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April 20, 2012

VIA MAIL AND EMAIL

Ms. Kirsten Walli  
 Board Secretary  
 Ontario Energy Board  
 P.O. Box 2319  
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Dear Ms. Walli:

**Re: Renewed Regulatory Framework for Electricity**  
**Board File Numbers: EB-2010-0377/EB-2010-0378/EB-2010-0379/EB-2011-0043**  
**and EB-2011-0004**  
**Vulnerable Energy Consumers Coalition's Written Comments**

As Counsel to the Vulnerable Energy Consumers Coalition (VECC), I am writing, per the Board's Letter of April 5, 2012 seeking comments from stakeholders regarding the Board's development of a Renewed Regulatory Framework for Electricity. The comments are organized according to the issues set out in Attachment A to the Board Staff's Letter. Following this, specific comments are also provided on Board's February 6<sup>th</sup> Straw Man

**A. Attachment A: Issues for Comment**

A-1 Planning (EB-2010-0377)

- A-1.1 How do we optimize planning across the sector to ensure that investment decisions achieve the level of reliability and quality of supply that consumers demand and are paying for?

*Comments*

The first step in optimizing planning is to clearly set out the objectives of the investment planning process. As the question suggests, in the case of electricity infrastructure, the objectives are a) achieving an acceptable level of reliability (and customer service) and b) doing so at an acceptable cost to consumers. The survey work undertaken for the Board by Pollara (EB-2010-0249) suggests that the majority of consumers are satisfied with the current balance between reliability and cost in that:

- There is a willingness and an expectation to accept a few power outages of limited length each year but
- Significant discounts would be required for them to accept a lower level of reliability.

Indeed, when it comes to reliability and customer satisfaction, the greatest area of concern to consumers appears to be not the outage itself but the nature of the consumers' interaction with the utility during an outage, which is a customer service issue as opposed to an investment planning issue.

It is also important to note that the work by Pollara identified differences in expectations regarding reliability across the regions of Ontario. This suggests that imposing a common reliability standard on all LDCs may not be appropriate. Instead, the Board's current approach of focusing on whether or not distributors are maintaining their historical levels of reliability would seem to be the preferred approach. However, there are a couple of caveats to this overall conclusion.

First, while there may be no basis for setting common reliability standards across all regions of the province, there is merit in establishing common reliability measures to be reported on by all distributors. Furthermore, additional measures should be developed that go beyond looking at system averages as is the case with SAIDI, SAIFI and CAIDI and developing additional measures that are more customer centric. For example, consideration should be given to tracking and reporting on each distributor's worst performing feeders.

Second, it would be worthwhile for the Board to publish annually the reliability performance of each distributor over the previous 3-5 years (as reported by each distributor per Section 2.1.4.1 of the RRR) and in doing so to note those distributors whose most recent and/or average performance fell in either the top or bottom 20-percentile of the overall observed range. This would assist the customers and management of utilities (particularly those with superior and inferior reliability performance) in considering whether the current trade-offs involved between cost and reliability are appropriate.

In order to optimize planning across the sector it is important that not only the appropriate trade-off is made between cost and reliability but also that needs are properly prioritized and that the most cost-effective solutions are pursued<sup>1</sup>. Furthermore, this must be done both within each individual distributor and (for regional planning issues) across distributors.

In the case of individual distributors this calls for a planning process that is needs based, that prioritizes based on risks and impacts of outcomes and that manages total spending with a view to both these priorities and the overall costs concerned. In the case of regional issues, it calls for regional planning that involves all the stakeholders and looks for the most cost-effective solution overall.

- A-1.2 How might coordinated regional planning between utilities and third parties (e.g., municipalities) promote the efficient and cost-effective development of infrastructure and enhanced regulatory predictability, while maintaining reliability and system integrity? What are the implications, if any, for distribution network investment planning?

#### *Comments*

In VECC's view, the benefits of coordinated regional planning between utilities and third parties (such as municipalities) are self evident. It provides utilities with better information regarding the need for future facilities, in terms of both their scope and timing. It also allows utilities to incorporate their need for distribution line right of ways and sub-station sites into the long term land use planning of the local/regional governments. Such insights can only benefit the utilities and their customers through both improved matching of investments to needs and lower costs.

The main implication for distribution network planning is that it is not/should not be a process that is "internal" to the utility self. The utility must engage other parties in its planning process and also become involved in their planning processes.

- A-1.3 How might the Board facilitate regional planning and the effective execution of the resultant plans as appropriate?

#### *Comments*

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<sup>1</sup> The most cost-effective solution may not always be the lowest cost solution as trade-offs are often required involving aspects that are difficult to monetize.

There are two facets to “regional planning”. One involves coordination between an electricity distributor and the municipalities it serves. The second involves coordination among neighbouring utilities in order to meet their aggregate needs in the most cost-effective way possible. It is evident from the cost of service applications filed by electricity distributors that many of them already do work (at least to some extent) with their local municipalities when preparing their load forecasts and capital plans. It was also evident from the March 29<sup>th</sup>, 2012 Stakeholder session that regional planning is going on amongst electricity distributors. Indeed, the OPA and distributors observed that regional planning amongst distributors was working well. The current problems were not with “planning” but with “execution” and were largely due to the existing cost responsibility provisions of the Transmission System Code<sup>1</sup>.

