McCarthy Tétrault LLP
Suite 5300, 66 Wellington St. W
Toronto, ON M5K 1E6
Canada
Tel: 416- 362-1812
Fax: 416-886-0673

**George Vegh**
Direct Line: 416-601-7709
Email: gvegh@mccarthy.ca

April 20, 2012

**Via Courier**

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto ON
M4P 1E4

Dear Madame:

**Re: Renewed Regulatory Framework for Electricity**
**Board File No.: EB-2010-0377; EB-2010-0378; EB 2010-0379; EB-2011-0043 and EB-2011-0004**
**Responses to Issues in April 5th, 2012 Letter of the Ontario Energy Board (the "Board")**

Enclosed please find two hard copies of a submission filed by the Intervenor DRRTF in the above-noted matters. A copy of this cover letter and attached submission has also been filed through RESS.

Sincerely,

*signed in the original*

George Vegh
Chair, Distribution Regulation Review Task-Force

GAV:mt
att.

McCarthy Tétrault LLP
Box 48, Suite 5300
Toronto Dominion Bank Tower
Toronto ON M5K 1E6
Canada
Tel: 416-362-1812
Fax: 416-868-0673

**George Vegh**
Direct Line: 416 601-7709
Direct Fax: 416 868-0673
Email: gvegh@mccarthy.ca

April 20, 2012

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto ON
M4P 1E4

Dear Madame:

Re: Renewed Regulatory Framework for Electricity
Board File No.: EB-2010-0377; EB-2010-0378; EB 2010-0379; EB-2011-0043 and EB-2011-0004
Responses to Issues in April 5th, 2012 Letter of the Ontario Energy Board (the "Board")

**Introduction**

This letter is written in my capacity as Chair of the Distribution Regulation Review Task Force (the "Task Force"). The Task Force is an initiative of the leading gas and electricity distribution utilities in Ontario aimed at encouraging thought and discussion on how the OEB's approach to regulating energy distribution can be enhanced. These utilities are: Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro Electric System Limited, and Veridian Connections Inc., Enbridge Gas Distribution Inc., Hydro One Networks Inc., and Union Gas Limited.

The Task Force appreciates the opportunity to participate in the Board's Stakeholder Conference to address the Renewed Regulatory Framework for Electricity Distributors and Transmitters ("RRFE") and has benefitted from the exchange of ideas and information provided. The Task Force also appreciates that the Board has continued to refine its approach in the RRFE as reflected in the Issues List accompanying its April 5th, 2012 letter (the "Letter").

It is the DRRTF's expectation that the objective in this round of submissions is to aid the Board to 1) understand the issues and 2) prioritize the issues to continue the momentum for the RRFE process. It is further the DRRTF's expectation that further more thorough discussion of the issues will take place in future proceedings in the coming months. For purposes of brevity, the comments in this submission are intended to highlight issues spelled out in the Letter as well as new issues arising from the Stakeholder Conferences. The new issues raised in the Letter are:

**Rate Setting and Mitigation**

- 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?

**Planning**

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

- 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?

Furthermore, two additional issues that arose at the Stakeholder Conference are addressed in these submissions:

- The suggestion that distribution rates should not be compensatory; and

- The related suggestion that the Board's distribution rate setting should take into account both distribution rates and electricity commodity pricing so that the Board can address the "total bill impact" on customers.

All of the above issues will be addressed in turn.

**Rate Setting and Mitigation**

- 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?

With respect to the issue of an interim ICM amendment, the Task Force is of the view that an interim amendment to the ICM rules is necessary. The RRFE is a comprehensive and thorough review of the regulatory framework. It will address issues that are new to the Board (such as distribution planning and objectives) and will have to reconsider issues such as performance measures. The current performance measures are clearly inadequate to meet the requirements of the *status quo*, let alone the performance based approach that the Board is considering. It is clear that there is a lot of work to be carried out before these measures are decided upon. Indeed, it is worth observing that there is not even agreement respecting the relevance and availability of information.[1]

Consultation on these measures is critical and, in the Task Force's submission, should involve a working group process. The Task Force supports the Board taking the time required to get this right.

