2008 Electricity Distribution Rates
Espanola Regional Hydro Distribution Corporation (ERHDC)
EB-2007-0901

OM&A EXPENSES

A. SHARED SERVICES

1. Ref: Exhibit 1/ Page 45
   Espanola Hydro notes the following in regards to management services:

"Espanola Hydro has a management services agreement with PUC Services Inc. which commenced in 2006. It includes participation in Board Meetings, supervision of all staff, oversight/awareness/monitoring of daily operations, regulatory & legislative requirements, contract administration, purchasing, customer service, billing and collecting, financial requirement, revenue requirements including rate setting, human resources, preparation of annual budgets and forecasts. A billing/customer service agreement with PUC Services has been in place since December 1, 2001."

a) Please indicate whether the services listed above are shared.
b) If they are not shared services, please explain why.
c) If the above services are considered "shared services", please file the following information:
i. Type of services
ii. Total annual expense by service
iii. Rationale and cost allocators used for shared costs, for each type of service.

B. EMPLOYEE COMPENSATION

2. Ref: Exhibit 4

On Page 31, Espanola Hydro provides a breakdown of employee compensation from 2006 to 2008. Please provide the 2006 Historical Board approved amounts for total salary and wages and total benefits. Please provide the drivers for the increase or decrease for 2006 actual amounts as compared to the 2006 Board approved amounts.

3. Ref: Exhibit 4

On Page 32, Espanola Hydro provides a breakdown of "Total Costs charged to O&M" from 2006 to 2008. Espanola Hydro's 2006 actual, 2007 bridge and 2008 test year data indicate that the utility has only charged 84% of its total employee compensation costs to O&M each year. Please explain where the remaining amount of total compensation costs was charged in 2006, 2007 and 2008.

C. OM&A Expenses

4. General Question

a) Please confirm that Espanola Hydro has not made changes to the company's accounting policies in respect to capitalization of operation expenses and/or has not made any significant changes to accounting estimates used in allocation of costs between operations and capital expenses post fiscal year end 2004. If any accounting policy changes or any significant changes in accounting estimates have been made post 2004 fiscal year end, please provide all supporting documentation and a discussion highlighting the impact of the changes.

5. Ref: Exhibit 4

Espanola's application Exhibit 4 page 3 shows 2006 Board Approved Total Operations cost of $1,125,215. Per the 2006 EDR model worksheet "5-1 SERVICE REVENUE REQUIREMENT" cell F17 the Board approved total is $1,095,645, as shown below in Board Staff Table 1.

Board staff Table 1

	2006 Board Approved		
	Per Application $	Per Board Staff $	Difference
Operation	$ 188,791	$ 188,791	$ 0
Maintenance	$ 88,939	$ 88,939	$ 0
Billing and Collections	$ 223,645	$ 223,645	-$ 0
Community Relations	$ 1,253	$ -	$ 1,253
Administrative and General Expenses	$ 227,879	$ 237,792	-$ 9,913
Controllable OM&A	$ 730,507	$ 739,167	-$ 8,660
LV Charges	$ -	$ 135,448	-$135,448
Amortization Expenses	$ 216,028	$ 216,028	$ 1
Taxes other than income	$ 5,003	$ 5,003	$ -
Total Operating Costs	$ 951,538	$1,095,645	-$144,107
Other Operating Costs	$ 173,677	$ -	$173,677
	1,125,215	1,095,645	29,570

a) Please confirm that Espanola agrees with the Board Staff value $1,095,645, as found in the 2006 EDR model worksheet "5-1 SERVICE REVENUE REQUIREMENT" cell F17. If Espanola Hydro does not agree, please explain why not.

b) Please reconcile and explain the differences identified in Board staff Table 1 above.

c) Espanola Hydro has included an entry called "Other Operating Costs" in the amount of $173,677. Board Staff note that this amount includes "Interest On Debt to Associated Companies" and "Other Interest Expense". Please provide a complete explanation as to why Espanola Hydro believes that this amount should not be included.

6. Exhibit 4

Board Staff Table 2 below was prepared to review Espanola Hydro OM&A expenses. Note rounding differences may occur, but are immaterial to the questions below. This table removes from the 2006 Board approved controllable expenses, the Low Voltage charges.