In VECC’s view there is nothing further to be gained by trying to (in some manner) mandate that regional planning occur. Rather, a utility should be required as part of the support provided for its capital plan (whether part of a single test year request as currently the case or a request for approval of a multi-year capital plan as envisioned by the Board Staff’s Straw Man) demonstrate – as needed – that its plan has been developed in cooperation with both the local municipalities and neighbouring distributors and is supported by these broader planning processes.

- A-1.4 If we revise cost responsibility under section the Transmission System Code in respect of transmission line connection facilities to pool the costs, should the pooling be on a province-wide basis, a regional basis, or some combination? Should the cost responsibility rules for industrial customers and distributor customers be the same? Why or why not?

#### *Comments*

Before addressing the question as posed, VECC believes it is necessary to comment on Section 6.3.6’s “otherwise planned” exception. During the course of the March 29<sup>th</sup> stakeholder session<sup>2</sup> a question was raised as to why line connection facilities identified as being required through a regional planning process wouldn’t be captured by this exception and, therefore, the cost be pooled. VECC notes that this exception dates back to the Board’s June 2004 Phase I Policy Decision in RP-2002-0120 where the Board stated:

“customers should not be required to bear the cost of facilities that were otherwise planned by the transmitter. In order to ensure that this does not happen, a transmitter will be required to provide to a potential or existing transmission customer, as part of the connection protocol, any pertinent existing transmission plans dealing with system expansion that cover the portion of the transmission system under review. Such plans are expected to be developed by transmitters to address growing demand, system sustainability, system reliability and integrity. Such a transmission plan will be essential to determine whether a particular connection project is truly triggered by the specific needs of a customer.” (page 61)

VECC believes that, before the Board determines whether the issue can be resolve through an interpretation of Section 6.3.6, it is important to go back to first principles and work through why it is appropriate to exempt connection facilities that are part of a “plan” from this cost responsibility provision. In VECC’s view such an exercise will provide the necessary insight into what is meant by a “transmission plan” to allow for a proper (and rationale) interpretation.

With respect to the first part of the question, VECC notes that the problem regarding cost responsibility appears to be more one of “affordability” of the costs than a principled approach to who should pay. This is evident from the fact that there appears to be no objection to a user pay approach for Transformation Connection assets – as they can more easily be sized to meet the needs of the specific transmission customers. The issue is fundamentally with the Transmission Connection facilities where, due to the lack of flexibility on sizing, the costs are often viewed as prohibitive. Furthermore, the issue of affordability arises whether the costs are assigned to just the requesting customer or to all customers in the region<sup>3</sup>.

In its June 2004 Policy Decision the Board affirmed<sup>4</sup> the principle first adopted in RP-1999-0044 that “customers who require the construction of new Connection facilities to meet their needs should bear the cost of those facilities, to the extent that the cost is not recovered in the Connection revenue”. In VECC’s view this principle should not be

<sup>1</sup> March 29, 2012 Transcript, pages 9 & 41

<sup>2</sup> March 29, 2012 Transcript, page 60

<sup>3</sup> March 29, 2012 Transcript, page 42

<sup>4</sup> Page 61



totally abandoned as would be the case under a fully pooled approach or the “basic service option approach” put forward by Hydro One Networks<sup>1</sup>. The claim that distributors should be exempt from the user pay principle on the grounds that they have an obligation to serve<sup>2</sup> ignores the fact that, their obligation to serve is tempered by their ability (under the DSC) to seek a capital contribution from customers who trigger system expansion that costs more than the anticipated revenues. The Transmission System Code, in its current form, essentially applies the same principle to transmission customers as the Distribution System Code applies to distribution customers.

However, in the interest of affordability and encouraging transmission customers to identify their needs as part of a regional planning process, VECC believes there is merit in:

- First, clarifying the difference between radial lines and network lines,
- Second, clarifying the interpretation of Section 6.3.6,
- Third, assigning cost responsibility on a regional basis, and
- Finally exploring ways of addressing the sizing issue associated with Transmission Connection assets, perhaps by pooling a portion of the costs based on the excess capacity of the line.

VECC believes that a working group of stakeholders, tasked with exploring these issues, is the best way to develop a workable solution.

In VECC’s view there are fundamental problems with adopting different cost responsibility rules for direct industrial customers versus distribution utilities (e.g., requiring capital contributions from industrial customers but not from distribution utilities facing similar circumstances). One of the fundamental tenets of ratemaking is that rates (i.e., cost responsibility) should reflect the costs customers impose on the system. The customer’s use of electricity, whether to produce industrial goods or to service residential customers is not material to the rate to be charged.

Furthermore, industrial customers sometimes have a choice between being a transmission customer or a customer of the local distribution company. Different rules for cost responsibility at the transmission versus the distribution level will lead to distortions in the economic decisions of industrial customers. In extreme cases such differences could lead to industrial customers setting themselves up as “distribution companies” (e.g., for town sites etc.) in order to avoid capital contributions for transmission connection costs.

- A-1.5 How can the Board satisfy itself that multi-year investment plans are appropriate?

