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May 4, 2012

Ms. Kirsten Walli, Board Secretary
ONTARIO ENERGY BOARD
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Renewed Regulatory Framework for Electricity
Board File Nos.: EB-2010-0377, EB-2010-0378, EB-2010-0379, EB-2011-0043 and EB-2011-0004

Enclosed are the comments of the Association of Power Producers of Ontario (APPrO), the Biogas Association (formerly the Agri-Energy Producers Association of Ontario, (BGA)), the Canadian Wind Energy Association (CANWEA), the Canadian Solar Industries Association (CANSIA), the Canadian District Energy Association (CDEA) with respect to the Renewed Regulatory Framework.

Yours truly,

NORTON ROSE CANADA, LLP

Elisabeth DeMarco

cc: Jake Brooks (via e-mail)

ONTARIO ENERGY BOARD
RENEWED REGULATORY FRAMEWORK FOR ELECTRICITY

BOARD FILE NOS: EB 2010-0377, EB 2010-0378, EB 2010-0379, EB 2011-0004, EB 2011-0043

WRITTEN SUBMISSIONS ON BEHALF OF

Association of Power Producers of Ontario ("APPrO")
Biogas Association (formerly the Agri-energy Producers' Association of Ontario) ("BGA")
Canadian Wind Energy Association ("CANWEA")
Canadian Solar Industries Association ("CANSIA")
Canadian District Energy Association ("CDEA")
Ontario Waterpower Association ("OWA")

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1. The following comments are provided on behalf of the below-mentioned electricity generation associations acting individually, on fuel-specific issues, and collectively, as the Generation Coordination Group (**GCG**), on common electricity generation issues. The GCG is comprised of the following member organizations (each a **Member Organization**): the Association of Power Producers of Ontario (**APPrO**), the Biogas Association (formerly the Agri-Energy Producers Association of Ontario, (**BGA**)), the Canadian Wind Energy Association (**CANWEA**), the Canadian Solar Industries Association (**CANSIA**), the Canadian District Energy Association (**CDEA**, which is further described in Appendix A); and the Ontario Waterpower Association (**OWA**).[i]

2. These comments are intended to both: (i) respond to the specific questions posed by the Board in its April 5, 2012 letter and (ii) provide written comments in response to the Board Staff discussion papers on each of the RRFE proceedings and the straw man model regulatory framework appended to the Board letter dated February 6, 2012 (the **Strawman**). In attempt to efficiently achieve both goals, the GCG and Member Organization submissions are organized as follows:

   I. **The Evolving Economic and Regulatory Context: An Impetus for Stability through Measured Change**
   II. **The Overarching Perspective: Vision, Process, Priorities**
   III. **The Detailed Perspective: Common and Fuel Specific Generation Considerations**
      i. **Distribution Network Investment Planning (EB-2010-0377)**
      ii. **Regional Planning (EB-2011-0043)**
      iii. **Performance Measures and Incentives (EB-2010-0379)**
      iv. **Rate Setting and Bill Mitigation (EB-2010-0378)**
      v. **Smart Grid (EB-2011-0004)**

I. The Evolving Economic and Regulatory Context: An Impetus for Stability through Measured Change.

3. The Board's RRFE proceeding was established in 2010 with the stated intent of developing a renewed regulatory framework for electricity and related Board policies which will: establish performance outcomes that reflect consumers' expectations and encourage enhanced utility productivity; provide for efficiently planned investments in grid sustainment, expansion and modernization that consider pace and prioritization; align rate setting cycles and investment planning horizons and provide for efficient recovery of costs; increase efficiency in the regulatory process through greater focus on outcomes; and consider the total bill impact on consumers.

4. The GCG submits that a new regulatory framework is necessary in order to: maximize the economic efficiency of infrastructure investments; ensure the appropriate implementation of the Government's current and evolving electricity, environmental, and social policy and legislative goals; and update the Board's dated electricity regulatory regime (which was developed in part as a proxy to electricity competition) to reflect the current and evolving electricity and economic context. The RRFE is also necessary to ensure the efficient and effective connection and operation of electricity generation resources that were invested in and developed in response to Government policy, and to avoid stranding new and/or efficient generation and related assets, and their resulting power.

5. The GCG submits that an examination of the current economic context and the major changes in the electricity policy, legislative, and regulatory regimes over the last decade and a half provides a clear impetus for measured change to facilitate predictability and to attract long-term sustainable development and investment in the sector in this dawning age of austerity. Table 1 provides a brief summary of such changes. We note that the Board has

also expressed many of these changes and we support the Board and its leadership in taking the initiative to develop this RRFE.

Year	Policy	Legislative	Regulatory	Economic
1998	Electricity competition - privatization Move away from the vertically integrated public utility Facilitate merchant generation	Energy Competition Act, 1998	Cost of service Consideration of performance based regulation model Experiment with targeted PBR in gas	Significant under supply Nuclear asset optimization decreasing base load power Supply adequacy, reliability pressing concerns Economy growing
2002	Retail price stability Wholesale competition Distributor consolidation	Reliable Energy and Consumer Protection Act, 2002 Electricity Pricing Conservation and Supply Act, 2002	Initial moves to performance based regulation for electricity	"New Economy Electric" model and secondary electricity financial (derivative) markets failing public acceptance Price escalation and gaming in California prompt government intervention and move away from full retail competition Economy strong and growing
2004	Government managed hybrid market Generation supply procurement by separate quasi government agency (OPA established) Long term supply planning Cleaner generation, RFPs, conservation, demand management	Electricity Restructuring Act, 2004	Move to performance based regulation/incentive regulation models for electricity Standardized reporting and record keeping Attempts to automate/standardize rate filings	Supply adequacy, reliability, rolling blackouts, very pressing concerns No merchant generation developed to date Immediate need for intermediate resources and gas generation Green economy growing rapidly
2009	Green energy procurement through feed in tariffs Transmission distribution right to connect for green generators Limit municipal actions to block	Green Energy and Green Economy Act, 2009 Energy Consumer Protection Act, 2010	Initial consideration of Board regulation/approval of large scale conservation, demand management and transmission and distribution infrastructure	World economic recession Automotive and manufacturing sectors hit hard Increased unemployment, business shut down/migration Renewable energy and

	green energy - retool the shrinking industrial /automotive manufacturing base as green energy supply chain Increased government management through directive powers Retail consumer protection Commencement of halted integrated planning process	Electricity Consumer Benefits Act, 2010	investments	related markets viable alternative for job growth Proliferation of climate change markets/regulation in North America Excess power supply
2012	Proposed reconsolidation of planning and procurement functions into single OESO Renewable and diversified electricity supply Short, medium, and long term planning to support necessary infrastructure investments Limit feed in tariffs Increased government management through planning and directive powers	Ontario Electricity System Operator Act, 2012 (Bill 75, proposed)	Status quo is proxy for competition, incentive regulation Significant new green generation requiring connection Board challenges reconciling large capital investment requirements with consumer rate/bill protection Consideration of performance outcome based regulation, OFGEM RIIO models Heightened focus on overall customer bill impacts in addition to specific rate impacts	Very slow economic recovery[ii] Individuals/ customers pinched and intolerant of rate increases NIMBYism Trade disputes re: domestic content requirements and transmission access Surplus baseload generation Successful development/contracting for ~10,000 MW of renewable energy supply well ahead of 2018 goal Massive transmission and distribution infrastructure required to replace aging grid and support new and intermittent generation

