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ONE Nicholas Street, Suite 1204, Ottawa, Ontario, Canada K1N

Michael Janigan
Counsel for VECC
(613) 562-4002 x26

October 7, 2016

VIA MAIL and E-MAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge St.
Toronto, ON
M4P 1E4

Dear Ms. Walli:

Re: Vulnerable Energy Consumers Coalition (VECC)
Final Submissions: EB-2015-0003
Application for the amalgamation of PowerStream Inc., Horizon Utilities Corporation, Enersource Hydro Mississauga Inc., and purchase of Brampton Networks Inc.

Please find enclosed the submissions of the Vulnerable Energy Consumers Coalition (VECC) in the above noted proceeding.

Yours truly,

Michael Janigan
Counsel for VECC

Gia DeJulio, Director, Regulatory Affairs, Enersource Hydro Mississauga Inc.
gdejulio@enersource.com
Indy Butany-DeSouza, Vice President, Regulatory Affairs Horizon Utilities Corporation
Indy.butany@horizonutilities.com
Colin Macdonald, Senior Vice-President, Regulatory Affairs & Customer Service, PowerStream Inc.
Colin.macdonald@powerstream.ca

EB-2016-0025

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch. B, as amended;

AND IN THE MATTER OF an Application by for approval to amalgamate Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, and PowerStream Inc. to form LDC Co. and for LDC Co. to purchase and amalgamate with Hydro One Brampton Networks Inc.

FINAL SUBMISSIONS

ON BEHALF OF THE

VULNERABLE ENERGY CONSUMERS COALITION (VECC)

October 7, 2016

Mr. Michael Janigan
Counsel
31 Hillsdale Avenue E,
Toronto, ON
M4S 1T4
Mr. Janigan's Direct line: 416-840-3907
mjanigan@piac.ca
PIAC Office: 613- 562-4002 ext. 21 (Donna Brady)

Vulnerable Energy Consumers Coalition (VECC)
Final Argument
Application to Amalgamate and Purchase Utilities

1 Summary

1.1 The important issue in this case is not simply whether this transaction meets the "no harm test". The important issue is the proposition that the Applicants, in making this transaction, may be afforded a rate plan developed, not on the basis of the facts of the transaction, costs of serving customers, but rather on a set of policies which purport to bind the ratemaking authority of future panels of the Board. This is unreasonable, unjust to ratepayers and in our submission seriously harms their interests.

1.2 The Applicant has drawn a distinction between approval of the relief sought in this type of an application and rate setting. Yet the Board's own policies actually draw the two together. The Handbook to Electricity Distributors and Transmitter Consolidations purports to determine all manner of rate making under the ambit of a consolidation. It establishes a regime under which the Board might abdicate direct oversight of the reasonableness of rates and substitutes a mechanistic combination of inflation adjusted rates and an ESM mechanism. As such, it leaves no avenue for rates to decline or even hold steady by incorporating even normal productivity growth let alone the productivity enhancements that the Applicants suggest will be realized. Not only are consumers unprotected from rate increases, but the application of these policies ignore inter-class inequities, and in this application inter rate zone inequity issues by assuming that the existing cost allocation and rate design post transaction are sufficient.

1.3 In our submission, without abandoning the objectives set out in the Handbook, the Board should not preclude an examination of the rate making consequences of a transaction for the next 10 years.

1.4 The Board has made great efforts over the past several years to try to engage the concerns of general electricity consumers in the difficult task of providing and planning for the electricity services of the future in a cleaner more efficient fashion. It is essential that mechanisms such as consolidations are seen to produce fair and balanced results. As VECC points out in this submission, there arises substantial doubt that the future projected realistic customer savings are a fair trade off for the merged company's ability to add capital and enjoy a 10 year hiatus from rebalancing financed by those customers The planned consolidation engages two stakeholders- owners and customers- with frequently opposing interests. The Handbook's endorsement of consolidation does not supercede the Board's responsibility to fix just and reasonable rates pursuant to the *OEB Act*. And, as we shall see, the Handbook itself recognizes necessity for a balanced approach.