*Comments*

It is VECC’s view that the best way for the Board to satisfy itself that multi-year investment plans are appropriate is through a process similar to what the Board currently uses to review and approve capital spending and the resulting rate base when considering Applications based on cost of service. Specifically, that is public hearing process (either oral or written depending upon the nature of the Application) where the electric distributor files its proposed multi-year investment plan along with supporting evidence and interested parties have an opportunity to test its appropriateness and make submissions regarding the plan.

The current Filing Guidelines for cost of service based applications (Chapter 2, pages 21-22) provide a good starting point for the types of supporting information that distributors should be expected to provide. However, as the longer timeframe of a multi-year plan increases the uncertainty as to how the future may actually evolve it will be particularly important for distributors to document their capital planning process in terms of what is driving the need for future investment, how capital projects are prioritized and how they propose to manage uncertainty (i.e., adjust their plan if circumstances change).

Having said this, VECC observes that there are now a plethora of planning-related documents that distributors need to either consider and/or provide including multi-year investment plans, asset condition assessments, asset management plans, Green Energy Plans and Smart Grid initiatives. Furthermore, in some cases, it remains unclear as to precisely the actual role/purpose of the requested information. One example is the asset management plans currently filed as part of rate proceedings. These plans vary in quality, consistency and detail on future spending. However, in its decisions the Board has not generally opined on the usefulness of plan or as to its expectations as to whether the plan will be followed or the consequences if it is not.

<sup>1</sup> March 29, 2012 Transcript, pages 10-11

<sup>2</sup> March 29, 2012 Transcript, page 11

Ideally each utility should produce one comprehensive capital plan that addresses all the various expectations of the Board. In order to facilitate this, the Board should integrate (into one document) its overall expectations regarding capital planning, particularly as they apply to a utility's rate application.

Finally, in VECC's view, the ability of the Board to "satisfy itself that multi-year investment plans are appropriate" will be determined not only by the qualify plan submitted but will also be a function of the evident robustness of the distributor's planning process.

- A-1.6 How should smart grid investments be treated (i.e., as part of rate base, or based on type of activity/asset)?

#### *Comments*

There are effectively two types of smart grid investments. The first one consists of those investments in smart grid technology which make good business sense (i.e., the "smart grid" technology has a demonstrated track record and there is sound business case for the distributor to adopt it). From a capital planning and rate base perspective, these types of "smart grid" investments should be treated the same as any other investment.

The second type of smart grid investment involves technologies and/or equipment that do not have a demonstrated track record and/or have not been fully commercialized but show potential promise in terms reducing cost or improving system reliability/customer satisfaction. The distinguishing feature will be that there is no clear business case with an obvious payoff for customers. However, there is a potential opportunity here that requires further investigation.

While it is legitimate for distributors to explore such opportunities, the activity must be carefully considered and coordinated. In such cases, the distributor should be required to demonstrate that it is not duplicating the efforts of others and also explain why it is appropriate for it to be the entity testing/piloting the project. This later requirement could involve linking the potential benefits of the new technology to a particular need/problem of that distributor. Also, the distributor should be required to demonstrate that it can manage this investment as part of its overall capital program from both a resource availability and cost management perspective.

- A-1.7 What empirical and qualitative tools and methods might be used to inform: (a) utility planning processes; (b) utility applications to the Board; and/or (c) the Board's review of utilities' plans?

#### *Comments*

As noted during the recent stakeholder session<sup>1</sup> there are different types of capital spending (e.g., Customer Attachment & System Expansion, Infrastructure Renewal, Mandated Investment, etc.), each with different drivers that will determine the need for future spending. As part of their capital planning processes, distributors should be expected (required) to identify the drivers underlying the need for each proposed capital project, explain why it must occur in the particular year(s) proposed and provide the basis for quantum of spending proposed (i.e., what is the basis for the cost estimate itself?). Within this context utility planning processes and the resulting applications to the Board can be informed by:

- Load forecasts setting out future system requirements, supported by a combination of econometric analysis, customer requests for connection and official municipal plans. Note: Official municipal plans can provide insight into not only future System Expansion and Reinforcement requirements but also future mandatory spending related to roadway expansions.
- Asset Condition Assessments and Asset Management Plans. Note: The two are very different. The former simply provides the distributor with information regarding state of its distribution system. The later, more importantly, provides a plan as to how the distributor sees itself responding to the assessment in a manner that seeks to maintain reliability but also manage the spending of resources. The Plan should therefore include expected outcomes in terms of planned spending and associated accomplishments/results to be achieved.

<sup>1</sup> March 28, 2012 Transcript, pages 133-134

- Risk Management Analysis that considers the various spending requirements and looks at: a) the possible impact or implications of not undertaking (or perhaps just delaying) the spending and b) the risk that this impact will occur. Note: The implications could be financial, legal/regulatory, reliability-based and/or related to other aspects of customer satisfaction. The outcome of the Risk Analysis is a prioritization of the distributor's spending requirements and should be a key component of both the Asset Management Plan and the distributor's overall (capital) spending plan. It should be noted that this risk management analysis can (and should) be applied to OM&A spending as well as capital spending.
- Procurement processes that rely on tendering and competitive markets.

In VECC's view capital spending remains a vexing issue under IRM as past cost of service applications have shown evidence that some utilities scale back capital spending during the IRM in order to improve returns. At the same time, the future is uncertain and capital plans must be flexible and subject to change if circumstances warrant. As part of an Application (particularly for a multi-year investment plan approval), distributors should be required to indicate what the key drivers are underlying their current capital plan, set out how they will monitor their planned/approved spending and outline the processes in place to adjust their spending if future circumstances/requirements change.