The uncertainty and inadequacy of the ICM needs to be addressed pending the outcome of a more enduring framework review.

First, the issue of capital investment is perhaps the most pressing issue in the sector. As the Chair has observed, "one of the major challenges facing the sector today and the most significant driver of costs is the scale of capital spending expected over the next few years from most utilities – generators, transmitters and distributors alike – to renew and modernize the system and provide for new demand."[2]

Second, the Board has now had several years experience with the ICM and all parties can learn from that experience to address this issue in a systematic way.

Third, there is considerable uncertainty as to how the current ICM is to be applied. Board panels have taken different positions on this issue. The following table sets out the approaches taken by the Board on the interpretation of the threshold to be met in an ICM request:

| **ICM Criteria** | **OEB Decision/Report** |
|---|---|
| "Materiality, Need and Prudence" | Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008, s. 2.5; see also, Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, September 17, 2008, Appendix B. |
| "Materiality, Need and Prudence", **plus** "extraordinary and unanticipated" | Hydro One Networks Inc. Decision, May 13, 2009 (EB-2008-0187). |
| Materiality, Need and Prudence", **plus** "extraordinary" | Oshawa PUC Decision, June 10, 2009 (EB-2008-0205). |
| "Applicants must demonstrate that the amounts | Guelph Hydro Electric System Inc., Decision, |

[1] For example, the experts on performance measures all apparently agreed that the Board's current performance measures are inadequate, but disagreed on whether data supporting improved measures is even available (See Transcript for March 29, 2012, pp. 185-191.

[2] Rosemarie T. Leclair, Chair & CEO, Ontario Energy Board, Remarks for the Ontario Energy Network, November 21, 2011, p. 7.

| | |
|---|---|
| exceed the Board's materiality threshold and clearly have a significant influence on the operation of the distributor, must be clearly non-discretionary and the amounts must be outside the base upon which rates were derived. In addition, the decision to incur the amounts must represent the most cost-effective option for ratepayers." | May 13, 2009 (EB-2008-0205(corrected)) June 10, 2009; and Oakville Hydro Electricity Distribution Inc., Decision (EB-2010-0104), June 10, 2009. |
| "Discrete, Material and non-discretionary" and, apparently, facility specific.[3] | Toronto Hydro-Electric System Limited (EB-2011-0144), Decision, January 5, 2012 |

Thus, the Board has not developed or applied a consistent approach to determining the threshold for the ICM. Certainty on how to approach infrastructure investment under the current regime is therefore required.

Further, it does not appear that all parties have an appreciation for the way in which the cost of capital is recovered during the term of an IRM. The rates under IRM implicitly include the depreciation expense of the rebasing year in revenue requirement. That depreciation expense is used to return the capital that utility investors have already invested (in regulatory nomenclature, this is known as the "Return of Capital" as opposed to "Return on Capital"). While it has been generally true that funds from depreciation have been re-invested in the business, they are also used to repay debt and equity principal that funded previous capital expenditures.

The authors of *Bonbright's Principles of Public Utility Rates* put it as follows:[4]

> "Under a systematic and consistently applied program of rate regulation, this procedure of capital-cost amortization through annual charges to revenue account is by no means one of mere bookkeeping. Instead, it is designed to afford a company an adequate opportunity to recoup from ratepayers its investments in fixed assets during their estimated useful-service lives. *The deduction for depreciation makes the rate base portray the company's net investment in used and useful properties – that part of its gross investment which it is entitled to recoup in the future and on which it is meanwhile entitled to earn a fair rate of return*."

…

> "On the general character and significance of the annual allowance for accruing depreciation, as distinct from its measurement, there is no longer room for serious dispute in light of modern accounting theory. The allowance for any given year is but one step in *a systematic and gradual transfer of capital costs into a series of charges to current*

[3] The decision referred to the fact that municipal transformer stations have been funded through ICM and suggested that an IRM application that requested funding for similar facilities would be "directly analogous to projects that the Board has previously approved under ICM for other distributors." (at p. 22).

[4] Bonbright, Danielsen, and Kamerschen, *Principles of Public Utility Rates* (2d) (Public Utility Reports, 1988), p. 270 and 273 (emphasis added).

