Canadian Niagara Power Inc. (Re)

Ontario Energy Board Decisions

Ontario Energy Board

Panel: Paul Vlahos, Presiding Member; Ken Quesnelle, Member

Decision: July 15, 2009.

Nos. EB-2008-0222, EB-2008-0223

2009 LNONOEB 85

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B); AND IN THE MATTER OF applications by Canadian Niagara Power Inc. - - Eastern Ontario Power, Canadian Niagara Power Inc. -- Fort Erie for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2009.

(164 paras.)

DECISION

INTRODUCTION

1 Canadian Niagara Power Inc. ("CNPI") is a wholly-owned subsidiary of FortisOntario Inc. CNPI owns and operates distribution businesses in the following three territories; Fort Erie, Port Colborne and Gananoque (or Eastern Ontario Power). Currently the three service areas have separate rates.

2 CNPI submitted a separate rate application for each of these service territories and the Board gave them file numbers as follows:

* CNPI -- Eastern Ontario Power EB-2008-0222,
* CNPI -- Fort Erie EB-2008-0223, and
* CNPI -- Port Colborne EB-2008-0224.

3 While the applications are separate, because they have been prepared by CNPI and contain some common elements and the intervenors are the same, the Board decided to deal with all three applications at the same time. However, as the evidentiary phase for the Port Colborne application has not concluded, this decision pertains to only the Fort Erie and Eastern Ontario Power ("EOP") applications. The issuance of these two decisions now will reduce the impact of retroactive rate increases for the affected customers.

4 The intervenors of record for all three applications are: the Association of Major Power Consumers in Ontario ("AMPCO"), Energy Probe Research Foundation ("Energy Probe"), the School Energy Coalition ("SEC") and the Vulnerable Energy Consumers Coalition ("VECC"). AMPCO was not active in these proceedings.

5 Fort Erie supplies electricity to approximately 16,000 customers. Its service territory is mainly the Town of Fort Erie. The Fort Erie application is seeking approval of $9,827,418 as the 2009 revenue requirement.

6 EOP supplies electricity to approximately 3,650 customers. Its service territory includes the Town of Gananoque and some parts of the Township of Leeds and the Thousand Islands, of the Township of Frontenac Islands and of the City of Kingston. The EOP application is seeking approval of $2,359,739 as the 2009 revenue requirement. The

EOP application also seeks approval to eliminate the current General Service 50 to 4,999 kW -- Time of Use class, in accordance with a previous Board decision (EB-2007- 0594), and to re-classify any customers in that class to the General Service 50 to 4,999 kW class.

7 The applications include a proposed harmonization of rates for the Fort Erie and EOP service areas with the exception of certain aspects that are specific to each service area, such as loss adjustment factors, transmission service rates and low voltage costs recovery. There is no harmonization proposed for Port Colborne.

8 The evidentiary phase of the Fort Erie and EOP applications concluded at the end of the oral hearing on April 23, 2009 and the filing of undertakings on April 30, 2009. CNPI filed an Argument-in-Chief on the two applications on May 14, 2009. Submissions by intervenors and Board staff were received by May 29, 2009 and Reply Argument was received on June 15, 2009.

9 The full record of the proceeding is available at the Board's offices. The Board has summarized the record in this Decision only to the extent necessary to provide context for its findings.

CAPITAL EXPENDITURES

10 The table below shows the proposed capital expenditures for Fort Erie and EOP for 2009 and compares them with prior years.

Capital Expenditures (excluding Smart Meters)

	2006 Actual	2007 Actual	2008 Bridge	2009 Test
CNPI – Fort Erie	$3,949,000	$4,501,000	$4,139,000	$4,110,000
CNPI – EOP	$264,000	$2,798,000	$967,000	$868,000

11 Board staff and VECC did not take issue with CNPI's proposed capital expenditures for the 2009 Test Year in either service area.

12 SEC stated that the Board does not have the context to assess the value of CNPI's capital investment as CNPI had an opportunity to provide its business plan and declined to do so. SEC submitted that the Board should compel CNPI to file with the Board its current long term business plan, with all narrative, and with all back up analysis, prior to the end of this year. SEC noted that this would not affect current rates but rather provide the Board increased visibility on CNPI and assist the Board in future CNPI cost-of-service rate applications.

13 CNPI responded that it has filed its business plans. This matter was specifically addressed in the SEC's motion on March 12, 2009, where the Board rejected the SEC's request to compel CNPI to provide additional information.

14 Energy Probe noted that CNPI considers age as the primary factor for replacing cables and argued that, although replacement of aging cables may be necessary, it is not apparent from the evidence that age is a reliable proxy for cable condition. Rather, diagnostic testing would provide a more objective basis for assessing the actual condition of distribution plant with age being used as one factor for selecting the plant to be tested. Energy Probe submitted that CNPI should provide diagnostic testing in future rate applications to support plant replacement rather than rely on age of the plant as the principal criterion.

15 CNPI responded that diagnostic testing can be very expensive and results are probability based. In a smaller utility like CNPI, with limited underground assets, it is unlikely there will be sufficient test results available to build a dependable database on which to draw probabilistic conclusions. CNPI also stated that its visual inspections, required by the *Distribution System Code*, combined with past operating experience are a reasonable approach for prioritizing future plant replacement.

16 CNPI has included capital expenditures to improve the load carrying capacity of the circuits feeding downtown Gananoque at a projected cost of $100,000. Energy Probe noted that, in cross examination, CNPI's witness acknowledged that the Gananoque load carried by this feeder has declined since its peak of 14 MW in the summer of 2008 to a forecast peak of 11 MW in 2009. Energy Probe noted that, according to the witness, the East side line described in this project is probably capable of carrying the 11 MW load that is now forecast for the downtown Gananoque area. Energy Probe submitted that, because this line is only required to carry the entire downtown load under contingency conditions (i.e. when the West line is out of service) and because the line is capable of carrying the current forecasted load, this project should be postponed until such time as it becomes necessary.

17 CNPI responded that Energy Probe assumes that the East line conductors, connectors and ancillary line equipment have not lost any of their current carrying capacity over their life. Good utility practice suggests that the utility will recognize weaknesses in the distribution system and take action to address those weaknesses in order to avoid jeopardizing the integrity of the system and provide reliable service. EOP has recognized a weakness associated with the East line and has implemented a plan to address that weakness. Energy Probe's submission that EOP defer the project until it is necessary (presumably when the line can no longer support the load) is not a reasonable solution and will unnecessarily expose the residents and customers of Gananoque to power outages.