Finally, VECC notes that, while not perfect, the OM&A per customer comparative analysis currently published by the Board is of assistance in testing and determining the reasonableness of past trends in and proposed spending on OM&A by electricity distributors. However, there are currently no comparable measures/metrics for capital spending. Clearly, the issue is more complex when it comes to capital as spending is influenced by the age/condition of assets and by system expansion plans. However, some thought should be given as to whether there are useful capital spending-related metrics that could be developed.

#### A-2 Performance & Incentives (EB-2010-0379)

- A-2.1 What outcomes for customer service and company cost performance should be established?

##### *Comments*

Outcomes should be considered in two contexts. The first is with respect the standard outcomes that the Board has set in terms of the performance standards that have been set for reliability and customer service. The second context is with regards to a distributor's future performance as it relates to the expectations established in its (cost of service/multi-investment plan) Application, as discussed in the foregoing section. These "outcomes" will by definition be distributor-specific and will be linked to the proposed spending plan.

- A-2.2 What standards and metrics for customer service and company cost performance should be established in regard to these outcomes? How do the performance benchmarks that are in place today relate to your proposed metrics?

##### *Comments*

VECC considers that Board's current performance benchmarks (regarding reliability and customer service) as providing useful benchmarks for utilities in terms of the overall expectations regarding their performance. As noted in the preceding discussion, more detailed (customer and utility specific standards/metrics) should be based on individual distributor's circumstances and priorities as reflected in their proposed spending. To this end, distributors should be required to (as part of their Applications) set out the outcomes they expect to achieve and propose suitable metrics for measuring/determining if the outcomes have been achieved.

- A-2.3 What are the characteristics of a "high-performing regulated entity" (i.e., what specific metrics can be used to evaluate the level of performance of the regulated entity)?

##### *Comments*

In principle, a “high-performing regulated entity” is one whose performance matches that of a “high-performing entity” in competitive markets in terms of delivering (in an efficient and cost-effective manner) products and services while achieving/maintaining superior customer satisfaction.

In a competitive market, consumers can compare prices in order to gauge whether a particular supplier is being efficient/cost-effective in delivering its products and services. However, this is not the case for a regulated entity. While customers may be satisfied with the price they pay for the quality of service received, it is only through regulation that a determination can be made as to whether a) a higher quality service could be delivered for an equivalent price or b) the same quality of service could be provided for a lower price. In VECC’s view, the overall purpose of regulation is to help ensure that the right dollars are spent on the right activities at the right point in time as defined by consumers’ requirements/expectations with respect to the price, reliability and quality of customer service with a view to also maintaining the overall financial capability of the utility to continue to deliver service in the future.

In the absence of a competitive market, the best “metrics” available to evaluate the performance of regulated entities are metrics that compare either performance across similar entities or metrics that compare the performance of a particular entity over time. The Board, through its various benchmarking exercises has attempted to develop such metrics for both distributors as a whole (in terms of its OM&A benchmarking) and for certain individual distributors (as evidenced by its direction to Hydro One in previous Decisions regarding compensation benchmarking). While both exercises are useful they are by no means definitive in terms of enabling the Board to evaluate the performance. Furthermore, as discussed above, similar metrics/benchmarking exercises do not currently exist for capital spending.

Also, while the Board has required electricity utilities to file some comparator and cohort information in rate cases the depth of information and its use in setting rates is unclear. For example, utilities are not required to explain year over year variances in their cost per customer, or changes in their relative place within a cohort. LDCs are required to file “cost driver” tables but they are not required to explain the value to customers from these drivers. Upon rebasing, a utility who demonstrates an increase in cost per customer or FTEs per customer is not currently required to show what new, improved or different services are being provided. That is, utilities will explain, often at length, the “what” of spending but much less effort goes into the “why” it is necessary. The more sophisticated argument that utilities should be making is in respect to either the resulting improvements in the quality of service or total factor productivity. Without this information the Board cannot, in VECC’s respectful view, be certain that the utility is not simply passing on the consequence of a decline in labour productivity. In competitive markets declines in productivity are met with lower sales and smaller profits. If such events are not uncovered in rate proceedings the results are higher distribution costs than are warranted.

At this time, the Board should not seek to establish specific measures with the view that they will allow the Board and other parties to (on this basis alone) judge the effectiveness of its regulatory oversight of Ontario’s electricity distributors. In VECC’s view there is no perfect metric due to both data limitations and the fact that performance must be measured across a wide range of parameters. For example, even if there was “perfect” metric for measuring cost effectiveness that could account for all the justifiable reasons why costs can and do vary across utilities, cost is not the only relevant performance indicator.

Rather, in VECC’s view, the Board should rely on maintaining an effective role in terms of regulatory oversight through an adjudicative process that:

- Allows for disclosure and testing of the facts behind an individual utility’s application,
- Provides for participation by interest parties, and
- Lead to a reasoned decision by the Board Panel hearing the case.

At the same time, comparator and cohort information can be useful in assisting the Board (and other parties) in assessing the reasonableness of an electricity distributor’s proposed OM&A and capital spending. As a result, efforts should be made to both refine/improve the current OM&A comparator analysis and develop comparable measures for capital spending.