Board Staff Table 2

	2006 Board Approved $	2006 Actual $	2007 Bridge $	2008 Test $
Operation	188,791	233,568	216,616	237,426
Maintenance	88,939	163,899	184,343	187,328
Billing and Collections	223,645	267,466	251,828	254,687
Community Relations	0	1,000	2,000	2,000
Administrative and General Expenses	237,792	326,591	286,325	282,788
Controllable OM&A	739,167	992,524	941,112	964,229
LV Charges	135,448			
Amortization Expenses	216,028	188,561	178,061	179,455
Taxes other than income	5,003	12,602	25,964	0
Total Operating Costs	1,095,645	1,193,687	1,145,137	1,143,684

Board Staff Table 3 below was created to review Espanola Hydro's OM&A forecasted expenses from the evidence provided in the application's Exhibit 4. Note rounding differences may occur, but are immaterial to the following questions. Board staff notes that Espanola Hydro are forecasting decreases to 2008 Controllable OM&A Expenses by $28,295 or (2.9%) from Actual 2006.

Board Staff Table 3

	2006 Board Approved $	Variance 2006/2006	2006 Actual $	Variance 2007/2006	2007 Bridge $	Variance 2008/2007	2008 Test $	Variance 2008/2006
Operation	188,791	44,777	233,568	-16,952	216,616	20,810	237,426	3,858
		6.1%		-1.7%		2.2%		0.4%
Maintenance	88,939	74,960	163,899	20,444	184,343	2,985	187,328	23,429
		10.1%		2.1%		0.3%		2.4%
Billing and Collections	223,645	43,821	267,466	-15,638	251,828	2,859	254,687	-12,779
		5.9%		-1.6%		0.3%		-1.3%
Community Relations	0	1,000	1,000	1,000	2,000	0	2,000	1,000
		0.1%		0.1%		0.0%		0.1%
Administrative and General Expenses	237,792	88,799	326,591	-40,266	286,325	-3,537	282,788	-43,803
		12.0%		-4.1%		-0.4%		-4.4%
Controllable OM&A	739,167	253,357	992,524	-51,412	941,112	23,117	964,229	-28,295
		34.3%		-5.2%		2.5%		-2.9%

Board Staff Table 4 below was prepared by Board staff to review Espanola Hydro's OM&A actual and forecasted expenses from the evidence provided in OM&A Cost Table in Exhibit 4. Note rounding differences may occur, but are immaterial to the following questions.

Board Staff Table 4

Cost Driver Review	2006	2007	2008
Opening Balance	$ 739,167	$ 992,524	$ 941,112
Dissolved Service Company			
Reallocation of management salaries	$ 110,404		
Harris support costs	$ 26,887		
Bad Debts sent to collector	$ 11,731		
Consulting fees - Audit, Legal PUC	$ 100,154	-$ 35,669	
Mgmt Salaries reallocated to Contract		-$ 13,980	
Labour - Overhead lines			$ 23,166
Unexplained Variance	$ 4,181	-$ 1,763	-$ 49
Closing Balance	$ 992,524	$ 941,112	$ 964,229

a) Please confirm that Espanola Hydro agrees with the three tables prepared by Board Staff presented above. If Espanola Hydro does not agree with any table, please advise why not and specify in which areas it does not agree. If Espanola Hydro determines that the tables require modification due to the difference reconciliation resulting from Board staff Table 1 above, please provide amended tables with full explanation of changes made.

b) Please provide a more comprehensive discussion on activities that created the significant increase in controllable costs from 2006 Board approved $739,167 to 2006 Actual $992,524.

D. GENERAL – REGULATORY COSTS

7. Please provide the breakdown for actual and forecast, where applicable, for the 2006 Board approved, 2006 actual, 2007 bridge year, and 2008 test year regarding the following regulatory costs and present it in the following table format:

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

a) Under “Ongoing or One-time Cost”, please identity and state if any of the regulatory cost is a “One-time Cost” and not expected to be incurred by the applicant during the impending two year period when the applicant is subject to 3rd Generation IRM process or it is “Ongoing Cost” and will continue throughout the 3rd Generation of IRM process.

b) Please state the utility’s proposal on how it intends to recover the “One-time” costs as a part of its 2008 rate application.

CAPITAL BUDGET

8. Ref: Exhibit 2/ Tab 1/Schedule 1/Page 2/Line 6.

i. Please confirm that Espanola’s definition of Rate Base is arithmetically as follows and consistent with the calculations of fixed assets as they relate to Capital Contributions and Grants:

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

ii. Please confirm that Gross Assets in Service includes Interest During Construction and Overheads

9. Reference: Exhibit 2/ Materiality Analysis/ Page 15.

Please confirm that the term “Cumulative Amortization” has identical meaning to “Accumulated Depreciation” used elsewhere in Exhibit 2.

10. Ref: Exhibit 2/ Capital Budget by Project / Page 26

Please confirm that Espanola has no projects for which a Leave to Construct under section 92 is required.