Board Findings

18 SEC asked the Board to compel CNPI to file with the Board its current long term business plan, with all narrative, and with all back up analysis, prior to the end of this year. This, in the Board's view would be inconsistent with, and in fact contrary to, the Board's normal processes and expectations by the stakeholder community generally. The purpose of this proceeding is to rebase rates for the duration of the current IRM plan based on 2009 as the test year. The Board is doing so on the evidence adduced, which included the filing of available business plans from CNPI, and having considered motions regarding the production of additional information. SEC is in fact rearguing what it had already argued in its March 12 motion before the oral hearing, in which it was not successful. The Board sees no compelling reasons to make the direction suggested by SEC.

19 Energy Probe has not suggested that any adjustment be made by the Board to the proposed capital expenditures for cable replacement for Fort Erie, and the Board will not make any adjustments. The Board is satisfied on the evidence that the proposed cable replacement is a reasonable undertaking as other cables at the same station (Station 12) and of the same vintage were replaced in 2000 or 2001 due to failures.

20 Energy Probe suggests that CNPI should provide diagnostic testing in future rate applications to support plant replacement rather than rely on age of the plant as the principal criterion. The Board is not prepared to make such blanket direction in this case for the reasons cited by CNPI. Specifically, CNPI has indicated that it has considered the potential benefits of more analytical testing procedures and has determined it may not be fruitful in their situation given the relatively small groupings of common assets. The Board accepts this rationale.

21 For the reasons cited by CNPI, the Board is not convinced by Energy Probe's argument that the capital expenditures to improve the load carrying capacity of the circuits feeding downtown Gananoque should be postponed. CNPI's capital expenditures are in line with historic spending and are primarily driven by sustaining and enhancement initiatives. A tenet of sound asset management is to smooth out the replacement of aging assets over time in a manner that seeks to optimize the useful life of the assets as well as well as their serviceability. CNPI's approach is consistent with this desirable methodology in that it has prioritized its sustaining/enhancement projects in such a way as to consider both the need to smooth its capital spending and optimize the useful life of the assets while timing their replacement in anticipation of a capacity shortfall. All three elements of this methodology must be considered in balance. Energy Probe's suggested approach places too high an importance on the capacity element which if applied to all system components would result in unmanageable peaks and valleys of construction and spending activity.

WORKING CAPITAL ALLOWANCE (WCA)

22 CNPI has used the standard methodology of calculating the WCA as 15% of the sum of controllable expenses and the cost of power. CNPI has documented that the WCA differs for all three of the service area applications depending on circumstances. For example, Fort Erie is not embedded to Hydro One Networks, and so LV charges do not factor into the determination of its WCA. CNPI has noted that it used the RPP price of $0.0545/kWh from the April 11, 2008 Regulated Price Plan Report of the Board to proxy the commodity price, and used RTS and Wholesale Market Charges from the Board's April 21, 2008 Rate Order, in determining the Cost of Power.

23 No party took issue with the methodology of determining WCA. Parties noted the need to update certain inputs in calculating the final WCA value, and CNPI agreed.

Board Findings

24 The Board notes that there is concurrence by all parties on this issue. Consistent with the Board's policy and practice, the Board agrees that, for the purposes of determining CNPI's 2009 distribution rates, the working capital allowance would be updated to reflect the current Board-approved transmission rates and the most current RPP commodity estimate available, namely $0.06072/kWh, from the Board's Regulated Price Plan Report of April 15, 2009.

25 The Board directs CNPI to submit with the draft rate order an updated Exhibit 2, Tab 4, Schedules 1 and 2, for each of the Fort Erie and EOP service areas, as support for that recalculation. CNPI should identify the commodity, RTS, Wholesale Market Service Charge and other applicable rates used in the Cost of Power update. The updated schedule shall also include any changes as the Board determines elsewhere in this decision.

LOAD FORECAST

26 CNPI used a combination of weather normalization work completed by Hydro One Networks and more current data from the Ontario Demand Forecast produced by the IESO.

27 Hydro One Networks had determined the relative percentages of distribution system loads that are sensitive and non-sensitive to influences of weather. The IESO had developed a measure of the effect of weather on the Ontario Loads. CNPI combined the two factors creating "uplift factors" that were used to proxy the impact of weather on its historic loads and to develop weather adjusted forecasts.

28 CNPI analyzed the microeconomics of both Gananoque and Fort Erie in order to produce its customer forecasts for the two communities. The parties did not raise any issues related to CNPI's customer forecasts. Some parties raised a number of concerns with CNPI's load forecast methodology and this section deals with those.

29 The following tables provide a summary of the actual, normalized actual and forecasted throughput volumes for the 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test year for each service area.

CNPI – Fort Erie Volumes (kWh)

2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
304,511,490	287,341,134	297,196,138	299,924,558	304,156,931

CNPI – EOP Volumes (kWh)

2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
85,815,078	75,398,070	66,086,052	65,252,488	62,979,630

30 Despite some reservations that related to weather normalization correction factor and to a lesser extend the future CDM effects, Board staff submitted that the load forecasts are reasonable.

31 VECC, supported by SEC, noted that the IESO weather normalization methodology captures the weather impacts across the entire province and, in doing so, reflects weather conditions and the amount of weather sensitive load across the entire province. As a result, the factor is not representative of either Fort Erie's or EOP's service area. Indeed, CNPI acknowledged this point during the oral phase of the proceeding. VECC also noted that the specific adjustment factor developed for each service area (i.e., the ratio of total load to weather sensitive load) is problematic. The definition of "weather sensitive" load assumes that all residential and GS[less than]50 class loads are weather sensitive when this is readily acknowledged as not being the case. Also, the factor works such that the higher the portion of weather sensitive load the lower the weather normalization adjustment, which is a counter intuitive result. Finally, CNPI has acknowledged this factor does not correct for the fact the IESO adjusts for weather conditions that are different than those in CNPI's service areas.

32 VECC submitted the Board should encourage CNPI to improve its load forecast methodology and noted that a number of electricity distributors have developed load forecast methodologies that utilize load conditions to produce weather normalized results.

33 With respect to the results, VECC noted that when comparing historical usage with forecast usage one would expect the historical values to be both higher and lower due to annual weather conditions. However, with respect to Fort Erie, VECC argued that the forecast average use values for 2008 and 2009 are too low. For the Residential class the historical results are higher than the projected average use except for two years (2004 and 2006) and in one of the two the difference is less than 0.2%. Similarly, for the GS[greater than]50 class, the historical results are less than the forecast for 5 out of the 6 years and for the one year where there is an exception the difference is only 0.6%. For the GS[less than]50 class the projected average use is less than that in any of the previous six historical years. In VECC's view the main reason for this is the flawed weather normalization methodology used by CNPI. VECC recommended that, at a minimum, the Board should direct CNPI to drop the utility- specific adjustment factor and rely only on the IESO adjustment factor. VECC argued that the utility-specific adjustment factor yields counter-intuitive results and does not properly adjust for service area specific conditions.