- A-2.4 What incentives, if any, are appropriate to reward utilities for cost-effective and efficient performance, including appropriate rewards for exceeding standards for customer service, and company cost performance? What incentives, if any, are appropriate for the purposes of rewarding performance with regard to multi-year capital programs?



- A-2.5 How might the Board enhance the alignment of customer and company interests through the use of incentive mechanisms?

*Comments*

In VECC's view "incentives" must be carefully thought through before they are implemented. Otherwise there is too much risk of creating incentives that produce unintended and inappropriate consequences. For example, some might view providing utilities an incentive based on the extent to which they actually accomplish the projects set out in their multi-year investment plan on or below budget as being appropriate. However, the offering of such an incentive would have to address the fact that circumstances may change over time and that the activities/spending as set out in the initial plan may no longer be in the best interests of customers. Otherwise, one could actually be incenting utilities to undertake the wrong activities.

Overall, in VECC's view, it is premature to discuss financial incentives when there are no agreed upon metrics upon which to measure success or failure. The converse of incentives is, of course penalties. Any incentive for reaching a target metric or objective begs the question of what is the penalty for falling below a target or metric. To not answer this questions risks developing a "selective" or asymmetrical rate making scheme. That, in VECC's view, would not be in the interest of ratepayers. The first step in advancing metric or comparisons as an effective tool for ratemaking is to see a more rigorous implementation of them in the current cost of service and IRM filings.

A-3 Rate-setting & Mitigation (EB-2010-0378)

- A-3.1 How might the Board align rate-setting with multi-year investment plans? Do you have a preferred approach, and what are its benefits and disadvantages?

*Comments*

A multi-year investment plan will produce a multi-year revenue requirement for the associated capital additions. The challenge in aligning this result with the Board's rate setting practices is that its current approach to incentive rate making focuses on price and not revenue requirement.

Under the Board's current Incremental Capital Module alignment is achieved by restating the test year's revenue requirement so as to include any additional approved capital and continue the price cap approach to IRM. In theory one could extend this approach and make it applicable to a full multi-year investment plan.

In the alternative, the Board could move to revenue cap approach where the OM&A portion of the revenue requirement is linked to IPI-X while the capital portion of the revenue requirement is calculated based on a cost-of-service type calculation that takes into account the approved multi-year capital additions. The following table sets out some of the advantages and disadvantages of the two approaches.

Rate Setting Approach	Advantages	Disadvantages
Price Cap with Capital Adjustment	<ul style="list-style-type: none"> <li>- Simpler to Implement</li> <li>- Results in productivity factor being applied to both capital and OM&amp;A</li> </ul>	<ul style="list-style-type: none"> <li>- Does not capture load forecast changes, particularly those that drive capital additions</li> <li>- Assumes all capital addition in the test year (unless additional adjustments are made)</li> </ul>
Revenue Cap	<ul style="list-style-type: none"> <li>- Allows capital additions to be incorporated in rates the year they occur.</li> <li>- Permits load changes that accompany capital additions to be included in rate-setting</li> </ul>	<ul style="list-style-type: none"> <li>- Requires a multi-year load forecast.</li> <li>- Does not permit productivity factor to be applied to capital (unless additional adjustments are made)</li> </ul>



There are likely additional advantages and disadvantages associated with each approach that would need to be explored. Furthermore, there are a number of issues that are common to both approaches and need to be addressed before the Board adopts a rate-setting approach that incorporates multi-year investment plans including:

- Should any provision be made for the fact that capital spending can impact on OM&A?
- Should cost of capital parameters be updated each year?
- If and how should the capital investment plan be updated as information on actual capital spending becomes available and if/when circumstances change over the IRM period?

At this point VECC does not have a preferred approach other than to note that there was some discussion during the recent stakeholder session about addressing the last point through after the fact true-ups and prudency reviews. While prudency is an issue with all distributor investment activities, it can be quite contentious particularly on an after the fact basis when the dollars have already been spent and the exercise involves second guessing the decision making of the distributor's management. As a result, in VECC's view, the Board should avoid setting up a regulatory regime that creates/relies on a need for such after-the-fact reviews. The only exception may be where the spending involved is related to investments that are common across distributors (e.g., smart meters and market transition costs) such that there is ready opportunity for benchmarking of costs.

- A-3.2 Should the Board amend the ICM rules as proposed by some participants to provide for an interim solution? If so, how? What are the implications of such an interim change in the context of the longer-term RRFE approach of incorporating multi-year capital plans in rates?

#### *Comments*

The current ICM rules (e.g., the fact that the proposed spending must be for addressing extraordinary/special needs that are clearly outside the scope of what was approved for the test year and the use of a materiality threshold) were designed so as to avoid any need for the Board to review in detail a distributor's entire capital spending plan for an IRM year. Indeed, in its September 2008 Supplementary Report the Board stated (pages 30-31):

The Board notes that there are clearly differences in perception as to the purpose of the incremental capital module. Ratepayer groups perceive the capital module as a mechanism aimed solely at addressing extraordinary or special CAPEX needs by distributors. The distributors, on the other hand, perceive the module as a special feature of the 3<sup>rd</sup> Generation IR architecture which would enable them to adjust rates on an on-going, as-needed basis to accommodate increases in rate base.