11. Ref: Exhibit 2/ Rate Base Summary Table/ Page 3

a. Please provide Espanola’s Code of Business Conduct.

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

i Net income;
ii Actual Return on the Equity portion of the regulated rate base (%);
iii Allowed Return on the Equity portion of the regulated rate base (%);
iv. Retained Earnings;
v. Dividends to Shareholders;
vi. Sustainment Capital Expenditures excluding smart meters;

vii. Development Capital Expenditures excluding smart meters;
viii. Operations Capital Expenditures;
ix. Smart meters Capital Expenditures;
x. Other Capital Expenditures (identify);
xi. Total Capital Expenditures including and excluding smart meters;
xii. Depreciation;
xiii Number of customer additions by class.

A	**B**	**$ Change (A-B)**	**% Change (A/B)**	**Cost Drivers for the change (increase or decrease) if the % change is either less than zero or more than 10%**
2003	2002			
2004	2003			
2005	2004			
2006 Actual	2005			
2006 Actual	2006 Board			

c. For the years 2002 to 2006 inclusive, please complete the following table including actual dollars and % where indicated. Please identify the cost drivers, as indicated in the table. Examples of cost drivers are: building new transformer station, replacement of obsolete poles, replacement of aging underground cables, etc. Please identify the type and amount of any one-time, unusual expenditure occurred in any particular year that caused the change outside the given threshold, as provided in the table. Please exclude the smart meters from the $ amount for the capital expenditure figures used in the table.

	Approved			
2007 Bridge Year	2006 Actual			
2008 Test Year	2007 Bridge Year			

12. Ref: Exhibit 2/ Rate Base Summary Table/ Page 3

a. Please provide an explanation for the variances in the rate base summary table including:

i. 2006 Year: Please provide a detailed explanation of the variances between 2006 Board approved and 2006 actual for each element of Utility Rate Base: - i.e., asset values at cost, accumulated depreciation, and allowance for working capital.

ii. 2006 Year: Please clarify why actual working capital for that year was as high as $79,199 above the Board-approved amount (i.e. 10.4% higher).

13. Ref: Exhibit 2/ Gross Assets Table/ Pages 13 through16

The table on page 13, 14 refers to A,B,C,D, etc. as explanations for the variance for each year. However, the table on page 16 does not provide an adequate explanation much beyond saying what the variance is. Please provide a more detailed explanation for each variance including, for example:

a. For 2006 Actual to Board Approved: A indicates that the reason for the variance is "a result of normal operating dispositions of fixed assets." Please describe what the normal operating dispositions are.

b. For 2006 Actual to Board Approved, there is an explanation below item G for projects 1830, 1835, 1840 and 1860. The explanation provided is that it "is the result of fully depreciated gross assets cost and related accumulated depreciation being adjusted in 2006" (our underline). Provide an explanation of the adjustments in 2006.

c. Provide a similar explanation for all the items on page 16.

14. Ref: Exhibit 2/ Capital Budget by Project/ Page 26

a. For each of the Capital projects please indicate what the basis is for undertaking the project including:

i. Was an asset condition assessment done for the replacement of physical distribution assets?

ii. Does the utility maintain reliability statistics and utilize them for determining when equipment should be replaced?

b. Please provide the basis for committing to the Pole, Towers and Fixtures project, estimated at $98,196 for 2008 test year.

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

d. Please confirm that all the 2008 test year capital projects will be in service by the end of that test year. For those that will not, please estimate the total carryover dollars to the following test year.

15. Ref: Exhibit 2/ Capitalization Policy/ Page 30

Please confirm that there has been no change in capitalization policy for Espanola. If there has been a change please provide details.

16. Reference: Exhibit 2/ Working Capital/ Page 33/ Line 11

Electricity Supply Expense and 15% thereof for Working Capital: 2006 actual to 2007: Please advise how much of the rise in cost (from $4,585,854 to $4,909,393) is due to increased purchased electricity unit price cost and how much is due to increased customer usage.

17. Ref: Exhibit 2 – page 220 states that “ERHDC has no major capital projects planned. The capital program is based on upgrading existing infrastructure to maintain reliability.”

Please indicate the relationship between the Service Reliability indicators and the 2008 capital expenditure program and describe the nature of that relationship.

COST OF CAPITAL

18. Re: Exhibit 1, page 161 – Changes in Methodology

Espanola Regional Hydro Distribution Corporation (“ERHDC”) states the following:

“The following is a summary of the changes in methodology requested by the ERHDC in the current proceeding:

a) Capital Structure

ERHDC has no current request to change the methodology addressing the capital structure. There is potential for future changes, however, the changes have not been finalized at the time of application.

b) Return on Equity

ERHDC has no current requests to change the methodology addressing Return on Equity. There is potential for future changes, however, the changes have not been investigated at this time."