> *operations* during the estimated useful lives of the depreciable fixed assets among the years during which they perform service instead of charging them in lumps either to the year of acquisition or to the year of retirement. *Thus the cost of a depreciable fixed asset is treated as a prepaid expense*, to be amortized through a series of subsequent charges against current revenues."

Depreciation is thus not a reserve that is available to be used for <u>increased</u> future capital expenditures. Increased future capital expenditures are funded by issuing debt and/or by receiving equity infusions (which may be from retained earnings). Thus, if a utility's capital expenditures during an IRM term are greater than its depreciation expense, the revenues under IRM will not fully cover its capital-related costs. This point is illustrated in the materials provided on today's date by Hydro One, Inc., in response to its undertaking to the Board to provide a numeric illustration of the inadequacy of the ICM to fund capital investment. The Task Force agrees with Hydro One's presentation on this point.

As a result, the failure to include prospective capital expenditures in the IRM model does not reflect efficiency; it reflects a model that is not consistent with the needs of utilities to properly serve customers in the current environment. As Ms. Taylor pointed out during the Stakeholder Consultation, there is an inherent regulatory lag between the time that capital investment is incurred and its inclusion in rate base following a Cost of Service ("CoS") rebasing.[5]

The main consequence of this approach is the creation of step-changes in rates that increase upon rebasing. This is not in the public interest. The presentation of the Retail Council of Canada (the "RCC") is informative in this regard. The RCC surveyed its members and reported that, of the issues ranked as important, "lumpiness" and "predictable prices" were high on the list.[6] As the RCC stated at the Stakeholder Session:[7]

> "What that means is that retailers are operating, in many cases, on razor-thin margins. There is not a lot of room to play here when factor costs increase.
>
> That means that there is a serious risk that when we have *large especially unpredicted factor cost increases*, there is going to have to be compensation in other places, and specifically we are looking at employment. So that means that we're having broad economic impacts not just on the retailers' bottom line, but also on the people who depend on retailers for their gainful employment."

Further, some parties have argued that the IRM in the electricity regulatory model is adequate because the gas utilities have managed well under their IRM models. The Task Force (which includes Ontario's gas distributors) acknowledge that the IRM experience has perhaps been better for the gas distributors, but has not been without its own challenges.

First, the gas sector IRM is materially different than the electricity sector IRM. Indeed, each of the gas utilities has customized IRM models that have largely been negotiated with rate payers.

---

[5] See transcript, March 28, 2012, p. 170.

[6] Presentation of Retail Council of Canada at Stakeholder Session, Slide 28.

[7] Transcript, March 28, p. 28 (emphasis added).

Second, the gas utilities face considerable inflationary pressures as well. These are being addressed in rebasing proceedings currently before the Board.

Third, the treatment of capital expenditures remains an issue in gas IRM and the gas utilities have participated in this process because they are of the view that a thorough consideration of the treatment of capital under IRM is required on a going forward basis.

All of this is to say that a well structured IRM can bring benefits to both utilities and customers. The challenge is to determine an appropriate approach to the treatment of capital investment as part of an IRM model on both a longer term and interim basis.

The longer term approach will be considered within the context of the new framework that results from this process.

In terms of what an interim approach would look like, there are a number of potential approaches. The proposals put forward by Hydro One at the Stakeholder Conference are all worth considering as options for a distributor to pursue. As a reminder, Hydro One proposed two basic approaches:[8]

- Prospective multi-year capital plans and in-service additions would be approved in a CoS hearing and the resulting rate base impacts on revenue requirement would be known, and fixed over the IRM period; or

- an annual review of proposed capital expenditures (the results of which can be implemented in rates through either a rate rider based on detailed review of forecast changes to rate base or a rate adder to provide required funding with review of changes to rate base deferred to the next CoS hearing).

The DRRTF believes this is consistent with the methodology proposed in the OEB straw man model, and that there may be other proposed approaches worth further consideration. The key objective should be to develop a model that facilitates required infrastructure spending, while also creating a rate profile that is more stable and predictable than the present IRM approach.

