ONTARIO ENERGY BOARD

STAFF SUBMISSION

2008 ELECTRICITY DISTRIBUTION RATES

PUC DISTRIBUTION INC.

EB-2007-0931

March 25, 2008

INTRODUCTION

PUC Distribution Inc. ("PUC" or the "Applicant") is the licensed electricity distributor serving a customer base of approximately 41,544 within the City of Sault Ste Marie, Townships of Prince and Dennis, and Rankin Reserve.

PUC submitted an application for 2008 electricity distribution rates on November 30, 2007. The application was based on a future test year cost of service methodology. On March 6, 2008, PUC submitted its response to interrogatories from Board staff and the 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 Applicant, and are intended to assist the Ontario Energy Board (the "Board") in evaluating PUC's application and setting reasonable and just rates.

THE APPLICATION

PUC has requested a revenue requirement of $17,191,211 to be recovered in new rates effective May 1, 2008.

OM&A

Background

The Applicant's Summary of Operating Costs is found at Exh 4/ Pg 6 of its application ("Summary"). The 2008 Total Controllable OM&A Expenses forecast is $8,506,470. This is a proposed increase in controllable operations expenses in the amount of $1,821,725 or 27% over the two year period from 2006 to 2008.

Discussion and Submission

Overall OM&A

Using the Summary as its base, Board staff created three different tables and asked interrogatories concerning each table. PUC confirmed the accuracy of each of the tables through its response to Board staff interrogatory #4a.

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

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

Table 1

	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
	$	$	$	$
Operation	1,496,528	2,051,174	2,156,507	3,018,799
Maintenance	1,793,258	1,430,922	1,448,545	2,277,648
Total Operation & Maintenance	3,289,786	3,482,096	3,605,052	5,296,447
Billing and Collections	959,171	941,104	934,991	1,338,873
Community Relations	400,269	428,632	408,719	473,852
Administrative and General Expenses	2,451,253	1,832,913	2,361,110	1,397,298
Total Administrative and General	3,810,693	3,202,649	3,704,820	3,210,023
Total Controllable OM&A	7,100,479	6,684,745	7,309,872	8,506,470
Taxes other than income	199,669	167,942	157,151	170,151
Other Operating Costs	2,830,510	2,845,705	2,829,662	1,984,620
Total Other Operating	3,030,179	3,013,647	2,986,813	2,154,771
Amortization Expenses	2,574,456	2,764,612	3,046,595	3,310,978
Total Operating Costs	12,705,114	12,463,004	13,343,280	13,972,219

Table 2

	2006 Board Approved	**Variance 2006/2006**	**2006 Actual**	**Variance 2007/2006**	**2007 Bridge**	**Variance 2008/2007**	**2008 Test**	**Variance 2008/2006**
	$		$		$		$	
Operation	1,496,528	554,646	2,051,174	105,333	2,156,507	862,292	3,018,799	967,625
		8.1%		1.6%		11.8%		14.5%
Maintenance	1,793,258	-362,336	1,430,922	17,623	1,448,545	829,103	2,277,648	846,726
		-5.3%		0.3%		11.3%		12.7%
Total Operation & Maintenance	3,289,786	192,310	3,482,096	122,956	3,605,052	1,691,395	5,296,447	1,814,351
		2.8%		1.8%		23.1%		27.1%
Billing and Collections	959,171	-18,067	941,104	-6,113	934,991	403,882	1,338,873	397,769
		-0.3%		-0.1%		5.5%		6.0%
Community Relations	375,332	53,300	428,632	-19,913	408,719	65,133	473,852	45,220
		0.8%		-0.3%		0.9%		0.7%
Administrative and General Expenses	2,215,726	-382,813	1,832,913	528,197	2,361,110	-963,812	1,397,298	-435,615
		-5.6%		7.9%		-13.2%		-6.5%
Total Administrative and General	3,550,229	-347,580	3,202,649	502,171	3,704,820	-494,797	3,210,023	7,374
		-5.1%		7.5%		-6.8%		0.1%
Total Controllable OM&A	6,840,015	-155,270	6,684,745	625,127	7,309,872	1,196,598	8,506,470	1,821,725
		-2.3%		9.4%		16.4%		27.3%

Cost Drivers

To assist in understanding the increases in Total Controllable OM&A expenses identified above, Board staff prepared the following cost driver table based on the Applicant's response to Board staff interrogatory #4b. The review starts with the 2006 Board Approved costs of $6,840,015 and progresses forward to the 2008 Test year amount of $8,506,470. In preparing this table, Board staff shortened the descriptions of some of the cost drivers contained in the original interrogatory response.

Table 3 Cost Driver Table

	Approved to 2006 Actual	**2006 to 2007**	**2007 to 2008**
Opening Balance (Previous Year)	6,840,015	6,684,745	7,309,872
PCB Removal Program			130,000
Railroad Crossing Fees			108,000
Pole testing			43,500
Reduction in Joint costs allocated to OM&A due to Cost Allocation Study			(192,000)
New maint. Programs			130,000
Line clearing			145,000
Smart Meters			365,000
Legal Fees			(75,000)
Labour rate increase for current staff			
3% increase in 2005	63,270		
3% increase in 2006	65,168		
3% increase in 2007		71,132	
3% increase in 2008			73,266
Staff increases in 2008			490,219
Staff increases part way through 2007		29,643	29,643
Staff increases part way through 2006	133,000	133,000	
Staff increase in 2007		96,800	
Reduction in overtime in 2004	(275,000)		
OEB adjustment to reduce requested admin expenses in 2006 EDR	348,788		
Engineering unallocated time	187,147		
Adjustment for transformers	(80,000)		
Reduced Stations Labour	(12,000)		
Costs to operate GIS	165,000		
Adjustment in 2006 following regulatory accouting review	148,000		
Change to allocate a portion of joint use assets to capital in addition to expense	(184,749)		
Substation work completed in 2004	(220,000)		
Bad debts	(112,852)		
Pension Adjustments	(350,000)	350,000	
Architect fees	(104,000)		
Installation of meters at substations	138,000		
Reduced legal fees	(140,000)		
Change in accounting for pole use fees	98,000		
Unexplained Difference	(23,042)	(55,448)	(51,030)
Closing Balance	**6,684,745**	**7,309,872**	**8,506,470**

Board staff grouped the factors contained in Table 3 into the following five areas:

Table 4 Cost Driver Summary

Cost Drivers	**Sum of 2007 and 2008 Increases**
Ongoing Employee Costs	$923,703
Network Related Costs	$556,500
Smart Meters	$365,000
Pension Adjustment	$350,000
Offsets	($373,478)

1. Ongoing Employee Costs

This item includes labour rate increases for current staff as well as staff increases. Board Staff's submission on employee costs is contained in the employee compensation section which follows.