2 The Cost of the Merger Transaction

2.1 The Applicants state that the total anticipated savings net of transaction costs over a ten year rebasing deferral period are approximately $312MM in operating costs and approximately $114MM in avoided capital costs.

2.2 The $426MM in total cash savings are expected to be accrued over the entire 10 years although most of the costs occur in the first three.

2.3 The transaction costs of the application include the purchase of Hydro One Brampton (HOBNI) at a price of between $607 and $601 million.[1] This represents a premium of about $202M over the HOBNI estimated book value of $405M. The applicants have arranged for a $500 million short-term debt working capital facility and a $625 million Acquisition Facility to finance the Hydro One Brampton acquisition at a purchase. The Applicants will implement a long-term debt facility to repay the two-year HOBNI acquisition facility[2]. To finance the premium requires that the consolidated utility find approximately $5M per year in incremental new savings.[3]

[1] B-Staff-16
[2] B-Staff-21
[3] Vol. 1 pg.169

2.4 The transition other costs are listed below:

Table 1 – Breakdown of Transition Costs ($MM)

	Transition Cost - Operating					Transition Cost Capital					
	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020	Total
Human Resources	**15.8**	**9.1**	**7.6**	**2.1**	**0.3**	**-**	**-**				**34.9**
IT - CIS Consolidation	**0.5**	**0.8**	**0.3**	**-**	**-**	**13.8**	**9.1**	**2.0**	**-**	**-**	
IT - ERP Consolidation	**1.5**	**0.3**	**-**	**-**	**-**	**5.9**	**2.0**	**-**	**-**	**-**	
IT - Engineering Systems Consolidation	**-**	**-**	**-**	**-**	**-**	**4.8**	**3.1**	**2.4**	**-**	**-**	
IT - Infrastructure Consolidation	**0.3**	**0.0**	**-**	**-**	**-**	**7.5**	**0.5**	**-**	**-**	**-**	
Corporate Branding	**2.1**	**0.2**	**-**	**-**	**-**	**1.4**					**3.6**
Consolidation of operational activities	**0.6**	**0.7**	**0.3**	**0.2**	**0.2**	**0.4**	**0.4**	**-**	**-**		**2.8**
TOTAL	20.9	11.1	8.2	2.3	0.5	33.7	15.2	4.4	-	-	96.3

Source B-Staff-3

2.5 The estimates of the costs of this transaction are likely to be of some debate. This is because the costs are predominantly related to the integration of IT systems, and specifically the billing system. In some sense, these are not strictly transaction costs as they are an investment in productivity. The true costs of the transaction are in the market premium paid for HOBNI and in the severance, the directly related finance and legal fees and in the directly related redundancy severances. In our submission these costs are likely much smaller than the IT investment costs put forward as transaction costs.

2.6 With respect to the market premium paid for Hydro One Brampton, VECC accepts the evidence that this cost will not be visited upon existing ratepayers.

3 Consolidation Savings

3.1 The ratepayer benefits are based on the premise that during the rebasing deferral period results in rates lower than if the stand alone distributors had carried on as separate utilities. Of course, this is only one alternative. Another is to consider what would be the rate impacts if the consolidated utility was required to rebase prior to the assumed 10 years. There are a number of assumptions built into this projection, most notably the Applicant’s view of the trend of rates based on the alternative of no transaction and being subject to Board periodic review. It is also anticipated that there will be a search by management for what may be termed “ordinary efficiencies” during the deferral period.[4]

[4] See Tr. Volume 2, p.144

3.2 In financing the acquisition of Hydro One Brampton, the new consolidated utility will lower HOBNI's existing embedded debt costs of 6.07%.[5] The indicative substitution rate is 2.38%.[6] The forecasts of net income, shareholder benefits, distribution revenues and customer benefits assume a 4% cost of debt for the HOBNI acquisition.[7] The payback period for the acquisition of HOBNI is expected to be 6 years.[8]

3.3 The Applicants expect to derive other efficiencies from the following areas of the business:

- More efficient delivery of corporate services such as Human Resources, Supply Chain,& Information Technology, Facilities, Fleet and Finance;
- More effective delivery of core services such as customer service, engineering, asset management and operations; and
- More effective use of consultants, auditors and legal counsel.