6. Table 1 illustrates the frequent and rapid pace of, significant changes in the economic conditions and government policy affecting the Ontario electricity sector. Government policy continues and realistically will continue to evolve (through for example, Bill 75, changes in renewable energy approvals, aboriginal community involvement, municipal support). Together these changes have resulted in the following challenges: (i) the relatively low level of certainty, predictability, and assurance of transmission and distribution infrastructure investment on a regional level and rational recovery at a local level is seriously compromising sustainable development and timely generator connections; (ii) generators and loads cannot make efficient and effective business and investment decisions as a result of uncertain and

changing cost-sharing and infrastructure development models; and (iii) first-in/free-rider problems and other unintended and perverse consequences resulting from the current rules are exacerbated by the potential for changing approaches to cost responsibility rules and the planning framework (which do not appropriately value overall network and societal benefits).

7. In contrast, sustainable and efficient development of the power sector requires certainty, predictability and rational incentives in order to support long term, capital intense infrastructure investments. As a result, the following GCG and Member Organization submissions are intended to assist the Board in developing in measured regulatory changes toward sustainable development of the sector. They are also intended to facilitate: efficient, predictable and timely connection of new generation resources; paced and measured grid infrastructure development to support efficient operation of existing generation resources; reduced surplus baseload generation; likely efficiencies for all customers; and the development of both generation and grid resources to support new economic growth in Northern Ontario.

8. Specifically, the following submissions are intended to assist the Board in developing a new electricity regulatory model with more predictable outcomes for:

   (i) **investment decision making:** the determination of what infrastructure investments utilities will be authorized to develop and add to their rate base;

   (ii) **cost allocation:** the allocation of transmission and distribution costs - especially the costs related to new infrastructure built as a result of generation connections;

   (iii) **process and performance measures:** the procedures applied by distributors and transmitters in responding to generation connection requests and related performance measures to be applied to distributors and transmitters through the applicable distribution and transmission codes and rate setting processes; and

   (iv) **implementation and operation:** the efficient development, valuation and operation of utility grid assets; and

   (v) **standards and enforcement:** a defined regulatory procedure to provide connecting generators with the regularized input into the development and application of technical grid connection standards to be applied to distributors and transmitters and legal recourse for connecting generators to ensure enforcement of such standards as applied by distributors and transmitters.

II. The Overarching Perspective: Vision, Process, Priorities

Vision for a sustainable and long-term regulatory regime.

9. The GCG envisions that the RRFE will achieve the following outcomes for the sustainable and long-term regulation of, and investment in, the electricity sector. The framework will:

    i. reflect the many and significant changes to the sector resulting from the Green Energy and Green Economy Act, 2009 and the current economic context;

    ii. be robust, standardized and result in the assessment of not only long term costs, but also long term, sector-wide benefits in the determination of significant infrastructure investment decisions and the allocation of related costs;

    iii. consider generators as recipients of transmission and distribution services, who warrant reliable and consistent customer service quality standards and measures;

    iv. effect customer bill mitigation by: requiring distributors and generation proponents to work cooperatively to minimize the costs of new connection; facilitating the efficient operation and connection of existing and new generation assets (including those connected to district energy systems) as an alternative to, and a key component of, rational grid expansion; and mandating a paced and measured approach to new distribution and transmission grid investments;

    v. encourage efficient investments in grid infrastructure through pragmatic, generator-focused performance and technical standards for the assessment of connection capacity and the design and implementation of generation connections;

    vi. result in stable and predictable conditions to support a measured pace for the efficient investment in, and development of, grid infrastructure, including required generator connections for varied renewable and traditional sources of power supply (including thermal, hydro, solar, both roof-mounted and ground-mounted, wind, biomass, biogas, high efficiency cogeneration and small-scale CHP, and facilities connected to district energy systems);

    vii. effect a nuanced approach to address the differences in sources of supply (addressing differences in fuel type and whether the generation asset is prescribed or regulated); and

    viii. facilitate the ongoing adaptability of the sector through pre-defined processes and mechanisms that enhance its measured evolution.

Required changes to evolve planning, mitigation, and performance policies.

10. The GCG submits that three (3) key changes are required to evolve planning, mitigation, and performance policies:

(i) the development and implementation of **a revised method to determine the system and societal costs <u>and benefits</u> of any grid infrastructure investment** and the incorporation of same into the *Transmission System Code* (**TSC**) and *Distribution System Code* (**DSC**), as applicable;

(ii) the **establishment of two generator, distributor, transmitter standing committees on** each of: (a) transmission and distribution **performance measures**, and (b) **technical standards** for the assessment of connection capacity, and design and implementation of generator distribution and transmission connections, that will, on a biennial basis, produce draft standards and measures for stakeholder comment, Board review and approval, and subsequent incorporation by reference into the TSC and the DSC, as applicable; and

(iii) the **establishment of a dispute resolution mechanism** in order to ensure distributor and transmitter compliance with the proposed biennial performance measures and technical standards for distribution and transmission connections in a timely manner and provide generators and other customers with meaningful and timely recourse for distributor or transmitter non-compliance.

Process.

11. GCG recommends that the Board proceed to develop the RRFE in accordance with the following steps:

(i) work with the government to **clarify and define for stakeholders the respective roles of the OEB and the OESO** in short, medium, and long term electricity sector planning and related investment decisions and approvals – particularly in light of the newly proposed Ministerial directive powers related to energy planning and how they may impact the RRFE proceeding;[iii]

(ii) **promulgate the next iteration of its revised regulatory framework for coordinated distribution network investment planning and regional planning - including a revised proposed system and societal benefits methodology** - for stakeholder input through a policy hearing process and implementation before the end of Q4 2012;

(iii) **establish two generator, distributor, transmitter standing committees on** each of: (a) transmission and distribution **performance measures**, and (b) **technical standards** for the assessment of connection capacity, and design and implementation of generator distribution and transmission connections, that will, on a biennial basis, produce draft standards and measures for stakeholder comment, Board review and approval, and subsequent incorporation by reference into the *Transmission System Code* and the *Distribution System Code*, as applicable;

(iv) **establish a dispute resolution mechanism** in order to ensure distributor and transmitter compliance with the proposed biennial performance measures and technical standards for distribution and transmission connections in a timely manner

(v) **establish a task force to consider customer bill mitigation** first by decreasing existing inefficiencies in the current power sector, second by increased productivity and demand efficiency measures, third by identifying opportunities to reduce the cost of generation connections while maintaining safety and system integrity, and fourth by targeted measures to address disproportionately affected classes of customers; and

(vi) ensure that all of (i) through (v) above are undertaken with the **consistent input of smart grid**[iv] **policy makers** and regulators charged with consumer relationships and communications.

