Ontario

Ontario Energy Board
Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2015-0090 AND

EB-2015-0328

NIAGARA PENINSULA ENERGY INC.

Application for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2016.

BEFORE: Allison Duff
Presiding Member

Victoria Christie
Member

March 17, 2016

1 INTRODUCTION AND SUMMARY

Niagara Peninsula Energy Inc. (NPEI) serves about 52,000 mostly residential and commercial electricity customers in the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham. As a licenced and rate-regulated distributor in Ontario, the company must receive the Ontario Energy Board's (OEB) approval for the rates it charges to distribute electricity to its customers.

NPEI filed an application with the OEB on September 28, 2015, to seek approval for changes to its distribution rates to be effective May 1, 2016. The OEB has established three different rate-setting methods for distributors. NPEI selected the Price Cap Incentive rate-setting (Price Cap IR) plan option to adjust its distribution rates. The Price Cap IR method has a five-year term. In the first year, rates are set through a cost of service rebasing application. NPEI last appeared before the OEB with a cost of service application for 2015 in the EB-2014-0096 proceeding. In the other four years, there is a mechanistic adjustment to rates based on inflation and the OEB's assessment of a distributor's efficiency.

On November 16, 2015, NPEI filed a second application to dispose of balances in the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) incurred as a result of administering conservation programs. In a letter issued on November 27, 2015, the OEB decided that it would hold a combined hearing for the applications filed by NPEI.

In the most recent cost of service application decision, the OEB directed NPEI to conduct a lead/lag study to determine the appropriate working capital allowance (WCA) to include in its rates and to file the study with its next incentive rates application.[1] NPEI's 2015 rates were approved on an interim basis, to be made final with the OEBs determination of the appropriate working capital allowance following the review of the lead/lag study. NPEI filed a lead/lag study proposing a WCA of 12.3%, yet updated its proposal to 12.61% in reply submission.

This is the OEB's Decision with respect to both of NPEI's applications (collectively referred to as the Application). The following issues are addressed in this Decision and Order.

- Price Cap Incentive Rate-setting
- Regulatory Charges
- Retail Transmission Service Rates
- Review and Disposition of Group 1 Deferral and Variance Accounts

[1] EB-2014-0096, Decision and Order, May 14, 2015, p.6

- Review and Disposition of Lost Revenue Adjustment Mechanism Variance Account Balance
- Residential Rate Design
- Working Capital Allowance
- Implementation and Order

In accordance with the OEB-approved parameters for inflation and productivity for 2016, NPEI applied for a rate increase of 1.80%. The 1.80% applies to distribution rates (fixed and variable charges) uniformly across all customer classes; it does not apply to the rates and charges listed in Schedule A.

NPEI also applied to change the composition of its distribution service rates. Currently, residential distribution rates include a fixed monthly charge and a variable usage charge. However, the OEB issued a new policy to change residential rates to a fully fixed rate structure, transitioning over a four-year period beginning in 2016.[2] The fixed monthly charge for 2016 will be adjusted upward as a result of this Decision by more than the mechanistic adjustment alone and the variable-usage rate is commensurately lower. The amount of revenue the distributor is expected to collect from residential customers will not be affected, only the proportion of revenue collected through variable and fixed charges.

The OEB approves the Price Cap IR adjustments to NPEI's application as calculated through this proceeding and directs NPEI to make certain changes in calculating its WCA.

2 THE PROCESS

The OEB follows a standard, streamlined process for incentive rate-setting (IR) applications under a Price Cap IR plan.

Initially, the OEB prepares a rate model that includes information from past proceedings and annual reporting requirements. A distributor then reviews and updates the model to include with its application.

In this case, NPEI provided written evidence and completed rate models to support its applications. OEB staff, Energy Probe, and the Vulnerable Energy Consumers Coalition (VECC) also participated in the proceeding. Questions were asked and answers were provided by NPEI to clarify and correct the evidence. Finally NPEI, OEB staff, and

[2] Board Policy: A New Distribution Rate Design for Residential Electricity Customers, EB-2012-0410, April 2, 2015

Energy Probe made submissions to the OEB regarding NPEI's application and proposals. VECC did not make a submission.