The anticipated savings are shown in the tables below.

Table 1 - Anticipated Reductions in Operating Expenditures by Function by Year ($MM)

Functions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Centralized	**2.4**	**7.7**	**16.1**	**19.1**	**20.9**	**20.9**	**20.9**	**20.9**	**20.9**	**20.9**	**170.7**
Asset Management & Engineering	0.9	2.5	2.3	2.5	2.5	2.5	2.5	2.5	2.5	2.5	23.2
Corporate	0.1	0.1	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	6.6
Finance	1.4	2.0	3.6	4.2	4.6	4.6	4.6	4.6	4.6	4.6	38.8
Human Resources	(0.8)	1.4	2.3	3.0	3.0	3.0	3.0	3.0	3.0	3.0	23.9
Information Technology	0.5	0.5	4.3	5.5	6.0	6.0	6.0	6.0	6.0	6.0	46.8
Procurement	0.4	0.6	1.2	1.4	1.4	1.4	1.4	1.4	1.4	1.4	12.0
Regulatory	(0.1)	0.6	1.6	1.7	2.6	2.6	2.6	2.6	2.6	2.6	19.4
De-centralized	**4.8**	**12.4**	**15.6**	**21.5**	**21.6**	**21.6**	**21.6**	**21.6**	**21.6**	**21.6**	**183.9**
Customer Service	-	0.8	2.0	7.6	7.5	7.5	7.5	7.5	7.5	7.5	55.4
Metering	0.3	1.0	1.2	1.6	1.7	1.7	1.7	1.7	1.7	1.7	14.3
Facilities, Logistics, Fleet	0.8	2.9	3.1	3.2	3.2	3.2	3.2	3.2	3.2	3.2	29.2
Construction, Control Room, Trouble Response	3.7	7.7	9.3	9.1	9.2	9.2	9.2	9.2	9.2	9.2	85.0
Grand Total	**7.2**	**20.1**	**31.7**	**40.6**	**42.5**	**42.5**	**42.5**	**42.5**	**42.5**	**42.5**	**354.6**

[5] The debt rates of all the named utilities is found at B-Staff-21
[6] B-Staff-24
[7] B-SEC-23
[8] JT1.1

Table 1 - Detailed Breakdown of Gross Capital Savings by Year ($MM)

Capital Synergies	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
Integration of Asset Management systems	1.4	1.2	0.3	0.2							3.1
Integration of IT systems	17.8	13.8	20.8	15.1	22.0						89.5
Supply Chain discounts and rationalization	0.5	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	29.3
Other Operations economies of scale	3.3	4.4	4.5	4.7	4.8	4.8	4.8	4.8	4.8	4.8	45.7
TOTAL	**23.0**	**22.6**	**28.8**	**23.2**	**30.0**	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**167.6**

Source B-AMPCO-4

3.4 Overall most of the savings in this transaction appear to be driven by the integration of billing systems. Given the size of the combined entity there are surprisingly few other discrete benefits identified.

3.5 The savings from the transactions are likely understated or will be underachieved under the 10 year rate deferral plan. In VECC's submission, this increases the risk to consumers under the 10 year rate deferral policy. That is because either such savings will be achieved and yet not shared with ratepayers, or that the consolidated utility will not realize all the benefits that could accrue if it were subject to the Board's scrutiny. Both results frustrate the objectives of the Handbook and the *OEB Act*.