In the Board's view, the distributors' view is not aligned with the comprehensive price cap form of IR which has been espoused by the Board in its July 14, 2008 Report. The distributors' concept better fits a "targeted OM&A" or "hybrid" form of IR. This alternative IR form was discussed extensively in earlier consultations but was not adopted by the Board. The intent is not to have an IR regime under which distributors would habitually have their CAPEX reviewed to determine whether their rates are adequate to support the required funding. Rather, the capital module is intended to be reserved for unusual circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capacities underpinned by existing rates.

The approach being proposed by some participants is one similar to the "hybrid form of IR" referenced in the Board's report. In VECC's view this represents a fundamental change and is not something that can be readily accomplished by "tinkering" with the current ICM. VECC submits that any attempt to create an interim solution by such tinkering would either not address the concerns raised by distributors<sup>1</sup> and/or would result in an ineffective regulation of distributors' multi-year investment plans. Rather than seek an interim solution the Board should focus its efforts on developing an effective permanent solution.

- A-3.3 How might further benchmarking be used to: (a) help determine appropriate cost levels; (b) achieve further efficiencies; and/or (c) assist in managing cost increases?

#### *Comments*

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<sup>1</sup> March 28, 2012 Transcript, page 130

As discussed above, the first step would be to incorporate the Board's current cost benchmarking activities/results into the rate application and review process by requiring distributors to not only include the results of the analysis in their applications but also explain trends in the metrics over time in terms of not only the underlying drivers but also any improvements in service to customers and/or total productivity.

As a second step, efforts should be made to expand the comparative analysis to include capital spending. This would be different from the total factor productivity analysis discussed during the stakeholder session as it would seek to develop comparators on the capital side equivalent to the OM&A/customer metrics currently used.

- A-3.4 How might the Board's approach to the application review process be proportionate to the characteristics of the application (including quality) and the performance of the applicant?

*Comments*

Implicit in this question are a number of assumptions, namely that:

- appropriate measures can be defined that will gauge the "performance of applicants".
- appropriate metrics can be calculated to attached relevant values to these "measures"
- the quality of an application can be readily discerned, and (most importantly)
- the effort or approach taken to a particular application should be commensurate with the quality of the application and the (past) performance of the distributor.

In VECC's view there are fundamental problems with each of these propositions.

As discussed above, in VECC's view, the Board's benchmarking and comparative analysis has not currently developed to the point where the Board (and other parties) can readily define and identify "high performing" distributors. Also, determining the quality of an application goes far beyond simply a matter of whether or not it is complete (i.e., contains sections dealing with all the relevant matters identified in the filing guidelines). The quality of an application can only be discerned by careful review to ensure that the facts presented are consistent and sufficient to support the planned expenditures and requested rates. In many of the cost of service-based Rate Applications currently filed with the Board it is not until after one or two rounds of interrogatories (or a technical conference) that the facts supporting the case have been clarified.

Having said this, VECC is of the view that the current processes followed by the Board do allow for a consideration of application and result in a process that is "proportionate" to the characteristics of the Application: Applications that are well supported and where the requests are non-controversial generally lead to fewer interrogatories, shorter technical conferences and settlement agreements. Furthermore, to the extent benchmarking and comparative analysis is used by parties to assess the reasonableness of a distributor's application distributors demonstrating superior performance in this area are currently subject to a proportionally less rigorous review.

Going forward, improvements in benchmarking and the increased focus on benchmarking and comparative analysis in electricity distributors' actual applications (as recommended above) may lead to the point where a more formal link can be made between a distributor's performance and the extent/degree of regulatory review the distributor's application would be subject to. However, even if a distributor can be identified as a "high performer" (based on past experience) and is deemed to have submitted a "quality application", this does not mean that the requested costs and associated rates should be summarily approved. There is a basic level of review and due diligence required in order for the Board to maintain effective regulatory oversight as described above (Section A-2.3).

- A-3.5 To support the cost-effective and efficient implementation of Board-approved network investment plans by transmitters and distributors and to help mitigate the effects of any unavoidable and significant bill impacts, what mechanisms might be appropriate?

*Comments*

Unavoidable and significant bill impacts can arise due to the need to pass through significant (justifiable) cost increases as they arise and are compounded when such investments are made but the need for any pass through is delayed and accumulates (e.g., during an IR period). VECC sees the move to considering multi-year investment

plans and incorporating their impacts in rates as spent as being one mechanism to help mitigate (or at least smooth) rate impacts.

However, to further mitigate the effect of capital spending on bill impacts distributors should be expected to: a) consider “affordability” as a criterion in their capital planning and prioritization processes and b) consider how spending patterns can be “smoothed” over time. This is not to say that necessary work is not to be done. Rather, as with people in their personal lives and with Canadian governments (both provincial and federal) decisions on whether or not to spend must be tempered with not only with the implications of not spending but also the capacity to spend.

#### A-4 Other

- A-4.1 In light of what you heard at the March 28-30, 2012 Stakeholder Conference, what are your priorities for the Board’s development of the RRFE and how might the Board manage the transition to the renewed regulatory framework in a manner consistent with your priorities?