3 ORGANIZATION OF THE DECISION

The OEB has organized this Decision into sections, reflecting the issues that the OEB has considered in making its findings.[3] Each section covers the OEB's reasons for approving or denying the proposals included in the application and affecting 2016 rates. The last section addresses the steps to implement the final rates that flow from this Decision.

4 PRICE CAP INCENTIVE RATE-SETTING

The Price Cap IR adjustment follows an OEB-approved formula that includes components for inflation and the OEB's expectations of efficiency and productivity gains.[4] The components in the formula are also approved by the OEB annually.

The formula is an *inflation minus X-factor* rate adjustment, which is intended to incent innovation and efficiency. Based on its established formula,[5] the OEB has set the inflation factor for 2016 rates at 2.1%.

The X-factors for individual distributors have two parts: a productivity element based on historical analysis of industry cost performance and a stretch factor that represents a distributor's efficiency relative to its expected costs. Subtracting the X-factor from inflation ensures that rates decline in real, constant-dollar terms, providing distributors an incentive to improve efficiency or else face the prospect of declining net income.

Based on industry conditions over the historical study period, the productivity factor has been set at zero percent. A stretch factor is assigned based on the distributor's total cost performance as benchmarked relative to other distributors in Ontario. For Price Cap IR applications, a range of stretch factors has been set from 0.0% to 0.6%.[6] The most efficient distributor, based on the cost evaluation ranking, would be assigned the lowest stretch factor of 0.0%. Higher stretch factors are applied to distributors whose

[3] See list of issues in the Introduction, p.1
[4] Report on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (December 4, 2013)
[5] As outlined in the Report cited at footnote 3 above
[6] Report to the Ontario Energy Board – "Empirical Research in Support of Incentive Rate-Setting: 2014 Benchmarking Update." Pacific Economics Group LLC. July 2015

cost performance falls below that of comparable distributors to encourage them to pursue greater efficiencies.

Findings

In this case, the OEB assigned NPEI a stretch factor of 0.30% based on the updated benchmarking study for rates effective in 2016.[7] As a result, the net price cap index adjustment for NPEI is 1.80% (i.e. 2.1% - (0% + 0.30%)).

The 1.80% adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes; it does not apply to the rates and charges listed in Schedule A.

5 REGULATORY CHARGES

There are a number of charges levied to consumers to cover the costs associated with various programs and wholesale market services.

The Rural or Remote Electricity Rate Protection (RRRP) program is designed to provide financial assistance to eligible customers located in rural or remote areas where the costs of providing electricity service to these customers greatly exceeds the costs of providing electricity to customers located elsewhere in the province of Ontario. The RRRP program cost is recovered from all electricity customers in the province through a charge that is reviewed annually and approved by the OEB.

Wholesale market service (WMS) charges recover the cost of the services provided by the Independent Electricity System Operator (IESO) to operate the electricity system and administer the wholesale market. These charges may include costs associated with: operating reserve, system congestion and imports, and losses on the IESO-controlled grid. Individual electricity distributors recover the WMS charges from their customers through the WMS rate.

The Ontario Electricity Support Program (OESP) is a new regulatory charge initiated in 2016. This program delivers on-bill rate assistance to low income electricity customers. All Ontario customers contribute to the OESP through the OESP charge.

These regulatory charges are established annually by the OEB through a separate order.

[7] As outlined in the Report cited at footnote 5 above

Findings

The OEB has determined[8] that the RRRP charge for 2016 shall be $0.0013 per kWh; the WMS rate shall be $0.0036 per kWh; and the OESP charge shall be $0.0011 per kWh. These changes have been in effect since January 1, 2016 for all distributors as a result of the generic order that was part of the OEB's separate decision. The Tariff of Rates and Charges flowing from this Decision and Order should be updated so as to reflect these new regulatory charges, as well as the OESP credits to be provided to enrolled low income customers.

6 RETAIL TRANSMISSION SERVICE RATES

Electricity distributors use Retail Transmission Service Rates (RTSRs) to pass along the cost of transmission service to their distribution customers. The RTSRs are adjusted annually to reflect the application of the current Uniform Transmission Rates (UTR) to historical transmission deliveries and the revenues generated under existing RTSRs. The UTRs are established annually by a separate OEB order. Similarly, partially embedded distributors, such as NPEI, must also adjust their RTSRs to reflect any changes to the applicable RTSRs of their host distributor, which in this case is Hydro One Networks Inc. Distributors may apply to the OEB annually to approve the RTSRs they propose to charge their customers.

