Cornerstone Hydro Electric Concepts Association Inc.

April 20, 2012

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O.Box 2319
Suite 2700
Toronto, Ontario
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Re: Renewed Regulatory Framework (EB-2010-0377, EB-2010-0378, EB-2010-0379, EB-2011-0043 and EB-2011-0004)

Dear Ms Walli:

Attached please find Cornerstone Hydro Electric Concepts Association's comments with respect to the Renewed Regulatory Framework.

CHEC is pleased to provide input at this stage and looks forward to further opportunities to participate in the process.

Yours truly,

Gord Eamer

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Lakeland Power Distribution	Midland Power Utility
Orangeville Hydro	Parry Sound Power
Rideau St. Lawrence Distribution	Wasaga Distribution
Wellington North Power	West Coast Huron Energy

RENEWED REGULATORY FRAMEWORK

In 2010, the Ontario Energy Board instituted a number of initiatives in relation to a Renewed Regulatory Framework. This paper reflects CHEC's position on these initiatives as of April 2012.

Cornerstone Hydro Electric Concepts Inc.
Kenneth B. Robertson, CGA
April 20, 2012

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Executive Summary

The Ontario Energy Board (OEB) currently has underway a consultation process to develop a Renewed Regulatory Framework for electricity distributors (RRF) and transmitters. The OEB has also invited interested stakeholders to provided written comments to assist the OEB in the development of the RRF. CHEC, as an interested stakeholder, has responded to this request.

The RRF currently consists of five main areas, namely, network investment planning, approaches to mitigation, defining and measuring performance, development of a Smart Grid and regional planning. This report follows a comparative format where each section compares details of the current framework to those of the proposed framework. CHEC's position is then summarized at the end of each of these sections.

In general CHEC does supports the network investment planning, defining and measuring performance and the development of a Smart Grid in Ontario initiatives, however, it was felt that there were several areas within each initiative that warranted improvement or further discussion. For each of these specified frameworks, CHEC has documented several suggestions that will assist the OEB with the next evolution of these RRF initiatives.

CHEC does not support or only partially supports the current approaches to mitigation and regional planning. With respect to mitigation measures, it was not clear that the proposed changes were beneficial. It was therefore suggested that further study be conducted in this area. It was felt that good planning and improvements to the current rate setting mechanism could reduce and/or eliminate the need for alternative mitigation measures. With respect to regional planning, CHEC is not supportive of the current transmission principles of "cost causality' and "beneficiary pays". It was felt that a pooled asset approach to recovery of transmission charges was more appropriate. CHEC does support the OPA's approach to regional planning providing the driving factor is not consolidation. It is in everyone's best interest for generators, transmitters and distributors to retain their individual entity status.

Overall, a number of comments and suggestions are provided. Some comments are for clarification and information purposes, while others suggest changes. Regardless of their nature, it is hoped that these comments and suggestions will assist the OEB with the development of the proposed RRF.

DISTRIBUTION NETWORK INVESTMENT PLANNING (EB-2010-0377)

Problem (Opportunity):

The OEB acknowledges the need for significant investment in the electrical sector but concerns over bill increases are leading to a sharper focus on the total cost to consumers. The objective of this initiative is to ensure that electrical distributor's network investment plans are economically efficient, cost-effective, and paced so as to match required expenditures with fair and reasonable rate adjustments and predictable changes to the elements of customer bills affected by the plans.

The current framework and approach requires the filing of a Cost of Service (CoS) application every four years with Incentive Regulation (IRM) applications to be filed in between. This process allows the OEB to make a determination as to whether or not the rates proposed by the distributor are just and reasonable. Since the OEB's examination of an application and the subsequent decision are based only on the empirical evidence provided by the distributor, the quality of information directly affects the OEB's assessment of the network investment costs included in, and the associated rate implications of, the application.