34 However, in VECC's view, given the acknowledged shortcomings of the IESO factor, a preferable approach would be to adopt the 6 year average historical per customer use value for each class as the basis for forecasting 2008 and 2009 volumes.

35 With respect to the results for EOP, VECC submitted that based on the historical data the forecast average use values for the Residential are reasonable. However, the GS[less than]50 and GS[greater than]50 (Regular) values used for 2009 are too low. For the GS[less than]50 class and the GS[greater than]50 (Regular) class, the proposed 2009 average use values are less than average use values in any of the previous 6 years. Similar to Fort Erie, in VECC's view the main reason for this is the flawed weather normalization methodology used by CNPI. Again, at a minimum VECC recommended that the Board should direct CNPI to drop the utility- specific adjustment factor and rely only on the IESO adjustment factor for the reasons outlined above. However, in a similar manner as outlined above, in VECC's view, a preferable approach would be to adopt the 5 year average historical per customer use value for each class as the basis for forecasting 2009 volumes. The use of a 5 as opposed to 6 year average is based on the cited problems with the 2002 and 2003 data.

36 CNPI responded to VECC's submissions as follows.

* CNPI's weather normalization methodology was based on the published IESO weather normalization factors which were modified by service area specific "uplift factors" determined from the ratio of weather sensitive and non-weather sensitive loads as determined by Hydro One Networks Inc. on CNPI's behalf in the 2006 Cost Allocation Filing.

* The results were intuitively reliable because they are based on actual data and are reflective of the historical results that CNPI has observed.
* CNPI incorporated the effects of CDM into its load forecasting by projecting previously realized CDM impacts into the Test Year forecast.
* While VECC's proposal may appear reasonable on the surface, it does not take into account the extensive review that CNPI had provided in its applications to compensate for the first-hand familiarity CNPI has with its customers. CNPI provided the Board with a thorough understanding of the communities serviced and the customer classes and CNPI's load forecast is a function of this knowledge and experience.

Board Findings

37 The parties that commented on CNPI's customer forecast submitted that they were reasonable and the Board accepts CNPI's proposed customer count.

38 The remaining issue of substance is the appropriateness of the use of the "uplift factors" that have been devised by CNPI to compensate for the variance between the IESO's correction factor and the local ratios between weather sensitive and non-sensitive loads as determined by Hydro One.

39 The hypothetical mathematical scenarios posited by VECC in its examination of the evidence were readily agreed to by CNPI. There is no dispute regarding the unsuitability of CNPI's methodology if one were to exchange the data used for the theoretical data in the illustrative example presented by VECC.

40 The Board is not convinced that the approaches suggested by VECC would produce results that are preferable to the one proposed by CNPI. CNPI has attempted to produce projections based on its empirical analysis of local results. The combination of relatively stable historic trends and CNPI's careful analysis of the historic results provides the Board with sufficient confidence to utilize the results of CNPI's methodology to determine load forecasts in this application for rate making purposes.

OM&A COSTS

41 The table below sets out the proposed OM&A costs for the test year for Fort Erie and EOP and compares them with prior years.

OM&A Costs

	2006 Actual	2007 Actual	2008 Bridge	2009 Test
CNPI – Fort Erie	$1,356,505	$914,403	$791,762	$841,410
CNPI – EOP	$286,543	$211,361	$234,418	$250,755

42 The Board deals below with the following issues:

* Sharing of Common Costs
* Vegetation Management Costs
* Control Room Costs
* Regulatory Costs
* OM&A Cost Benchmarking

Sharing of Common Costs

43 Within CNPI, management and specialist staff and certain key systems and facilities are shared among three service areas and with the transmission function. CNPI retained BDR NorthAmerica Inc. ("BDR") to review the methodology and computations used for the allocation of shared costs. This report (the "BDR Report") was filed as part of the evidence. The BDR Report confirms BDR's opinion as to the reasonableness of the overall approach by CNPI and the specific allocation of each cost function.

44 No party opposed the methodology or results of the study.

Board Findings

45 The Board accepts the overall approach in allocating common costs and the specific allocation of each cost function to Fort Erie and EOP as reasonable.

Vegetation Management

46 VECC noted that the 2009 vegetation management costs for Fort Erie includes a one-time cost increase of $68,608 and submitted that this amount should be levelized over the four year IRM period rather than embedded in 2009 base rates. In response, CNPI noted that it will have to return before the Board in three years to address the Port Colborne lease and therefore its IRM period would be three years.

47 EOP has a three year cycle for vegetation management. Board staff invited EOP to comment on the reasonableness of the three year cycle when a neighbouring utility, Hydro One Networks, uses an eight year cycle. CNPI responded that it is difficult to comment on Hydro One Networks' vegetation management program without understanding their operating strategy. Because of the inherent operational differences, a straight comparison of EOP and Hydro One Networks is difficult to assess.

Board Findings

48 The Board agrees with VECC that it is appropriate to amortize the one-time costs of $68,608 for Fort Erie. The Board reduces the OM&A costs in this regard by $45,738 to $22,870 for the purposes of setting 2009 rates to reflect the expectation that the CNPI's rates will be rebased after three years.

49 At the next rate rebasing, the Board expects CNPI to file appropriate evidence as to the reasonableness of the vegetation management cycle it plans to use going forward.

Control Room Costs

50 CNPI operates a 5 day 15 hour control room in the Fort Erie distribution territory. The main duties of control room operators are monitoring and operating the SCADA system and directing the switching and work protection activities of line staff working on the distribution system.

51 Energy Probe noted the evidence that the number of incidents per year that occur during evening shifts that require an operator to manage restoration of the system occur only "several times per year" and the number of incidents requiring an operator to be called in to manage restoration of the system in the overnight and weekend periods when the control room is not manned occurred a "few times per year". Energy Probe submitted that the level of activity on the Fort Erie system does not warrant an evening shift for the control room. Manning a control centre for a few incidents annually is not a prudent expense when, by its own admission, CNPI is able to cope with a similar small number of incidents occurring overnight or on weekends simply by calling an operator in to manage system restoration. Energy Probe also noted that CNPI's position that system control operators must work evenings to prepare switching orders and update system maps is without merit because the size of the Fort Erie system and the CNPI line work force is not large enough to generate any substantial changes to the system on a day to day basis nor require extensive switching orders for the following day's work. Energy Probe submitted that $100,000 cost for the evening shift should be denied by the Board unless CNPI can demonstrate that other distributors of similar size and complexity also run evening control room shifts and recover those costs in rates.