Finally, with respect to implications of an interim change in the context of the longer-term RRFE approach of incorporating multi-year capital plans in rates, there are two main points.

First, it is clear that *some* type of treatment of capital is necessary pending the longer-term RRFE approach. Given the lack of consistency around the treatment of the current approach, at a minimum, a new and more consistent approach is necessary. Settling this approach will involve some form of stakeholder participation, whether through a hearing or consultation process. That process can consider the issue of a reasonable transition from a new interim approach to a longer-term RRFE approach of incorporating multi-year capital plans in rates.

Second, experience from the interim period could be very helpful in developing and evaluating a longer term approach. In other words, the Board may allow a few different approaches during the interim period to provide information from and experience with some different models with the deliberate goal of incorporating the learning from these approaches into the longer term

[8] See Hydro One, *Investment Recovery* presentation to RRFE Stakeholder Consultation, slides 4-7.

framework. This can help identify areas that need to be addressed and provide some concrete information with respect to those areas.

In terms of timing, the Task Force proposes that the interim review should commence as soon as possible and new approaches to infrastructure investment be considered in time for rate applications filed in 2012 for implementation in the 2013 rate year.

**Planning**

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

- 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?

The main issue respecting regional planning at the Stakeholder Conference related to the need for clarification respecting cost allocation under the Transmission System Code ("TSC"). This issue has been discussed for several years.[9] While there was some discussion respecting the need to avoid redundant distribution assets through a regional planning approach, there was no suggestion that there are currently redundant assets or that there is a considerable risk that there may be in the future.

Further, the OPA described how it is currently conducting an approach to regional planning. Developing a separate planning approach for distribution rate making could lead to confusion and overlap. This is not to suggest that considerations of duplication of resources and the

[9] The following exchange between counsel for the CME, and representatives of Hydro One and the OPA put the issue well (Transcript, March 29, 2012, pp. 73-74):

MR. THOMPSON: My question of you, Susan, is: Is there a way -- I am looking for a process to resolve this relatively expeditiously, because if it is just changing the words of 6.3.6, my question is: Is there some way that the words there would be more comforting to you, but still respect the principle that Ken has raised? And if so, is it as simple as proposing an amendment and circulating it the way the Board deals with amendments to codes? Does that get us over the cost-allocation issue?

MS. FRANK: I would believe that that would be an excellent place for us to start and see how well that works, and like a lot of these things I am not convinced that you can come up with a final solution as we sit around the table or as we work over the next few months.

I think you start it, you transition to it.

I think getting the clarity on the code is the place to start, and let's see; that might be enough.

MR. LYLE: Let me just add that I think part of the confusion with respect to the interpretation of 6.3.6 comes out of the Board's connection procedures decision, where it stated that:

"Where planning involves joint studies between Hydro One and one or more distributors to meet different timing and supply needs such as load growth, the Board views such plans as customer-driven, where a capital contribution would be required."

So I think some of the confusion around how we're going to interpret the 6.3.6 and what joint planning work is appropriate stems from that.

MR. THOMPSON: I was just going to say we don't want to do another ten years of the dance, do we?

MS. FRANK: No. No.

consideration of regional impacts of investments in facilities should not be considered in rates cases in the context of evaluating prudence. It is currently best practice for LDCs to consult with neighbouring utilities with respect to the timing and coordination of facilities' investments and this should be continued.

It would therefore appear that the issue to be addressed in this area is fairly discrete and ripe for resolution in a TSC amendment process. In other words, there is no need for this to await the completion of the RRFE. The Task Force therefore suggests that the Board "carve out" the regional planning issue from the framework review and have it addressed as a discrete TSC amendment process.

**Should Distribution Rates be Compensatory?**

Some stakeholders suggested that distribution rates should not cover the costs of distribution, that customers should be entitled to reduced costs, regardless of whether that results in compensatory rates. This point was argued primarily by SEC.

