ONTARIO ENERGY BOARD

Response of the Coalition of Large Distributors to Board Staff's Proposed Minimum Filing Requirements for Electricity Transmission and Distribution Rate Applications and Leave to Construct Projects

Introduction

The Coalition of Large Distributors (CLD), whose members are Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited and Veridian Connections Inc., submits these comments in response to Board staff's Proposed Minimum Filing Requirements for Electricity Transmission and Distribution Rate Applications and Leave to Construct Projects. The CLD supports the goal of clearly specifying the minimum filing requirements for future rate applications and basing these applications on a forward test year, but it does not support Board staff's proposed approach. Adopting staff's approach would further increase regulatory cost pressures on electricity distributors without producing any corresponding benefits for electricity consumers. It would represent a step backward in the progress of electricity distribution rate regulation in Ontario.

The CLD comments below focus exclusively on Board staff's rate regulation proposals; they do not address the leave to construct process. The comments are provided in two parts. The first part discusses the major issues raised by the staff's proposed approach. The second part contains detailed comments on the individual sections of Chapter Two in the staff proposal.

1. Major Issues Presented by the Staff Proposal

1.1 The Staff Proposal Ignores the Substantial Progress Already Made In Defining Cost of Service Information for Electricity Distributors

Over the past several years, the Board, its staff, distributors and intervenors have all invested substantial effort in developing and refining the cost of service approach used by electricity distributors. Work on the 2006 Electricity Distribution Rate Handbook (along with the associated EDR and PILs models), Electricity Reporting and Record Keeping Requirements (RRRs), Regulatory Information

Filings System (RIFS), Phase II of the Review and Recovery of Regulatory Assets, the Accounting Procedures Handbook and the Uniform System of Accounts has been aimed at increasing the quality and consistency of the information used to support distributors' regulatory filings in a way that makes sense in the context of their business. This information has been used to develop rates and is being used in the ongoing Cost Allocation Review. Rather than continuing to build on and improve this work, Board staff proposes largely to abandon it.

In its decision in Hydro One's 2006 EDR proceeding, the Board commented that intervenors, Board staff and the Board itself all recognized the thoroughness and detail of Hydro One's filing. The Board concluded that the information provided would allow for the development of an appropriate baseline for assessing Hydro One's future costs. (Decision with Reasons, RP-2005-0020 EB-2005-0378, pp. 11-12.) Distributors took these comments and other similar remarks about the Hydro One filing as an indication that the Board was prepared to use this filing as the standard for future electricity distributor filings.

Hydro One's application was consistent in substance with the 2006 Electricity Distribution Rate Handbook. Hydro One used the Handbook's forward test year option and provided additional information, particularly in areas where the Board had previously requested specific studies. In establishing minimum filing guidelines based on Hydro One's application, it will be important for staff and industry to work together to develop a plan for incorporating the additional detail provided by Hydro One over a realistic time frame.

While assembling a filing with the level of detail provided by Hydro One will be a stretch for most distributors, it is a reasonable long-term goal. This approach builds on a model that is tailored to presenting the costs of the electricity distribution business. In addition, it uses the revenue requirements approach that is typically used for regulating electricity distributors throughout North America.

The CLD continues to believe that using Hydro One's filing as a model will allow the Board to determine whether an application provides all the information necessary to establish just and reasonable rates pursuant to section 78 (3) of the Ontario Energy Board Act. If, over time, the Board identifies the need for additional information, it would be easy to modify future filing requirements to fill the identified gap.

Board staff now proposes an abrupt change in direction. Ignoring a clear model of an electricity distribution regulatory filing, staff seeks instead to impose filing requirements from the natural gas industry that are both unnecessary and unsuitable for electricity distributors. Staff proposes this dramatic change without any explanation or analysis of why the gas model would be superior and how it would mesh with current requirements.

Staff introduces these new requirements with the threat that filings that fail to contain every element will be rejected summarily as incomplete. Such threats are unnecessary and work against the cooperative working relationship that should, and presently does, exist between distributors and Board staff.