52 In response, CNPI stated that Energy Probe provided a limited description of the functions of the Control Room Operator. The Operator provides oversight for both Port Colborne and Fort Erie and for CNPI Transmission. Control Room costs are allocated to Fort Erie as well as to Port Colborne and Transmission. CNPI is a licenced transmitter and, as such, has obligations under the Transmission System Code and its ancillary operating agreements with Hydro One Networks Inc. and the Independent Electricity System Operator in respect of its operations.

Board Findings

53 The Board will not make any adjustments to the proposed costs for Fort Erie associated with the Control Room. CNPI has adequately justified the need for the Control Room and the recovery of the costs allocated to Fort Erie.

Regulatory Costs

54 CNPI's proposed regulatory costs were $475,000, amortized over three years, for the three distribution service areas. For Fort Erie, the proposed regulatory costs are $123,031. For EOP the proposed regulatory costs are $110,771. In both cases, the proposed costs also amortized over three years. The balance is attributable to Port Colborne.

55 SEC argued that the $475,000 amount for the three services is excessive. SEC submitted that a more appropriate maximum budget would be $300,000.

56 In response, CNPI noted that when viewed on an individual basis, the proposed amounts for Fort Erie and EOP are reasonable, even when compared to regulatory costs awarded by the Board in other proceedings.

Board Findings

57 The proposed three-year amortization of the one-time costs associated with the 2009 rates proceeding is acceptable as it is expected that the 2009 rates will be in effect for three years in the case of CNPI. The issue for the Board is whether the one-time costs for Fort Erie and EOP are reasonable for ratemaking purposes.

58 Comparison with regulatory cost amounts incurred or allowed by the Board for other distributors cannot be a precise exercise for many reasons, including but not limited to, the complexity and quality of the filing, size of the utility, dependence on external resources, type and complexity of proceeding, and intervenor costs. The Board has allowed recovery of amounts both higher and lower than the above amounts for other distributors. The Board concludes that, on balance, it is reasonable in this case to allow $100,000 as one-time regulatory costs to be recovered from ratepayers of Fort Erie and $75,000 as one-time regulatory costs to be recovered from ratepayers of EOP. These one-time costs shall be amortized over three years.

OM&A Cost Benchmarking

59 SEC proposed that the Board direct CNPI to report in its next rebasing application on tangible OM&A savings it has achieved through its capital spending initiatives and otherwise, and also report on its future plans to get its cost levels in line with comparable Ontario LDCs.

60 In response, CNPI submitted that it is currently within the purview of the Board to examine CNPI's capital spending in the context of a cost of service application and no special directive is required from the Board. Further, it has not been established the CNPI's cost levels are not in line with comparable Ontario LDC's. Reference to and inferences made with respect to the benchmarking analysis prepared for the Board by Pacific Economics Group ("PEG") are comparative indicators only and have not been tested thoroughly. Any PEG comparative inferences should not be a decisive measure in the Board's Decision.

Board Findings

61 SEC's suggestion on comparative analysis goes in effect to benchmarking and cohort grouping. The Board will use the results of benchmarking by cohort groupings for the first time for purposes of annual rate adjustments under the 3rd generation incentive ratemaking, beginning in 2010. The Board has not used the results of any benchmarking or cohort groupings for purposes of rate rebasing and it is not evident at this time if it will do so or when. There is no compelling basis in the Board's view to treat CNPI uniquely and distinctly from other distributors and will not make the specific directions sought by SEC. At the next rebasing proceeding, it is open to SEC and others to test the reasonableness of the proposed revenue requirement for CNPI's service areas.

Rate Benchmarking

62 In its written argument, SEC prepared and included as Appendix "A" a table comparing annual distribution charges (fixed charge and variable charges) for forty electricity distributors and made a number of observations regarding the relative ranking of Fort Erie and EOP, inviting CNPI to propose different comparisons, either by adding more LDCs to the table or by suggesting appropriate cohorts or peer groups.

63 In reply, CNPI noted that it is troubled by the analysis provided by SEC as it is new evidence that has been introduced after the evidentiary portion of the proceeding ended. CNPI has not had the opportunity to test this evidence through interrogatories or cross examination. CNPI submitted that Appendix "A" should be disregarded by the Board.

Board Findings

64 The Board agrees with CNPI that this is new evidence that was not presented to CNPI through interrogatories or cross- examination and as such the Board has chosen to not consider it in making its decision. The Board was surprised and disappointed with SEC's approach in this matter.

INCOME TAXES

65 CNPI is an investor-owned corporation that pays Federal and provincial taxes, in contrast to PILs (Payments In Lieu of taxes) that municipally-owned or provincially- owned distributors are subject to. CNPI is subject to taxes as one corporate entity. It documented the allocation of taxes in a top- down method, allocating between transmission and distribution and then, within distribution, between the three service areas.

66 Board staff noted the recently-passed Federal Budget has provisions which may impact on a corporation's tax liability for 2009. Board staff submitted that CNPI should flow through applicable changes and update the tax allowance to determine the revenue requirement and rates resulting from the Board's Decision. CNPI agreed.

Board Findings

67 The Board notes that there is no dispute as to the method and inputs in calculating the final income tax amounts to be reflected in rates. CNPI shall include the appropriate details in the draft rate order.

DEFERRAL AND VARIANCE ACCOUNTS

Disposition of Accounts

68 In the pre-filed evidence for both Fort Erie and EOP, CNPI sought to dispose of Account 1508 - Other Regulatory Assets over one year. The proposal not to request disposition of other accounts was based on CNPI's understanding that the Board had initiated a review of the disposal of the RCVA and RSVA accounts.

69 On request by Board staff at the oral hearing, CNPI provided the quantum and impact on rates of other accounts. In its AIC, CNPI stated that it would be amenable to the Board dispersing these accounts as part of this proceeding and that the balances be disposed of over three years.

70 The balances at December 31, 2007 and interest to April 30, 2009 for Fort Erie and EOP are shown in the tables below (Numbers in brackets are credit to customers).

Account Balances at December 31, 2007 (Fort Erie) (including interest up to April 30, 2009)		
Account Description	**Account #**	**Total ($)**
Other Regulatory Assets - OEB Cost Assessments	1508	43,004
RSVA – Wholesale Market Service Charge	1580	(591,650)
RSVA – One-time Wholesale Market Service	1582	41,864
RSVA – Retail Transmission Network Charge	1584	98,795
RSVA – Retail Transmission Connection Charge	1586	97,446
RSVA – Power	1588	1,108,288
Total		**797,747**

Account Balances at December 31, 2007 (EOP) (including interest up to April 30, 2009)		
Account Description	**Account #**	**Total ($)**
Other Regulatory Assets - OEB Cost Assessments	1508	12,171
RSVA – Wholesale Market Service Charge	1580	(282,563)
RSVA – One-time Wholesale Market Service	1582	-
RSVA – Retail Transmission Network Charge	1584	(159,249)
RSVA – Retail Transmission Connection Charge	1586	(5,990)
RSVA – Power	1588	659,159
Total		**223,528**

71 Board staff noted that the separate Board initiative for the disposition of commodity account 1588 (RSVA power) and other related RSVAs has not yet been finalized. In this regard however, Board Staff Discussion Paper "Electricity Distributors' Deferral and Variance Account Review Initiative" (EB-2008-0046, 2009 LNONOEB 105) issued on April 1, 2009, proposes that distributors be required to file an application to dispose of all account balances (with a few exceptions such as PILs, CDM, smart meters and account 1590) as part of their cost-of-service application. Board staff submitted that notwithstanding the fact that the Board staff proposal is not yet confirmed Board policy, the Board should order disposition of all of the above stated deferral and variance account balances and not just the disposition of account 1508.