Findings

The OEB has adjusted its UTRs effective January 1, 2016,[9] as shown in the following table:

2016 Uniform Transmission Rates

Network Service Rate	$3.66 per kW
<u>Connection Service Rates</u>	
Line Connection Service Rate	$0.87 per kW
Transformation Connection Service Rate	$2.02 per kW

The OEB also approved new rates for Hydro One's Sub-Transmission class, including the applicable RTSRs,[10] as shown in the following table:

[8] Decision and Rate Order, EB-2015-0294
[9] 2016 Uniform Electricity Transmission Rate Order, EB-2015-0311
[10] Rate Order, EB-2015-0079, issued January 14, 2016

2016 Sub-Transmission RTSRs

Network Service Rate	$3.34 per kW
Connection Service Rates	
Line Connection Service Rate	$0.78 per kW
Transformation Connection Service Rate	$1.77 per kW

The OEB finds that these 2016 UTRs and Sub-Transmission class RTSRs are to be incorporated into the filing module to adjust the RTSRs that NPEI will charge its customers accordingly.

7 REVIEW AND DISPOSITION OF GROUP 1 DEFERRAL AND VARIANCE ACCOUNT BALANCES

Group 1 Deferral and Variance Accounts track the differences between the costs that a distributor is billed for certain IESO and host distributor costs (including the cost of power) and the revenues that the distributor receives from its customers for these costs through its OEB-approved rates. The total net difference between these costs and revenues is disposed to customers through a temporary charge or credit known as a rate rider.

The OEB's policy on deferral and variance accounts[11] provides that, during the IR plan term, the distributor's Group 1 account balances will be reviewed and disposed if the pre-set disposition threshold of $0.001 per kWh, whether in the form of a debit or credit, is exceeded. It is the distributor's responsibility to justify why any account balance in excess of the threshold should not be disposed. If the balances are below this threshold, the distributor may propose to dispose of balances.

NPEI's 2014 actual year-end total balance for Group 1 accounts including interest projected to April 30, 2016 is a debit of $105,677. This amount results in a total debit claim of $0.0001 per kWh, which does not exceed the preset disposition threshold. NPEI did not seek disposition of balances in its application.

Findings

The OEB finds that no disposition of the Group 1 account balances is required at this time as the disposition threshold has not been exceeded.

[11] Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (July 31, 2009)

8 REVIEW AND DISPOSITION OF THE LOST REVENUE ADJUSTMENT MECHANISM VARIANCE ACCOUNT BALANCE

As part of the Ministry of Energy's conservation-first strategy, the OEB requires distributors to engage in and deliver conservation and demand management activities in an effort to reduce total energy consumption and reduce peak demand on the provincial electricity system. The OEB policy[12] established the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) to capture the revenue implications for the distributor from the reduction in actual demand, as compared with the last OEB-approved load forecast, resulting from conservation and demand management activities. These differences are recorded for each of a distributor's customer classes.

A distributor may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of its IRM rate application, if it deems the balance to be significant.

NPEI requests disposition of its LRAMVA balance of a debit of $482,804.19, consisting of lost revenues in 2011 through 2014 from conservation and demand management programs contributing towards NPEI's 2011-2014 reduction targets.

OEB staff submitted on January 22, 2016 that it had no issues with NPEI's LRAMVA claim.

NPEI's LRAMVA claim includes amounts related to conservation and demand response programs deployed in demand billed classes. In a memorandum from the IESO to OEB staff dated February 24, 2016, and shared by the OEB with the applicant on March 3, 2016, the IESO clarified its definition of verified demand savings. The IESO reported that its methodology for evaluating demand response program results "makes no attempt to verify the impact that a demand response event may have on a customer's demand for the purposes of billing for distribution service, even in months where the demand response program was activated." The memorandum also reported that while demand savings due to energy efficiency investments may persist beyond the peak season, effects are expected to vary based on the type of program.

Findings

The OEB will not approve the disposition of the LRAMVA balance at this time.

