572

The Applicant is requesting disposition of Account 1572, Extra-ordinary Event Losses. In the response to Board staff interrogatory 43, NPDI elaborated that the principal balances in 1572 were caused by two storms in 2007 that resulted in damages to the system. A distributor is required to demonstrate 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.

The two storms were an ice storm in January 2007 which resulted in costs of $161,763 and wind storms in June 2007 which resulted in costs of $37,971. Since the costs were caused by extreme weather, the expenditures may be considered to be outside management's control.

As per the July 31, 2007 Decision EB-2007-0514, EB-2007-0595, EB-2007-0571, EB-2007-0551, and per the December 20, 2006 *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Board Report"), for extra-ordinary event costs, "amounts claimed will be considered material and therefore eligible for potential recovery if they meet a certain materiality threshold. 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." However, all parties including utilities in the EB-2007-0514, EB-2007-0595, EB-2007-0571, EB-2007-0551 proceeding agreed that the materiality threshold was too low. In this proceeding, the Board stated that it would "review the current materiality threshold in due course. In the meantime, the Board expects that distributors will exercise good judgement on whether or not claims should be filed, even if the costs incurred pass the materiality threshold."

The total amount requested for disposition as at April 30, 2008, including interest, is $207,739, which is 0.54% of December 31, 2006 net fixed assets. On a per event basis, the $161,763 January principal costs represent 0.42% of net fixed assets while the $37,971 June principal costs represents 0.10% of net fixed assets.

The proceeding further identified causation as a stand alone issue, namely, "the appropriateness of the storm damage cost claims relative to the value associated with the risk for this type of event that is currently imputed in each distributor's rates."

The Board noted in the EB-2007-0514, EB-2007-0595, EB-2007-0571, EB-2007-0551 decision that "generally, some measure of cost recovery for storm damage is already included in distribution rates for Ontario LDCs. However, since the Board does not have information relating to distributors' historic storm cost levels, distributors should make every effort to demonstrate that damage inflicted on their systems by extraordinary events is genuinely incremental to their experience or reasonable expectations." NPDI did not provide any information in its reply to Board staff interrogatory 43 that the damage inflicted on their systems by these two extraordinary events is genuinely incremental to its experience or reasonable expectations.

Finally, in response to Board staff interrogatory 43 NPDI stated that the balances requested for disposition have not been independently verified, although the Applicant stated that would be done as part of the 2007 year-end audit Board staff notes that in the natural gas sector, utilities do forecast principal and interest on deferral and variance accounts for disposition to the end of the current test year. However, generally, these forecasts do not exceed two or three months once the applicant provides an update before the decision is released. The forecasted balances are then trued up to the actual and any differences are placed in a deferral account for disposition at the next rate case. This approach has not been used for electricity distributors.

In the electricity distribution sector, it has not been Board practice to order disposition of unaudited balances on deferral and variance accounts. 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, plus forecasted carrying charges on those balances up to the start of the new rate year. The most recent NPDI balances that have been independently audited are the December 31, 2006 balances. Account 1572 is the only regulatory asset that NPDI is applying for disposition on a post December 31, 2006 principal balance. Forecasting principal balances would be inconsistent with the Board's previous usual practice in this sector.

Treatment of RSVAs

The Applicant is applying for disposition of RCVA and RSVA accounts. RSVA account 1588 is reviewed quarterly for disposition by the Board as part of a separate Board process. The Board has recently issued a letter dated February 19, 2008 announcing the Board's intention to launch an initiative to review commodity variance accounts, possibly including other RSVA and RCVA accounts as well.

Treatment of Carrying Charges

In its response to Board staff interrogatory 41, NPDI stated that it had been using the interest rate of 4.59% to calculate carrying charges for the deferral and variance accounts from January 1, 2005 to April 30, 2008. However, for interest rates up to April 30, 2006, the Board's guidelines for prescribed interest rates for approved accounts are set out in the 2000 Electricity Distribution Rate Handbook. The rates are dependant upon the size of the utility's rate base. For NPDI, this rate should have been 7.25%. In addition, for prescribed interest rates from May 1, 2006, the Board provided guidelines in its letter of direction dated November 28, 2006 that identified a process whereby specific rates would be set on a quarterly basis to be used by all distributors regardless of size. For the second quarter of 2006 i.e. April 1 to June 30, 2006 the prescribed rate was 4.14%. The prescribed rate for July 1, 2006 to December 31, 2006 was 4.59%.