Although this framework and approach are relatively sound, a number of potential opportunities and options for enhancing and refining the framework have been identified. This includes:

- Harmonizing existing information requirements;
- Adopting a systematic, proportional approach to network planning-related filing requirements and associated level of OEB scrutiny;
- Improving the quality and consistency of planning information submitted in support of regulatory applications;
- Enhancing the qualitative and quantitative information that distributors could use to support the OEB's assessment of their planned investments thereby enhancing regulatory predictability; and
- Periodic reviews of the OEB's network investment planning framework.

Solution:

With respect to distribution network investment planning, a coordinated consultation process will assist with the OEB's determination of its policies in relation to distribution network plans, including information to be provided by distributors in support of cost of service and other applications to demonstrate how investments are prioritized and paced with a view to the total bill impact on consumers. It is expected that enhancing the current framework and approach to regulatory assessments of network plans should also facilitate the timely approval of appropriate network investments. It is the OEB's view that network plans and planning processes are more likely to yield information that better supports regulatory assessments if they are:

- **Optimized** – Optimizing distribution infrastructure investment is one of the stated goals of the OEB's 2011-2014 Business Plan. Network planning is an optimization process whereby a number of objectives are sought to be met within the confines of applicable technical, resource, funding, and risk related constraints. The result is a "multi-year investment plan that maximizes stakeholder value"
- **Integrated** – A "holistic", longer term planning approach that seeks and utilizes opportunities to achieve multiple objectives through an investment project is more likely to yield economically efficient and cost effective outcomes than a relatively narrower, shorter term planning approach.
- **Rationalized** – The OEB's current framework recognizes that network plans and planning processes may vary in terms of complexity depending on the characteristics of a distributor's network. Planning tools and processes that reflect such characteristics enhance the effectiveness of network planning.
- **Adaptable** – Long term ratepayer value is enhanced by distributor planning processes and network plans that acknowledge and accommodate the potential for change in areas such as underlying drivers, resource availability, and sources and levels of risk.
- **Clear** – Information quality has a significant role in fostering an efficient and effective regulatory process. Network planning processes and plans that are clear, coherent and comprehensible will facilitate the regulatory process for all concerned.

Several opportunities have been identified whereby the existing regulatory framework can be enhanced. It is believed that these changes will ensure distributor network plans are economically efficient, cost-effective and paced so as to match required expenditures with fair and reasonable rate adjustments and predictable changes to the elements of customer bills affected by the plans. This includes:

- **Harmonizing Information Requirements** – There may be opportunity to enhance related elements to enhance consistency and simplicity (i.e.: harmonizing elements of the DSC Code, GEA and Benefits Framework).
- **Proportional Processes & Information Requirements** – Matching the assessment process and related information requirements to the characteristics of proposed investments. A proportional approach to regulatory assessments would systematically vary the degree of detail required for, and the level of scrutiny applied to, a given network investment proposal depending on its characteristics.
- **Information Quality** – Opportunities exist to leverage both qualitative and quantitative analyses to help justify proposed network investments.

- **Policy Framework Review** – It is useful for the OEB to be regularly informed of distributor network investment outcomes and of planning process influences and advancements.

CHEC's Position:

CHEC agrees that the current regulatory framework serves its purpose, however, there are also a number of areas that could be improved. For example, there is a concern that long-term planning is not adequately funded in the current rate setting model. Likewise, LDC's that must borrow for new capital may at some time exceed the 60/40 debt equity threshold. Under the current regulatory framework, the interest expense for debt above 60% is not funded by the customers that benefit from it and is therefore not sustainable. These issues, as well as others, need to be addressed if the OEB is to meet its objectives of investing in the electrical sector while maintaining a sharp focus on the total bill impact.

CHEC largely supports the new regulatory framework for Distribution Network Investment Planning, in particular the need for an increased planning window (up to 5 years) as well as a multi-year capital plan. However, LDC capital plans vary significantly and all LDC's may have difficulty meeting this proposed requirement. It is recognized that expenditures such as plant renewal may be within the LDC's control however expansion for new growth, catastrophic failures and municipal planning can affect the actual expenditures compared to budget. These variations need to be accommodated in the planning and rate setting mechanism.