The issue of the appropriateness of adjustments to IESO-verified CDM results to impute lost distribution revenues in demand billed classes has arisen in NPEI's and a number of other applications currently before the OEB. Given the generic nature of this issue

[12] Guidelines for Electricity Distributor Conservation and Demand Management (April 26, 2012)

and the absence of clear revenue impact evidence in certain classes as a result of CDM demand response program deployment, the OEB intends to hold a stakeholder meeting on March 31, 2016 to determine the appropriate approach for the demonstration and calculation of the distribution revenue impacts from demand savings for LRAMVA purposes. In a March 3, 2016 letter the OEB communicated this plan and indicated that it expects to issue further guidance on the LRAMVA following the stakeholder meeting.

The postponement of the disposition of an LRAMVA claim at this time shall be without prejudice to any future claim once further policy guidance is available. Interest will continue to accrue in the LRAMVA account until disposition.

9 RESIDENTIAL RATE DESIGN

Currently, all residential distribution rates include a fixed monthly charge and a variable usage charge. The OEB's April 2, 2015 policy on electricity distribution rate design sets out that distribution rates for residential customers will transition to a fully fixed rate structure from the current combination of fixed and variable charges over four years. Starting in 2016, the fixed rate will increase gradually, and the usage rate will decline.

The 2016 rate model has been revised to include the first year of the gradual transition to fully fixed rates and its impact to the monthly fixed charge that residential customers will pay. The OEB is requiring distributors to calculate and report on the rate impacts of the change so that strategies may be employed to smooth the transition for the customers most impacted, such as those that consume less electricity. In support of this, the OEB requires distributors to calculate the impact of this change to residential customers in general; it also requires applicants to calculate the combined impact of the fixed rate increase and any other changes in the cost of distribution service for those customers who are at the 10th percentile of overall consumption. Any increase of 10% or greater to these low-consumption customers' bills arising from changes made in this Decision, or an increase to the monthly fixed charge of greater than $4 prior to incentive rate-setting adjustments, may result in the requirement for a longer transition period than four years specified in the OEB policy. Distributors may also propose other strategies to smooth out these increases as appropriate.

Findings

Due to other findings in this Decision, the impact of NPEI transitioning to fixed rates for residential customers over a four-year period has not yet been determined. NPEI is to provide the increase in the fixed charge prior to IRM adjustments and the percentage bill impact for the low volume customer as part of its draft rate order. The OEB will then determine whether a four-year transition period is appropriate.

10 WORKING CAPITAL ALLOWANCE

In the decision for NPEI's most recent cost of service application, the OEB directed NPEI to conduct a lead/lag study to determine the appropriate working capital allowance (WCA) to include in its rates and to file the study with the OEB during its next incentive rates application. The WCA represents the amount of cash required to operate NPEI's business on a day-to-day basis, taking into consideration the time lag between when payments are made by the distributor for goods and services and when payments are received from its customers. NPEI's 2015 rates were approved on an interim basis, to be made final with the OEB's determination of the appropriate WCA following the review of the lead/lag study.

NPEI filed a lead/lag study with this Application. OEB staff's and Energy Probe's submissions identified concerns with the following parameters calculated in the study:

- Payment in Lieu of Taxes (PILs) Expense Lead
- Collections Lag
- Operations, Maintenance and Administration (OM&A) Expense Lead
- Long Term Debt (LTD) Expense Lead
- Cost of Power Expense Lead
- HST Expense Lead for Revenues

The table below summarizes the WCA that was proposed by each party in their submissions:

Party	WCA (%)[13]
NPEI	12.61
Energy Probe	10.17
OEB staff	8.67

PILs Expense Lead

NPEI's lead/lag study includes an expense lead for PILs of -562.75 days. This reflects the NPEI credit balance with the Ministry of Finance which it expects will last for the

[13] Expressed as a percentage of the sum of the cost of power and OM&A expenses.

next five years. In response to interrogatories, NPEI estimated that it would have an expense lead of 36.22 days for PILs if it were not in a credit position.

Both OEB staff and Energy Probe submitted that the OEB should deem an expense lead of 36.22 days as NPEI has, in effect, already prepaid its PILs. NPEI submitted that it realized its PILs are unique to its lead/lag study and accepted the argument of OEB staff and Energy Probe.