Treatment of 1508, 1525, and 1586

In its response to Board staff interrogatory 45 and to VECCs interrogatory 27, NPDI stated that it accrued costs in both accounts 1508 and 1525 from Hydro One invoices for Phases I and II of Hydro One's regulatory asset recovery as approved by the OEB. NPDI did not apply for the disposal of these accounts in order to mitigate the impact on customer bills. On December 31, 2006, account 1508 had a balance of $566,828 and

Account 1525 had a balance of $15,591. However, total Hydro One charges for Phase I and II of Hydro One's regulatory assets should be accrued in accounts 1586 as per the APH and the December 2005 Frequently Asked Questions #8 and #9. NPDI is applying for disposition of account 1586.

Board Staff is unclear if NPDI used account 1586 to record historic Hydro One charges for Phase I and II of Hydro One's regulatory assets. These amounts are a proxy for the amounts included in the distributor's regulatory asset rate riders in relation to Hydro One's Low Voltage charges approved for the periods ended December 31, 2003 and April 30, 2006 respectively. From the response to Board staff interrogatory 45 and to VECCs interrogatory 27, it is unclear whether the balances are appropriately accounted for in 1508, 1525, and 1586.

Board staff has not been able to verify whether the Applicant is complying with the APH and the December 2005 Frequently Asked Questions #8 and #9 in accounting for accounts 1508, 1525, and 1586. Board staff is also concerned on how NPDI has accounted for amounts that have not been paid to Hydro One but have been accrued. Finally, it is not clear how the Applicant transferred approved 2006 EDR balances from 1508, 1525 and1586 to 1590. Therefore Board staff is uncertain that the underlying balances in accounts 1508, 1525, and 1586 are correct.

<u>Transfers to 1590 – 2006 EDR</u>

From the regulatory asset continuity schedule in the response to Board staff interrogatory 42, it is unclear whether the transfer to 1590 for the regulatory assets approved for disposition in 2006 EDR occurred. $4,794,517 of regulatory assets was approved for disposition in 2006 EDR and this transfer is not shown in the continuity schedule, impacting account 1590. The impact of this transfer on the other regulatory assets is not clear.

SMART METERS

Background

Authorization for Undertaking Smart Meter Activity

The Applicant is not one of the 13 distributors authorized to undertake smart meter activities and is not named in the combined smart meter proceeding, EB-2007-0063.

The Board, in its decision on NPDIs 2007 IRM application (EB-2007-0560), confirmed its understanding that NPDI would not be undertaking any smart metering activity in 2007.

In its response to Board staff interrogatory 51 a-II), NPDI confirmed that it had not installed any smart meters in 2006 & 2007, and that it is planning to install 18,021 smart meters in 2008.

In its response to VECC interrogatory 10 g), NPDI stated that the smart meter capital expenditure amounts of $25,185 and $49,000 for 2006 and 2007 were approved as part of 3rd Tranche CDM.

The Applicant did not provide any evidence that it is authorized to undertake smart metering activities though it was requested to do so through Board staff interrogatory 51 a-I).

In response to Board staff interrogatory 51 a-I) and VECCs interrogatory 10 f), enquiring whether NPDI received approval from the Ministry of Energy regarding its smart meter plan, the utility indicated that it is a member of the Niagara Erie Power Alliance (NEPA) and provided a copy of a letter, dated December 21, 2007, signed by the Assistant Deputy Minister, Consumer and Regulatory Affairs of the Ministry of Energy, which stated:

> ”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.” and

> "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**.** (emphasis added)."

Smart Meter CAPEX and OM&A expense & Method of Recovery of Costs

In response to Board staff interrogatory 51 b, NPDI confirmed that it included the smart meter capital expenditure amount of $4,061,000 in 2008 rate base, instead of tracking the revenue requirement impacts in the smart meter deferral account and establishing an appropriate rate adder. In response to VECC interrogatory 10 f), enquiring on what basis NPDI decided to include the smart meter costs for 2008 in its distribution revenue requirement, the utility stated: "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."

Staff notes that the amount of $4,061,000 represents 65.0% of the total capital expenditure of $6,245,800 (per Exhibit 2 /Tab 3 /Schedule 3 /Page 1) proposed by NPDI for 2008.

In its response to Board staff interrogatory 42, NPDI provided a reconciliation of continuity schedules for deferral accounts including "Account 1555 – Smart Meter Capital and Recovery Offset Variance" with an April 30, 2008 credit balance of $40,417 where it is indicated that NPDI is not requesting the disposition of this credit balance in the smart meter deferral account.