CHEC would also support the following:

- *Distribution rates cannot be utilized to offset other pressures on bill increases. While efficiencies are important at all levels of electricity generation, transmission and distribution, the portion of the distribution cost compared to total cost needs to be recognized. The impact of government, societal directions and generation renewal cannot be mitigated solely at the distribution level.*
- *One size does not fit all with respect to the rate setting process. This suggests that requirements could be differentiated based on factors such as: the size of the LDC (proportional approach), the percentage of increase requested, and the level of planning and preparedness in past hearings. Well prepared plans, thoughtful development and management of systems should set the standard for regulatory requirements.*
- *For planning purposes coordination, simplification, harmonization and integration of existing regulatory requirements as well as standardized templates may help to streamline the planning requirements, which in turn would lower costs, increase efficiencies and better the overall results. More flexibility in system plans to accommodate the various planning drivers which LDC's are required to respond to would allow for management of the total costs and local needs at a local level.*

- *Review of the intervenor process is recommended. CHEC would support a self-funding intervenor model. Further coordination of issues between applications by OEB staff would assist to reduce the time and effort for both intervenors and LDC staff in subsequent applications. Question asked, question answered.*
- *During the stakeholder meetings there was general support for LDC delivery of conservation. Separation of LDC budgets from impacts of conservation would help to reduce the upward pressure on rates.*
- *A move from a volumetric distribution rate to a fixed distribution rate would also be beneficial to both the LDC and the consumer. Fixed rates provide stability to an otherwise volatile market.*
- *There is also support for an "outcomes" based approach to rate setting. In this sense, an outcomes based approach is viewed as LDC's living within specified directives (i.e.: 2-3% inflation and 9% ROE max). If a LDC can live within these ranges, rate setting would not be required. If not, the rate setting process would be initiated to detail and justify an increase in rates.*

APPROACHES TO MITIGATION (EB-2010-0378)

Problem (Opportunity):

The OEB acknowledges the concerns over electrical bill increases and the effects on consumers. The objective of this initiative is to assist the OEB with determination of its policies in relation to considerations for mitigating the effects of rate and/or bill impacts that will be used to inform the setting of rates whether through a cost of service review or through a multi-year rate adjustment mechanism or as part of a specific application.

The OEB's current approach to mitigation involves an ex-post approach with a focus specifically on distribution charges. This case-by-case approach utilizes conventional mitigation mechanisms such as cost recovery, deferred rate decreases, customer rebases and funding adders. Existing mitigation policy also focuses on the "typical" customer within each rate class and whether the total bill impact experienced by that customer exceeds 10%. Under exceptional circumstances, OEB policy can superseded this threshold. Past expectations have been for Distributors to appropriately plan investments and manage utility activity so as to avoid significant volatility in rates.

Rate and/or bill impacts over the next several years are expected to be driven by significant levels of investment for the renewal of assets to maintain appropriate service levels and system reliability and to connect new generation. As a result, the current framework for mitigation needs to be reassessed.

Solution:

The OEB's suggests that its statutory objectives are best promoted using an outcomes-based approach with multi-year rate-setting. Therefore, in addition to the guiding concepts for the renewed regulatory framework as a whole, it may be useful to consider the following guiding concepts in the context of a framework for mitigation:

- **Minimized Intergenerational Inequity** – This involves the extent to which policy options separate incurred costs from the period in which related services are provided. While financial accounting principles usually match costs to benefits, doing so may conflict with other regulatory objectives such as rate stability and predictability, and earnings stability. This is an important consideration whereby mitigation alters the timing of cost recovery.
- **Sustainability** – A framework should be sustainable through adaptability to changing and varied circumstances. Different approaches to mitigation may be necessary depending on the underlying cause(s) of the rate or bill increase, the utility involved, and the point in time.

- **Gradualism / Economic Efficiency** – A framework should strike a reasonable balance between gradualism in rates/bills and economic efficiency. Minimizing the magnitude of increases or volatility in the rates paid by consumers must be balanced with price signals that reflect the true cost of the services that are being provided to them. While mitigation can be a useful regulatory instrument, it ought not to be overused to the extent that consumers fail to appreciate the direct and unavoidable consequences of utility activities.
- **Return on Capital** – A framework should ensure that regulated utilities continue to have the opportunity to earn a fair return on capital.
- **Regulatory Predictability** – A framework should promote regulatory predictability by allowing utilities, consumers and other stakeholders to understand how and on what basis regulatory decisions regarding rate and/or bill impacts are likely to be made.