4 The Transaction Rate Plan

4.1 During the deferral period, Enersource and HOBNI will stay on Price Cap IR, PowerStream is assumed to be on Custom IR in 2016-2020 and move to Price Cap IR in 2021, and Horizon is assumed to be on Custom IR until 2019 and move to Price Cap in 2020. The Table below shows the current rate plan status of the amalgamating utilities:

Figure 1 – Rate Setting During the Ten Year Rebasing Deferral Period

	1	2	3	4	5	6	7	8	9	10
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Enersource	IRM with potential for ICM									
Horizon Utilities	Custom IR (Annual Filing)			IRM with potential for ICM						
PowerStream	Custom IR (Annual Filing)*				IRM with potential for ICM					
HOBNI	IRM with potential for ICM									

Source B-Staff-28

4.2 The Applicant's rate proposal also means that customers of the consolidated utility will not be subject to a single rate but rather four rate zones. The rate shock or cost allocation reasonableness of harmonizing rates 10 years hence is unknown.

4.3 The Applicants are not content to have all aspects of the revenue requirement alleviated from being scrutinized for 10 years. Instead, during this period, they allow themselves the opportunity to included new capital costs through a number of planned ICMs. That is they take advantage of the inconsistency in Board policy which allows them to garner the benefits of rate base building while shielding themselves from OM&A, Capital, Tax and all other aspects of the rate formula.

4.4 The only check on overearning by the merged entity is an earning sharing mechanism ("ESM") that commences after year 5 of the deferral period. Earnings in excess of 300 basis points above the Board's established regulatory return for the consolidated entity would be divided on a 50/50 basis between LDC Co. and its ratepayers. There is some uncertainty as to how ESM would be calculated.

It is to be noted that the ESM in place after five years of the deferral period is the only safeguard on extravagant over-earning by the merged entity. There is no expectation of the same thus allowing for the proposed ICMs.

> MR. JANIGAN: Thank you. Now I wonder if you could turn up page 11 of my compendium. This is part of the Enersource decision in EB-2015-0065, and it's noted under paragraph 3.3 that as part of the need criteria and the OEB applies the means test when reviewing ICM applications.
> The means test states that when -
> "If a distributor's regulated return exceed 300 basis points above the deemed return on equity ROE embedded in its rate, the funding for any incremental capital project will not be allowed."
> How does that decision affect your plans over ten years, if your estimates of savings are met or exceeded, and how will be able to support future capital requirements?
>
> MS. BUTANY-DeSOUZA: Well, I think, first, we've been asked in several interrogatories, as well as undertakings, what the ROE -- what the projected ROE would be, and we're not showing that we'll be above 300 basis points, above the regulated return.
> That being said, page 9 of the Board's policy on distributor -- rate-making for distributor consolidations so that is EB-2014-0128, the Board set out that it believes, at the bottom of page 9 in that policy, that a distributor may now apply for an ICM that includes normal and expected capital investments.
> We expect that ICM is applicable to us during the rebasing deferral period and in the context of a merger.[9]

[9] Tr. Vol 2 pp 147,148

4.5 It would appear that the Applicants expect the ESM to be a substitute for a review of whether rates and reasonable. The merger proposal is that they maintain the Horizon ESM on a separate basis and that the share of earnings, if any, will be credited to a newly proposed deferral account, for clearance at the next applicable annual rate filing.

4.6 The Applicants also propose that the ESM exclude:[10]

- The settlement of any regulatory assets/liabilities including the lost revenue adjustment mechanism ("LRAM");
- Changes in taxes/PILs to which Account 1592 applies, which will be shared through that account rather than through earnings sharing;
- Horizon Utilities-zone related Rate of Return on Stranded Meters at the short term debt rate of 2.11%;
- Revenue collected from any ICM recovery rate riders;
- Rate of Return on Monthly Billing capital and operating implementation costs should LDCs be permitted to recover these costs from ratepayers; and
- Donations.

4.7 Rates are proposed to be calculated separately on the basis of rate zones. This leads to some uncertainty as to how shared costs of the consolidate utility will be allocated to the four rate zones[11].

> "We haven't determined the methodology as yet for the cost allocation. There are some shared costs that will have to be allocated across the rate zones, back office, et cetera. Again, that's in development.