72 VECC on the other hand submitted that since there is a separate proceeding to examine the disposition of RSVA accounts, it would be premature to approve the disposition of all the named accounts absent further testing.

73 Board staff noted that the RSVA Power account 1588 comprises Cost of Power and the Global Adjustment sub-account and further that the Cost of Power balance is attributable to all customers, whereas the Global Adjustment balance is attributable to only non-RPP customers. In this regard, Board staff submitted that CNPI should provide for both Fort Erie and EOP:

* the closing balances corresponding to RSVA - Cost of Power account (excluding the global adjustment) and the Global Adjustment sub-account; and
* updated rate riders to reflect the allocation treatment discussed above (i.e., Cost of Power balance is attributable to all customers, whereas the Global Adjustment balance is attributable to only non-RPP customers).

Board Findings

74 In proceedings for other electricity distributors, the Board has taken various approaches in disposing of the balances in accounts that are the subject of a separate Board initiative. The approach taken in each case is driven by the specific circumstances. In this case, the Board concluded that it would be better to defer the disposition of the other accounts. This is partly due to VECC's submission that the balances in this case have not been adequately tested and partly due to the additional information requested by Board staff which would need to be tested.

75 The Board accepts the disposition of Account 1508 - Other Regulatory Assets over one year as proposed by CNPI for both Fort Erie and EOP.

International Financial Reporting Standards (IRFS) Deferral Account

76 CNPI sought the establishment of a deferral account to record costs associated with the transition of utility accounting from Canadian Generally Accepted Accounting Principles to International Financial Reporting Standards.

77 SEC submitted that such account should not be established except as determined in EB-2008-0408, *2009 LNONOEB 106*, where the Board is considering IFRS issues in the proper context.

Board Findings

78 The current Board initiative on this matter is not yet completed and there are no Board pronouncements in this regard. It would be premature for this Board panel to authorize the requested account as it is not exclusive to CNPI. The establishment of an IFRS deferral account is of general sector applicability and there will need to be a sector-wide approach. The Board will not authorize the establishment of the requested deferral account at this time.

COST OF CAPITAL

Capital Structure

79 The proposed deemed capital structure for both Fort Erie and EOP is 43.3% common equity and 56.7% debt, composed of 52.7% long-term debt and 4.0% short-term debt.

80 There were no issues raised related to CNPI's capital structure.

Board Findings

81 The proposed capital structure is compliant with Board guidelines and is approved for ratemaking purposes.

Return on Common Equity

82 The applications reflected a rate of return on equity of 8.39% based on May 2008 *Consensus Forecast.* On February 24, 2009, the Board issued a letter to all distributors announcing updated cost of capital parameters to be used, in which the maximum rate of return on common equity is 8.01% for 2009.

Board Findings

83 When CNPI prepares the draft rate orders it shall reflect a maximum rate of return on common equity of 8.01%.

Short Term Debt Rate

84 The applications reflected a short term debt rate of 3.38% based on May 2008 Consensus Forecast. On February 24, 2009, the Board issued a letter to all distributors announcing updated Cost of Capital parameters to be used, in which the deemed short term debt rate is 1.33% for 2009.

Board Findings

85 When CNPI prepares the draft rate orders it shall reflect a cost rate for short term debt of 1.33%.

Long Term Debt

86 CNPI has third-party long term debt of $30 million in senior unsecured notes. These were issued on August 14, 2003, bear interest of 7.092% and are payable at maturity on August 14, 2018.

87 CNPI also has a $15 million debt obligation to its affiliate FortisOntario. The debt instrument is dated August 13, 2008, bears an interest rate of 6.13% and is callable on demand. The Board's deemed long-term debt rate in 2008 was 6.10%, as announced in the Board's letter of March 7, 2008 on the 2008 Cost of Capital parameters. The $15 million promissory note bears a debt rate of 6.13%, which was set by FortisOntario to match the Board's deemed long-term debt rate at that time.

88 CNPI forecasts that its debt requirements in the 2009 test year will increase, and expects that the $15 million debt instrument will be recalled and replaced with a $21 million instrument in 2009 Q4. CNPI proposed that the current deemed long- term debt rate of 7.62% should apply to the $21 million debt.

89 Board staff noted that while the 7.62% updated deemed debt rate is in compliance with the Board's guidelines, it is less than clear about what rate should apply as the CNPI/FortisOntario approach is more complicated than the scenarios contemplated in the Board Report. Board staff submitted that one option could be to treat the affiliated debt as two instruments as follows:

* $15 million at the 6.10% deemed debt rate for 2008, for the promissory note issued in 2008; and
* $6 million new (incremental) debt for 2009 at the updated deemed long-term debt rate of 7.62%.

90 In SEC's view, the proposal is an attempt to use the Board's policies to recover the maximum amount possible from ratepayers, without consideration of market rates or fairness as between ratepayers and shareholder. SEC submitted that the Board should reduce the revenue requirement by the proposed increase in the amount to be recovered on the existing $15 million indebtedness. The evidence is that CNPI cannot repay that at will, so reduction of the interest rate recoverable to the original 6.13% is an approach that seems fair. As to the additional $6 million, as CNPI has not provided the evidence it should have provided as to market rates, the 6.13% rate should apply at most.

91 VECC submitted that the Board Report did not seem to contemplate the asymmetrical conditions that exist for CNPI with respect to affiliate long-term debt.

92 In response, CNPI argued that the debt rate of the $15 million instrument is irrelevant, since it will be recalled and replaced in the 2009 test year. CNPI reiterated that the 7.62% for the full $21 million is consistent with the Board's policies.

Board Findings

93 Non-arm's length debt arrangements are common in the electricity distribution industry and the Board has adopted guidelines as to how to deal with such arrangements. However, guidelines cannot contemplate every possible debt arrangement that may exist or how it may evolve.