#### *Comments*

Based on the comments made during the recent Stakeholder Conference VECC considers the most pressing issues to be:

- The need to address the cost responsibility issues associated with section 6.3.6 of the Transmission System Code, and
- The need to address the issue of capital spending during the IR period.
- The need to update the current cost of service filing requirements to improve the information on and the use of metrics and comparators

In VECC’s view, working groups (involving Board Staff, distributors and customer representatives) should be established and tasked with developing and assessing alternatives with a view to putting forward one or more solutions on each of these issues.

- A-4.2 Are there other key issues that should be considered in the development of the RRFE?

#### *Comments*

There are three other issues that VECC believes Board should consider/address:

- First, just as the Board is now re-thinking its approach to how incremental capital requirements should be addressed, it should also reconsider the need/benefits of earnings sharing as a mechanism for balancing distributor and ratepayer interests during an IRM period.
- Second, to the extent the RRFE proposals alter the revenue risk that distributors currently face, the Board should consider adjusting (downwards) the allowed ROE for distributors.
- Finally, in VECC’s view, the Board must adopt a more proactive approach in its regulatory oversight of earnings during IRM periods. VECC notes that of the two distributors for which the Board directed almost a year ago that filings be made for 2012 rates due to concerns about over-earning, one has only just recently filed and the second has not.

### **B. Board Staff Straw Man Model**

#### B.1 Integration of Planning

#### *Model Framework*

- Plans include sustainment and expansion requirements, smart grid, generation connection and regional considerations. This is depicted in the graphic below.
- Planning expectations developed to enhance predictability of reviews.
- Focus on outcomes.



## Changes

- Longer planning/rate setting horizon.
- Coordination and integration facilitates optimal investments and cost savings.
- Performance affects distributor compensation / customer benefit symmetry.

## Comments

VECC supports an approach to investment planning that integrates the spending on sustainment, expansion, smart grid, generation connections, etc. and presents the results as one comprehensive plan that reflects all of the underlying drivers for capital spending. Such plans should have clear and measurable objectives (other than spending). In subsequent rate reviews the Board should consider the achievement (excess or lack of) in setting rates.

To this end, the overall planning process (including the risk assessment and prioritization) should work towards the development of one plan that represents the best use of a utility's resources (including dollars to be spent). In this context, VECC agrees that the focus should be on outcomes, in terms of the risks/implications (e.g. reliability, customer service, etc.) of spending versus not spending and the impacts on consumers' rates and bills.

## B.2 Treatment of Capital

### Model Framework

- Multi-year approval of capital to match from approved multi-year investment plans throughout term.
- Outcome driven planning and focus on reliability.

## Change

- Pre-approval of multi-year capital plans.
- Focus on reliability

## Comments

As discussed in the preceding sections, VECC is generally supportive of utilities developing and receiving approval for multi-year capital plans. However, as noted in Section A-3.1, the "devil is in the details" and there are a number of issues that need to be addressed before a workable approach can be established.

VECC agrees that reliability is a key consideration in capital planning. However, it is not the only consideration and, indeed, improvements in reliability should not be pursued regardless of cost (see Section A-1.1).

Finally when it comes to capital planning the focus must not only be on the proposed "outcomes" but also how adaptive the utility and its plan are to the uncertainties associated with longer term capital planning (see Section A-1.7)

## B.3 Performance Standards and Incentives

### Model Framework

- Desired outcomes established for the utilities in addition to existing core performance standards:
  - Enhanced customer standards used to set outcomes.
  - Reliability standards developed.
  - Experts retained to assess utility plans and audit utility planning processes to assess the utility's effectiveness in prioritizing and pacing network investment with regard to bill increases

to consumers.

- Achievement of investment plan objectives will be encouraged through the use of specific incentives (i.e., financial, reputational, and proportionate processes).

### *Change*

- New performance expectations associated with investment planning and reliability.
- Potential for expedited review based on utility's effectiveness in prioritizing and pacing network investment with regard to bill increases to consumers.
- Financial consequences potentially tied to achievement of investment plan objectives.

### *Comments*

VECC has some reservations regarding the “desired outcomes” of the Model Framework in this area. It is not clear what is meant by “enhanced customer standards” and “reliability standards developed”. VECC is supportive of “enhanced customer standards” in terms of establishing reasonable expectations and service level requirements in other areas related to customer service and customer satisfaction (e.g. communication during outages). However, as noted earlier, customer expectations do vary across Ontario and setting higher targets for existing measures must consider the inevitable trade-off between cost and quality service.

Clearly Board Staff requires the requisite skills to be able to support and assist the Board in reviewing multi-year investment plans. Furthermore, to the extent these skills are not available internally, experts could be retained to assist the Board. However, the Board should not attempt to fulfill roles for which is neither suited nor has the mandate. The OEB is not a regulator in terms of safety and engineering like that of the TSSA or ESA. Rather it an economic regulator. While it is mandated to ensure that utilities operate safely it does so from the perspective of ensuring that it has the proper funds to do so and that those funds are expended in a reasonable way. Clearly there is some crossover between engineering and costs and at times the Board may require assistance to understand whether funds are being expended prudently. However VECC would respectfully suggest that the Board not start down a murky and costly road of purporting to oversee the engineering of Ontario's distribution or transmission sector. Rather, in our view the Board should require that utilities provide clear objectives for asset and investment plans. These measures should discuss such things as meeting expected customer growth, new initiatives to meet demands of government or regulators like the ESA and OEB and overall system reliability and service.