Please explain further what potential changes ERHDC is contemplating, and the rationale that ERHDC believes would support these changes. What is the timeframe for these potential changes?

19. Re: Exhibit 6, pages 3-4 and Exhibit 1 – 2006 Audited Financial Statements – Capital Structure

ERHDC shows a negative equity component in the capital structure for the 2006 Board-approved and 2006 Actual years, but shows $1,365,916 in equity for 2007 bridge and $1217,114 for 2008 test years. The negative equity in 2006 is supported by ERHDC's Audited Financial Statements for 2006, which shows a deficit in Retained Earnings in the Balance Sheet.

Please provide further information on ERHDC's capital structure change between 2006 and 2007, including when it occurred and the reason for the change.

20. Re: Exhibit 6, page 4 – Short-term Debt

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

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

"The Board has determined that the deemed short-term debt rate will be calculated as the average of the 3-month bankers' acceptance rate plus a fixed spread of 25 basis points. This is consistent with the Board's method for accounting interest rates (i.e. short-term carrying cost treatment) for variance and deferral accounts. The Board will use the 3-month bankers' acceptance rate as published on the Bank of Canada's website, for all business days of the same month as used for determining the deemed long-term debt rate and the ROE.

For the purposes of distribution rate-setting, the deemed short-term debt rate will be updated whenever a cost of service rate application is filed. The deemed short-term debt rate will be applied to the deemed short-term debt component of a distributor's rate base. Further, consistent with updating of the ROE and deemed long-term rate, the deemed short-term debt rate will be updated using data available three full months in advance of the effective date of the rates."

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

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

21. Re: Exhibit 6, page 8 – Return on Equity

ERHDC states that it is requesting an equity return of 8.69% per the Board's formulaic approach as documented in Appendix B of the Board Report, with the final ROE for 2008 rate-setting purposes to be established based on January 2008 Consensus Forecasts and Bank of Canada data per the methodology in the Board Report. Please provide further information on the derivation of the 8.69% ROE shown in the table labeled "Return on Equity Calculation" in Exhibit 6 / Tab 1 / Schedule 4 showing the source data used, and identifying fully the data sources and date(s) of the data used.

22. Re: Exhibit 6, pages 3 to 5 and Exhibit 1, 2006 Audited Financial Statements – Long-Term Debt

ERHDC shows a long-term debt rate of 5.82% for the debt due to its municipal shareholders for 2007 and 2008 on page 5 of Exhibit 6, in contrast to the 5% rate for the debt in 2006. On pages 3 and 4 of Exhibit 6, ERHDC shows a long-term debt rate of 5% for 2006 and 2007, but 5.82% for 2008. At the bottom of page 4 of Exhibit 6, ERHDC states:

"ERHDC intends to reduce the long-term debt that is held by the municipal corporation shareholder to move the actual capital structure closer to the deemed capital structure of 60% debt and 40% equity to be in effect by 2010. The reduction of the long-term debt is being negotiated with the municipal shareholder at a rate of 5.82%."

Note 5 of ERHDC's 2006 Audited Financial Statements states the following:

"Amounts due to municipalities represent notes payable without security or specified terms of repayment. Interest at 5% per annum is paid on the notes payable."

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

"For rate-making purposes, the Board considers it appropriate that further distinctions be made between affiliated debt and third party debt, and between new and existing debt.

The Board has determined that for embedded debt the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt.

The Board has determined that the rate for new debt that is held by a third party will be the prudently negotiated contracted rate. This would include recognition of premiums and discounts.

For new affiliated debt, the Board has determined that the allowed rate will be the lower of the contracted rate and the deemed long-term debt rate. This deemed long-term debt rate will be calculated as the Long Canada Bond Forecast plus an average spread with "A/BBB" rate corporate bond yields. The Long Canada Bond Forecast is comprised of the 10-year Government of Canada bond yield forecast (Consensus Forecast) plus the actual spread between 10-year and 30-year bond yields observed in Bank of Canada data. The average spread with "A/BBB" rate corporate bond yields is calculated from the observed spread between Government of Canada Bonds and "A/BBB" corporate bond yield data of the same term from Scotia Capital Inc., both available from the Bank of Canada.