Counsel for SEC put it as follows:[10]

> So let's start with the market proxy. You are all familiar with this. The basic premise is that the Board is here to replace the market because utilities have a monopoly powers, and, therefore, they can charge monopoly rents, unless the Board steps in and acts like the market.
>
> …
>
> Now, the important part to understand about that is that cost-of-service is not actually a market-like activity. The market doesn't look at individual firms and say, Oh, your costs have gone up? Okay, we will pay more for your product.
>
> That doesn't happen. In fact, indeed, in your own businesses, if you are an LDC, if you are an LDC representative here in the room, you don't do cost-plus pricing with your suppliers either. You demand, instead, that you pay the market for things.

The description of the Board as a proxy that replicates the outcomes that a market would achieve is simply incorrect. The Board does and legally must set rates in a manner that is compensatory. Even if this is not how the market works (and the SEC's suggestion that consumers set price ignores the fact of underlying inflationary realities that do exist in competitive markets), it is how economic regulation works.

The fundamental problem with SEC's suggestion is that it misconstrues the notion of a proxy for market failure in this context. The proxy idea arises because, in a market, the forces of supply and demand are sufficient to meet the public interest. In the absence of a market, such as is the case with electricity distribution and transmission, competition is insufficient to meet the public interest and therefore the Board sets the price and other terms of service.[11] It does so, not as a

[10] Transcript, vol. 3, pp. 12-13.

[11] The Board thus regulates where competition is insufficient to protect the public interest. This basic framework is reflected in s. 29(1) of the *OEB Act, 1998* which provides that the Board will refrain from regulating "where competition [is] sufficient to protect the public interest."

proxy for the *market* in the sense that the Board seeks to replicate an outcome that the market would provide, but as a proxy for the *public interest* which, by definition, the market cannot serve in a natural monopoly construct. As the Divisional Court stated in the *Low Income Case* "The Board's regulatory power is designed to act as *a proxy in the public interest* for competition in view of a natural gas utility's geographical natural monopoly."[12]

In other words, while the market structure of a natural monopoly causes the need for regulation, the form of regulation does not try to mimic the market. In fact that would be impossible. This is explicitly addressed by Harvard Professor Stephen Breyer (now of the United States Supreme Court) in his seminal work on economic regulation. He notes that "it is virtually impossible for the regulator to replicate the price and cost results of a hypothetically competitive industry."[13]

> "Certain important differences are inevitable. In the competitive world, prices adjust rapidly; investors earn rents when the price of reproducing old equipment increases; they may suffer windfall losses when technology lowers reproduction costs; costs tend to be based upon present costs, not those of a test year; changes in demand resulting from change in price are taken into account as they occur; and firms can experiment with different price structures. In the regulated world, on the other hand, prices remain stable for fixed periods of time; the prices set may not yield the revenue that the regulator expects; and as costs increase or decrease due to added efficiency, prices do not change; nor do prices change to reflect possible increases or decreases in the cost of supplying similar services, and firms find price experimentation difficult."

As a result, although a regulator may look to the market to set the costs for an input to a utility's costs (i.e., to determine prudence, including cost of capital), regulation does not function like a market. Instead, regulation meets the challenge of the natural monopoly market structure, not by seeking to mimic the market, but by protecting the public interest through a regulatory compact, under which a utility has the duty to serve customers and in turn is entitled to a just and reasonable rate.

Arguing that a utility's rates should not be compensatory because a market is not compensatory is like arguing that a utility should not be required to serve all customers or that its rates should be unregulated. It simply misses the point of regulation.

The requirements for just and reasonable rates include the requirement that rates be compensatory. Anything less than compensation for prudently incurred costs is confiscatory. As the Board noted with respect to the fair return standard (which is a component of compensatory rates), "Meeting the standard is not optional; it is a legal requirement. As set out by Enbridge in their final comments, the Supreme Court of Canada has "described this requirement that approved rates must produce a fair return as an 'absolute' obligation."[14]

Although the Board has considerable flexibility in setting rates, that flexibility can only be exercised within this context. Thus, for example, in finding that the Board has authority to set

[12] *Advocacy Centre for Tenants v. Ontario Energy Board* (Divisional Court, May 16, 2008) (emphasis added).

[13] Stephen Breyer, *Regulation and Its Reform* (1982, Harvard University Press), at p. 58.