Priorities.

12. Given the long lead times necessary for prudent investment, the Board should prioritize:

(a) clarification of the roles and responsibilities of the Board in relation to network planning particularly in light of the newly proposed Ministerial directive powers related to energy planning;[v]

(b) distribution network and regional planning (as they may correct existing inefficiencies and assist in mitigating customer bill impacts); and

(c) the parallel operations of performance measures and technical standards task forces in order to further mitigate customer bill impacts.

13. In light of recent developments and the Legislature's recent introduction of *Bill 75*, which revises agency and government roles in relation to energy and related grid planning, the Board may also wish to revise and update its proposed RRFE approach if and as *Bill 75* proceeds through the legislative process.

III. The Detailed Perspective: Common and Fuel Specific Generation Considerations

i. Distribution Network Investment Planning (EB-2010-0377)

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?

14. The GCG recommends that the Board adopt and mandate a broad cost/benefit approach for the assessment of new grid infrastructure investments. The new approach should be robust, clear and result in the assessment of not only long term costs, but also long term, sector-wide benefits in the determination of significant infrastructure investment decisions and the allocation of related costs. It should always consider generators as recipients of transmission and distribution services, who warrant customer service quality standards and measures. It should also be proactive in facilitating efficiencies through cooperation by requiring distributors and generation proponents to work cooperatively to minimize the costs of new connection, facilitate the efficient operation and connection of existing and new generation assets, and mandate a paced and measured approach to new distribution and transmission grid investments with a defined dispute resolution process.

15. GCG submits that the Board should optimize the outcomes of planning activities and encourage efficient[vi] investments in grid infrastructure by establishing two standing task forces in order to promulgate and regularly update pragmatic, customer-focused performance and technical standards for the assessment of connection capacity and the design and implementation of generation connections.

16. This approach should result in stable and predictable conditions to support an appropriate investment pace for efficient development of infrastructure, including requisite generator connections for varied renewable and traditional sources of power supply (including thermal, hydro, solar, both roof-mounted and ground-mounted, wind, biomass, biogas, high efficiency cogeneration and small-scale CHP, including facilities connected to district energy systems). In this manner the Board will facilitate the execution and implementation of the objectives of the *Green Energy Act, 2009*.

The Proposed System/Societal Cost-Benefit methodology (SSCBM).

17. GCG suggest a system and societal cost-benefit analysis methodology that addresses the following concerns and achieves the following objectives.

18. The planning processes affecting the development of electrical infrastructure in Ontario are likely to be extremely varied and subject to change. In some cases a distributor's capital plan may be the driving force, whereas in other cases co-ordinated efforts amongst neighbouring distributors may determine the course of major investments. In certain locations a regional plan may set key parameters, while other locales may rely on the guidance of a provincial plan combined with specific regulatory approvals. The entity championing major new infrastructure could be a municipality concerned with economic development, a distributor, a transmitter, major consumers, private developers or a consortium of any of the above. It appears that there is no one model of development that will suit all situations.

19. Under such circumstances it is difficult to design rules and regulations that can be universally applied to all electrical network planning processes. For this reason, it is particularly important for responsible parties in any of the concerned agencies to be able to access consistent and reliable data on which to base decisions. The area in which consistent data has been most lacking is in the assessment of upstream benefits of network investments. While costs are reasonably transparent, and characterizing the downstream consumer volumes is reasonably

straightforward, the assessment of upstream benefits is more complicated. While enhancing infrastructure to accommodate generation usually has a variety of impacts on the local grid, the benefits are characterized and measured in different ways, depending on the circumstances of the distributor.

20. In order to ensure that distributors have high quality information on the value and benefits of a network investment under consideration, they will need access to a consistent set of metrics that have been reviewed and tested in a regulatory context and which make use of common terminology. This will facilitate comparisons between distributors and improve transparency of planning processes at whatever level they occur (within the distributor, regionally or provincially).

21. The Generator Co-ordination Group envisions a set of metrics that will assess the following network benefits (without limitation) on a consistent basis: loss reduction, avoided or deferred upstream costs, local reliability (including contributing to the kind of regional reliability reinforcements sought by Hydro One), ability to serve more load customers, voltage support, reactive power, VARs, improved power factor, other ancillary benefits, black start, storage, statistical probability of using lower cost local resources more frequently, and ability to respond to local needs and provincial policy directions.

22. The Ontario Energy Board received useful evidence on a proposed SSCBM in the EB-2007-0630 proceeding: Development of a Standard Methodology for the Quantification of DG Benefits, July 31 2008. We strongly urge the Board to facilitate the detailed development of a broad SSCBM for distribution and transmission infrastructure investments starting with the proposed approach outlined therein.

23. Performance measures for distributors in Ontario have generally been developed with load customers rather than generation customers in mind. Although it is reasonable to expect that most performance measures will continue to be load-focused, in order to have an efficient and balanced system some performance measures should also be applied on the generation side. The GCG recommends that performance measures be developed to create appropriate incentives in the following areas: ensuring a prudent and proactive approach to enabling and enhancing generation connection capacity in appropriate parts of the local grid; designing with input from the generation applicant and other relevant parties the lower cost connection options for any given application; ensuring the accuracy of cost estimates; and facilitating the timeliness of cost estimates and construction.

24. Attention should also be paid to the potential for utilities to facilitate the installation of renewable and non-renewable generation in a way that backstops and reinforces renewable generation. This approach, which has been developed in northern Europe, can improve reliability on the network and raise the utilization factor of network investments. In doing so, we note that water-power storage may be used to backstop other renewable generation.

25. There is little doubt that as distributors publicly express their readiness to consider new proposals for smart grid enhancements, suggestions will come forward that are suited to the particular combination of loads and generation that are connected in specific areas. If the options are pursued in an open and transparent fashion, opportunities for cost-effective grid enhancement and bill mitigation will likely emerge in a corresponding fashion.

The straw man.

The Board's Strawman is a reasonable starting point, but it is deficient in that it contemplates a fairly static process that does not fully account for the rapidly changing nature of the sector, which may be more conducive to the system benefits and standing committee processes recommended herein.

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?

26. If a cost benefit model is established and made transparently available then any proponent or member of municipal council could be shown the expected costs and benefits of any proposal or combination of proposals. A freely available model would of course allow for testing of many variations, under different assumptions, greatly enriching the information base and level of public understanding of the planning options.