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

a) Please provide copies of the current debt instruments with the municipal shareholders.

b) Please indicate when the renegotiated debt instruments have been completed.

c) Please demonstrate if and how the renegotiated debt instruments, with respect to the proposed rate of 5.82% and other terms and conditions (fixed versus variable rate, renegotiable, callable on demand) comply with the Board's policy for long-term debt rate treatment for rate-setting purposes as documented in section 2.2.1 of the Board Report.

REVENUE OFFSETS AND SPECIFIC SERVICE CHARGES

23. Ref: Exhibit 7, Page 2

The value used in the 2008 Test Year Other Operating Revenue (Net) on Exhibit 7 Page 2 is reported as $156,075. The application reference Exhibit 3, Page 14 identified this value as the 2007 Bridge value. Please confirm the number as presented is correct or provide a corrected amended schedule.

Ref: Exhibit 3, Page 14

Exhibit: 3

Espanola Regional Hydro Distribution Corporation (ERHDC)

OTHER DISTRIBUTION REVENUE

	2006 Board Approved	2006 Actual	Variance form 2006 Board Approved	2006 Actual	2007 Bridge	Variance form 2006 Actual	2007 Bridge	2008 Test	Variance form 2007 Actual
	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)
Other Distribution Revenue									
Distribution Services Revenue									
Retail Services Revenues	852	5,610	4,758	5,610	5,760	150	5,760	8,650	2,890
Service Transaction Requests (STR) Revenues	2	262	260	262	100	(162)	100	125	25
Electric Services Incidental to Energy Sales									
Transmission Charges Revenue									
Transmission Services Revenue									
Interdepartmental Rents									
Rent from Electric Property	27,791	40,283	12,492	40,283	38,900	(1,383)	38,900	39,500	600
Other Utility Operating Income									
Other Electric Revenues	28,397	68,951	40,554	68,951	41,895	(27,056)	41,895	28,957	(12,938)
Late Payment Charges	9,185	11,378	2,193	11,378	12,200	822	12,200	12,200	0
Sales of Water and Water Power									
Miscellaneous Service Revenues	22,388	45,821	23,433	45,821	57,220	11,399	57,220	57,220	0
Provision for Rate Refunds									
TOTAL	88,615	172,305	83,690	172,305	156,075	(16,230)	156,075	146,652	(9,423)

a) Please provide an explanation as to why the number for Total Revenue Offsets for 2006 Board Approved ($88,615) is different from the approved 2006 EDR Model, Sheet 5-5, Cell D25 ($125,226).

b) Please state whether or not Specific Service Charges are included in the above table and if so, in which line item. If not, please state why not and make any necessary adjustments to the application.

c) Please provide a description of each variance from 2006 Board Approved versus 2006 Actual.

d) It is shown that the “Other Electric Revenues” decreases significantly in 2007 to $41,895 and in 2008 Test to $28,957. Please provide a complete explanation of this change.

e) The total amount for Other Distribution Revenue is shown as follows:

2006 Actual - $172,305
2007 Bridge - $156,075
2008 Test - $146,652

Please provide a thorough explanation of the decreases.

FORECASTING

24. Ref: Exhibit 3/ page 5

On page 5, the Applicant states that the weather normalization that was generated was performed by Hydro One.

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

25. Ref: Exhibit 3/ pages 5 to 9

In pages 5 to 9 the Applicant explains how it developed its 2008 load forecast. The approach used appears to Board staff to be that the Applicant:

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

Please:

a) Confirm that the above is the essence of the Applicant's load forecasting methodology: If any aspects are incorrect, please identify them and provide a description of the correct methodology.

b) Provide a description of the difference between the approach used for weather sensitive loads and that used for non-weather sensitive loads.

26. Ref: Exhibit 3/ pages 7 and 8

Espanola outlines on pages 7 and 8 the method used for determining the class loss factors.

Please provide:

a) a detailed description of this process, and

b) supporting values and calculations.

27. Ref: Exhibit 3/ pages 8 and 9

The Applicant notes on pages 8 and 9: "Billed kW is estimated based on a load factor calculated using a ratio of historical billed kW to historical retail kWh, by class."

Please provide:

a) a detailed description of this process, and

b) supporting values and calculations.

28. Ref: Exhibit 3/ pages 5 to 9

In pages 5 to 8, Espanola explains how it determined the 2004 retail normalized average use per customer (NAC) for each class and how it has used this value for other years. Board staff questions whether this provides an accurate weather-normalized energy usage in historical years and if it allows for the possible change in energy usage per customer over the 2002 – 2008 period due, for example, to Conservation and Demand Management. The minimal amount of weather normalization and the constant retail energy assumption could potentially lead to forecasting errors.