2. Network Related Costs

This item includes cost increases in such areas as PCB Removal Program, Railroad Crossing Fees, Pole Testing, New Maintenance Programs and Line Clearing. Board staff's observations on each of these items is as follows:

(a) PCB Removal Program:

The Applicant states that it is increasing its PCB removal program to meet legislated requirements. Board staff notes that the amount of $130,000 indicated in PUC's response to Board staff interrogatory #4b and in Table 3 differs from the amount filed in the Applicant's original application [Exh 4/ Pg 11/ Ref. 5] The amount filed was $176,335, resulting in a difference of $141,227 from the 2007 actual, rather than the $130,000 differential shown in the interrogatory response. The Applicant may wish to comment on this observation in its reply submission.

(b) Railway Crossing Fees:

The Applicant indicated that fees increased for railway crossings. Board staff notes that the amount of $108,000 indicated in PUC's response to Board staff interrogatory #4b differs from the amount filed in the Applicant's original application (Exh 4/ Pg 11/ Ref. 7) of $117,868. The Applicant may wish to comment on this observation in its reply submission.

(c) New Maintenance Programs:

The Applicant has indicated an expenditure of $130,000 for the introduction of programs for the maintenance of transformer gauges, refurbishment of breakers, and relays. Board staff notes that this differs from the amount filed in Applicant's original application (Exh 4/ Pg 12/ Ref. 9), which showed a 2008/2007 differential of $116,381. The Applicant may wish to comment on this observation in its reply submission.

(d) Line Clearings:

The Applicant has indicated an expenditure of $145,000 to implement an effective vegetation management program. Board staff notes that this differs from the amount filed in PUC's original application (Exh 4/ Pg 12/ Ref. 11), which showed a 2008/2007 differential of $251,475. The Applicant may wish to comment on this observation in its reply submission.

(e) Pole Testing

The final component of this increase is a $43,500 increase in expenditures for continued pole testing.

3. Smart Meters

Staff's submission on this cost item is contained within the Smart Meter section of the submission.

4. Pension Adjustment

The Applicant has included a Pension adjustment in the amount of $350,000. Board staff observes that the $350,000 amount is shown as a reduction from 2006 Board Approved to 2006 Actual and an increase from 2006 Actual to 2007 Bridge. The Applicant attributes this amount to an adjustment in 2006 following a regulatory accounting review. Board staff is unclear what this means. The Applicant may wish to provide further clarification on this adjustment in its reply submission.

5. Offsets

This item includes a reduction in joint costs allocated to OM&A owing to a cost allocation study amounting to $192,000, a reduction in legal fees of $75,000 in 2008 and a remaining unexplained difference of $106,478 (roughly 6% of the total differential).

<u>Other Operating Costs</u>

Exh 4 / Pg 6 of PUC's application includes a component of Total Operating Costs entitled "Other Operating Costs" in the amount of $1,984,620 in the 2008 Test Year. A breakdown at Exh 4/ Pg 8 attributes this amount to "Interest on Debt to Associated Companies" and "Other Interest Expense." Board staff interrogatory #3c sought a detailed explanation as to why this amount was included by the Applicant. In its response, the Applicant stated that it had included this amount for comparative purposes and that the other interest expense is not included in the rate base. The Applicant may wish to clarify this matter in its reply submission and confirm that there is no double recovery of interest expense contained in its application.

<u>Employee Compensation and Benefits</u>

Board staff notes that employee costs are charged indirectly through PUC's affiliate company, PUC Services. The Applicant states in Exh 1/ Pg 43 that there are no employees in PUC Distribution Inc.

The following Table 1 prepared by Board staff summarizes the information on labour costs provided in Exh 4.

Table 1 Total Compensation and Benefits

	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
Compensation	$ 2,220,578	$ 2,899,244	$ 3,140,742	$ 3,731,527
Pension and Benefits	$ 845,239	$ 1,104,535	$ 1,173,175	$ 1,329,770
Incentive Pay	$ 30,000	$ 30,000	$ 30,000	$ 30,000
Total Compensation	$ 3,095,817	$ 4,033,779	$ 4,343,917	$ 5,091,297
Capitalized	$ 1,305,315	$ 2,000,742	$ 2,307,311	$ 2,404,918
OM&A	$ 1,790,502	$ 2,033,037	$ 2,036,606	$ 2,686,379
Total Compensation	$ 3,095,817	$ 4,033,779	$ 4,343,917	$ 5,091,297
Capitalized	42%	50%	53%	47%
OM&A	58%	50%	47%	53%

In response to Board staff interrogatory #1, the Applicant confirmed that it has not made any changes to its capitalization policies or estimates. Board staff notes that while the splits appear to be reasonably consistent over the period, there is some fluctuation in the above percentage splits from the 2006 Board approved year to the 2008 test year. The Applicant may wish to provide any additional clarification for this fluctuation in its reply submission.

In comparing the distributor's labour costs to Total Controllable OM&A, Board staff notes that labour averages approximately 29% of operating costs as indicated in the following Table 2.

Table 2 Total Compensation as a percentage of Total OM&A

		2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
OM&A Labour	A	$ 1,790,502	$ 2,033,037	$ 2,036,606	$ 2,686,379
Total Controllable OM&A Expenses	B	$ 7,100,479	$ 6,684,745	$ 7,309,872	$ 8,506,470
Labour as a percent of OM&A	C = A / B	25.2%	30.4%	27.9%	31.6%

Board staff prepared the following Table 3 to identify the final value of labour cost drivers to be used in the following cost driver analysis table.

Table 3 Year over Year Change in Total Compensation

	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
OM&A	$ 1,790,502	$ 2,033,037	$ 2,036,606	$ 2,686,379
Annual Labour Changes		$ 242,535	$ 3,569	$649,773
% Change		12%	0.2%	24.2%

From Table 3, the significant variance is the 24% increase in the 2008 test year. One of the key components of this increase is total salary and wages, which have increased by 28% from 2006 to 2008. Since 2006, the Applicant has hired 9 employees, including 2 Engineering Technicians, 1 Line Planning Technician, 3 Linemen, 1 Forestry Technician, 1 P&C Engineer and 1 Billing Supervisor, resulting in an increase of $557,000 to total salary and wages. The Applicant noted that this staffing increase is required to replace aging infrastructure, to perform maintenance work in order to improve system reliability and to satisfy Ontario Regulation 22/04 requirements. The Applicant further noted that annual wage increases of 3% have increased total salary and wages by $180,000.