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

27. Regional planning should be undertaken by the proposed consolidated OESO with the early and iterative input of key stakeholders including generators through a formalized process. It should include recognition of the North as a series of distinct regions with unique requirements and generation opportunities and include the proposed SSCBM set out in paragraphs 17 to 25.

If we revise cost responsibility under 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?

28. The allocation of costs should be aligned with the assessment of system and societal benefits through the proposed SSCBM. Cost responsibility and allocation should depend on the determination and assessment as to what entities benefit from the proposed grid investment goal being delivered. Where broader government goals are being serviced, such costs should be recovered on a province-wide basis. The specific formulaic approach should be developed in consideration of the approach proposed in EB-2007-0630.

29. Aside from new provisions to encourage regionally planned investments, the GCG does not recommend any other major changes to the current cost responsibility and cost allocation approach. The investment community places a high value on the continuity of rules in this area. Any future changes to cost responsibility or technical standards should not be **[name-plated]** from transmission to distribution as this will inevitably impose requirements that are unnecessary and substantially more expensive. For small scale generation this is a significant concern.

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

30. The Board should incorporate quality assurance and control measures into the process that is focused on all of short, medium and long term planning and updated on a maximum 3-year cycle. Regularized production of cost-benefit studies using long-term parameters, performance measures and technical standards in a consistent format will allow for review by multiple parties and repeated testing of underlying assumptions.

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

31. The only aspect of smart grid investments that should be rate-based are the costs of infrastructure for data collection or control that most effectively operated by the distributor. The viability of central infrastructure can only be determined through market studies to estimate and identify the likely private sector investment that would come forward in the event of central infrastructure development. Smart grid investments need to be moderated, and although beneficial are not necessary in all cases. The focus should be placed on finding cost effective alternatives that uphold reliability and safety requirements.

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?

32. Two key recommended tools include: (i) the development of revised method to determine the societal costs and benefits of any grid infrastructure investment and (ii) the establishment of two generator, distributor, transmitter standing committees and a related dispute resolution mechanism as outlined in paragraphs 19(iii) and (iv) and paragraphs 17 through 25.

<u>Fuel Specific Considerations</u>

CANSIA:

33. CANSIA believes that it is important to create a standing committee where generators can review and provide input into technical interconnection standards of all distributors, and in particular Hydro One Networks Inc.

    Moreover the resulting standards may differ in order to most efficiently accommodate the clearly different technical implications of roof mounted solar PV installation and ground mounted installations. The cost responsibility principles for industrial and other distributors customers should be uniform. However, this may result in treatment that is not identical for all customer classes.

CANWEA:

CANWEA strongly supports a standing committee approach to technical standards and performance measures given the rapidly evolving nature of the renewables sector - and in particular developments in turbine technology and pumped gas electricity storage to address variability. The government has expressly acknowledged and facilitated these developments through its recent FIT Review and related establishment of the Clean Energy Export Development Strategy and related Task Force.

CDEA:

The CDEA submits that there are a number of existing inefficiencies in the assessment, design, and implementation of distribution grid connections that warrant redress through this RRFE proceeding on distribution network investment planning and the bill mitigation proceeding. Currently, connecting district energy providers are faced with costs and impediments resulting from distributor imposed technical requirements and specifications that are well beyond what is required for prudent short, medium and long term distribution network planning. These "gold-plated" requirements are outlined more fully in the GCG's general comments on the bill mitigation proceeding (EB- 2010-0378).

CDEA submits that significant efficiencies and preferred outcomes in distribution network investment planning may be gained through the implementation of the technical standards and performance measures standing committee and dispute resolution mechanism as outlined in paragraphs 19(ii) and (iv) of this Submission.

ii. Regional Planning (EB-2011-0043)

34. The Board Staff discussion paper on regional planning appears to recognize the potential need for a modified approach to cost allocation for transmission with regional benefits that is triggered by a single connecting generator, but does not go as far as to address the broader issues and potential solutions through a revised SSCBM. The GCG offers the following comments for the Board's consideration.

35. **Importance of developing generally recognized criteria for assessing the benefits of upstream investments in a regional context.** It is critical to determine appropriate cost sharing for regionally beneficial transmission investments. The availability of such a mechanism has the ability to make or break projects, for both generators and loads, producing economic consequences well beyond the electricity system. A robust SSCBM is a key part of ensuring rational investment on a regional level. There are a number of circumstances and related societal and regional economic and policy considerations that necessitate a departure from the strict cost causation principles (including Regional/Northern development, like Plan Nord in Quebec, *Green Energy Act* policy priorities, and priority grid investments such as those identified in the Long Term Energy Plan). It is also necessary to address the first-in/free-rider problems when "chunky" upstream costs are triggered. A key objective for the Board should be the achievement of a more predictable process for network investment in general, including capital investment for both regulated and unregulated generators. This should not be done in an *ad hoc* manner that strands assets or results in related inefficiency.

36. **Ensuring that generators are recognized as recipients of transmissions and distribution services and worth of equitable treatment from a customer service related perspective.** Changes in regulatory policy should not unduly affect one class of customers at the expense of another. A key principle for the Board should be to ensure that generators are treated in a rational/efficient, fair and orderly manner, and fairly consistent with the equitable treatment of load customers. Some entities are not large enough or constituted to negotiate directly with distributors and therefore require both process and procedural protection. Any changes to the relative treatment of generators and related loads should be designed to achieve consistency where feasible, economic efficiency, and align with the SSCBM. The Board should recognize that efficiency and consistency can have very large and beneficial implications for economic efficiency in the energy system, well beyond the network itself. Ensuring predictable and fair treatment of generators is not inconsistent with the principle that the ultimate design objective of the electricity system is to minimize costs to consumers. In fact, in order to minimize total long term costs to consumers, it is critical to ensure that generators are treated in a rational and consistent manner that encourages efficient behavior by generators. Treating generators fairly is entirely consistent with minimizing total long term costs for consumers. The focus should be on creating efficiencies rather than on shifting costs. A rule change that shifts costs to generators usually results in higher costs being passed along to consumers. In contrast, a rule change that increases efficiency for generators and/or dispatchable loads generally saves money for everyone.

37. **Watch for unintended consequences of changes to the planning framework and cost responsibility rules.** The current cost responsibility rules were designed in large part to maximize economic efficiency. Hastily conceived changes could interfere with that and inadvertently produce uneconomic behavior. We therefore recommend the SSCBM approach outlined in paragraphs 17 through 25.

38. **Establishing stable and predictable conditions for the pace of new development, including the infrastructure necessary to enable new generator connections.** The GCG is concerned about both the certainty and speed of development and construction of physical assets that will improve generator connection capacity and the less than stellar transmitter

compliance with the timelines and standards set out in the TSC. It is important to ensure that conditions allow for the various types of infrastructure development, particularly high priority projects, to proceed as quickly as possible, given the role of new and existing generation in the achievement of the government's coal phase out requirements.