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

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

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

iii. the values of the weather conversion factors used,

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

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

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

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

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

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

iii. as a footnote to the table, for each of the weather-sensitive classes describe in detail the trend analysis performed in ii. above.

c) Please file an updated version of the historical/forecast table in Exhibit 3, page 9, utilizing the weather corrected data determined in b) above.

COST ALLOCATION AND RATE DESIGN

29. Low Voltage

Reference: Exhibit 1 / pages 182 and 188

Account 4750 ‘Charges – LV’ shows an expense of $119,393 in the bridge year 2007, and a forecast amount in the test year of $139,296.

a. Please provide an explanation of the increase in this expense item, including a detailed history of recent billing quantities that would support the forecast amount.

b. Please indicate the proportion of LV Charges that is comprised of Shared Lines charges, and provide a calculation of the effect that a decrease of 8.4% applicable to the Shared LV Line charge would have on the forecast of Account 4750.

c. Please provide a brief explanation of Espanola’s LV expenses and revenues from the rate adder since 2006, considering that

- Espanola received approval for an expense of $120,398 in 2006,
- at Exhibit 2, page 33 the total for Account 4750 shows an actual cost of $16,843,
- at Exhibit 5, page 4, Account 1550 LV Variance is expected to have a positive balance of $62,681.

30. Cost Allocation

Please file the “rolled-up” Cost Allocation Informational Filing EB-2007-0003 as an official part of the record of this Application. Run 2 is the only one requested. (The hard copy reply needs to include only the input tables (Sheet I3 – I8) and Sheets O1 and O2.)

31. Street Light Revenue to Cost Ratio

Ref: Exhibit 8 / page 8, and Exhibit 9 / page 25

a. Please give the rationale for raising the Revenue to Cost Ratio to an amount of only 29%.

b. Please provide a calculation of the rates that would yield a ratio of 70% for the street lighting class, and a calculation of the total bill impact on the Street Light class if the distribution rates were implemented.

32. Rate Design

GS < 50 kW

Ref: Exhibit 8 / page 9

Please provide the rationale for proposing an increase in the monthly service charge for the GS < 50 kW class, considering that the proposal is to decrease revenue from this class and that the currently approved monthly service charge appears to be within the range of customer-related costs in the Informational Cost Allocation study.

Regulatory Asset Recovery Rate Riders

33. Period of Recovery

Exhibit 1/ pages 155 – 157, and Exhibit 5 / page 6

In Exhibit 5, the fourth step in designing the rate riders divides the amount of recovery over two years. In Exhibit 1, the rate impacts are shown for typical customers in each class. Considering that the impacts for most customers are not very large, why is the full recovery not designed for a single year?

34. Rate Rider Sentinel Lights

Reference: Exhibit 5 / pages 4 and 5

a. Calculation of the 2008 Rate Rider for Sentinel Lights yields a result of $0.1558 per kW per month, whereas the entry on page 5 is $0.1591. Please explain the source of this discrepancy (eg rounding error, not including carrying costs from page 4), and if appropriate please provide a single correct amount.

Reference: Exhibit 1 / page 158

b. The rate rider is shown in the Impact calculation as $0.10170, and is not equal to either amount in part (a). Please explain the discrepancy or change whichever entry is incorrect.

35. Rate Rider Street Lights

Reference: Exhibit 3 / page 10, and Exhibit 5 / page 5

a. The load for Street Lights is shown in Exhibit 3 as being 1718 kW, but the rate rider is calculated in Exhibit 5 using a load of 1446 kW, which yields a rate rider of $0.7666. Please explain the discrepancy in the amount of kW, or change the incorrect entry.

Reference: Exhibit 1 / page 157

b. The rate rider is shown in the Impact calculation as $1.14050, and is not equal to the rate rider in part (a) using either value of kW mentioned there. Please explain the discrepancy, or change whichever entry is incorrect.

36. Retail Transmission Service Rates

Wholesale Transmission Rates were changed effective November 1, 2007.

a. Please provide information on the quantity of load that is forecast under each of the Wholesale Transmission charge determinants, and show the forecast cost under the wholesale rates previously in effect and those now in effect.

b. Please provide retail transmission service rates that would recover the forecast costs under the new wholesale transmission rates.

c. Please provide updated calculations of customer impacts using the Retail Transmission Service Rates calculated in part (b), together with such corrections as may be appropriate to rate riders and any other rates.