Board staff observes that total employee benefits have increased by 20% between 2006 and 2008. Board staff interrogatory #17 requested that the Applicant provide the rationale and justification for this increase. In its response, the Applicant stated that the benefits table provided includes benefits charged directly to the Applicant by PUC Services for employees whose primary function is to provide distribution services. The Applicant further noted that benefits as a percentage of wages have decreased from 2006 to 2008.

Board staff also observes that, in Table 4 (Cost Driver Summary) in the Cost Drivers section, ongoing employee costs are increasing by a total of $923,703 in the 2006 to 2008 period, based on an aggregation of employee cost related items enumerated in Table 3 of the Cost Drivers Section. However, Table 3 (Year over Year Change in Total Compensation) shows that costs are increasing only by $653,342. The Applicant may wish to provide clarification of this matter in its reply submission.

<u>Shared Services</u>

Background

When the electricity sector restructured in 2000, the former City of Sault Ste. Marie Public Utilities Commission which provided water and electricity services to the city was restructured into the PUC Inc. group of companies. PUC, the local distribution company, is the wholly owned subsidiary of PUC Inc. Other wholly owned subsidiaries of PUC Inc. are PUC Services Inc., PUC Telecom Inc., and PUC Energies Inc. While PUC owns the distribution assets, PUC operates the distribution system through PUC Services Inc. PUC Services Inc. is an integrated utility provider, providing services to its affiliated companies at cost, either as a direct charge for specific services to a specific affiliate or as an allocation of services common to all the affiliates.

Discussion and Submission

Board staff notes that the Applicant is proposing a significant increase in its shared services costs for 2008 of 20%.

These increases are primarily as a result of the implementation of the recommendations of a study prepared by RDI Consulting Inc., entitled "Full Absorption Cost Allocation Report," dated September 20, 2007 and prepared for the Applicant's affiliate PUC Services Inc. The report proposed implementation of its recommendations effective January 1, 2008. An earlier study of the same issue had been completed by KPMG in 2001. This was filed in response to Board staff interrogatory #7.

The cost impacts of the implementation of the study recommendations were provided in Exh 4 / Pg 20. These impacts reflected an increase in shared services costs from $2,480,758 in 2007 to $3,248,899 in 2008, an increase of 31%. In response to Board staff interrogatory #8, this increase was revised down to 20% due to a correction to the 2007 number which was increased to $2,688,508, resulting in a 2008 increase of $560,390.

The Applicant explained this increase as being due to three factors. The first of these factors was a new cost of capital charge, which accounted for $381,391 of the increase. This charge was designed to allow PUC Services to recover the costs of the financing of the purchasing of its assets from the users. Previously, only depreciation related to PUC Services owned assets was recovered from the users of these assets. The Applicant justified this charge on the basis of the RDI report which discussed the reasons for its proposed implementation in Exh 4 / Pg 21. In response to Board staff interrogatory #9, RDI also provided a justification for its recommended use of the Applicant's deemed weighted average pre-tax cost of capital for the PUC Services.

The second factor was a "Use of Assets Charge." This had an impact of $89,564 and was explained by the Applicant as the "result of the use of additional vehicles by the LDC due to the increased operations staff and the implementation of upgraded software driven by the need for the LDC to better maintain records as a result of Reg. 22." The Applicant further stated that asset charge allocation had also been revised to use more appropriate allocators as per the study.

The third factor was the joint services allocation which increased by $89,435. The Applicant explained this increase as due to a reduction in the percentage of joint services costs allocated as per the study, offset by wage increases of 3% and the addition of a shared billing supervisor and a shared IT manager.

Board staff observes that the increase in these proposed costs is significant. With reference to evidence already filed, the Applicant may wish to provide further clarifications in this area in its reply submission. Board staff invites parties to provide their views on these costs.

RATE BASE

Background

The Applicant currently delivers electricity through a network of over 720 kilometers of conductor, through distribution stations, to approximately 33,000 customers in residential, commercial and small industrial classes. The distribution system is connected to the provincial transmission grid through two transformer stations and 8 km of connecting line all owned by the Applicant. The Applicant submitted a commissioned report that characterizes the facilities as aging and requiring increasing attention as the facilities age further. The service area has a mildly declining population.

The average rate base for 2008 is projected by the Applicant to be $49,406,580 compared to $44,192,326 in 2007 and $43,661,268 in 2006. The Applicant projects a 2008 capital expenditure level of $12,160,313 for 2008 (or $5,422,771 without smart meters). Table 1 below provides the rate base comparisons and the capital expenditure comparisons for 3 years. Annual capital expenditure for 2006 and 2007 averages about $3.6 million per year.

Table 1:

	2006 (Actual)	2007	2008 - Projected
Capital Budget Expenditure	$3,356,044	$3,831,237	$12,160,313 (or $5,422,771 without smart meters)
% of increase as compared to the prior year	-	+114.2%	+217.4% (or +41.5% without smart meters)
Rate Base (average) $	$43,661,268	$44,192,326	$49,406,500 or $46,037,774 without smart meters)

% of increase as compared to the prior year	-	+1.2%	11.8% (or +4.2% without smart meters)

Discussion and Submission

Board staff notes that the rate base aspects of the application, supplemented by interrogatory responses, were essentially complete. However, Board staff notes that the Applicant did not provide the calculations for the Profitability Index (PI) in order to determine the revenue-producing capital expansions and to quantify the required capital contributions. The PI information was expected to be filed with the Board as a part of the Applicant's 2008 rate application, as outlined in the Board's *Filing Requirements for Transmission and Distribution Applications*, issued November 14, 2006. In response to Board staff interrogatory #23d, the Applicant responded that "economic analysis was not completed. PUC will be reviewing the method used to handle contributed capital in order to improve in the future". Parties are invited to comment on this matter.

<u>Drivers for Increase in 2008 Capital Expenditures</u>

Conversion of transformers to higher voltage and response to customer demand for new or upgraded services continue to be the cost drivers for capital expenditures for 2006, 2007 and 2008 (excluding smart meters).

In response to Board staff interrogatory #20a, the Applicant provided the following information as shown in Table 2 below.