39. In order to avoid unintended consequences and policy/program revisions of the nature and frequency outlined in Table 1, the GCG also recommends that the Board encourage that the government clarify for stakeholders the intended new roles and responsibilities of Ministry of Energy, OEB and the proposed OESO.

40. Priority consideration should be given to projects that have a longer duration development period (1-3 years) and how these projects transition without serious implications. A network planning and development system that is planned and stable is far preferable to a "boom and bust" approach that does not ensure equitable access to all generation types and disadvantages certain fuels through "first to connect" gaming and related cost and inefficiencies.

Are there any specific circumstances where generators should not be responsible for the costs related to an upstream upgrade that they triggered? If so, please identify those circumstances and the reasons why the generators should not be responsible for those costs.

41. Yes. Whenever the benefits to customers other than the generator are significant or whenever other policy, system or societal goals are being served by the connection, cost-sharing is appropriate and a rationalized SSCBM approach should be used to allocate cost responsibility. In principle, the facility is economic if the net present value of its benefits exceed the net present value of its costs. Such facilities should be constructed and costs up to the level of benefits received by the generator should be paid for by the generator. However, where significant benefits accrue to customers other than the generator, costs should be allocated in a pro rata manner in proportion to the respective benefits within reasonable accuracy limits to ensure administrative simplicity. Northern regional investments, in the transmission grid are but one good example of where a single generator that triggers the connection should not bear the entire cost of the connection. In this circumstance, broad societal/industrial benefits are being achieved, gaming and first in problems are being avoided and at least a minimum quality of life will be ensured for remote and disadvantaged communities that are currently reliant on diesel generation.

42. The GCG supports a formal process for regional planning. It promotes the cost-effective development of electricity generation and grid infrastructure through coordinated planning on a regional basis. However it must involve existing, contracted, and major proposed generators and loads to ensure efficiency. Regional planning, particularly in the Far North will facilitate system certainty through regional flexibility in order to accommodate the specific needs of a region. Requisite studies and consultation parameters on any such plan should include criteria specific to encourage cleaner and diversified generation sources and development of untapped hydropower resources.

Planning Horizons

The GCG supports the planning horizons proposed by the OPA in its submissions to the Stakeholder Conference.

Fuel Specific Considerations:

OWA:

There is a real need for regional planning that is not simply based on MW targets. Summer peak, MWh, ancillary services and dispatchability should all be considered in the development of any plans at the early planning stages and input should be updated on an iterative basis. OWA is concerned that much of the conceptual RRFE and existing framework is designed for the South and linked to Official Plans. A distinct approach is required for the Far North in relation to both industrial and mining development and remote communities. It is particularly necessary to addresses the challenges and societal benefits of diesel-dependent off-grid northern and/or Aboriginal communities.

BGA:

Biogas is generally limited geographically to rural areas of Ontario. In the scope of long range planning this is important in the priority of infrastructure investment in the distribution system in rural areas. Regional planning should actively incorporate due and ongoing consideration of the potential for stable, predictable biogas-fuelled generation associated with any and all existing agricultural operations. In this manner the dual objectives of both food security and energy efficiency may be achieved.

CANSIA:

The government's significant commitment to solar generation and the related manufacturing activities is evident in its ongoing Feed-in-Tariff program and the Clean Energy Export Development Strategy featured in the FIT Review. Any regional planning activities should be consistent with the government's green energy manufacturing and green jobs policies and facilitate the Premier's vision of Ontario as a green energy economy in which solar and photovoltaics play a major role.

CANWEA:

In addition to the GCG submissions and recommended SSCBM approach, regional planning activities should be managed in a manner that addresses unfounded local opposition to wind and provides guidance on the future of off-shore wind generation in the Province.

iii. Performance Measures and Incentives (EB-2010-0379)

The Board Staff Paper does not fully acknowledge and reflect the dynamic and changing nature of the sector and therefore the corresponding need for regular updating of related performance measures, incentives, and in certain cases lack of incentives. The GCG provides the following additional comments and proposed measures for the Board's consideration.

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

The Board should recognize, through performance measures and financial incentives that generators are very important recipients of transmission and distribution services that should be afforded customer service quality assurance and control through performance measures and technical standards. In this regard we strongly recommend that the Board proceed with the implementation of the performance measures and technical standards standing committees and dispute resolution outcomes that are outlined more fully in paragraphs 19 (iii) and (iv).

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?

The GCG generally recommends that the applicable performance and measures and metrics be established through the standing committees proposed in paragraphs 19(iii) and (iv) and evolve accordingly. Examples of relevant standards are set out in the CDEAs full specific considerations below, which are supported by the other Member Organizations. The currently existing measures and incentives TSC and DSC are not radically different than those proposed by GCG and the Member Organization, however enforcement and compliance are larger issues resulting in considerable inefficiencies.

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)?

A "high-performing regulated entity" will always, without exception, meet the DSC and TSC measures and those established through the proposed standing committees. It will have no unresolved disputes related to such standards and measures.

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?

The Board may wish to consider regulatory expediency and fast tracking incentives for entities that meet and exceed the suggested performance metrics and technical standards.

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

The proposed standing committees and related dispute resolution mechanisms better align customer and company interests with limited involvement of the Board until the final approval stage. They facilitate robust and updated measures and ongoing communication that are appropriate in the evolving context.

Fuel Specific Considerations:

CDEA:

43. **Performance Metrics;**

DE providers who are adding CHP units, must interact with their distributor to connect into local electricity grids. As such, they are dependent upon:

(i) Better Standardization of Connection Requirements by Local Utilities

- Review previous work on Distribution System Code that attempted to provide standard connection requirements
- Not all utilities using same criteria, some do not have standards
- Address "gold plated standards" for small generation, especially in light of the ancillary benefits of small scale CHP to the local supply utilities, as identified above.
- Given ancillary benefits to both the distributor and upstream transmission provider from embedded small scale load dispatchable CHP units, consider priority given to connection requests and / or preferential cost allocation regimes related to imputed benefits

(ii) Specific elements may include:

a) Distributor Engineering & technical review – The distributor's currently have essentially the unilateral right to set standards and insist on technical requirements. There is no real way to challenge the technical need or requirements, and the attendant costs which are charged to the generator for these requirements. Such higher costs ultimately result in higher costs to electricity consumers.

- The CDEA therefore believes that there is merit in identifying a uniform list of technical requirements and operating standards for CHP units, below 15 MW, and that are appending to the connection requirements included in the Distribution System Code.

b) Connection capability – Currently, distributor's have the unilateral right to advise as to whether there is sufficient connection capacity on a feeder or a Transformer Station, or whether the fault levels are too high, etc. This exposes DE operators to the uncertainty of connection, and in some cases a lack of knowledge of the requirements of small scale CHP units may result in overly conservative estimates being applied by the distributor, and a general unwillingness to look at alternatives for options to address fault levels, or to identify special generator operating procedures to deal with unusual contingencies.