94 As a general principle, when a debt instrument is callable on demand, this is at the call of the debt holder. The holder will do so if the holder feels that would be beneficial and not do so if it would not be beneficial to the holder. This asymmetry has not been contemplated in the Board's guidelines. The Board therefore will deal with this issue on the specifics of this case.

95 The evidence is that CNPI will not be in a position to pay the $15 million debt upon demand. It is reasonable to assume that, on the face of no ability to pay, the debt holder who is also the shareholder would not make such demand. It appears that the intent to recall the $15 million existing debt is an attempt to take advantage of the higher refinancing rate of affiliated debt stipulated in the Board's updated cost of capital parameters. If the updated capital parameters were lower than those in 2008, the $15 million loan would not be recalled and CNPI's additional $6 million debt requirements would have been satisfied through alternate arrangements. The additional $6 million debt requirement would be either through third-party debt or through FortisOntario.

96 In the circumstances, the Board finds it reasonable to deem the cost of the affiliate debt to be the continuation of the $15 million existing affiliated debt with FortisOntario at the rate of 6.13% and an additional $6 million affiliated debt with FortisOntario at the rate of 7.62%.

97 The Board notes from the evidence that CNPI assumes refinancing in Q4 of 2009 (Undertaking Response JT2.6) but its revenue requirement reflects an amount equivalent to having refinanced in mid year (E6/T1/S1, page 4). The Board directs CNPI to make the necessary adjustments to the cost of debt when it files its draft rate order.

98 The Board notes that there are no issues raised with respect to the third-party debt of $30 million, and will allow this debt at its documented rate of 7.092%.

99 When CNPI prepares the draft rate order it shall reflect a cost rate for long term debt that reflects the above debt rates weighted by the principal of each debt instrument.

COST ALLOCATION AND RATE DESIGN

Combination of two classes for EOP

100 Currently there are two GS[greater than]50 customer classes in the EOP service area: a) GS[greater than]50 (Regular) and b) GS[greater than]50 (TOU). For 2009, EOP proposed to combine these two class into one (GS[greater than]50). This proposal is in response to the Board's EB-2007-0594 Decision, *2007 LNONOEB 73*, which directed EOP to eliminate the GS[greater than]50 (TOU) class as part of its next rate application. The cost allocation and harmonization proposals reflected this combination of the classes.

101 No party objected to this proposal.

Board Findings

102 The Board accepts the proposed combination of the current GS[greater than]50 (Regular) and GS[greater than]50 (TOU) classes into one GS[greater than]50 class for EOP.

Harmonization of Distribution Rates

103 Currently, CNPI operates three distribution territories, Fort Erie, EOP and Port Colborne, as well as a transmission operation. CNPI operates primarily from a single location, Fort Erie, with a single work force and allocates assets and services to each of these business units. CNPI proposed to harmonize the distribution rates of the Fort Erie and EOP service territories. CNPI's rationale for the harmonization is to eliminate duplicated efforts related to financial and regulatory reporting, regulatory compliance and rate setting. The Port Colbome service territory was intentionally omitted from the harmonization due to restrictions related to the lease agreement with Port Colbome Hydro Inc.

104 The approach taken by CNPI is to blend the Fort Erie and EOP revenue requirements that had been developed separately and combine them as one. The applicants' evidence and position was that any incremental rate impacts of this design are minimal.

105 In the harmonized rate design, in general, those costs that have common cost drivers are being harmonized while those with cost drivers unique to the service territory remain segregated. The harmonization would apply to the following:

* Monthly service charges
* Volumetric distribution charges
* Smart Meter Adder

106 There would not be harmonization for the following charges. These would remain specific to each of the two service territories.

* Low Voltage charges (as these only apply to EOP)
* Distribution loss factors
* Retail transmission rates
* Specific Service Charges

107 To limit bill impacts, CNPI's harmonization proposal included rebalancing the revenue split between fixed charges and volumetric rates.

108 Both VECC and Board staff supported the harmonization proposal.

109 SEC noted that the apparent effect of harmonization appears to be to transfer more than $0.2 million of revenue responsibility from already under-contributing residential customers and over-contributing small GS customers to the already heavily over-contributing large GS customers.

Board Findings

110 The Board approves the harmonization proposal. CNPI's rationale for the harmonization is appropriate. There are invariably impacts on customers from harmonization, positive and negative. In this case, the Board has noted CNPI's attempts to mitigate the negative impacts with the result that such impacts are not of concern. SEC's concerns are largely an issue of the final revenue-to-cost ratios. The Board deals with revenue-to-cost ratio issues later in this decision.

Low Voltage Charges

111 Low voltage charges are applicable to EOP only as EOP is an embedded distributor within Hydro One Network's (HONI) distribution system.

112 The harmonized rates for the EOP service area include an LV rate adder. The proposed adder is based on 2009 forecast LV costs of $95,837. This value was developed prior to the Board's Decision regarding HONI's 2009 Distribution Rates.

113 VECC invited the applicants to address the impact of HONI's 2009 rates on the forecast LV costs as part of its final argument. In response, the applicant provided calculations to demonstrate that this difference is minimal and does not impact rate design.

114 VECC also noted that the allocation of the LV costs to customer classes is based on allocation factors derived from the 2006 EDR. VECC submitted that the allocation factors should be updated to reflect the 2009 forecast Retail Transmission Service Rate - Connection revenues by customer class. In response, CNPI agreed that such an exercise may be required given the significant redistribution of costs between the customer classes resulting from the loss of larger customers in EOP.

Board Findings

115 The Board considers reasonable to direct EOP to adjust the low voltage allocation factors to reflect the 2009 Retail Transmission Service Rate -- Connection Charge revenues by customer class, and so directs.

116 The Board will not direct an update to LV costs based on HONI's 2009 rates as the differences are not material and there is a variance account to capture such differences.

Retail Transmission Service Charges

EOP

117 EOP is embedded in the distribution system of HONI. In response to Board staff IR #66, EOP stated that an analysis of the relationship between the transmission service charges from HONI and the revenue associated with retail transmission through distribution rates for the years 2006 and 2007 indicates revenue exceeded charges by an average of 15% in both network service and connection service.

118 HONI has proposed an increase of 11.44% and 5.85% (2009 vs. 2008) in its retail transmission rate for sub-transmission customers for transmission network service and line and transformation connection service respectively.

119 EOP has proposed a 15% decrease from its 2008 tariff in both its transmission network service rates and line and transformation connection service rates.

120 These rate movements are tabulated below.

Rate Movements			
	Average percentage spread between revenues and charges 2006-2007	Proposed change in HONI's transmission rates for sub-transmission customers from 2008 to 2009	Proposed change in EOP's retail transmission rates from 2008 to 2009
Network	15%	11.44% increase	15% decrease
Connection	15%	5.85% increase	15% decrease

121 Board staff submitted that it would be reasonable for EOP to calculate revised network and connection rates which would capture:

* the spread between historical transmission charges and revenue, and
* HONI's proposed 2009 over 2008 increase in its retail transmission rate for sub-transmission customers.