Table 2

	2002	2003	2004	2005	2006	2007	2008
Net Income	319,327	1,263,632	-1,387,081	-738,755	-329,739	-517,419	1,571,858
Actual return on Equity Portion of the regulated rate base %	7.25%	9.57%	3.3%	4.52%	5.68%	5.18%	7.2%
Allowed return on the Equity portion of the regulated rate base %	8.12%	8.12%	8.12%	8.12%	7.67%	7.67%	7.52%
Retained earnings	9,906	1,273,538	-113,545	-852,300	-1,182,037	-1,699,462	-127,604
Dividends to Shareholders	0	0	0	0	0	0	0
Sustainment Capital Expenditures excl Smart Meters							
Development Capital excluding Smart Meters							
Operations Capital Expenditure							
Smart meters capital expenditure	0	0	0	0	0	0	6,737,612
Other capital expenditures (identify)	2,228,519	1,775,800	2,759,696	3,761,856	3,356,036	3,831,237	5,422,571
Total Capital Expenditures incl smart meters	2,228,519	1,775,800	2,759,696	3,761,856	3,356,036	3,831,237	12,160,183
Total cpital expenditures excel smart meters	2,228,519	1,775,800	2,759,696	3,761,856	3,356,036	3,831,237	5,422.571
Depreciation	2,455,890	2,495,457	2,574,456	2,668,236	2,764,612	3,046,595	3,310,977
Construction Work in Progress							
Number of customer Additions by class							
Residential	37	49	32	1	38	30	30
GS<50	42	-13	35	18	36	-35	10
GS>50	5	3	14	1	1	-6	0
Street Lights(connections)		51	31	-15	56	31	31
Sentinel Lights (connections)	0	0	0	-13	-7	-5	-5
USL (connections)	2	0	15	1	0	-2	0
Rate Base	43,150,941	42,529,922	43,107,019	45,747,269	43,661,268	44,192,326	49.406,580

This table demonstrates that the Applicant is proposing a capital expenditure of $5.42 million in 2008 that is considerably higher than the historical values. The Applicant is planning this expenditure in order to upgrade the asset infrastructure and meet customer demand. This is a significant increase as compared to the average capital expenditure of $3.1 million per year for 2003 to 2007 period and as compared to $3.6 million per year (the average of 2006 and 2007).

In response to Board Staff interrogatory #23, the Applicant indicated that the $875,000 capital works that were budgeted in 2007, but yet not completed, are carried over to 2008. The work comprises of additional pole replacements and for 35kV cables at substations and transformer station equipment.

Further, in response to Board Staff interrogatories #22b and 22d, the Applicant provided the following explanations as the drivers for the increases:

- $653,590 for a voltage conversion program for capital expenditures for transformers, and
- $154,550 for a customer demand (new and upgraded services) for capital expenditures for services.

Board staff invites parties to comment on these drivers.

Allocation of Overhead Cost to Capital Projects

In response to Board staff interrogatory #23e, the Applicant provided the following information for the total dollar overhead allocated within the 2006, 2007, and 2008 capital budgets. Board staff calculated the percentage of overhead allocation, as shown below.

Year	Total Capital Expenditure	Overhead Included	Overhead %
2006	$3,356,044	$125,369	3.9%
2007	$3,831,237	$207,750	5.7%
2008	$12,160,383	$960,431	8.6%

Board staff observes that the percentage of overhead allocated to the 2008 capital projects is higher than that of 2006. With reference to evidence already filed in the application, the Applicant is invited to explain this increase in the percentage of overhead allocation to the 2008 capital projects and comment if the capitalization policy has been changed.

Service Reliability Indices

The Applicant states in Exh 2/ Pg 25/ Para 4 that "Over the past five years we have witnessed a dramatic decrease in system reliability". Various sources of information have been provided by the Applicant regarding system reliability performance. Board staff has documented this information in Table 3 below.

Board staff observes that the information provided by the Applicant in Exh2 / Pg 70/ Fig 19 is inconsistent and differs from the information supplied in the response to Board staff interrogatory #24b, [Table and histogram on Pg 55]. Board staff is not clear if the performance indicators provided in Exh 2 / Pg 70 / Fig 19 includes or excludes loss of supply data. The Applicant is invited to clarify this matter.

Table 3

Reference:	Exhibit 2, Page 70 figure 19		Response to Board staff Interrogatory #24b (excludes loss of supply)	
	SAIDI	SAIFI	SAIDI	SAIFI
2002	1.8	1.7	2.06	1.78
2003	2.4	1.9	2.77	1.8
2004	3.6	3.25	3.61	2.65
2005	4.45	4.45	4.04	3.97
2006	2.4	3.2	2.38	3.29

If the reliability indicators provided in Exh 2 / Pg 70 / Fig 19 exclude loss of supply data, Board staff would expect that these figures should have lower values than those indicators that include such information. Board staff notes from Table 3 that the indices reported in response to Board staff interrogatory #24b have higher values when loss of supply data is excluded (shaded areas in the table above) e.g. 2003 SAIDI value of 2.77 vs. 2.4 (as referenced in Exh 2 / Pg 70 / Fig 19). The Applicant is invited to provide an explanation for the differences in the figures for the reliability indicators and comment on this issue.

Board staff also notes that the figures in Table 3 indicate that reliability in 2007 is within the bounds of the previous three years. However, by reviewing the histogram in Exh 2 / Pg 70 / Fig 19 and the information that is provided in Table 3, Board staff observes that that the reliability performance in recent years has declined significantly, as compared to the prior years, i.e., pre-2003 period.

The Applicant did not directly respond to the Board staff interrogatory #24c to provide the 2008 reliability targets. Staff is unclear if and how the Applicant has considered establishing service reliability improvement targets while developing and implementing its Asset Management Plan. Parties are invited to comment on this matter.

Asset Management Plan

The Applicant's Asset Management Plan appears to be included within its "Long Term Capital and O&M Needs Report", as filed in Exh 2 / Pgs 41-125. It is a comprehensive report compiled by in-house management including a 5-year budget for renewal and replacement of aging assets. It includes a commissioned independent opinion on the adequacy of the proposed plan and budget. It also includes an asset assessment program conducted by BDR North America and Mesco, which advocates three major upgrading initiatives over the next decade, 80% of medium voltage underground cables, 5 to 10% of the wood poles and a large number of circuit breakers. A report by PoleCare International Inc. is also included.

Board staff notes that the BDR report advises that many upgrades are required and that significant investment is necessary to avoid reliability problems due to aging of assets. Numerous changes in practice have been suggested and are in the process of being adopted according to the Applicant. It appears that staffing to implement the plan may be a major challenge for the Applicant. Board staff invites parties to comment on these elements of the BDR report.