As the Board recognizes, it is pursuing a very aggressive regulatory agenda for the electricity distribution sector. A number of proceedings that are of crucial interest to distributors are proceeding simultaneously including, cost of capital, cost allocation, second generation incentive regulation, and CDM. Given this challenging regulatory environment, proposals to fundamentally change the minimum filing requirements should be carefully considered. Effective regulation of electricity distributors requires more than simply advocating the wholesale transfer of the natural gas filing guidelines to the electricity distribution sector with little explanation and analysis.

The timing of the proposed changes is particularly acute for distributors who will be required to file cost of service applications for 2008 rates. Applications for these filers are likely to be due in mid-2007. In order to prepare a filing that approaches the level of detail filed by Hydro One, let alone one that meets the staff's proposed requirements, these distributors must start preparing their applications immediately. The fact that the list of 2008 filers is not yet known and may not be available for several months creates substantial uncertainty. The Board should consider allowing distributors who believe that they are capable of preparing a filing for 2008 rates to volunteer.

1.2 Adoption of the Staff Proposal Would Impose Expensive and Unnecessary Data Collection and Accounting Changes

Staff proposes moving away from the revenue requirements approach that currently underpins electricity regulation to the revenue sufficiency/deficiency approach used for natural gas. Adopting staff's proposal would raise a number of issues. Electricity distributors currently do not have the processes and data necessary to employ this approach. While some of the largest distributors have developed forecasting tools and weather normalization techniques, no distributor has the ten-year set of actual and forecast customer consumption data by customer class that the staff guidelines would require. Developing these and other aspects of the required information would impose additional cost for questionable benefit.

The proposed guidelines appear to contemplate the continuation of a rate year that differs from the fiscal year used by distributors to plan, budget and operate their businesses. If the revenue sufficiency/deficiency approach is adopted, distributors will have to create *pro forma* income statements for periods that do not match their fiscal years. This approach will introduce an unnecessary source of error as distributors translate their calendar year forecasts to the rate year.

This approach would also require translating historical information, kept on a calendar year, to the rate year for comparison purposes.

The staff proposal makes no mention of any plan to develop and distribute a model similar to the 2006 EDR model or to prepare a new rates handbook. The lack of a model and a handbook will complicate the process of reviewing distribution filings by ensuring variances among distributors in the interpretation of filing requirements and the presentation of required information. It will also increase the cost to distributors of preparing these filings by necessitating expenditures to develop and refine their own models.

Some of the required information appears to be of limited utility. For example, the requirement that operations, maintenance and administration (OM&A) information be provided on the department level would yield little or no value because the structure of departments is not consistent among distributors and will typically change over time within a given distributor. Thus, even if this information were tracked and filed it would not assist in performing meaningful comparisons, either among distributors or within individual distributors over time. The data groupings included in the 2006 EDR handbook and based on the Uniform System of Accounts provide a much more useful basis of comparison than would be provided by individual distributor definitions of departments.

In addition, to the extent that the guidelines seek information to allow comparisons among distributors, great care must be taken in ensuring that the resulting comparisons are accurate and meaningful. The effort that the Board has undertaken with its Comparators and Cohorts Study demonstrates the difficulty of making such comparisons and the caution that must be exercised in using the resulting information.

Both the number and detail of the required variance analyses are excessive. The threshold for variance should depend on the size of the distributor. In addition, the variance should focus on changes between the historical year and the forward test year and only include the last Board approved rate year if it differs from the historical year.

The bridge year is a forecast like the test year. Explanations of variances between the bridge and test years are likely to be either of little relevance (e.g. in an account that changes substantially in the bridge year and moves back to its historical level in the test year) or subsumed in the explanation of the variance between the historical and test years (e.g. an account where values change in the bridge year and continue this change into the test year). Furthermore, to the extent that the rate and fiscal years continue to differ, an additional source of variance will exist and will need to be examined and explained.

The staff proposal also cites the potential to reduce the large number of interrogatories as a potential benefit of its approach. While the CLD agrees that a common understanding of the information required of applicants could potentially reduce the number of interrogatories, the proposed approach will have the opposite effect. One has only to look to the number of interrogatories submitted in the gas proceedings to reach this conclusion. Moreover during the initial implementation of these requirements for electricity distributors the number of interrogatories is likely to increase as both applicants and other parties struggle to understand unfamiliar analyses and categories.