- The GCG therefore believes that there is merit in identifying a dispute resolution procedure whereby the distributor is required to provide advice to generators as to the ability to connect, and if there is an ability to connect, either provide options that they will build and operate (potentially at the generator's cost) and/or agree to the generator using a mutually acceptable third party contractor to provide an estimate of cost and time to build the necessary capacity to enable connections to a level acceptable to the distributor.

c) Improved Response to Connection Applications and More Certainty on Cost Estimates

(i) This may include:

- 90 day response criteria for Connection Impact Assessment, including response from transmission company
- A subsequent 45 day response criteria for cost estimates, including response from Transmission Company.
- +/- 20% guarantee on cost estimates, with any overage or underage at the distributor's risk
- Dispute resolution process embedded into each timeline, including option to obtain alternative time and cost estimate from third party qualified contractor, acceptable to both parties, such acceptance not to be unreasonably withheld.
    - Utility must demonstrate to the reasonable requirements of the regulator that they have been advancing the project.
    - The OEB must generate a response to a dispute process within 30 days
- Expect to have post project audit rights of the costs of the distributor.

(ii) Specific additional elements may also include consideration of the following matters.

a) Project timelines are often dictated by the availability of third party financing and contingent on equipment sourcing within finite timelines. At times, these timelines are a function of government fiscal incentives which obligate project commissioning within defined schedules. For all of these reasons, distributor responsiveness and time-lines to requests for connections (Connection Impact Assessments, cost estimates) are critical to project build-out.

b) The CDEA and GCG therefore believe that a performance metric be built into the Distribution System Code obligating distributors to provide the results to an information requestor (the "requestor") of a Connection Impact Assessment ("CIA") for a new generation unit below 15 MW within 90 days, and a subsequent cost estimate within a further 45 days. In the event that the building of such infrastructure triggers an upstream to the distributor investment (e.g. in TS), the distributor is obliged to obtain impact assessment and costs from the upstream service provider within these same timelines. The failure to meet these timelines should trigger recourse to the OEB by the requestor.

c) The CDEA and Generator Co-ordination Group submit that local generation (depending on type) can improve power factor and generate VARs, which has value for many distributors. At present, there is no consistent way to identify and capture this benefit, even though it is often a much cheaper solution than having the distributors put in capacitor banks for power factor correction. In addition, the Generator Co-ordination Group, submits that a consistent methodology for the identification and calculation of upstream benefits must be implemented.

iv. Rate Setting and Bill Mitigation (EB-2010-0378)

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?

The GCG does not have a preferred approach at this point in time but notes that enhanced information base associated with the proposed SSCBM will likely be of assistance, and strongly recommends that compliance with the proposed performance metrics and technical standards should feature prominently in rate recovery.

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?

The GCG does not support an *ad hoc* approach to capital investment pending the outcome of the RRFE as it may result in inefficient investment and potentially stranded assets.

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?

Please see the proposed outcome outlined in paragraphs 19(iii) and (iv) that provides for ongoing benchmarking of an applicant's performance.

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?

The Board may wish to consider facilitating regulatory expediency or fast -tracking incentives for entities that meet and exceed the performance measures and technical standards resulting from the recommended standing committees.

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?

44. First, address easy to manage inefficiencies in the system. This would mean being able to respond to a request from a generator to have a simpler, less expensive solution considered and approved, in cases where the distributor is using relatively high standards or proposing grid expansion where conservation, generation or district energy may be far more efficient. The two proposed standing committees are intended to address such inefficiencies. The Board may also wish to consider addressing surplus baseload generation through targeted cross border transmission investments.

45. A good example of existing potential inefficiency is found in the treatment of OPG-owned generation assets that have been "prescribed" and are treated as regulated. Many of the regulatory principles that are espoused in the RRFE and the Strawman are intended to promote efficiency within the sector. Their application should not therefore be unduly restricted to transmission and distribution assets, and should extend to prescribed generation assets. Similarly, any regulatory principles designed for transmission and distribution and applied to regulated generation assets may need to be constructed carefully, to avoid unintended consequences on the generation market. In this manner, the entire power sector and all electricity customers are likely to benefit from the pacing and prioritizing of major capital investments through predictable recovery regimes. For example, changes may be introduced in order to enhance the regulatory certainty and predictability of distributor capital investments through incentive regulation (IRM and the ICM). There may also be similar

concerns for new compressed air electricity storage initiatives. Such changes may benefit consumers by smoothing resulting “lumpy” rate impacts of large capital investments on consumers. Sector-wide efficiencies may be further enhanced if such changes also apply to any and all regulated entities (including generators) that are also governed by IRMA.

46. Address current design and implementation of connection inefficiencies through the two standing committees and dispute resolution mechanisms set out in paragraph 19 (iii) and (iv). Currently there are a number of gold plated connection requirements that are not necessary. These include: Gold plating - full SCADA remote monitoring of small generators. While these items are appropriate and technically desirable for larger generators, the economics of smaller projects (< 3MW) cannot bear this level of protection. A load customer with a large motor of the same magnitude does not have the same burden. Other examples include:

    1. Required transfer tip and Non-Utility Generation-end open protection on 200 kW inverter-based projects
    2. Multiple circuit breaker protection schemes (circuit breaker fail protection, in addition to fuse protection)
    3. Insisting on isolating circuit breaker at primary voltage (27.6 kV) rather than generation (4kV) voltage
    4. Hypothetical worst case fault levels halting projects and/or contingency feeder levels

<u>Fuel Specific Considerations:</u>

The above-mentioned submissions and listed inefficiencies reflect a compilation of fuel-specific concerns and the collective experience of members of each of APPrO, OWA, BGA, CANSIA, CANWEA, in consultation with the CDEA.

v. Smart Grid (EB-2011-0004)

The integration of smart-grid

GCG has reviewed the Board Staff Discussion Paper on the "Establishment, Implementation and Promotion of a Smart Grid in Ontario" including the working group discussions. It is clear that the development and implementation of smart grid objectives will be an evolving and long term initiative that well require development over time. As a result, the GCG respectfully submits that the performance measures and technical standards standing committees and related dispute resolution mechanisms outlined in paragraphs 19 (iii) and (v) as well as the proposed SSCBM outlined in paragraphs 17 through 25 will best achieve the cooperation, communication, and collaboration required to assess, implement and execute on the smart grid and related investments.

Appendix A

District Energy Related Considerations from the Canadian District Energy Association

Introduction:

47. The CDEA believes that District Energy (DE) systems, with small scale CHP facilities, are an important part of the portfolio of options that Ontario communities should consider when planning their community developments. CHP combined with district heating networks is the most energy efficient way to produce both electricity and heat, and that the CDEA's interest in the proceeding is that barriers are removed, and in-fact local CHP is encouraged.