122 VECC submitted that EOP should revise its retail transmission service charge rates to reflect HONI's proposed 2009 over 2008 increase in its retail transmission rate for sub-transmission customers. VECC also invited CNPI to comment on the impact of historical timing differences between HONI's rate implementation and EOP's rate implementation.

Fort Erie

123 Fort Erie is directly connected to CNPI's transmission grid. In response to Board staff IR #68, Fort Erie stated that an analysis of the relationship between the transmission service charges and the revenue associated with retail transmission through distribution rates for the years 2006 and 2007 indicates charges exceeded revenues by an average of 3% in network service and 5% in connection service.

124 The uniform transmission rate is higher by approximately 11.26% and 5.45% (2009 vs. 2008) respectively for transmission network service and line and transformation connection service.

125 Fort Erie has proposed a 14.26% and 10.45% increase from its 2008 tariff in its transmission network service rates and line and transformation connection service rates respectively.

126 These rate movements are tabulated below.

Rate Movements			
	Average percentage spread between revenues and charges 2006-2007	Proposed change in uniform transmission rates from 2008 to 2009	Proposed change in Fort Erie's retail transmission rates from 2008 to 2009
Network	-3%	11.26% increase	14.26% increase
Connection	-5%	5.45% increase	10.45% increase

127 Board Staff submitted that Fort Erie's proposed increase (network and connection rates) which captures both the spread between historical transmission charges and revenue and the 2009 over 2008 uniform transmission rate increase is acceptable.

128 VECC invited Fort Erie to comment on the impact of historical timing differences between implementation of uniform transmission rates and Fort Erie's rate implementation.

129 In response, CNPI noted that it has no control over the approval and implementation of HONI's retail transmission service charge rates or the uniform transmission tariff and as a result timing differences are inevitable. CNPI noted that the retail service variance accounts are designed to capture these differences "and are working", and it is likely that any resultant change to rates would be insignificant and any attempt at correcting for this timing difference is temporary.

Board Findings

130 The Board does not accept EOP's proposal. A more reasonable result would be for the transmission network service rates and line and transformation connection service rates to be reduced from their 2008 tariff levels by 3.56% and 9.15% respectively, and the Board so finds.

131 The Board accepts Fort Erie's proposal to increase its transmission network service rates and line and transformation connection service rates from its 2008 tariff by 14.26% and 10.45% respectively as reasonable.

Other Charges

132 Fort Erie and EOP proposed to:

* Continue with all of its currently approved Specific Service Charges in each service area;
* Continue with the previously approved Wholesale Market Service charge of $0.0052 per kWh in each service area;
* Continue to charge $0.0010 per kWh for Rural or Remote Rate Protection in each service area; and
* Continue the current Z-factor rate rider applicable to Fort Erie until August 30, 2009, as was approved by the Board in EB- 2007-0514 dealing with storm damage.

133 No party opposed these proposals.

134 In a letter to the Board dated December 18, 2008, CNPI had requested approval to charge $0.0013 per kWh for Rural or Remote Rate Protection as per the Board's direction.

Board Findings

135 Including the change to the Rural or Remote Rate Protection charge to $0.0013 per kWh, the Board finds the proposals acceptable and approves them.

Smart Meter Adder

136 CNPI currently collects a smart meter rate adder of $0.26 per metered customer per month in EOP and $0.27 per metered customer per month in Fort Erie. Under the harmonization proposal, CNPI proposes to charge a smart meter rate adder of $0.27 per metered customer per month in both service areas.

137 No party objected to CNPI's proposal.

Board Findings

138 The Board approves the requested smart meter rate adder of $0.27 per metered customer per month for both Fort Erie and EOP.

Loss Adjustment Factors

Fort Erie

139 Fort Erie is proposing a Distribution Loss Factor of 1.0357 and a Total Loss Factor of 1.0391 for the 2009 test year, which is the observed average for the three year period from 2005 to 2007.

140 Both Board staff and VECC submitted that the proposed TLF value is acceptable.

EOP

141 EOP is proposing a Distribution Loss Factor of 1.0438 and a Total Loss Factor of 1.0719 for the 2009 test year, which is the observed average for the three year period from 2005 to 2007.

142 Board staff submitted that EOP should provide detailed information about the distribution loss factor when reconfiguration of the distribution system is complete. CNPI noted that it has already begun exploring system reconfiguration opportunities that may lend themselves to technical loss reductions. These include reconfiguration of the East line. CNPI is amenable to discussing these and other opportunities with the Board.

143 Board staff further submitted that the Total Loss Factor value resulting from the averaging process is acceptable for 2009 rates.

144 Energy Probe submitted that the line losses to transmit on 39 km of distribution line the generation output from three hydro electric generation stations along the Rideau canal to the Main substation should be borne by the generator and not by CNPI customers. CNPI viewed Energy Probe's suggestion that customers connected to that line be assessed the specific losses on that line to be contrary to the Retail Settlement Code where losses have "postage stamp" consideration.

145 VECC submitted that it favours an averaging of the 2006 Board Approved distribution loss factor with the 2005 to 2007 actual average. CNPI noted this argument fails to consider the impact of lost industrial loads. The industrial loads were connected at 26 kV and 44 kV distribution voltages; their loss means a greater percentage of total system load is supplied by the 4 kV system and as a result will yield greater losses as a percentage of load supplied. Factoring in historical losses, in the manner suggested by VECC, does not address the reality of the impact of these plant closures. The reality is that the system configuration has changed, likely for the long term, and that change has adversely impacted the distribution loss factor.

Board Findings

146 The Board accepts the proposed loss factors for Fort Erie as reasonable.

147 With respect to the EOP, the Board is satisfied with CNPI's explanations and arguments with respect to the submissions and suggestions made by Energy Probe and VECC. The Board approves CNPI's proposed loss factors as reasonable.

Revenue-to-Cost Ratios

148 CNPI's proposed harmonized revenue to cost ratios (R/C ratios) for each rate class for 2009 are shown in the table below in column 5. The table also shows R/C ratios per the informational filing on a separate and combined basis (columns 1, 2, 3) and the Board policy range (column 6).

149 VECC submitted that in the Board's cost allocation model the treatment of the transformer ownership allowance results in an over allocation of costs to those classes where customers generally do not own their own transformers (e.g. Residential and GS[less than]50). In response to a VECC interrogatory, CNPI has provided a revised version of its Cost Allocation Informational filing that corrects this anomaly. However Board staff submitted that there is a mismatch between "Total Revenue" and "Revenue Requirement" apparently because revenue was not adjusted from gross to net of the transformer ownership allowance. As a result Board staff in their submission recalculated the ratios on a combined basis as shown in column 4 of the table. Board staff noted that these ratios should be the starting point rather than the combined informational filing ratios in column 3.