Speaking to cost allocation-rate design generally it is anticipated that there will be no changes over the deferred rate period[12]:

> MR. JANIGAN: Now, during that ten-year period, is it your understanding that there can be rate harmonization and changes to cost allocations during that period of time?
>
> MS. BUTANY-DeSOUZA: No.

[10] B/T7/S2/pg.1
[11] Vol. 1 pg.112
[12] Vol 2 pgs.147-148

MR. JANIGAN: So there are no changes to rate harmonization or changes to cost allocation during that ten-year period -- with one exception; you can apply for incremental capital?

MS. BUTANY-DeSOUZA: I'm reminded that for Horizon Utilities, our annual filing from 2016 had a change to cost allocation for the street lighting rate class, and so that's a change that we will be implementing over the remainder -- remainder of our custom IR term, so through 2017, '18 and '19. So in fact, for the Horizon Utilities rate zone, that change will be ongoing. But on an umbrella basis, no, there wouldn't be changes to cost allocation. Those changes are usually brought forward in a rebasing application.

4.8 The Applicant's will also be proposing to defer monthly billing for two of the rate zones due to issues related to the consolidation of billing.

4.9 The Applicants are giving notice that they will be seeking ICMs in their application and have indicated that such filing will be made in the future. The estimated incremental capital that might be sought from these applications is $414 M.

4.10 The Board requires LDCs to have an updated Distribution System Plan. The Applicant intends to bring forward a consolidated plan in 2019 It also expects to file partial DSP for rate zones as part of future ICMs[13]. The total revenue requirement impact of the forecast ICMs are $130M are shown below.

Table 1 - Incremental ICM Revenue

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Incremental ICM Revenue ($MM)	**3.7**	**6.1**	**7.3**	**8.9**	**10.3**	**12.7**	**16.0**	**19.3**	**21.9**	**24.3**

Source B-AMPCO-9

4.11 VECC notes, that in its cross-examination with CCC, the Applicant accepted that the Board's policy with respect to earning sharing should be flexible and fit the circumstances of the particular transaction[14]. In VECC's submission all parties agree that it is within the Board's purview to establish an ESM mechanism to fit the particular circumstances of this application. We suggest that the Applicant's proposal in this regard is not sufficient.

[13] Vol. 1 Pg.119-121
[14] See Vol. 1 pgs. 29-30

5 Are the Provisions of the Handbook to Electricity Distributor and Transmitter Consolidations sufficient to protect consumers?

5.1 In the Argument in Chief (AIC), counsel for the applicants not surprisingly relies upon the provisions of the Board's Handbook to Electricity Distributor and Transmitter Consolidations (the "Handbook"), released on January 18, 2016, to severely limit the ambit of the inquiry into the terms of the merger transaction sought to be approved. This involves an elaboration on the no-harm test that provides not much more than an assurance that things won't get worse. The AIC notes:

> "The guidance indicates that it's not the Board's role to determine whether another transaction, whether real or potential, can have a more positive effect than the transaction that has been placed before the Board. … The Board will not consider issues relating to the overall merits or rationale for applicants' consolidation plans, nor the negotiating strategies or positions of the parties to the transaction. And finally, the Board will not consider issues relating to the extent of the due diligence, the degree of public consultation or public disclosure by the parties leading up to the filing of the transaction with the Board.

This is all guidance from the Handbook, and indeed is well-established guidance, I believe, from the Board."[15]

5.2 The AIC also repeats support for the Applicants choice of a ten year deferral of rebasing period, the proposed filing of ICMs during that period and the suggested provisions for the ESM that commences after five years. In particular, the AIC notes:

> "The deferred rebasing period in accordance with the guidance is longer than the shortest remaining termed (sic) to rebasing of any of the consolidating distributors and, as I've already stated, no supporting evidence according to the handbook is required to justify the selection of the deferred rebasing period.
>
> Further, the applicants have proposed an ESM that "follows the form" set out in the 2015 report. The ESM will be implemented if the consolidated entities' ROE is greater than 300 basis points above the allowed ROE, as set out under the incentive regulation policy, and will be based on 50/50 sharing of excess earnings with customers."[16]