Findings

The OEB approves a PILs expense lead of 36.22 days. The OEB finds it appropriate to eliminate the credit balance from the calculation as it is unique, temporary and does not reflect the ongoing working capital needs of NPEI.

Collections Lag

A collections lag represents the average length of time between when a bill is issued and when it is paid by the customer. NPEI calculated its collection lag of 29.24 days based on the dollar weighted average of monthly accounts receivable balances grouped by aging category into “bins” of 0-30 days, 31-60 days, 61-90, 91-180, and > 181 days, and using the mid-point method to calculated the service period for each bin.

In response to an interrogatory from OEB staff, NPEI split the 0-30 days category in two bins of 0-19 days and 20-30 days, which resulted in a collections lag of 24.13 days. Both OEB staff and Energy Probe submitted that the use of smaller bin sizes resulted in a more accurate estimation of the collections lag. In reply submission, NPEI revised the calculation to 24.61 days after correcting the mid-point of the 20-30 day category.

In response to interrogatories, NPEI indicated that bad debts are written off in journal entries posted once a year. NPEI indicated that this annual bad debt write-off was reflected in a reduction to the October 2014 accounts receivable balance for the > 181 days aging category. OEB staff submitted that NPEI’s collections lag was overstated because the > 181 days group included bad debt in all but one month of the accounts receivable data. OEB staff proposed that the average monthly accounts receivable for the > 181 days group be reduced by the average bad debt that was reported in NPEI’s most recent cost of service rate application. OEB staff submitted that the collections lag would fall to 17.6 days as a result of this change.

NPEI stated that it had provided detailed evidence supporting a collections lag of 29.24 days using a methodology that is consistent and comparable with other lead/lag studies previously filed before the OEB. NPEI submitted that the proposed changes to the methodology, submitted by OEB staff and Energy Probe, are inconsistent with the methods used in past lead/lag studies that have been approved by the OEB. NPEI indicated that OEB staff's calculation, removing the bad debts from each month, would result in an annual bad debt expense of $3.2 million, which exceeded the actual three-year average bad debt of $273,604.

Findings

The OEB approves a collection lag of 24.61 days. The OEB finds it appropriate to divide the accounts receivable 0-30 day aging category in two. The OEB finds that this refinement provides more information on which to estimate the working capital needs of the utility.

Ideally utilities would track the collection lag of each customer bill, which is impractical. The use of account receivable categories and billing cycles enable the actual collection lag to be estimated at an aggregate level. Balances in the 0-30 day aging cateogory are significant for NPEI, holding 88.68% of its total accounts receivable balances. Dividing the largest aging category in two provides valuable additional information regarding working capital needs. While the OEB has approved collection lags based on one 0-30 category in other cases, better information is available for NPEI and will be used.

The OEB will not adjust the collection lag associated with NPEI's accounting practice of writing off bad debts once a year. The working capital allowance should be based on actual data and actual practice during the study period. However, if NPEI changed its accounting practice to write off bad debts each month, the 180+ category balances, and the associated collection lag, would be reduced.. The OEB encourages NPEI to consider its accounting practices with the added objective of managing its working captial needs efficiently.

OM&A Expense Lead

NPEI's lead/lag study calculated an expense lead of -1.73 days for OM&A expenses. This result indicates that, on average, NPEI pays its OM&A expenses in advance of receiving service from its vendors. The negative expense lead was mainly caused by the weighted contribution of annual prepaid expenses which lowered the collections lag by 19.16 days despite representing only 6.55% of total OM&A costs. The annual prepaid expenses category includes software maintenance, insurance and membership fees, and regulatory expenses relating to NPEI's 2015 cost of service rate application. NPEI had applied a service period of five years for regulatory costs.

OEB staff submitted that the five-year service period for the regulatory costs is inappropriate for the nature of those costs. OEB staff stated that the services provided by legal and consultant costs only provided benefit while a cost of service application was being heard by the OEB. OEB staff submitted that the OEB should, at minimum, impose an expense lead of 4.27 days for OM&A expenses. This would be achieved by applying an expense lead of -182.5 days to the full amount of annual prepaid expenses without amortizing regulatory expenses.[14]

OEB staff also observed that, even at 4.27 days, NPEI's OM&A expense lead is lower than OM&A expense leads from other recent studies filed with the OEB. OEB staff submitted that NPEI has not provided any evidence to indicate why its circumstances would be unique relative to other Ontario distributors. OEB staff stated that the OEB could also consider imposing an OM&A expense lead based on the results of previous studies.