Staff notes that not requesting the disposition of the credit balance in the smart meter deferral account would be inconsistent with the Board's statement in the 2nd and 3rd paragraphs of the section "The Rate Increase Methodology" on page 18 of its combined decision in EB-2007-0063 for authorized utilities: "Only three utilities, Toronto Hydro, Chatham-Kent and Middlesex are asking for recovery through rates at this time. The others propose to defer the matter until the next time. The Board will allow each utility to recover its costs as set out in Appendix "A" by including these costs in rate base for the 2006 and 2007 rate years and calculating a revenue requirement on that investment in the manner set out in Appendix "E". Before calculating a rate increase from this revenue requirement, however, the utility must first deduct the amount of money previously collected in rate adders pursuant to the Orders of March 21, 2006. (emphasis added)".

In response to Board staff interrogatory 24, NPDI provided a detailed breakdown for smart meter capital expenditure budget of $4,061,000 and for OM&A cost of $362,000 for 2008, indicating that NPDI considers all the components of both amounts to be "minimum functionality".

Discussion and Submission

Authorization for Undertaking Smart Meter Activity:

- Though requested to do so, NPDI did not provide sufficient evidence that it is authorized to undertake smart meter activities. NPDI is proposing, as a participant in the NEPA group's smart meter implementation plan to install 18,021 smart meters in 2008.

Smart Meter CAPEX and OM&A expense & Method of Recovery of Costs:
In the event that NPDI is allowed to undertake smart meter activities in 2008, the parties should comment on whether:

- Its 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;

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

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

LINE LOSSES

Background

In response to Board staff interrogatory 34, NPDI reaffirmed that the proposed Total Loss Factor (TLF) for 2008 of 1.0560 is the continuation of the approved TLF for 2007. The underlying distribution loss factor (DLF) corresponding to the proposed TLF is 1.0513, based on a Supply Facilities Loss Factor (SFLF) of 1.0045.

NPDIs actual DLF[1] has fluctuated in the 5-yr period from 2002 to 2006 as shown in the table below.

Year	2002	2003	2004	2005	2006	Average
Actual DLF	1.0693	1.0539	1.0598	1.0539	1.0571	1.0588

Discussion and Submission

The Applicant is a partially embedded distributor, served by host distributors Hydro One Networks Inc. (“HONI”) and Haldimand County Hydro (“HCH”). The DLF provided by NPDI should be in-line with the DLF of an embedded distributor provided it includes losses incurred in the host distributor’s system. However in their interrogatory response, NPDI has stated that the DLF and SLF provided do not include losses that occur in the HONI distribution system (typically 3.4%) and HCH distribution system (typically 2.53%).

Notwithstanding the fact that the DLF corresponding to the proposed TLF is lower than the actual DLF in any year in the 5-yr period, Board staff is concerned that the DLF associated with a distributor with a compact service territory as is the case with NPDI would be as high as the value proposed (1.0513).

Board staff observes that NPDIs overall TLF deduced after including upstream HONI and HCH losses and their proposed TLF of 1.0560 could potentially be comparable to

[1] NPD’s Application - Exh 4/Tab 2/Sch 7/Pg 3

HONIs proposed TLF for its core retail customers located in a lower density service territory compared to NPDIs customers. Parties may wish to comment on the reasonableness of the comparison noted above.

CONSERVATION AND DEMAND MANAGEMENT

Background

The Applicant submitted an application for the 2008 electricity distribution rates on February 15, 2008 which included an amount of $68,612 in the Community Relations account 5415 – Energy Conservation.

Discussion and Submission

The Applicant, in its response to Board staff interrogatory 49, stated that it is not requesting any incremental funding for Conservation and Demand Management, and that spending in the 2008 Test year is the residual amount remaining from its original Third Tranche funding. In VECCs interrogatory 31, details were requested on the proposed 2008 spending, and whether there were any new programs for which TRC screening had not been submitted to the Board. In its response, NPDI stated that it was granted an extension until March 2008. The Applicant also reported that the new program in question continued to be active, and that the TRC results will not be available until March 2008.

Board staff notes that in a decision dated August 23, 2007 (EB-2007-0690), the Board approved a request by NPDI to extend the deadline for completion of Third Tranche Conservation and Demand Management activities to March 31, 2008. It is not clear to Board staff whether NPDI is seeking to spend the $68,612 past the Board approved extension of March 31, 2008 and the Applicant is invited to clarify this based on evidence on the record.

In regards to the new “program in question” referenced in NPDIs response to VECC interrogatory 31, Board staff notes that NPDI has not fulfilled the applicable filing requirements set out in the Board’s November 14, 2006 Filing Requirements for Transmission and Distribution Applications.

Board staff also notes that it is not clear whether the $68,612, which NPDI identified as Third Tranche funding, and thus already included in rates, is captured in NPDIs 2008 revenue requirement and NPDI is invited to clarify this based on evidence on the record.

All of which is respectfully submitted