LOSS FACTORS

37. References:

i. Exhibit 4, Tables titled “Loss Adjustment Factor Calculation” and “Total Utility Loss Adjustment Factor”
ii. Exhibit 4, Materiality Analysis on Distribution Losses
iii. Exhibit 9, Existing Rate Schedule
iv. Exhibit 9, Proposed Rate Schedule
v. Exhibit 1, Explanation of Host and Embedded Utilities

The 1st reference provides calculations for distribution loss factors (DLF) for 2004 to 2006 and proposed values for total loss factor (TLF). The 2nd reference provides a narrative on distribution losses. The 3rd and 4th references respectively provided currently approved and proposed TLFs. The 5th reference provides an explanation of host and embedded utilities.

a. The two tables in the 1st reference provide a proposed DLF of 4.95% i.e. 1.0495 (based on the average of 2004 to 2006), a Supply Facilities Loss Factor (SFLF) of 1.0045 and a TLF of 5.43% i.e. 1.0543.

- Please provide a rationale for proposing that the 2008 loss factor be an average of the loss factors for 2004-2006 rather than some lower factor such as a replication of the 2006 loss factor of 1.03938.

- Please explain the significance of the second last number (0.0048) in the Total column.

b. The 2nd reference addresses the “distribution” loss factor of 1.0724 in the currently approved 2007 rates and 1.0543 proposed for 2008. Further the narrative states that the decrease in the loss factor applied for in this application is 1.7%.

- Please confirm if “distribution” label is incorrect and “total loss factor” is the correct label for these numbers.

- Please explain how the 1.7% figure is obtained.

c. Given that Espanola Hydro is embedded in the Hydro One Networks Inc. (HONI) distribution system (5th reference), please confirm if the DLF values provided include the HONI loss factor of 3.4% for embedded LDCs.

- If this is not correct, please confirm if losses that occur in the HONI distribution system are included in the SFLF and provide a breakdown by separating out the HONI losses.

DEFERRAL AND VARIANCE ACCOUNTS

38. Ref: Exh1//Pg33

The applicant is requesting a new deferral and variance account for the Late Payment Class Action Suit.

a. Please provide the regulatory precedent for the collection of these costs in this proposed deferral account?

b. Please provide the justification for this account?

c. Please provide the journal entries to be recorded?

d. When does the applicant plan to request disposition?

e. Since the costs or fees are not known, what would be the basis of the approval to record these amounts in a deferral account?

f. Please provide a brief description of this account.

39. Ref: Exh1//Pg33

The applicant is requesting a new deferral and variance account for Meter Data Management Repository Account (MDMR).

a. Please provide the regulatory precedent for the collection of these MDMR costs in this proposed deferral account.

b. Please provide the justification for this account.

c. What are the journal entries to be recorded?

d. When does the applicant plan to ask for its disposition?

e. Since the costs or fees are not known, what would be the basis of the approval to record these amounts in a deferral account?

f. Please provide a brief description of this account.

40. Ref: Exh2/30

a. Is ERHDC using the Board-prescribed interest rate, as per the Board's letter to LDCs dated November 28, 2006, for construction work in progress (CWIP) since May 1, 2006?

b. If not, what interest rate has ERHDC been using for CWIP?

c. If not using the Board-prescribed interest rates, please estimate the impact on ratebase, revenue requirement, and CWIP if ERHDC did use the prescribed interest rates?

41. Ref: Exh5/Pg2 -3

Please provide a brief description of all outstanding deferral and variance accounts.

42. Ref: Exh5/Pg5

a. Please explain the composition of the balance in Account 1508.

b. Is there a balance in account 1508 sub-account OMERS that represents costs paid to OMERS by an affiliate of the LDC?

c. If yes, what is the balance?

d. If yes, have the billings by the affiliate to the LDC reflected an increase in OMERS pension costs beginning in the period that costs were collected in 1508? If so, what has been the increase in burden beginning in this period? What is the period?

e. If no, what does the balance in account 1508 sub-account OMERS represent?

f. For low voltage costs from Hydro One what account did the applicant use before May 1, 2006? After May 1, 2006?

43. Ref: Exh5/Pg4&5,

The applicant is requesting disposition of regulatory variance accounts in Exh5/Pg4. Most of the totals do not agree to totals reported to the Board under S.2.1.1 of the Reporting and Record Keeping Requirements for the period ending December 31, 2006. Please provide the information as shown in the attached continuity schedule for regulatory assets (excel spreadsheet) and provide a further schedule reconciling the continuity schedule with the amounts requested for disposition on Ex5/Pg 5. Please note that forecasting principal transactions beyond December 31, 2006 and the accrued interest on these forecasted balances and including them in the attached continuity schedule is optional.