NPEI provided an updated derivation of its OM&A expense lead of 3.48 days which was calculated by separating regulatory costs from the annual prepaid expenses category while maintaining the proposed five year service period. NPEI submitted that the OEB should accept the revised calculation of 3.48 days. NPEI submitted that it does not agree that an alternative value, based on the results of other studies, is warranted. NPEI stated that it had demonstrated its actual results and that there is no evidence to support any value other than that filed by NPEI.

Findings

The OEB approves an OM&A expense lead of 4.27 days. The OEB appreciates that expenses incurred in a cost of service proceeding are amortized over five years. However, working capital needs should be calculated using the lead time between billing and payment dates for the third-party invoices.

LTD Expense Lead

NPEI's lead/lag study calculated a LTD expense lead of 4.38 days. NPEI provided evidence that it regularly made monthly interest payments on its affiliate debt. The conditions of NPEI's affilitate loan agreements state that interest payments are to be made quarterly.

Energy Probe submitted that the OEB should impose a LTD expense lead of 28.34 days which would reflect the payment terms of the affilitate loan agreements. Energy Probe

[14] EB-2015-0090 and EB-2015-0328, OEB Staff Submission, January 25, 2016, p.4

observed that NPEI is not required to make monthly payments and that doing so results in higher costs for its customers.

NPEI submitted that using the legal obligation due date is inconsistent with the methodology of the lead/lag study which considers actual cash inflow and cash outflow during a 12 month study period. NPEI believed that applying the legal obligation principle to one element of its expense lead calculation is selective in nature and inappropriate.

Findings

The OEB approves an LTD expense lead of 28.34 days. The working capital allowance is generally based on actual data, reflecting actual practice. However in this case, the affiliate prepayment practice is a voluntary management decision which leads to an overstatement of the working capital needs. NPEI's two affiliates benefit from the monthly prepayments as the affiliates have use of the money earlier than the quarterly payments contractually required. The OEB will not rely upon verbal agreements or past practice to base its findings.

The OEB finds it appropriate to adjust the actual data from the study to determine the LTD expense lead, given the affiliate relationship. Customers should not pay the cost if they do not benefit. NPEI may chose to continue its current practice of monthly payments, but it will bear the related cost.

Cost of Power Expense Lead

In June of 2015, the Independent Electricity System Operator (IESO) reduced NPEI's trading limit by $1.7 million. The reduction to its trading limit was expected to expose NPEI to additional margin calls. When NPEI receives a margin call warning, it makes a pre-payment to the IESO which results in a partial payment of that month's IESO invoice before the usual due date. As a result, NPEI adjusted its calculated expense lead for the cost of power purchased from the IESO to reflect the the reduction to its trading limit. This had the impact of reducing NPEI's overall cost of power expense lead from 30.95 days to 29.59 days.

Energy Probe submitted that the OEB should approve a cost of power expense lead of 30.95 because it is consistent with the period used to estimate all other revenue lags and expense leads used in the study and because NPEI is not required to make a payment when it receives a margin call warning.

NPEI submitted that the IESO expense lead was consistent with the study period because actual IESO invoice amounts were used from that period. NPEI adjusted the dates when pre-payments would have been made based on its updated trade limit from the IESO. NPEI stated that the change to the trade limit was a material and known change to its business conditions which should be reflected in the results of the study. NPEI noted that it has always made pre-payments to the IESO at the time of a margin call warning and expressed its belief that there is financial risk involved in waiting for a margin call.

Findings

The OEB approves a cost of power lead of 29.59 days. The OEB accepts that this reflects the lower trading limit on an ongoing basis and NPEI's actual risk management practices. The OEB agrees with NPEI that known, material changes should be considered in determining the working captial allowance.

HST Expense Lead for Revenues

NPEI had calculated an HST expense lead of -10.45 days for revenues. NPEI's calculation was based on the mid-point of the service period as the starting point.