In order to smooth revenue requirements, the OEB proposes an approach to mitigation that involves both an ex-ante and an ex-post methodology with a focus on the total bill instead of only distribution charges. In addition to conventional mitigation mechanisms, it is also suggested that alternative mechanisms such as lease of assets, securitization, changes in accounting treatment, and voluntary customer payment plans be considered. Furthermore, policy should reflect a threshold based on empirical data instead of an arbitrary threshold of 10%.

CHEC's Position:

CHEC largely supports the current mitigation mechanisms (cost recovery, deferred rate decreases, customer rebases and funding adders) but finds the 10% threshold can place excessive constraints on the LDC's.

CHEC is reserved as to the effectiveness of the proposed alternative mechanisms (lease of assets, securitization, changes in accounting treatment, and voluntary customer payment plans). More information and/or study are required in order to draw conclusions as to which measures, if any, would be effective.

The need for mitigation can be altered by good planning and the associated rate mechanism. With a five year and/or longer term plan, LDC's can predict revenue requirements over the period. Rather than a one-time rate setting process, an approved multi-year rate, with year 1, 2, & 3 rates set on planned needs would allow LDC's to manage the plan and smooth rate impacts over the period. It is recognized that appropriate regulatory mechanisms, such as variance accounts to allow for a true up would be required. However, a multi-year plan supported by a multi-year rate approval could assist with mitigation and allow the LDC to manage within the envelope.

CHEC would also support the following:

- *Failing a multi-year plan and rate approval, smooth rate increases would suggest a streamlined CoS/IRM process for annual incremental increases instead of the current regime.*
- *During the course of the stakeholder meetings consumers indicated they would prefer lower rates instead of increased reliability beyond the current levels. This would imply that generally there is acceptance of the current system reliability and that rate relief would be preferred over further increases in reliability with associated costs. This perspective however needs to be tempered to ensure that continued system renewal is not predicated on the need for a reduction of reliability. Continued renewal to maintain the existing level of performance (or where below standard to improve) will be required.*
- *Thresholds should be based on empirical data, not an arbitrary number.*
- *Consumers continue to be challenged to understand their bills. With the initiative to provide more transparency on the bill the number of cost factors increase. How these cost factors interact and how they impact on the total bill all assist to confuse the interpretation. In addition rebates, time of use, and time of year changes add further to the confusion. The OEB along with LDC's have made efforts to provide some clarity to customers, however, at the present time electricity rates are complex because of the many components. Further education and/or simplification in this area must be considered.*

DEFINING & MEASURING PERFORMANCE (EB-2010-0379)

Problem (Opportunity):

The OEB acknowledges that defining and measuring performance is an important goal of economic regulation. Therefore OEB policy must reflect appropriate performance measures and the role of such measures in the OEB's setting of rates whether through a cost of service review or through a multi-year rate adjustment mechanism or as part of a specific application.

Under the OEB's current licensing regime, distributors licensed by the OEB must comply with all of the conditions of their licence, including compliance with any of the codes listed in their licences. These codes currently define the minimum standards in the context of defining and measuring performance. For regulatory purposes, these minimum requirements include:

- **Customer Service Indicators** – Distributors are currently required to comply with provisions in the Distribution System Code on Customer Service Indicators such as connection of new services, appointment scheduled, met and missed, telephone accessibility and call abandon rate, written response to enquiries and emergency response.
- **Service Quality Regulation** – The OEB has implemented a "monitoring approach" to system reliability for electricity distributors. Distributors must monitor and report the following System Reliability Indicators on regular basis:
  - System Average Interruption Frequency Index (SAIFI);
  - System Average Interruption Duration Index (SAIDI); and
  - Customer Average Interruption Duration Index (CAIDI).
- **Rate Regulation** – Benchmarking and the Incremental Capital Module are designed to promote efficiency and flexibility.
- **Empirical Tools** – The Electricity Reporting and Record Keeping Requirements ("RRR") set the minimum reporting and record keeping requirements with which a distributor must comply. Other requirements may also be contained in codes, licenses or other regulatory instruments. Minimum requirements include accounting & financial data, service territory statistics, service quality indicator data, and affiliate transaction information. Annual Yearbook data for Distributors has also been included since 2005.
- **Performance Reviews** – Distributors continuously submit to several reviews to ensure compliance with statutory and regulatory requirements as well as adherence to financial performance measures. This includes Regulatory Audit and Accounting reviews as well as the OEB's compliance reviews and enforcement process. Distributors also follow a self-certification process to ensure they are in compliance with OEB policy objectives.

The OEB recognizes that the rate-making policies must continue to facilitate the cost-effective and efficient implementation of OEB-approved plans. As a result, it is necessary that appropriate standards for performance, efficiency, and reviewing performance must be considered.

Solution:

The OEB proposes that an outcome based approach be established in addition to existing core performance standards. An outcome-based approach focuses on “results”; not merely “activities” carried out to achieve the results. Consequently, an outcome-based approach can identify the short term effects on customers as well as the long-term impact on the market. An outcome-based approach would also link utility efficiency in its production of outputs to the intended results, reflecting the utility’s effectiveness.

Consistent with this view, it is suggested that the OEB’s statutory objections are best promoted using an appropriate framework for defining and measuring performance. This framework is based on the following criteria:

- **Sustainable** – The framework must be flexible and able to handle change
- **Predictable** – The framework facilitates planning and decision-making
- **Effective** – The framework encourages efficiencies
- **Practical** – The framework costs should not exceed benefits

As the OEB continues its focus on how well the utilities across the province achieve results, it needs to continue to improve its approaches to measuring results. This is best achieved by ensuring desired outcomes are established for utilities in addition to existing core performance standards. Experts would be retained to assess utility plans and audit utility planning processes while achievement of objects will be encouraged through the use of specific incentives (i.e.: financial, reputational, proportional, etc.).

CHEC Position:

CHEC largely supports the existing general framework and acknowledges that defining and measuring performance is an important goal of economic regulation. However, it also submits that the increased costs associated with performance measures should be compared to its relative value as perceived by the customers that pay for it.

CHEC also supports an approach that focuses on “results” and not merely “activities” carried out to achieve the results. If new performance measures are to be developed, it is strongly suggested that they be appropriate and relevant metrics that can identify the short term effects on customers as well as the long-term impact on the system and market.

CHEC would also support the following:

- *Performance measures should take into consideration both capital and OM&A spending.*
- *Performance measures should be clearly defined and identify the benefit to the customer. If a defined benefit to the customer cannot be determined then the need for the measure is questionable.*
- *While LDC's may track several measures for internal use however, these should not necessarily be required for provincial reporting because there is no guarantee that measurement parameters are consistent between LDC's. Reported measures should focus only on results.*

SMART GRID (EB-2011-0004)

Problem (opportunity):

The OEB acknowledges the current requirement for distributors to file distribution systems plans that accommodate the connection of renewable generation and allow for the development and implementation of a smart grid in Ontario. Furthermore, the OEB has examined the issues associated with the implementation of Smart Grid in order to gain a better understanding of the technical issues associate with a Smart Grid.

In addition to the above, the OEB has formed a working group to assist in developing guidance for the implementation of a Smart Grid in Ontario. This working developed the following policy objectives:

- **Efficiency** – Improve efficiency of grid operation, taking into account the cost-effectiveness of the electricity system. Several types of efficiencies were identified including, physical (energy lost), operational (staff processes and resources), and market level (economic efficiency). Additionally they suggested that there are also different 'levels' of efficiency (i.e.: total grid improvements versus efficiencies at the individual distributor level.). It was agreed that efficiencies related to the Smart Grid are related to more and better information, leading to better decision making and better processes.
- **Customer Value** – Although different types of customers will derive different benefits from the smart grid, the primary benefit for all customer classes will be better information which should result in better service, reduced costs and the facilitation of localized decision-making by consumers.
- **Coordination** – Coordination between and among distributors will be key to achieving the full benefits of the smart grid.
- **Interoperability** – Adopt recognized industry standards that support the exchange of meaningful and actionable information between and among smart grid systems and enable common protocols for operation. Where no standards exist, support the development of new recognized standards through coordinated means.
- **Security and Privacy** – Cyber security and physical security should be provided to protect data, access points, and the overall electricity grid from unauthorized access and malicious attacks.
- **Safety** - Maintain, and in no way compromise, health and safety protections and improve electrical safety wherever practical.
- **Economic Development** – Encourage economic growth and job creation within the province of Ontario. Actively encourage the development and adoption of smart grid products, services, and innovative solutions from Ontario-based sources.

- Environmental Benefits –Promote the integration of clean technologies, conservation, and more efficient use of existing technologies.
- Reliability - Maintain reliability of the electricity grid and improve it wherever practical, including reducing the impact, frequency and duration of outages.

The following customer control objectives are introduced for the purpose of providing the customer with increased information and tools to promote conservation of electricity, which will “expand opportunities to provide demand response, price information and load control to electricity customers.

- **Access** – Enable access to data by customer authorized parties who can provide customer value and enhance a customer’s ability to manage consumption and home energy systems.
- **Visibility** – Improve visibility of information to and by customers, which can benefit the customer and the electricity system, such as electricity consumption, generation characteristics and commodity price.
- **Control** – Enable consumers to better control their consumption of electricity in order to facilitate active, simple, and consumer-friendly participation in conservation and load management.
- **Renewable Generation** – Provide consumers with opportunities to provide services back to the electricity grid such as small-scale renewable generation and storage.
- **Customer Choice** – Enable improved channels through which customers can interact with electricity service providers, and enable more customer choice.
- **Education** – Actively educate consumers about opportunities for their involvement in generation and conservation associated with a smarter grid, and present customers with easily understood material that explains how to increase their participation in the smart grid and its benefits.

The need for flexibility has been recognized within the Smart Grid system. As a result, the following objectives have been established.

- **Distributed Renewable Generation** – A flexible system infrastructure that promotes distributed renewable generation.
- **Visibility** – Improved visibility of grid conditions for grid operations including the siting and operating of distributed renewable generation.
- **Control & Automation** – Improved control and automation to promote renewable generation.
- **Quality** – Maintain and improve quality of power delivered by grid.

The need for an adaptive infrastructure has been recognized within the Smart Grid system. As a result, the following objectives have been established.

- **Flexibility and Forward Compatibility** – Provide flexibility within the Smart Grid to support future innovative applications, such as electric

vehicles and energy storage. Also protect against technology lock-in to minimize stranded assets and investments and incorporate principles of modularity, scalability and extensibility into smart grid planning.
- **Innovation** – Keep the ability to adapt to and actively encourage innovation in technologies, energy services and investment / business models. Encourage information sharing, relating to innovation and the smart grid, and ensure Ontario is aware of best practices and innovations in Canada and around the world.

Solution:

The development of a smart grid in Ontario relates to the investment plans of electricity distributors as well as regional planning and the requirements for plans for the purpose of assessment and approval by the OEB. In particular, it is expected that the outcome of this smart grid implementation will be integrated into the outcome of the planning assessment and review initiative outlined above.

Furthermore, as the Smart Meter Grid is currently a ministry directive and much work has already applied towards the development of a Smart Grid, the focus of this matter is in regards to the best guidance practices outlined above. Going forward it is important that the following key issues be addressed.