Board staff also observes that while the "Long Term Capital and O&M Needs Report" includes essential components of a plan, it may require inclusion of a structured process for updating the budget and the needs identification on a regular basis. Parties may wish to comment on this observation in its reply submission.

Treatment of Construction Work in Progress

In response to Board staff interrogatory #49, PUC stated that the cost of funds on Construction Work in Progress (“CWIP”) is not currently captured as there are “no major projects of long duration”. This cost of funds is also known as the allowance for funds used during construction (“AFUDC”).

However, the Accounting Procedures Handbook (“APH”) clearly states that a utility shall record AFUDC. The Applicant did not provide the dollar impact on rate base and revenue requirement in the interrogatory response, nor did it state that it will start recording AFUDC prospectively. In theory, not capitalizing interest means that the rate base is lower over the long term, which results in lower return. This will impact PUC’s balance sheet and income statement. Since the dollar impact cannot be calculated on a historical basis, Board staff submits that PUC should start recording AFUDC prospectively.

COST OF CAPITAL

Summary

The Applicant provided its proposed Cost of Capital in Exh 6 of its application. The following table summarizes PUC’s proposed Cost of Capital:

Summary of Capital Structure

Cost of Capital Parameter	**PUC’s Proposal**
Capital Structure	53.3% debt (composed of 49.3% long-term debt and 4.0% short-term debt) and 46.7% equity, in accordance with the transition to a deemed capital structure of 60% debt and 40% equity, as documented in the Board Report.
Short-Term Debt	4.77%, to be updated in accordance with section 2.2.2 of the Board Report.
Long-Term Debt	5.82%, as the forecasted interest rate on long-term debt owed to the municipal shareholder and which is being renegotiated, and to new third-party debt forecasted to be incurred in 2008. This is further discussed below.
Return on Equity	8.69%, 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	7.12% 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.

PUC's approach to cost of capital appears generally to be consistent with the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Electricity Distributors* issued on December 20, 2006 (the "Board Report"). However, certain information was sought through discovery to complete, clarify and correct the record. With the explanations and clarifications provided, Board staff submits that PUC's proposal, with the exception of the capital structure, is consistent with the cost of capital methodology in the Board Report.

In its response to Board staff interrogatory #28e), the Applicant has shown a 2008 cost of capital which includes a ROE of 9%, a long-term debt rate of 6.35%, no short-term debt, and a resulting weighted average cost of capital of 7.68%. These figures are different from those shown elsewhere in the application. Board staff invites the applicant to identify evidence on the record of this application which clarifies and supports the applicant's response to this interrogatory.

Discussion and Submission

Long-term Debt Rate

The Applicant proposed in Exh 6 a long-term debt rate of 5.82%. A Table "Cost of Debt" in Exh 6 shows the Applicant's debt consists of Promissory Notes due to the municipal shareholders and a forecasted third-party loan secured in 2008. Copies of the Promissory Notes were filed in response to Board staff interrogatory #28. While the copies of the Promissory Notes show higher rates, the Applicant has noted that the interest rates on the Promissory Notes are being renegotiated with the municipal shareholder. The Applicant has also proposed that the 5.82% rate apply to the forecasted third-party debt.

As the proposed rate of 5.82% is less than or equal to the "market-based" rate of 6.10% announced by the Board on March 7, 2008, Board staff considers the Applicant's proposed rate of 5.82% to be consistent with the guidelines in the Board Report.

For the expected third-party debt to be incurred in 2008, Board staff submits that the proposed rate of 5.82% is a prudently negotiated debt rate that should be applied for rate-setting purposes since it is lower than the deemed long-term debt rate of 6.10% announced by the Board on March 7, 2008.

LOAD FORECASTING

Background

In Exh 3 of the Application, the development of the Applicant's customer count and load forecasts are discussed. Utilizing the 2002 to 2006 historical data, the 2007 actual customer count was projected to establish the 2008 test year customer count 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's forecasting interrogatories.

Discussion and Submission

Methodology and Model

The Applicant has provided a comprehensive explanation of the trend in customer connections experienced during the 2002-2006 period and the extrapolation of that trend to 2007 and 2008. The Applicant noted that it had used a simple trend growth given the slow growth and consistent trend in customer numbers in the Applicant's service territory and the minor variations experienced over time. The tabulated customer data support the textual explanation.

Turning to its kWh volume forecasts, the Applicant explained that for its weather sensitive load, it first developed the retail normalized average use per customer ("retail NAC") by customer class. The retail NAC value by class was based on the 2004 load values that had been weather-normalized for the Applicant by Hydro One. The Applicant explained in Exh 3, and confirmed in response to Board Staff interrogatory #32, that the 2004-based retail NAC was assumed to be applicable in the future and was used as the basis for the load forecasts. The forecasted kWh loads were determined by multiplying the 2004-based retail NAC by the forecasted number of customers in the forecast year.

Board staff observes that the methodology chosen utilizes only a single year of weather-normalized historical load to determine the future load. Board staff notes that assuming that the retail NAC value remains constant over a number of years may not be a robust assumption. This is the equivalent of stating that no CDM improvement has occurred during the past few years and none is expected in the immediate future. The effect of the constant assumption could be an error in the estimate of the weather sensitive load by a few percent and correspondingly underestimate the required rates.

<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 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 which is virtually identical to the historical 2002-2006 historical growth of 0.2% per annum. Board staff observes that the forecasted growth in customer numbers is fairly consistent with what one might expect based on the input data.

The Applicant's forecast shows a negative 0.3% annual average kWh load change from 2006 to the 2008 Test Year. [Exh 3 / Pg 10] This compares with an average annual kWh load change of negative 0.6% during the 2002 to 2006 period. [Response to Board staff interrogatory #35]

As noted earlier, using the 2004-based retail NAC values for 2008 is likely to result in a less accurate load forecast. In response to Board staff interrogatory #35, the Applicant developed an alternative forecast that took weather normalization fully into account for each of the years 2002 to 2006. Parties may wish to comment on Board staff's observation that the Applicant's filed forecast is about 1%-2% higher than the data would suggest.

SMART METERS

Background

<u>Authorization for Undertaking Smart Meter Activity</u>

PUC 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.

PUC 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 #43a)-i. In response to the same interrogatory, the Applicant stated that PUC has not been authorized to undertake smart meter installations. PUC further stated that it is a member of the Northeast Ontario utilities working group (or District 9) 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. This letter is addressed to London Hydro and states:

"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. <u>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</u>. (emphasis added)."