The proposed requirements also are not likely to reduce the degree of controversy at the hearing stage of proceedings. In general, gas distribution proceedings have been at least as controversial as electricity distribution proceedings, if not more so. In particular, because the revenue sufficiency/deficiency approach places so much importance on the load forecast and associated normalization, these issues are sure to become more contentious than they have been typically in electricity distribution proceedings. The CLD questions the wisdom of introducing a regulatory approach that increases the controversy around the load forecast used in rate setting at the same time that the Board is considering a lost revenue adjustment mechanism to compensate distributors for revenues lost due to conservation and demand management efforts. The intent of such a mechanism is to reduce the impact of variations between forecast and actual consumption on distribution revenues.

2. Detailed Comments

This section provides detailed comments organized according to the heading in Chapter Two of the staff proposal. At this time, the CLD has no specific comments on the Chapter Two headings not included below.

2.1 Introduction

The last paragraph on page 6, discusses the volume of interrogatories generated by the process, and suggests that applicants “consider those commonly asked questions and include the information that is the subject of those questions in their initial filings.” This suggestion places the onus of “guesswork” on the applicants. If the Board has identified information needs that were not met by the majority of distributors through the 2006 process, these needs should be specifically identified in minimum filing guidelines that build on the 2006 EDR approach.

2.1.1 Key Planning Parameters

The establishment of “key planning parameters” indicates that these parameters encompass underlying regulatory principles to be applied in rate setting. For distributors to comment effectively on the validity of these principles, they must fully understand the terminology and concepts involved.

The following key planning parameters require full definition and explanation of their usage within a rate application:

- Metric Units – This term has not previously been used in rate applications by electricity distributors, and is not referenced further in the Minimum Filing Requirements;
- Average of monthly averages valuation method – full definition and specific formulas for calculation should be provided;
- Total Capitalization equates to Total Rate Base – full definition and specific formulas for calculation should be provided.

The 12th parameter states: "When filing, the electricity price will be that available from the most recent Board approved RPP, at the time of filing". The purpose of using the RPP price is unclear. If the intent is to use this RPP price to determine Cost of Power, then the Hourly Ontario Energy Price (HOEP) should be used instead.

The 15th key planning parameter appears to be contradictory in nature. It suggests that if all calculations are based on the proposed methodology and a summary of the drivers is provided, then the impacts <u>of the change</u> in methodology should be provided. If the application follows the proposed methodology, what is meant by the change? Clarification is required as to what is meant here.

2.2 Exhibit 1. Administrative Documents

2.2.1 Administrative

The specific "Policies and Regulations of the Company" that are required should be specified. If this refers to the "Conditions of Service", exclusively, the requirements should so state.

2.2.2 Overview

The filing requirements include "Correspondence regarding Budget levels – goals, strategies and guidelines." This needs to be specifically defined including the relevant time frame. The requirements also should explain why this information is required.

2.3 Exhibit 2. Rate Base

1. Gross Assets – Property Plant and Equipment

The staff proposal states that "Customer Additions and System Expansion with PI values" are required. The concept of "System Expansion with PI values" is not meaningful to electricity distributors operating pursuant to the Distribution System

Code. This exemplifies the difficulty in simply transporting gas industry requirements to electricity.

The staff proposal requires applicants to provide capital budget for the Historic Year, Bridge Year and Test Year. Only allowing for the inclusion of capital spending for these years, may lead to distributors deferring necessary investments in distribution assets until the next cost of service application. The CLD suggest that providing distributors with the option of filing a multi-year capital plan would help mitigate this issue. For example, a distributor could file a cost of service application for 2008 that includes a capital plan for 2009 and 2010. This approach would allow the Board to determine a capital escalator.

2.4 Exhibit 3. Operating Revenue

Reference is made to “normalization methodology.” The filing requirements should provide examples of acceptable forms of normalization and state clearly that this refers only to weather normalization.
The proposal states that information is required on 2) Transactional Services and 4) Revenue Sharing without providing a definition or specific requirements.