	Revenue to Cost Ratio					
	1	2	3	4	5	6
	Info. Filing CNPI-EOP	Info. Filing CNPI-FE	Info. Filing Combined	Transformer Ownership Allowance Adjusted - Combined	Proposed 2009 – Harmonized Rate Design	Board Policy Range
Residential	73.02%	82.69%	80.52%	82.03%	82.88%	85% - 115%
GS < 50 kW	142.48%	129.81%	133.51%	134.23%	120.00%	80% - 120%
GS > 50 kW	158.23%	151.44%	154.80%	148.91%	152.66%	80% - 180%
USL	65.94%	56.76%	57.76%	57.39%	44.69%	80% - 120%
Sentinel Lights	31.77%	37.35%	37.46%	37.78%	54.61%	70% - 120%
Street Lights	27.64%	19.16%	19.51%	20.58%	23.91%	70% - 120%

150 Board staff further submitted that:

* CNPI should:
    * rebalance rates such that revenue to cost ratios that are outside the Board policy range move to the closest boundary of the range; and
    * assess the rate impact resulting from this action, particularly for residential customers in EOP.
* For those rate classes, where the rate impact
    * is not excessive, the movement of the ratio should be in one step in the first year; and
    * is excessive, the movement of the ratio should be in multiple steps, halfway to the closest boundary of the range in the first year, and in equal steps in the subsequent two years.

151 In its reply submission, CNPI noted that Board staff's suggested approach is reasonable.

152 VECC noted that regarding harmonization of cost allocations, CNPI included in EOP the charges from HONI for LV (now ST) service in the base distribution revenue requirement to be allocated. VECC noted that CNPI has agreed that the corrected calculation could be included in its rate derivation.

153 SEC submitted that the Board order the following:

* R/C ratio of 85% for Residential class
* R/C ratio of 70% for Sentinel Lights and USL classes
* R/C of 37% with a goal of 70% by 2011 for Street Lights
* R/C ratio of 142% with a goal of 137% by 2011 for GS[greater than]50 class

154 SEC further submitted that, with the implementation of the changes proposed, the GS[less than]50KW and GS[greater than]50KW classes, containing most of the enterprises that drive the local economy and provide local services, will still be over- contributing at a high level, and the Residential, Sentinel, Street and USL classes will still be under-contributing in substantial amounts, but the level of the cross-subsidy will have been narrowed slightly.

Board Findings

155 Consistency with Board practice and with earlier 2009 rate decisions made by the Board for other distributors dictates that the move by 50% to the closest boundary of the Board's policy range should be accomplished by starting with VECC's approach, where the transformer ownership allowance is removed and using the R/C ratios in column 4 of the table as a starting point. Therefore, CNPI shall move the:

* Residential class from the new starting point of 82.03% to 83.52%
* USL class from the new starting point of 57.39% to 68.70%
* Sentinel Lights class from the new starting point of 37.78% to 53.89%
* Street Lights class from the new starting point of 20.58% to 45.29%
* GS[less than]50 class from the new starting point of 134.23% to 127.12%

156 CNPI shall apply the net of the revenue responsibility increase related to the Residential, USL, Sentinel Lights and Street Lights classes and revenue responsibility decrease related to the GS[less than]50 class to reduce the revenue responsibility related to the GS[greater than]50 class by moving the R/C ratio from the current starting point of 148.91% to a lower point. This is justified by the fact that the GS[greater than]50 class has the highest starting point ratio.

157 For 2010 and 2011, CNPI shall further move the R/C ratios for the Residential, USL, Sentinel Lights, Street Lights and GS[less than]50 classes to the closest boundary of the Board's policy range in two equal steps. As stated above, CNPI will apply the net of the revenue responsibility increase to move the R/C ratio for the GS[greater than]50 class to a lower point.

IMPLEMENTATION AND COST AWARDS

Implementation

158 Both Fort Erie and EOP requested in their rate applications that their proposed rates be made effective on May 1, 2009. Because the distribution rates for Fort Erie and EOP were made interim as of May 1, 2009, the Board has the jurisdiction to make their rates effective on May 1, 2009.

159 Both Fort Erie and EOP filed their rate applications on August 15, 2008 in accordance with the Board's January 30, 2008 letter regarding its multi-year rate setting plan. Furthermore, Fort Erie and EOP met all deadlines set out in procedural orders during the course of the proceeding. The delays in the proceeding can be attributed to disputes over the relevance of certain matters raised by intervenors, SEC in particular.

160 No party opposed the May 1, 2009 effective date.

161 The Board approves an effective date of May 1, 2009. Given the time that is required for the process leading to the issuance of a rate order and the need for Fort Erie and EOP to implement the new rates into their billing systems, it may not be possible to implement the new rates until September 1, 2009. The foregone revenue from May 1, 2009 to August 31, 2009 shall be recovered through a rate rider in effect from September 1, 2009 to April 30, 2010.

162 The Board's findings outlined in this Decision are to be reflected in a Draft Rate Order. The Board expects Fort Erie and EOP to file detailed supporting material, including all relevant calculations showing the impact of the implementation of this decision in its proposed revenue requirement, the allocation of the approved revenue requirement to the classes and the determination of the final rates, including bill impacts. Supporting documentation shall include, but not be limited to, filing a completed version of the Revenue Requirement Work Form excel spreadsheet, which can be found on the Board's website. Fort Erie and EOP should also show detailed calculations of any revisions to their rates and charges.

163 A final Rate Order will be issued after the following steps have been completed.

1. Fort Erie and EOP shall file with the Board, and shall also forward to intervenors, a Draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision, within 21 days of the date of this Decision.
2. Intervenors shall file any comments on the Draft Rate Order with the Board and forward to Fort Erie and EOP within 7 days of the date of filing of the Draft Rate Order.
3. Fort Erie and EOP shall file with the Board and forward to intervenors responses to any comments on its Draft Rate Order within 7 days of the date of receipt of intervenor submissions.

Costs Awards

164 The Board has concluded that it would be easier for all parties concerned if intervenors filed their cost claims at one time for all three of CNPI's cases. Therefore, the Board will issue its directions regarding cost awards for all three cases at the time it issues its decision in the Port Colborne case (EB-2008- 0224).

DATED at Toronto, July 15, 2009

ONTARIO ENERGY BOARD

Original signed by

Paul Vlahos
Presiding Member

Original signed by

Ken Quesnelle
Member