The Board, in its decision on PUC's 2006 EDR application (RP-2005-0020 / EB-2005-0412) noted that PUC had included amounts related to smart meters, but had not included a Smart Meter plan explicitly in its application. The Board stated: "Absent a specific plan or discrete revenue requirement, the Generic Decision provides that $0.30 per residential customer per month be reflected in the Applicant's revenue requirement. The Board finds that this increase in the revenue requirement amount will be allocated equally to all metered customers and recovered through their monthly service charge."

The Board, in its decision on PUC's 2007 IRM application (EB-2007-0568), confirmed its understanding that PUC would not be undertaking any smart metering activity in 2007.

In its response to Board staff interrogatory #43a)-iii, PUC confirmed that its capital costs of $53,625 for 2007 is with respect to:

- Formation of Northeast Ontario smart meter working group;
- Hiring of a consultant;
- Evaluation of AMI and smart meter installation vendors;
- Preparation of smart meter capital operating budget for 2008 based on response from 4 potential AMI vendors.

In its response to Board staff interrogatory #44 d), PUC stated that as a participant in the Northeast Ontario utilities working group's smart meter implementation plan it will install 31,522 smart meters in 2008 [30,587 residential and 935 GS<50 kW].

<u>Smart Meter CAPEX and OM&A expense & Method of Recovery of Costs</u>

In response to Board staff interrogatory #43a)-v and interrogatory #44g), PUC confirmed that it included the smart meter capital expenditure amount of $6,737,612 in 2008 rate base [or account "1860 – Meters"], instead of tracking the revenue requirement impacts in the smart meter deferral account and establishing an appropriate rate adder.

Board staff observes that the smart meter capital expenditure amount of $6,737,612 represents 55.4% of the total capital expenditure of $12,160,313 [per Exh 2 / Pg 33] proposed by PUC for 2008.

In response to Board staff interrogatory #4c), PUC stated that a portion [$230,561] of the smart meter 2008 OM&A budget amount of $521,685 is charged to the smart meter deferral account and the remainder [$291,124] is charged to OM&A account "5315 – Customer Billing".

Board staff notes that in the amount of $230,561 PUC included a $150,133 "Smart Meter Entity MDMR" fee and $80,428 for "Repair of Unsafe Meter Bases". In response to Board staff interrogatory #46b), PUC indicated that "With the deployment of smart meters PUC Distribution expects the IESO will be charging PUC Distribution for the usage of the Meter Data Management Repository before the next rebasing rate application. Since PUC Distribution does not know what these charges will be it has not included any MDMR costs in the projected revenue requirement. However, PUC Distribution may be charged for a service which it may not be able to recover from customers until the next rebasing rate application." In response to Board staff interrogatory #46f), which requested an explanation of the basis of the approval to record these amounts in a deferral account, PUC stated: "The basis of the approval to record costs in the proposed deferral account is that these costs have been reasonably incurred in the normal course of business. The fairness and reasonableness of the costs can be tested when they are proposed to be recovered in rates."

In response to Board staff interrogatory #44e) and #4c), PUC confirmed that its 2008 smart meter capital budget [$6,737,612] and OM&A budget [$291,124] meet the "minimum functionality" criteria.

Discussion and Submission

Authorization for Undertaking Smart Meter Activity:

PUC did not provide evidence that it is authorized to undertake smart meter activities. Nevertheless, PUC is proposing to install 31,522 smart meters in 2008.

Parties are invited to comment on this matter.

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

In the event that PUC is allowed to undertake smart meter activities in 2008, parties are invited to comment on whether:

- PUC's proposal to incorporate the smart meter capital expenditure amount of $6,737,612 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;

- PUC's proposed smart meter OM&A cost of $291,124 charged to account "5315 – Customer Billing" is acceptable;

- PUC's proposed smart meter OM&A cost of $230,561, charged to the smart meter deferral account is acceptable.

- PUC should be allowed to charge the "Smart Meter Entity MDMR" fee of $150,133 when no charges have been determined for the "Smart Meter Entity MDMR".

LINE LOSSES

Background

In response to Board staff interrogatory #42, PUC reaffirmed that the proposed total loss factor ("TLF") for 2008 is based on an averaging of actual TLFs for the 3-yr period 2004 to 2006 and is 1.0454, slightly higher than the 2007 approved TLF of 1.0430. PUC has further submitted that since its transmission assets are considered a part of its distribution system, the TLF is also the distribution loss factor ("DLF").

PUC's actual TLF has fluctuated during the 3-yr period from 2004 to 2006 as shown in the table below.

Year	2004	2005	2006
Actual TLF	1.0479	1.0437	1.0446

Discussion and Submission

Board staff concurs with PUC that, because it owns the facilities from the deemed delivery point and these facilities have been classified as distribution assets, the DLF is in effect also the TLF. Board staff submits that PUC's proposed TLF for the test year 2008 is acceptable.

REVENUE TO COST RATIOS

Background

The Application 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%. The result of this re-balancing can be seen in the following table, by comparing columns 1 and 2. (Ref: Exh 9 / Pg 9) For ease of comparison, the Board's target ranges are shown in column 3.

PUC Revenue to Cost Ratios

%	Informational Filing Col 1	Application: Exhibit 8 / p. 9 Col 2	Board Target Ranges Col 3
Customer Class			
Residential	90	93	85 – 115
GS < 50 kW	137	120	80 – 120
GS > 50 kW	132	128	80 – 180
Street Lights	17	40	70 – 120
Sentinel Lights	38	40	70 – 120
USL	82	82	80 -- 120

Discussion and Submission

Board staff notes that two classes have proposed ratios that remain outside the Board's 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 whose ratio is within the target range but above 100%.

<u>Street Lighting</u>

PUC proposes to raise 2.40% of its total revenue requirement from Streetlighting, compared to 0.87% at present. The cost allocation study allocated 6.07% of total cost to Streetlighting. PUC's calculation is that the proposed revenue to cost ratio would be 40%, compared to 17% in the Informational Filing, as shown in Exh 8 / Pg 9.

In its response to Board staff interrogatory # 37(b), PUC's calculation of the total bill impact from its proposed distribution rates, together with changes in other components of the bill, is an increase of more than 10%. Board staff invites parties to comment on whether PUC should adjust the proposed revenue to cost ratio so that it moves approximately half the distance from the status quo to the nearest boundary of the Board's target range.