1. Throughput Revenue

The 3rd requirement discussing normalized data requires clarification:

- Does the “current test year normal” mean the Bridge Year as identified in “2.1.1 Key Planning Parameters”?
- What is meant by to normalize to a current test year normal and to normalize to the normal approved by the Board?

The 6th item requests ten years of historical data on both actual and forecast consumption by customer class. It is virtually certain that no electricity distributors will possess forecasted consumption for this historical period by rate class as this information has not been included in past filing requirements. It is also very unlikely that applicants will have accurate actual consumption by rate class for this period due to utility amalgamations and the introduction and elimination of various rate classes over this ten-year period.

This requirement appears to be of little if any value. Assuming that it is meant to allow a test of an applicant’s “track record” of forecast vs. actual consumption over the past ten years, it has little meaning given that during this period the industry was only required to make sporadic rate filings based largely on historical information. In most years, there was no need to produce forecasts of consumption by customer class. Going forward, after forward test year filings have been established for some time, this information may eventually become useful, but it is unnecessary now.

The 7th item outlines specific requirements for “large volume (contract) customers”. A full definition of the term “large volume (contract) customers” is required. Again, this appears to be a term taken from the gas industry. In any event, it is highly unlikely that most distributors have five years of forecast versus actual normalized data available for individual customers.

3. Other Revenues

A full definition of “non-core delivery activities” is required. A full explanation of the detailed calculation of “rate of return” on such activities is also required.

2.5 Exhibit 4. Operating Costs

Item 3) “Status of Non-RSVA Related Deferral Accounts and Variance Accounts” is listed under both Exhibit 4 and Exhibit 5. Item 4) “CDM” is listed under this exhibit yet no detailed information requirements are outlined.

1. Operating & Maintenance and Other Costs

The first item requires a breakdown of each of the OM&A costs on a departmental basis. The allocation of costs within an applicant’s accounting records by department is a subjective exercise and the results will vary among distributors. Moreover, departmental structures change frequently as operations change in scope and complexity. This will make historical comparison impossible as distributors will not be able to recreate the departmental structures that existed previously and account for the costs that these departments would have incurred.

No accounting guidelines or code requirements are provided to distributors regarding “departmental accounting.” The CLD suggests that rather than using a departmental basis, information should be aggregated using the major accounts groupings of the 2006 EDR Handbook based on the Uniform System of Accounts. Definitions of activities to be recorded in each of these accounts already exist within the Accounting Procedures Handbook (APH) and distributors are required to follow these procedures. This will provide greater consistency and comparability among distributors and less volatility in year over year comparisons.

The second item outlines salary, wage and benefit information. It is virtually certain that few distributors have payroll related figures specific to OM&A costs as payroll records are kept by employee, not by function or cost centre and employees often are employed in both OM&A and capital activities.

The year over year levels of labour deployed in capital versus OM&A varies dependent upon each specific year’s capital requirements. As well, capitalization policies and application of labour overheads vary between distributors, which would make comparisons between them less meaningful. Total compensation information should be provided separately at the same level of detail as provided within the 2006 EDR applications in schedules 6-4 and 6-5.

Salaries & Wages and Benefits also are required to be broken down by employee type (i.e. management, analyst, non-unionized, and unionized). The listed employee types should be examples rather than mandatory categories because not all distributors use these categories.

Further information is required regarding how an analyst is defined. In some distributors there are analysts in both non-union and union positions creating an overlap with both the unionized and non-unionized categories.

2.6 Exhibit 5. Deferral and Variance Accounts

This Section requires the utility to provide, among other things, a "detailed method of recovery of existing accounts proposed to be cleared as part of the main rates case including bill impacts and rate design implications". It is unclear how this process would coordinate with the Board's other processes for dealing with variance/deferral accounts, such as EB-2006-0114 and EB-2006-0115.