48. The CDEA completed research on behalf of Natural Resources Canada in June 2011, entitled, *An Action Plan for Growing District Energy Systems in Canada*. The purpose of this research was to identify Canadian stakeholder's vision of District Energy, barriers to that vision being realized, and ways to mitigate those barriers. The technology is proven, and stakeholders have not identified technical barriers to DE implementation. Instead, the most common barriersto DE implementation are a lack of awareness of District Energy system potential and benefits and a lack of enabling policy, legislation and regulation (regulatory certainty).
49. We believe that these barriers are hampering Ontario communities from implementing DE plans. We would like to ensure that distributors account for the DE-related CHP opportunities in their system planning, connection assessments, regional plans and cost estimation.

- In Ontario, many communities have and are looking to develop District Energy systems. In start-up situations, the addition of small scale CHP units (particularly those under long term contractual arrangements) can assure a revenue stream necessary to offset early stage development risk, and greatly improve project financeability.

- The CDEA believes that there are many positive ways to accelerate community energy solutions in Ontario and particularly district energy solutions, where they make economic sense to a community. In so doing, these programs will remove implementation barriers that would otherwise result in missed opportunities such as those that occur when developers default to conventional forms of heating and cooling.

- As such, we think that the Board's current RRFE review is an important opportunity to raise the profile of this energy opportunity with the regulator, the distribution and transmission suppliers and other important Ontario energy stakeholders. We have therefore provided a background of the CDEA, District Energy (DE) characteristics and benefits, as well as specific issues and requests on behalf of the CDEA members

- We applaud the Board for undertaking this important work initiative to increase transparency and certainty of process and system requirements in order to ensure the cost effective development of the energy systems that communities need and want.

Who is the CDEA?

50. The Canadian District Energy Association (CDEA) is a non-profit industry association representing over 85 member utilities, government agencies, building owners, consulting engineers, suppliers, developers, bankers and investors, who share a common interest in promoting the growth of district energy in Canada. Many Ontario municipalities have expressed interest in developing more robust long-term energy plans to serve existing and

new communities. In this proceeding, the CDEA is representing those District Energy owners and operators who have small scale Distributed CHP Generators linked to their thermal district energy grids.

What is District Energy?

51. District heating and cooling is defined as a community scale system of generating and distributing heat or cooling and domestic water heating from a centralized location to multiple mixed-use community buildings (residential, commercial, institutional and industrial buildings) in a specific geographic area. The thermal energy is delivered via a grid of underground buried pipes, and is analogous to a electricity grid—delivering an energy product to multiple consumers. It is able to produce energy using a multitude of primary and secondary fuel sources. In addition to providing thermal energy (district heating and cooling), these systems create sufficient scale to accomodate and enable the application of efficient equipment, heat recovery strategies, and alternate/renewable fuel strategies that would not be feasible on single-building applications. Even modern hot water thermal distribution systems have an inherent system loss, which operators continuously strive to minimize through efficient production plants and alternate fuels. Community scale DE systems can accomodate combined heat and power (CHP) generation facilities and thermal storage units, both of which are meaures to enhance and optimize the operating energy efficiency of the thermal energy grid (i.e. most cost effective output per unit of input). CHP units obviously provide electrical power for customers in either the same catchment area served by the DE system, or via sales back into the electrical grid. Thermal storage units can ensure that DE operators can use off peak electricity to produce hot or cooled water, thus creating a method to virtually 'store' electricity for peak hours.

52. District energy is not a technology. Rather, it's an "infrastructure strategy" necessary to connect electricity and thermal energy supply and use. The thermal grid enables technology options to heat and cool building stock because DE systems can produce thermal and electrical energy using a variety of non-renewable and renewable fuels, including biofuels, energy from waste or industrial processes, geoexchange, solar thermal and combined heat and power. Substitution and large scale integration of renewables (such as urban based wood biomass) enhance security of local energy supply and substantially reduce emissions of greenhouse gases. This obviously represents a 'resiliency and security' tool to protect communities over time, thereby mitigating their exposure to price and supply variability of any one fuel source. DE systems represent an important component of smarter integrated community energy grids.

District Energy Systems, with Combined Heat and Power:

53. District Energy grids are designed and operated primarily to distribute thermal energy (heating, cooling, domestic hot water) to communities. This is in contrast to the electrical grids, which are built and operated to distribute electricity. Even where CHP units are added to the thermal grid, the primary focus is still to produce thermal energy with electricity as a by-product of meeting the thermal load through thermal energy production. The economic viability of most DE CHP projects depends upon the revenue from recovered thermal energy. Therefore, the size of the available thermal load generally determines the size of the CHP unit. Electricity is the by-product of the device that is sized to meet those thermal load requirements.

54. Given that these small scale CHP facilities tied to thermal DE grids are sized in the first instance to meet the thermal needs of the community served by the District Energy system, they are often considered small scale 'cogen' (<15 MW), projects to those in the conventional electricity business. In the majority of cases, these CHP are operated using natural gas as a feedstock, although some diesel generation is used in remote communities. In some locations a renewable biomass source has been used. Both gas turbine and reciprocating engines are used. These units are readily dispatchable, and can be ramped up and down as needed to follow load trends. They are non-intermittent, highly reliable units, located close to where the electricity is required, typically in urban areas where concentrated heating loads are available. They are most often connected or 'embedded' within a local distribution system. As they are small scale, they usually can be accommodated within the current operating flexibility of most distributors and connections can often be made without major capital improvements to the distribution or transmission system.

55. Small scale CHP generation facilities tied to thermal systems can make a significant contribution to meeting community energy needs in an economic and energy efficient manner, including :

- enabling communities to meet energy efficiency and emission goals
- relieving local electricity delivery constraints, and supporting local community development
- using synchronous generators that provide benefits to the local distribution network (generators do not normally create harmonic or voltage disturbance issues to the connecting utility that often results from the connection of certain renewable generation)
- reducing system losses, providing local voltage support to a feeder or transformer station and reactive power for the supply utility
- providing back up supply security, islanding capacity and including such ancillary services as black start capability
- operating during peak and mid peak time periods and on a seasonal basis when building heating loads are at a maximum (gas fired CHP installations are also available to operate on short notice unlike some other types of generation and can provide valuable peak capacity to the power grid); and installations that are connected "behind the fence" in industries or large institutions can often be operated in an islanded mode to provide long term power security to the owners)
- relieving the need for additional distribution and transmission capacity building to bring generation produced outside the community into the community
- providing an important stream of revenue to DE projects, often offsetting the poor economics of building out DE grids, particularly in the early stages of community building when the thermal load is not yet fully developed
- meeting a much broader set of community development goals (energy, environment and economic development).