The Handbook does provide an expression of support and for consolidation of local distribution companies and the basis for the same:

[15] Transcript Vol. 5, p.49
[16] Ibid, p.47

"The Commission on the Reform of Ontario's Public Services, the Distribution Sector Review Panel and the Premiers Advisory Council on Government Assets have all recommended a reduction in the number of local distribution companies in Ontario and have endorsed consolidation. According to these reports, consolidation can increase efficiency in the electricity distribution sector through the creation of economies of scale and/or contiguity. Consolidation permits a larger scale of operation with the result that customers can be served at a lower per customer cost. Consolidations that eliminate geographical boundaries between distribution areas result in a more efficient distribution system."[17]

5.3 VECC does not seek to challenge the proposition that consolidations may produce efficiencies that reduce costs and provide for a better electricity system. In turn, the regime of superintendence that the Board has proposed for itself provides principally for the application of a no harm test. This test has its legitimacy by the direction that it must true up with the statutory objectives of the *OEB Act*. The Handbook provides:

"The "no harm" test considers whether the proposed transaction will have an adverse effect on the attainment of the OEB's statutory objectives, as set out in section 1 of the OEB Act. The OEB will consider whether the "no harm" test is satisfied based on an assessment of the cumulative effect of the transaction on the attainment of its statutory objectives. If the proposed transaction has a positive or neutral effect on the attainment of these objectives, the OEB will approve the application."[18]

5.4 As the AIC notes, the objectives of the OEB address a number of overall goals:

The first of course is to protect the interest of consumers with respect to prices. Another is to protect the interest of consumers with respect to the adequacy, reliability and quality of electricity service, also to promote the education of customers -- consumers, I'm sorry, to promote economic efficiency cost effectiveness, to facilitate the maintenance of a financially-viable electricity industry, to promote electricity conservation and demand management in a manner consistent with provincial government policies and having regard to the economic circumstances of consumers, to facilitate the implementation of a Smart Grid and finally, to promote use and generation of electricity from renewable energy sources in a manner consistent with government policies.

5.5 The problem here is that there is a difficult fit between the concept of fairness to customers and the premise that <u>any</u> economic betterment of consumers by way of potential reduction of revenue requirement that is shouldered by them allows a merger transaction to skip though the door with a huge 10 year potential windfall for only one stakeholder, the applicants. The proposed allocation of consolidation benefits is reported elsewhere, but while the revenues from synergies flow directly

[17]" Handbook to Electricity Distributor and Transmitter Consolidations", Ontario Energy Board , January19, 2016, p.1
[18] Ibid p.4

to the shareholder (subject to potential division with the shareholder, of additional earnings over the required ROE of 300 basis points after 5 years of the deferral period) the customer share is less substantial. The customers must content themselves with the notion that they could have been facing bigger rate increases from custom IRs that would have been filed and inflated rates greater than the IRM and proposed ICMs during the 10 year deferral period.[19]

5.6 In an on-line essay, prominent author and utility regulatory specialist, Scott Hempling has identified some problems with the traditional deference that is often accorded mergers by regulators:

> "Merger applicants often assert a public interest purpose, like (1) lowering costs through horizontal or vertical economies of scale, or (2) improving service quality by meshing two companies' skills and strengths. To distinguish these claims from realities, we need other evidence, like (1) the absence of shareholder windfalls arising from a purchase price above book value; (2) a merger-planning process that identified and committed to ways to reduce costs and improve service; (3) symmetrical sharing, between customers and investors, of the transaction's risks and benefits; and (4) regulators' full access to information to verify the results."[20]

The simplistic comparison to the status quo, (as gloomily projected by the merger applicants) should not be enough to get over the bar of no harm. As Hempling notes in a later essay:

> "Think about it this way: Approving one merger precludes other mergers, just as buying one car precludes buying other cars. You don't buy the car that runs better than your existing car; you buy the car that best meets your full set of criteria—cost, reliability, comfort, looks. Yet commissions regularly ignore this simple practice, approving mergers because they improve (or do not harm) the status quo. Whether merger-produced improvements come at a reasonable cost can be determined only by comparison to an objective case, one consisting of the best options among all feasible alternatives."[21]

5.7 In this proceeding, the larger and more certain benefits of consolidation synergies are to be allocated to the shareholders of the applicants in the lion's share in the deferral period. The majority of customer benefits, post ICMs and winnowed down synergistic cost reductions by rebasing at the end of the deferral period might be gleaned afterwards(leaving aside problems of generational equity).

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[19] It is to be noted that at least two of the revenue requirements for the merger components had their Custom IR forecast without a productivity factor (Transcript, Vol. 2 p.143

[20] "The Dangers of Merger Deference I", Scott Hempling, September 2013, http://www.scotthemplinglaw.com/essays/merger-deference1

[21] "Merger Posture, Don't Defer – Lead", Scott Hempling, November 2013, http://www.scotthemplinglaw.com/essays/merger-posture

5.8 In the absence of the approval of the pursuit of consolidation in fulfillment of a statutory objective pursuant to the OEB Act, reasonable rates must reflect costs incurred to provide service and earn an ROE. Thus the clear standard for the making of just and reasonable rates is that the regulator attempts to limit revenue requirement to that amount required to allow the regulated firm to operate its franchise and earn its rate of return for its shareholders' investment of capital. This was stated by the Divisional Court in Union Gas Ltd. v Ontario (Energy Board):

> "it is the function of the OEB to balance the interest of the appellant [company] in earning the highest possible return on the operation of its enterprise (a monopoly) with the conflicting interest of its customers to be served as cheaply as possible."[22]

5.9 Put in another way, the regulated industry is essentially allowed to recapture its cost of providing service, including the cost of attracting and rewarding capital. Fairness to the ratepayer lies in limiting the rates to that amount which is "sufficient, but no more than clearly sufficient, to cover total cost actually and prudently incurred."[23]

5.10 Canadian courts have recognized and allowed departures from strict cost of service principles where important statutory objectives are pursued. However, the balancing of interests between the utility and its customers must still be a component of any departure from the strict cost of service. The Ontario Court of Appeal in *Toronto Hydro Electric System Ltd. v. Ontario (Energy Board)* upheld the Board's authority to require the appellant to obtain the approval of a majority of its independent directors before declaring any dividends. In doing so the court reiterated that the Board was a "highly specialized expert tribunal with broad authority to regulate the energy sector in Ontario" and "to balance the interests of ratepayers in terms of prices and service while at the same time ensuring a financially viable electricity industry that was both economically efficient and cost effective". The court concluded that the Board's power in respect of setting rates was to be "interpreted broadly and extended well beyond a strict construction of the task". In the result, the legislation reflected "a clear intent by legislators to use both a subjective and open-ended grant of power to enable the Board to engage in the impugned inquiry in the course of rate setting."[24]

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[22] 43 OR (2d) 489 at p 11, see also *Northwestern Uti1ities v. The City of Edmonton*, [I9291 S.C.R. 186 at 192.
[23] J. Bonbright, *Principles of Public Utility Rates* p.240 (1961).
[24] 99 O.R. (3rd)481 (C.A.)

5.11 In VECC's view, the balancing of interests described as the model in the above-noted Ontario Court of Appeal fails to be achieved in the merger proposal of the applicants. While efficiencies will likely be realized, there are grossly disproportionate shares of merger benefits that are to be allocated to shareholders and customers. In our view, it is possible to give assurance to merging applicants of the recovery of merger costs and give incentive to the achievement of efficiencies, without burdening the transaction unduly. Ratepayers require some assurances beyond the promise of a pot of gold at the end of the rate deferral period. This should be a win-win proposition, not simply a win-not lose.