2.7 Exhibit 6. Cost of Capital and Rate of Return

2. Component Costs

This section proposes requiring distributors to provide "Consensus Forecasts." Since the consensus forecast would be the same for all distributors, it makes little sense to have each distributor's application include them. Instead, the Board could simply state the forecast interest rate figures to be used by all applicants in a given year. In addition, this requirement seems inconsistent with Board Staff's proposal in the consultation on Cost of Capital and 2nd Generation Incentive Regulation. There, staff proposes replacing the consensus forecast with a yield curve based on the discounts associated with various maturities of "zero coupon" bonds.

3. Calculation of Return on Equity and Debt

This section is unclear. Is the intent that Chapter 5 – Cost of Capital, 2006 Electricity Distribution Rate Handbook will still be applicable or will it be replaced by the requirements that come out of EB-2006-0088?

2.8 Exhibit 7. Calculation of Revenue Deficiency or Surplus

A full definition of "Determination of Net Utility Income" and detailed instructions for its calculation are required.

The “Deficiency or Sufficiency in Revenue” and the “Gross Deficiency or Sufficiency in Revenues” are both to be net of energy costs and revenues. Is the “Deficiency or Sufficiency in Revenue” based only on Distribution Rate Revenue and the “Gross Deficiency or Sufficiency” in Revenues based on Distribution Rate Revenue plus Specific Service Charges, Other Regulated Charges and Other Income?

This is a complete change in the revenue requirement rate setting methodology. If the proposed approach is adopted, distributors would be required to produce *pro forma* income statements, the preparation of which would be severely complicated by the differences between the “rate” year and each distributor’s fiscal year. All internal planning tools are based on the fiscal year. If the OEB is committed to this approach it should change the rate year to run from January to December. Otherwise, distributors would have to develop 2 totally independent planning processes, one of which would not align to its audited financial statements.

2.9 Exhibit 8. Cost Allocation

This Section requires the distributor to file “the Board approved cost allocation” study, but it is unclear what this requirement means. Except for a few distributors specifically directed to use newly developed cost allocation information for setting 2007 rates, for most distributors the cost allocation filings required under EB-2005-0317 are for informational purposes only. As outlined in the draft Cost Allocation Review: Staff Proposal on Principles and Methodologies, issued June 28, 2006, the Board will not be approving these filings but “will prepare a report summarizing the overall outcome” and make “recommendations for the next steps”.

The filing required under EB-2005-0317 will be based on the costs and revenues underlying the approved 2006 rates. For distributors who filed on an historical test year, this is 2004 information. The draft appears to suggest that separate Cost Allocation Studies must be filed for the Historic Year, Bridge Year and Test Year. This view is supported by the Revenue/Cost Ratios that are required under Section 2.10. It is unclear how applicants can use 2004 data to file cost allocation studies for the Historic Year, Bridge Year and Test Year for future filings where the Test Year may be as late as 2010.

The implied requirement to perform annual cost allocation studies would be onerous, inconsistent with standard regulatory practice and a waste of resources. Cost allocation studies typically are done periodically to check whether the allocation in place continues to reasonably reflect cost causality. They are usually not redone unless there is a reason to believe that cost causation has changed or the passage of time has rendered the study stale. Further, it should be noted that the requirements for updated load data could not currently be met as distributors have not been instructed to continue to collect interval load data to support ongoing cost allocation studies.

Distributors should be required to file one cost allocation study which supports the rates they have requested. Any deviations from the OEB prescribed methodology and any adjustments to rates that are made (or not made) as a result of the cost allocation study should be explained.

2.10 Exhibit 9. Rate Design

This section lists “deviations from the rate handbook” as a required item. This requirement is unclear in a number of ways. There is no mention of which rate handbook and what section(s) of that handbook are being referenced. Furthermore, there is no discussion of what level and type of deviations are contemplated by this requirement.

Revenue/Cost Ratios for Historic Year/Bridge Year and Test Year would require Cost Allocation Studies for each of these years. This is discussed as part of the comments in section 2.9 with respect to Cost Allocation Studies.

Conclusion

Based on the review above, the CLD urges the Board to modify the filing requirements proposed by the staff to reject the wholesale adoption of the natural gas industry revenue sufficiency/deficiency model and reflect a forward test year revenue requirement approach modeled on the 2006 distribution rates filing by Hydro One.

All of which is respectfully submitted on behalf of the CLD,

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