[14] British Columbia Electric Railway Co. Ltd. v. Public Utilities Commission of British Columbia et al [1960] S.C.R. 837, at p. 848.

rates based on a customer's income, the Divisional Court made it clear that this power must be used in a manner that kept the utility whole:[15]

> "Nor does our conclusion presume as to what methods or techniques may be available in determining 'just and reasonable rates.' Efficiency and equity considerations must be made. Rather, this is to say only that *so long as the global amount of return to the utility based upon a 'cost of service' analysis is achievable*, then the rates/prices (and the methods and techniques to determine those rates/prices) to generate that global amount is a matter for the Board's discretion in its ultimate goal and responsibility of approving and fixing 'just and reasonable rates.'"

**Total Bill Impact**

CME has argued that, in setting rates, the Board should take into account not just distribution rates, but electricity commodity rates. This argument is similar to SECs in that it is effectively requesting the Board to transfer wealth from utilities to customers; the difference between the two is the rationale for CME's request, which is based on affordability to customers in light of electricity cost increases elsewhere in the system.

CME's proposal to address electricity generation costs in distribution rates is clearly beyond the Board's authority. The Task Force appreciates that CME's members face a number of economic pressures, including international commodity price increases, currency exchanges and the increasing cost of skilled labour and benefits of an aging workforce. Distributors are not immune from these cost pressures.

However, in setting distribution rates, the Board does not have the legal authority to reduce distribution rates to help reduce the burden of these pressures. The fact that commodity rates are collected in the same bill as distribution rates has absolutely no legal or economic relevance to this consideration.

Further, the Board does have some ability to manage the cost of electricity commodity if it considers that the cost of new generation is too high. As the Task Force has indicated to the Board in previous correspondence, the Board has some tools to address utility system expansions that lead to electricity price increases. In its letter to the Board in October, 2010, the Task Force noted that the Board's power to address generation costs is explicitly addressed in s. 25.36 (1) (b) of the Electricity Act, 1998 which provides that a transmitter or distributor shall connect a renewable energy generator provided that "the applicable technical, economic and other requirements prescribed by regulation or mandated by the market rules or by an order or code issued by the Board have been met in respect of the connection."[16]

Thus, the Board has the mandate to develop rules for the economic connection of generation through an order or code under s. 25.36 (1) (b) of the *Electricity Act, 1998*. Once those rules are in place, they will provide distributors and transmitters with direction on what types of generation connection the Board considers to be economic. Those rules will then, of course, be complied with by distributors and transmitters and the cost of meeting the connection obligations

[15] *Advocacy Centre for Tenants v. Ontario Energy Board* (Divisional Court, May 16, 2008), p. 12 (emphasis added).

[16] *Electricity Act,* s. 25.36 (1)(b).

that result from those rules will be incorporated into distribution plans that are filed with the Board. Those plans are likely to be filed as part of rate applications.

The Task Force suggests that proceeding under the Board's authority to set economic requirements for connection under s. 25.36(1)(b) of the *Electricity Act, 1998* is more appropriate than reviewing either the costs of generation generally or the economics of connections as part of distribution rates applications. Given that the network component of these costs is relatively minor, and that the rates case process involves other issues and participants, the rates case process would not provide the optimal forum to directly address the issue of generation costs.

**Conclusion**

The Task Force continues to actively support the RRFE and appreciates the opportunity to participate in the Stakeholder Consultations and ongoing workshops and other forums.

Sincerely,

*Signed in the original*

George Vegh,
Chair, Distribution Regulation Review Task-Force

c: Norm Ryckman – Enbridge Gas Distribution Inc.
Gia DeJulio – Enersource Hydro Mississauga Inc.
Indy Butany-DeSouza – Horizon Utilities Corporation
Ian Malpass – Hydro One Networks Inc.
Jane Scott, Patrick Hoey – Hydro Ottawa Limited
Colin Macdonald, Sarah Griffiths – PowerStream Inc.
Colin McLorg – Toronto Hydro Electric System Limited
Mark Kitchen – Union Gas Limited
George Armstrong – Veridian Connections Inc.