56. The opportunity of building small scale CHP systems to support community energy (electricity and thermal) needs has been recognized and encouraged by the Ontario Power Authority's (OPA) Combined Heat and Power Standard Offer Program (CHPSOP), in which many CDEA members are participants. Other CDEA members already have operating small scale generation facilities, and are looking to expand or add to these facilities to support growing thermal load requirements. Further, given trends in provincial urban population growth, we believe that future electricity supply building will occur to meet this load growth and to maintain electricity supply reliability and operability in targeted urban and electricity system constrained areas. We believe this will become more critical than meeting increasing overall electricity demand.

57. Several Ontario municipalities, associations and energy providers are currently working to identify mechanisms to ensure that smarter energy grids, including district energy grids with small scale CHP, will be planned and built to meet community growth requirements in the most cost and time efficient manner. We believe that long term energy plans will increasingly include the surgical application of small scale, high efficiency, intermediate load distributed generation units (i.e. CHP) on existing and planned thermal grids, which can also meet electricity demand growth in urban areas in an economic manner. They can also reduce GHG emissions in a community-acceptable manner. This is particularly critical in areas of population density, and areas of local electricity system constraints (e.g. GTA, Kitchener-Waterloo, Barrie, Ottawa, etc.), where such plants can also provide critical peaking capacity. Such plants may defer or eliminate the need for large scale electricity transmission and generation infrastructure in congested, difficult to retrofit urban areas (e.g. downtown Toronto, and the GTA).

CDEA Member Interest in the current OEB proceeding on RRFE.

58. Given the increased interest in DE grids and small scale CHP, it is appropriate and efficient to incorporate DE infrastructure considerations into distributor planning. While recognizing that the OEB continues to pursue and should be expanded to the 'smart grid', we believe that the interest and issue list is confined to considerations of electricity integrated smarter energy grids that CDEA members are involved with.

59. CDEA has therefore chosen to limit our participation to those matters most directly related to the intersection of electricity distributors and transmitters with DE system providers (community, campus and institutional). We are confining our feedback to the ease with which small scale CHP units can be connected to distributor systems which requires adequate planning to accommodate such distributed generation, and then time and cost efficient connections to electricity grids. The terms under which small scale CHP units are connected to the distribution grid as the procedures for responding to connection requests, and the costs thereof, can make the difference between such generation projects being viable or non-viable.

60. CDEA members are interested primarily in the *"Distribution Network Investment Planning"* proceeding (EB-2010-0377) and the "Defining *and Measuring Performance of Electricity Distributors and Transmitters"* preceding (EB-2010-0379). The CDEA is also interested in a consistent methodology to acknowledge and attribute value to the upstream benefits of reliable small scale CHP located to electricity load. Currently, the CDEA is only recognized as an intervenor in the EB-2010-0377 and EB-2010-0379 proceedings, and will therefore be limiting our participation in the regional planning proceeding until Board clarification on cost eligibility is received.

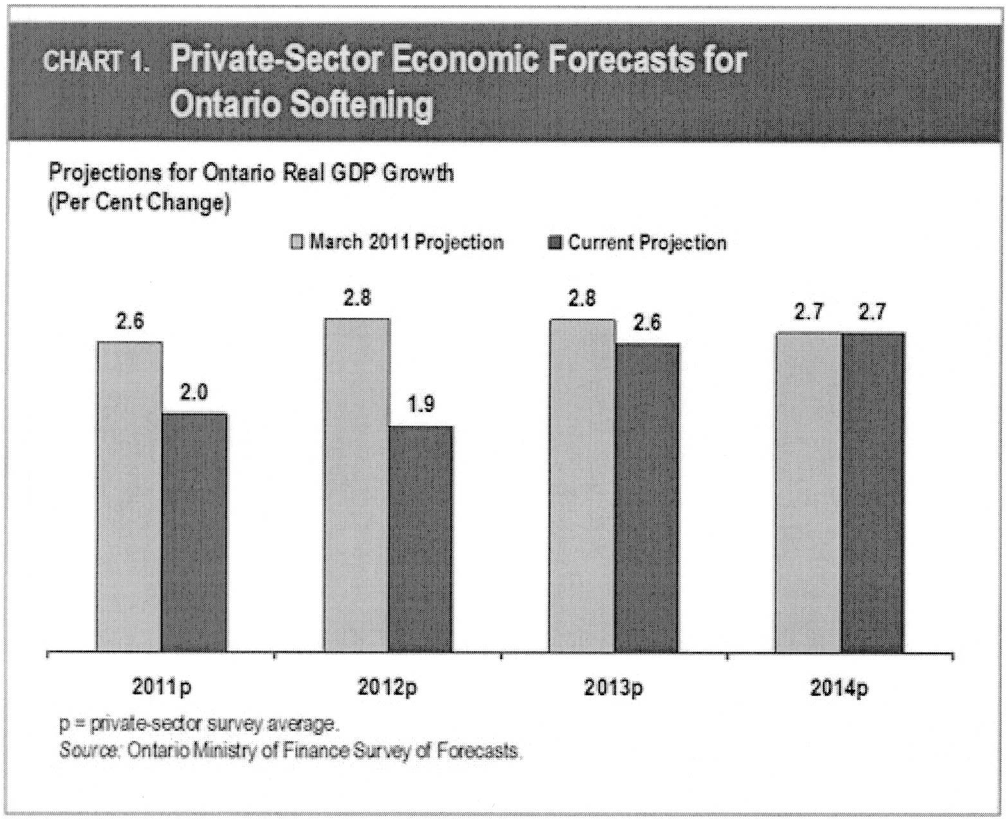
End Notes

[i] Certain of the Member Organizations have also provided independent comment on April 20, 2012.
[ii]

Table 1
Ontario Economic Outlook
(Per Cent)

	2008	2009	2010	2011p	2012p	2013p	2014p
Real GDP Growth	(0.6)	(3.2)	3.0	1.8	1.8	2.5	2.6
Nominal GDP Growth	0.5	(0.9)	5.3	4.0	3.7	4.4	4.5
Employment Growth	1.6	(2.5)	1.7	1.8	1.1	1.4	1.5
CPI Inflation	2.3	0.4	2.5	3.2	2.0	2.0	2.0

p = Ontario Ministry of Finance planning projection.
Sources: Statistics Canada and Ontario Ministry of Finance.



[iii] *Bill 75, The Ontario Electricity Supply Operator Act.* First reading, April 26, 2012. Sections 25.32 allowing the Minister to direct the OESO to enter into supply contracts and the terms upon which the OEB will refer same to OEB; s.25.30 Minister to direct OEB on capital costs and other matters that it may review when considering energy plans generated by the Minister.
[iv] We understand that the “smart grid” will, when practical and efficient, include the integration of thermal and electrical considerations in the policy development.
[v] ibid
[vi] We do not support investments in redundant or “gold-plated” grid infrastructure.