<u>Sentinel Lighting</u>

PUC proposes to raise 0.13% of its total revenue requirement from Sentinel Lighting, compared to 0.11% at present. The cost allocation study allocated 0.32% of total cost to the Sentinel Lighting class. PUC's calculation is that the proposed revenue to cost ratio would be 40%, compared to 38% in the Informational Filing shown in Exh 8 / Pg 9.

In Exh 9 / Pg 3, PUC's calculation of the total bill impact from its proposed distribution rates, together with changes in other components of the bill, results in an increase of 13.3%. Board staff notes that PUC's impact calculation is based on a single connection for the service charge component, whereas the volumetric charge component is based on 63 kW. These inputs may result in more weight given to the volumetric component in relative terms, and a calculation with a heavier weighting on the fixed charge may produce a slightly lower calculation of the total bill impact.

Board staff invites parties to comment on whether PUC ,despite the small proportion of revenue from Sentinel Lighting, should increase the proposed rates to yield a higher revenue to cost ratio that is more closely in line with Board policy.

RATE DESIGN

Background

For most of the classes, the monthly service charge in 2006 was within the range between the floor and ceiling amounts calculated in the Informational Filing cost allocation study. The Applicant responded to VECC interrogatory # 26 (a) and (b) stating that the percentage of revenue that would be derived from the fixed charges is proposed to remain constant or nearly so for all classes.

Discussion and Submission

An apparent exception to the general pattern is the proposal to increase the monthly service charge of the GS < 50 kW class from $11.20 per month to $15.40, an increase of 37.5% whereas the volumetric rate is proposed to increase by 13.4% as shown in Exh 9 / Pg 26. The effect is to take the fixed charge from a point mid-way between the floor and ceiling, and to put it at the ceiling. In its response to Board staff interrogatory # 38, the Applicant has stated that the rationale is to reduce its revenue volatility.

The impact on the total bill as shown in Exh 9 / Pgs 24 –26 is 3.6% for small customers in the class, and 0.0% - 0.2% for the large customers in the class. Board staff recognizes that the impact on larger customers is going to be affected by the decreases in the Regulatory Asset Recovery rate rider and the Retail Transmission Service Rates, both of which affect the bill only through volume. Nevertheless, Board staff invites parties to comment on whether the monthly service charge and the distribution volumetric rate should be changed by a uniform percentage, so that the bill impacts would be more uniform across the class.

Board staff notes that the monthly service charge for the GS > 50 kW class is approximately double the ceiling calculated in the cost allocation model. The proposal is to leave this rate unchanged (except for the Smart Meter adder). Board staff invites parties to comment on the appropriateness of this proposal.

RETAIL TRANSMISSION SERVICE RATES

Background

PUC charges Retail Transmission Service rates for Network service, but not Connection. The wholesale Transmission Network rate was decreased by 18% in 2007. As shown in Exh 9 / tables on Pg 21 – 31, the proposal is to decrease the retail rates by 10.3% for some classes and 11.2% for other classes.

Discussion and Submission

The proposed adjustment to the retail rates is considerably lower than the underlying decrease in the wholesale rate. The variance account appears to be already in surplus [response to Board staff interrogatory # 53 (a)]. Board staff notes that if a further surplus ensues as a result of revenues decreasing by less than costs, the disparity will be recorded in a deferral account.

Board staff notes that the rate for Interval Metered customers in the GS 50 – 4999 kW class is not reduced (shown in Exh 9 / Pg 14 and 17). Board staff invites the Applicant to confirm that this is an oversight and that it will be corrected in the Draft Rate Order. Board staff also notes the Applicant's response to Board staff interrogatory # 41 that the non-uniform adjustments are a result of rounding error.

PILs

Background

The federal government introduced tax legislation in its October 30, 2007 Economic Statement. Effective January 1, 2008 the federal income tax rate declined to 19.5%.

In response to a Board Staff interrogatory #2a) [Pg 191], PUC agreed to use the combined federal and Ontario rate of 33.5% when it submits its Draft Rate Order.

PUC pays more interest to its shareholder than the Board's deemed structure permits. In its Budget of March 22, 2007, the Ontario government introduced legislation that will minimize the interest deduction used in the PILs calculations in the actual tax returns. In its application, PUC added back the higher forecast 2008 interest expense and deducted the lower deemed interest expense in the PILs calculations. The effect of this treatment raises taxable income and would increase the PILs allowance in rates.

In the 2006 EDR Handbook, the Board provided for an excess interest penalty to be included in the PILs calculations. In its 2008 application, PUC applied for an increase in PILs for excess interest, as opposed to a reduction as indicated in the 2006 Handbook.

In response to a Board staff interrogatory #2d) [Pg 192], PUC submitted a PILs calculation that excludes the interest addition and deduction, and uses the effective tax rate of 33.5%.

Discussion and Submission

Board staff invites parties to comment on whether PUC should include the revised 2008 PILs forecast submitted in response to Board staff interrogatory #2d) [Pg 195] of $1,380,155 in its Draft Rate Order. The excess interest penalty should not be required since the government's legislation should limit the interest deduction used in the actual tax returns.

DEFERRAL AND VARIANCE ACCOUNTS

Background

PUC is proposing to:

- continue certain existing deferral and variance accounts;
- establish new deferral accounts for capital works during the non-rebasing years, meter data management repository (MDMR) costs, and smart meter full year return on smart meter assets and depreciation expense in 2009 and 2010; and
- clear the balances of certain deferral and variance accounts.

Request for Disposition

PUC is requesting that the following accounts and balances as per PUC's response to Board staff interrogatory #53 be cleared for disposition as of December 31, 2006 balances plus interest to April 30, 2008.

1508	Other Regulatory Assets $509,595
1518	RCVA – Retail, ($152,514)
1548	RCVA – STR, $56,068
1580	RSVA – Wholesale Market Service Charge, ($510,825)
1584	RSVA – Retail Transmission Network Charges, ($468,200)
1588	RSVA – Power, ($592,397)

Sub-total	($1,158,273)
Residual Balance in 1590	$ 540,928
Total	($ 617,345)

The Applicant's proposal is to collect these amounts from ratepayers over 2 years beginning May 1, 2008 via rate riders as per its response to Board staff interrogatory #53.

Discussion and Submission

<u>Continuation of Deferral and Variance Accounts</u>

The Board has already approved and defined, through the APH and associated letters, the period and functionality of deferral and variance accounts in the electricity distribution sector. Therefore, Board staff questions the necessity for the Applicant to request permission to continue using open deferral and variance accounts as per the APH.