5.12 VECC understands that wholescale change of the provisions of the Handbook may be undesirable, but it is possible to ensure more customer savings and still meeting the principles of cost recovery of merger costs, enabling of consolidation efficiencies and avoidance of unnecessary windfalls to the shareholder.

6 Remedy

6.1 The Board's allowance of a 10 year deferral of rebasing policy applied as proposed in the application poses a threat of harm to customers in that it not only insulates the utility against being saddled with unrecoverable merger costs, it appropriates too much of the savings for too long a period of time. While the Handbook envisioned the deferral period as a fair balance between the utility and customers to allow legitimate cost recovery and promote efficiency, there is every likelihood of a shareholder windfall and ephemeral customer benefits.

6.2 Ideally, the Board' should limit its decision to the issue of whether the consolidation is approved. VECC believes that the approval should be granted. However, the Board should not attempt to grant rights for rates relief that do not reasonably reflect the costs of service or a reasonable trade-off to ultimately achieve statutory objectives. The +- 300 basis point ROE policy for the last five years of the deferral of rebasing period does not, in and of itself, determine what is "just and reasonable", nor is it a substitute for the Board's statutory mandate to approve utility rates.

6.3 The Board, itself has stated that this is not a rates case. No evidence has been led on the reasonableness of maintaining separate rate zones by a single utility. That question is not even before the Board in this application. Nor can the Board presuppose that simply because the future consolidated utility manages its business such as to keep its ROE within 300 basis points of the approved ROE that this is reasonable. For example, if the compensation of employees rises well above its market value, is it reasonable for customers to pay that in rates. Imprudent acquisitions or management may drive up costs that otherwise might have resulted in earnings shared with customers after the five years of rebasing. These contingencies speak for a comprehensive rate review of these now amalgamated utilities.

6.4 Our submission has attempted show the dichotomy between the goals of the Handbook and some of the processes that were put in place to realize those goals. VECC's believes that the application of the latter in this case produces a result that skirts a key reason for the Handbook itself – producing efficiencies that will result in lower rates for electricity customers. Both the results and the optics of the applicant-proposed regulatory treatment of this merger are less than mediocre. A subsequent rate review could possibly lead to more savings by examining the assumptions about general plant investment and compensation as well as the planned DSP.

6.5 In our submission, a preference for fewer distributions utilities to accord with the efficiency objective in the OEB Act does not reflect a priority recognized in Act. As we have noted, while the Board has much leeway in fashioning rates, ultimately it must do so to reflect the balancing of interests, and in particular, the interest of customers with respect to prices. For these reasons we submit that the consolidated Utility should provide a rate harmonization plan for consideration of the Board no later than 3 years after the approval of this transaction. That application should include consideration of such overarching rate issues as depreciation rates, rate design, cost of capital and the operating and expenses of the consolidated utility. Should the panel examining that application believe that the productivity initiatives of the new utility warrant rate of return incentives it can consider that based on the facts before it.

6.6 In the event that the Board is of the view that it is simply necessary to tweak the Handbook components to achieve a fair result, VECC would suggest a lowering of the 300 point overearning band for the ESM and its application from the commencement of the deferral period. While that would not allow for a highly desirable review as suggested above, it could provide some safeguards against an unacceptable division of consolidation benefits.

6.7 VECC also recommends that in the event that the 10 year deferral period is maintained that the suggested rate review be triggered by factors such as excessive over-earning or a failure of the merged utility to meet reasonable performance metrics.

7 Amended Licence Proposals

7.1 The Applicants have provided proposed amended licences. These amendments were given at the end of the proceeding and without the aid of discovery or included in the hearing of this application. VECC makes no submissions on the merits of the proposed amendments since they have been made after the conclusion of the hearing. In our view, any amendments to the licence or licences of the consolidated utility as seen fit by the Board to go forward should be subject to a discrete and different proceeding and as part of the licence application.

8 Reasonably Incurred Costs

8.1 VECC submits that its participation in this proceeding has been focused and responsible. Accordingly, VECC requests an award of costs in the amount of 100% of its reasonably-incurred fees and disbursements.

Dated October 7, 2016