VECC's other concern is that, in those areas where it may legitimately need external assistance, many of the experts/firms with the necessary skills and knowledge are already engaged by utilities. The challenge will be for the Board to obtain (either internally or through 3<sup>rd</sup> parties) expertise that is clearly independent and arm's length from the utilities it regulates.

VECC is unclear as to what it meant by “Potential for expedited review based on utility's effectiveness in prioritizing and pacing network investment with regard to bill increases to consumers”. As discussed earlier, there is balance to be maintained between a scheme of expedited review and maintaining effective regulatory oversight. In VECC's view, by the time the Board has established that a utility's Application is based on an effective capital planning process that prioritizes potential spending based on an comprehensive assessment of needs and consequences the bulk of the “regulatory review” will have already been completed. Furthermore, it is important to remember that the prioritization process itself will reflect the distributor's perspective regarding priorities and consequences – both of which are legitimately open to challenge.

Finally, VECC notes that extreme care will have to be taken in establishing any financial incentives that are tied to “investment plan objectives”. The opportunity that such incentives will create unintended consequences is too great to ignore. One of the inherent problems will be actually defining the “investment plan objectives” in a measurable way given that the future is uncertain and that needs/consequences are likely to change going forward over the multi-year period covered by the investment plan. VECC submits that it is by no means a simple matter of measuring spending variances from an approved plan.

### *Model Framework*

#### Partial PBR:

- OM&A is indexed to performance outcomes and a productivity measure; capital based on approved plan is a pass-through.
- Total cost benchmarking of distributors implemented to encourage effective cost containment and help the Board to determine appropriate cost levels associated with investment plans.
- Total factor productivity will inform, and total distribution cost benchmarking will be used to support an envelope approach to ratemaking.

### *Change*

- Sever treatment of OM&A and capital to increase pursuit of operating efficiencies and recognize significant need for capital investment.
- Measures will be developed to ensure allocative efficiency.

### *Comments*

VECC's views on the proposed Model Framework for Rate Setting are discussed in Section A-3.1. A couple of the key challenges with the envisioned Straw Man are:

- The fact that OM&A and Capital Spending are not totally separable and there may need to be a provision for explicit adjustments to OM&A to recognize this fact.
- While the Board Staff Straw Man acknowledges the need to integrate productivity improvement expectations into the capital spending part of rate setting process it is by no means clear how this will occur. Compounding this issue is the fact that Board currently has not developed any utility metrics/measures for either capital spending or total factor productivity and, indeed, there is a continuing debate on whether or not the requisite data to do so is available for the latter<sup>1</sup>.

### B.5 Period of COS/IRM Review

#### *Model Framework*

- Term is based on the utility's plan, as approved.
- Off-ramps determined by performance against plan

### *Change*

- Period between COS reviews more flexible.
- Off-ramps more strict.

### *Comments*

In VECC's view the Board should establish both minimums and maximums for the permitted IRM term. As a starting point for discussion, VECC submits that 3 and 5 years would be appropriate values respectively.

In VECC's view there would be two types of off-ramps. The first, and more significant type, would be off-ramps that trigger as new full cost of service filing. Events that could lead to such an effect could be significant over/under earnings or material changes in service territory. The second type of off-ramp would be one that is triggered by a need to materially revise the approved capital plan but does not give rise to the need for a full cost of service review.

<sup>1</sup> March 29, 2012 Transcript, page 186



This second type of off-ramp would provide distributors with a mechanism/opportunity to update their capital plans to reflect changing circumstances.

## B.6 Total Bill Mitigation

### *Model Framework*

- *Ex-ante and ex-post.*
- Total bill considered.
- Threshold based on empirical data.
- Conventional and alternative mechanisms considered.

### *Change*

- *Ex-ante* added.
- Changes in all charges considered.
- Threshold set empirically.
- Alternative mechanisms.

### *Comments*

VECC supports the addition of “ex-ante” considerations regarding rate/bill impact mitigation. As discussed earlier, both individuals and governments take their available resources into account when developing their budgets and determining what “must” be done in the coming year(s). Electricity distributors should be expected to operate in a similar fashion. This not to say that work which must be done does not get accomplished. Rather, what it requires is that distributors when prioritizing and considering need for capital spending do so with a view to the total costs.

VECC is also supportive of an approach that recognizes that other components of the bill are also changing and will impact on the same consumers that pay distributors their costs.

In terms of total bill versus distribution bill considerations, VECC notes that to date distributors have been perfectly content to have bill impact considerations measured at the total bill level assuming no changes in the other components, thereby diluting the impact of any increase in the distribution component of the bill. However, now that a proposal has come forward to consider the real total bill impacts they are objecting and saying that they can not be held accountable for mitigating total bill impacts. If distributors want to held accountable for only their component of the bill then ex-poste mitigation requirements should be established based on increases solely for the distribution component of the bill.

One possible way of reconciling these two concerns is to require that:

- Distributors consider total bill impacts in the development of their spending plans (i.e. on an ex-ante basis), but
- Requirements for specific bill impact mitigation plans (on an ex-poste basis) would be linked to the anticipated increases in the distribution component of the bill, including all related rate riders and adders.

Thank you for the opportunity to comment on this important initiative.

Yours truly,

*Original signed*

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