<u>Request for New Deferral Accounts</u>

PUC is requesting three new deferral accounts:

a. Capital works during the non-rebasing years
b. MDMR account
c. Full-year return and depreciation on smart meter assets for 2009 and 2010

In evaluating the request for these new accounts, consideration should be given to each of the four regulatory principles which guide the establishment of new accounts:

1. Materiality
2. Prudence
3. Causation
4. Management ability to control

There are also two other considerations that are universal to the three deferral accounts that all parties should consider:

1. In the electricity distribution sector, the Board normally uses the APH, the Uniform System of Accounts, and supporting letters of directions to allow the use of deferral and variance accounts by utilities. Deferral and variance accounts open to one utility, and the usage of those accounts, are usually open to all distributors. Therefore, creating a new deferral account for one distributor may set a precedent for other distributors.

2. The establishment of new deferral and variance accounts that are not governed by the APH will impact the level of business risk that a utility is exposed to, which may directly affect the equity component of the return on capital.

The three new proposed accounts are discussed in more detail as follows

a. Capital works during the non-rebasing years

PUC is requesting to establish a deferral/variance account for capital works during the non-rebasing years to collect the revenue requirement costs associated with the cost of construction. PUC will record the cost of service associated with the new assets and will include depreciation and return but not PILs.

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

Rate base does impact revenue requirement, satisfying causality. PUC did not provide the total expected costs or calculations in its response to Board Staff Interrogatory #45, so materiality cannot be determined.

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 questions the need for this new account. Parties are invited to comment on this matter.

b. MDMR account

PUC is requesting a new deferral account to record MDMR costs.

PUC has not provided evidence of the materiality and causality of this request in its response to Board staff interrogatory #46.

The costs that PUC would incur are not known. This demonstrates that PUC has not satisfied the principles of causality and materiality. Provincial regulation O. Reg. 426/06, states that a distributor may not recover costs for functionality exceeding minimum functionality unless the costs are approved by the Board. At this time, it is unknown if MDMR costs will be considered excess functionality.

If the MDMR costs are considered to be cost recoverable, the Board already has defined through the APH, the variance and deferral accounts that could be used. One is account 1556, which is defined by the APH to "be used by the distributor to record incremental operating, maintenance, amortization and administrative expenses directly related to smart meters." However, account 1556 may not be the most appropriate mechanism as MDMR costs will be levied by the IESO. The IESO has not brought forward an application to the Board concerning recovery of these costs. Further, the appropriate recovery mechanism is also unknown. One mechanism could be a fee to distributors, for which account 1556 may be the most appropriate account. Another recovery mechanism could involve a wholesale market charge, thereby impacting the RSVAs instead of account 1556.

Board staff is unclear about the need for a deferral account specifically for MDMR when the Board has not yet approved if, and how, the MDMR costs will be recovered.

c. Full year return and depreciation on smart meter assets for 2009 and 2010

PUC is requesting a deferral account for the variance between the return on capital and depreciation expense associated with smart meters capital for 2009 and 2010 and that which is included in revenue requirement for 2008 and subject to the half-year rule. The mechanism to be used to calculate the balance for this deferral account is similar to the mechanism used in Appendix E of the EB-2007-0063 decision. However, the EB-2007-0063 decision implied that only distributors authorized to install smart meters under Ontario Regulation 427/06 and part of the combined proceeding could claim a return on capital for installed smart meters. As stated in its response to Board staff interrogatory #43, PUC agrees that it is not a distributor that has been designated for rapid deployment under Ontario Regulation 427/06.

Since PUC is not allowed to install smart meters as per Ontario Regulation 427/06, Board staff is not convinced that the principle of causality has been satisfied. Furthermore, PUC can request rate relief when and if Ontario Regulation 427/06 is modified to allow PUC to install smart meters or for the Board to provide guidance in regards to the smart meter deferral and variance accounts.. Granting the deferral account at this time may create a precedent for other distributors in regards to smart meter capital expenditures.

Parties are invited to comment on these observations.

<u>Treatment of account 1590</u>

The response to Board staff interrogatory #53 indicates a residual balance of $540,928 as at April 30, 2008 and that no principal balances are being forecasted beyond December 31, 2006. However, in response to VECC interrogatory #22, PUC stated that balances are being forecasted beyond December 31, 2006 and a different balance in the account is proposed of $534,945 as at April 30, 2008. PUC is invited to direct Board staff to evidence already filed that reflects the correct balance for account 1590 as at April 30, 2008 and to confirm whether the balance requested for disposition includes principal accruals post December 31, 2006.

An amount of $4,651,697 of regulatory assets was approved for disposition in the 2006 EDR. However, it is not clear whether the transfer to account 1590 occurred properly. The full amount of this transfer is not shown in the regulatory asset continuity schedule provided in response to Board staff interrogatory #50. Also, the impact of this transfer on the other regulatory assets is not clear.

Additionally, in the Phase 2 decision for the Review and Recovery of Regulatory Assets for the five large distributors (RP-2004-0117, RP-2004-0118, RP-2004-0100, RP-2004-0069, RP-2004-0064), the Board stated that:

> Also as of April 30, 2005, all four Applicants shall debit the Regulatory Asset Recovery Account (1590, Recovery of Regulatory Asset Balance) by the approved total recovery amounts. Starting May 1, 2005, revenue from the monthly rate riders shall be credited to the Regulatory Asset Recovery Account (1590). Interest shall continue to apply to this account. (Section 9.018)
>
> At the end of the three year period, at April 30, 2008, as there will be a residual (positive or negative) balance in the Regulatory Asset Recovery Account (1590), this balance shall be disposed of to rate classes in proportion to the recovery share as established when rate riders were implemented. (Section 9.019)

The Phase 2 decision quoted above suggests that the rate rider associated with account 1590 be removed as of May 1, 2008. Once the residual balance in account 1590 is finalized, the residual balance is to be disposed at a future proceeding. The final balance in account 1590 cannot be confirmed until after the current recovery period has expired, i.e. April 30, 2008. In addition, the Board's standard practice for the electricity sector is to defer disposition of accounts until the requested balance has been finalized and verified.

<u>Treatment of RCVAs and RSVAs</u>

The Applicant is applying for disposition of RCVA and RSVA accounts. The Board has recently announced that it intends to develop a streamlined process for account 1588 RSVA Power. This process could also include the remainder of the RCVA and RSVA accounts. The Board may wish to consider the impact of ordering disposition of these accounts upon that initiative.

~ All of which is respectfully submitted ~