Energy Probe submitted that HST is payable on the last day of the month following the invoice date and that the billing date should be used as the starting point of the calculation, not the service date. Energy Probe submitted that the OEB should approve an HST expense lead of -19.33 days for revenues which reflects the use of the billing date starting point.

NPEI submitted that it had calculated the HST expense lead for revenues correctly and that the OEB should approve the revenue lag of -10.45 days as filed in its study. NPEI stated that Energy Probe's method of calculating the HST revenue lag yields the same result as NPEI's calculation if:

1. NPEI's proposed collection lag of 29.24 days is used instead of the 24.13 days proposed by Energy Probe
2. NPEI's billing lag of 29.24 days is used instead of Energy Probe's assumption of 15.21 days
3. 30 days is used for the average month instead of 30.42 days, as calculated by Energy Probe

As a result, NPEI felt that no changes were required to the results of its study.

Findings

The OEB approves an HST expense lead for revenues of -19.33 days. The OEB finds that the relevant starting point for the calculation is the billing date, when the HST liability is recognized and recorded. The billing date is when the liability is quantified as a payment owing for which working captial is needed until the HST payment is made. The service date is a relevant starting point for calculating other working capital needs, but not HST.

11 IMPLEMENTATION AND ORDER

The OEB has made findings in this Decision and Order which changes the 2015 approved rates and 2016 distribution rates as proposed by NPEI.

The OEB expects NPEI to file a draft Rate Order, including a proposed Tariff of Rates and Charges for 2015 and 2016 and all relevant calculations showing the impact of this Decision and Order on NPEI's determination of the final rates. Supporting documentation shall include, but not be limited to, calculation of the revised WCA, a revised Revenue Requirement Work Form (RRWF) for 2015 and a completed version of the 2016 IRM Rate Generator model

NPEI's 2015 rates were approved on an interim basis pending completion of the lead/lag study.[15] The 2015 rates were implemented and effective June 1, 2015 and were based on a 13% WCA. As a result, NPEI has over collected revenue from its customers. NPEI shall calculate the amount of the overcollection and propose rate riders to return the funds to its customers.

A Rate Order will be issued after the steps set out below are completed.

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. Niagara Peninsula Energy Inc. shall file with the OEB, and shall also forward to the Intervenors, a draft rate order attaching proposed Tariffs of Rates and Charges for 2015 and 2016, reflecting the OEB's findings in this Decision, by **March 24, 2016**. The draft rate orders shall also inlcude:

[15] EB-2015-0096, Decision and Order, May 14, 2015, p.8

- The updated calculation of the Working Capital Allowance
- Updated RRWF for 2015 in Microsoft Excel format
- Calculation of the revised 2015 rates effective June 1, 2015
- Updated Rate Generator model for 2016 rates using the revised 2015 rates in Microsoft Excel format
- Calculation of the rate riders to return the overcollection of revenue for 2015
- Customer rate impacts, including for low-volume residential customers resulting from the implementation of this Decision.

2. OEB staff and Intervenors shall file any comments on the draft rate order with the OEB, and forward the comments to Niagara Peninsula Energy Inc. on or before **March 30, 2016.**

3. Niagara Peninsula Energy Inc. shall file with the OEB and forward to the Intervenors responses to any comments on its draft rate order on or before **April 4, 2016**.

All filings to the OEB must quote the file number, EB-2015-0090/EB-2015-0328 and be made electronically through the OEB's web portal at https://www.pes.ontarioenergyboard.ca/eservice/ in searchable / unrestricted PDF format. Two paper copies must also be filed at the OEB's address provided below. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

ADDRESS

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

Attention: Board Secretary

E-mail: boardsec@ontarioenergyboard.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

DATED at Toronto, March 17, 2016

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Schedule A

To Decision and Order

List of Rates and Charges Not Affected by the Price Cap or Annual IR Index

OEB File No: EB-2015-0090/EB-2015-0328

DATED: March 17, 2016

The following rates and charges are not affected by the Price Cap or Annual IR Index:

- Rate riders
- Rate adders
- Low voltage service charges
- Retail transmission service rates
- Wholesale market service rate
- Rural or remote electricity rate protection charge
- Standard supply service – administrative charge
- Transformation and primary metering allowances
- Loss factors
- Specific service charges
- microFIT charge
- Retail service charges