44. Ref: Exh5/Pg4

ERHDC is seeking disposition of $4,625 of Account 1570 as at April 30, 2008.

a. Was this balance of transition costs included in Account 1590 when the transfer was made to debit 1590 and credit 1570, upon approval of 2006 EDR regulatory assets?

b. Given that the account should have a zero balance upon approval of the 2006 EDR regulatory assets, please confirm that ERHDC is seeking disposition for the $4,625 amount.

c. If so, please provide a breakdown of this balance identifying each type of cost included and provide the regulatory precedent for this request.

45. Ref: Exh5/Pg4, Exh1/Pg175,176, Exh1/Pg191

The regulatory asset balances as at December 31, 2006 in Ex5/Pg4 do not match the balances at the same date in the audited financial statements on ExH1/Pg175&176. For example, the RSVA total of ($107,226) on the audited financial statements do not match the total of 1580, 1584, 1586, and 1588 on Ex5/Pg 4 of $146,406.

a. Please explain all differences between the two schedules.

b. On Ex1/Pg191, ERHDC states that there are no reconciling items for the deferral and variance accounts. Please explain why there were no reconciling items on this schedule. Please update the reconciliation on Exh1/p191 with the differences.

46. Ref: Exh5/Pg 5

a) On Ex5/Pg 5, the December 31, 2006 balances are used as the basis for recovery, instead of April 30, 2008 balances as per usual Board practice. The April 30, 2008 balances are to be comprised of the December 31, 2006 balances with interest forecast to April 30, 2008. Please revise this schedule with the balances as at the correct date.

b) Are principal balances on 1590 being forecasted beyond December 31, 2006 and included in the amount for disposition in the schedule?

47. Ref: Exh5/Pg4

Does ERHDC have a business relationship and service agreements with any retailers? If yes, why is there a zero balance in 1518 RCVA Retail and 1548 RCVA STR?

PILS

48. For the 2006 tax year, please provide the following:

i. Actual federal T2 tax return and supporting schedules – signed original and any returns that were subsequently amended and re-filed;

ii. Actual Ontario CT23 tax return and supporting schedules – signed original and any returns that were subsequently amended and re-filed;

iii. Financial statements that were submitted with the tax returns to the Ministry of Finance;

iv. Notices of Assessment, and any Notice(s) of Re-assessment, including Statement of Adjustments, received from the Ministry of Finance for the 2006 tax year; and

v. Any correspondence between the Ministry of Finance and Espanola regarding any tax items, or tax filing positions that may be in dispute, or under consideration or review, that may affect the tax situation of the utility for 2006 or future years.

49. Reference Exhibits: Exhibit 1, Audited financial statements, Note 14, Loss carry-forwards

In note 14 of the 2006 audited financial statements in Exhibit 1, the loss carry-forwards are shown as $115,272. In Exhibit 4, page 36, the loss carry-forwards are disclosed as $457,257.

Please explain why the difference exists.

What is the correct amount?

50. Reference Exhibits: Exhibit 4, 2007 and 2008 Taxable Income Projections, pages 39, 43 and 45

Please provide a schedule that explains the other additions and other deductions used in the calculation of PILs.

Excess interest was calculated on Exhibit 4, page 45, but the deduction of this excess interest was not shown in the PILs calculations for 2007 and 2008. Please explain why the deductions were not made.

In the March 2007 Budget, the government indicated its intent to limit the deduction of interest expense by reference to the Board's deemed structure. Please explain why the applicant plans to have excess interest in 2008 when it is not tax efficient to do so.

SMART METERS

51. Ref: Exhibit 1 /Draft Issues List

Matter: Is the proposed plan for smart meter installations in 2009 appropriate?

In the 1st paragraph of page 35 (under "Draft Issues List"), Espanola Regional Hydro states: "In this rate application ERHDC has not included any costs related to Smart Metering. ERHDC's smart meter plan for installation is to commence in 2009." And in the next paragraph, Espanola Regional Hydro adds: "To cost-effectively plan for the deployment of smart meters and ensure due diligence, ERHDC has come together with other Northern Ontario LDC's and through a concentrated effort along with the assistance of Util-Assist Inc. has examined the benefits of a collaborative approach to planning as well as procurement of AMI and Installation services."

Espanola Regional Hydro is not one of the thirteen licensed distributors authorized by Ontario Regulation 427/06 to conduct discretionary metering activities with respect to smart meters.

i. In light of its “un-named” status, please identify under what authority Espanola Regional Hydro has undertaken smart meter activity.

ii. Please identify any smart metering capital and O&M costs that Espanola Regional Hydro is seeking approval of, or recovery of, in its 2008 rate application?

iii. Please confirm whether Espanola is planning to continue the Smart Meter rate adder in 2008, and if so, state the level of the rate adder.