- **Treatment of the Smart Grid** – Should the Smart Grid be integral to all investments or should be considered as separate from the normal grid?
- **Evaluation Criteria** – Are the principles of increased efficiency, reduced costs, improved reliability, integration of renewable energy and enhanced customer service adequate?
- **Customer Control** – Does the current framework meet the needs for customer control or does it need to be modified?
- **Demarcation Point** – Is the meter an appropriate demarcation point or should the OEB's guidance deal with behind-the-meter solutions?
- **Cyber Security and Privacy** – Should cyber security and privacy measures be part of the Smart Grid plans or a condition of license?
- **Investments** – In order to ensure flexibility, should the Smart Grid be pursuing technologies that serve clearly defined consumer needs or technologies that are easily scalable?
- **Proposals** – Do the current requirements and materiality levels outlined in the APH, CoS and DS filings requirements provide enough detail with respect to distributors proposals to the OEB?
- **Smart Grid Standards** – What roles should the distributors and the OEB play in relation to international efforts to establish Smart Grid standards?

CHEC Position:

CHEC supports the current objectives related to the development of a Smart Grid in Ontario with the caveat that economic discipline is required within the framework. The implementation of smart grid technology should have a demonstrated ability to improve the overall value to the customer. Without this discipline smart grid will merely add system functionality, generate activity and add to employment, all at the expense of the electricity consumer. With economic discipline the customer will benefit by the appropriate technology being applied while achieving a positive impact on electricity value.

CHEC would also support the following:

- *Clearly defined objectives of the Smart Grid which would outline exactly what is meant by Smart Grid. There appears to be much confusion as to the concept and capabilities of a Smart Grid.*
- *The Smart Grid should be incorporated into the capital plan and coordinated with overall system planning and infrastructure replacements. This would suggest a more encompassing planning process. CHEC sees this as an opportunity to leverage the Smart Meter process and for the ongoing development of the electrical system.*
- *The level of system sophistication should be determined by local needs, not a provincial standard. General criteria should be developed on which to base local decisions. There is a concern that the Smart Grid concept is being presented to the LDC's and the LDC's are being looked upon for a solution. The solution should be right sized for the various locations and requirements.*
- *The ability to provide connectivity for generation in any location should be weighed against its cost and benefits. Site selection of distributed generation should include a cost with the proponent providing a contribution to reduce the cross-subsidization from distribution customers.*
- *Clear direction on the evolution of the Smart Grid is required. The current situation sees conflicting direction coming from multiple agencies at the same time.*
- *With evolution of the Smart Grid, there is a need to have established guidelines such as a cost benefit analysis with a post audit completed to ensure that objectives are met.*
- *As the Smart Grid evolves, there is an increased need for a mechanism to address issues as they arise.*
- *It is important that all Federal and other jurisdictional issues are addressed up front and not after the fact as occurred with the smart meter project (such as register read and loss factor application).*

Regional Planning for Electricity Infrastructure (EB-2011-0043)

Problem (Opportunity):

The OEB acknowledges the need to examine cost responsibility in regards to load connections as current cost responsibility policies may inhibit rather than facilitate the construction of facilities that are necessary to meet regional load growth. Furthermore, these policies do not provide sufficient regulatory certainty for infrastructure planning and investment purposes.

Under the current regulatory framework, the Transmission System Code (TSC) governs transmitters in relation to planning and cost responsibility for new or modified assets. At a high level, the framework can be captured by the following four points:

- **Customers** – All customers (industrial and distributor) are treated the same in relation to cost responsibility. In the normal course, load customers (including distributors) would pay a capital contribution for connection asset upgrades to the transmission system, which are triggered by the load customer. In the case of a distributor, this includes upgrades that are required as a result of the connection of renewable energy generation facilities to the distributor's distribution system;
- **Capacity** – A transmission capacity evaluation process is required to be undertaken when the available capacity on a connection facility falls below a certain pre-set percentage of total normal supply capacity.
- **Planning** – Does not require transmission customers to pay a capital contribution for connection asset upgrades that, at the relevant time, were 'otherwise planned' by the transmitter, except for any advancement costs; and
- **Benefits** – Does not require transmission customers to pay a capital contribution in relation to upgrades to Network assets, which benefit all customers in Ontario, except in exceptional circumstances.

The OEB's current cost responsibility policy, as reflected in the TSC, is generally based on two regulatory principles, namely cost causality and beneficiary pays. Both Principles support efficient decision-making with respect to transmission system growth. These underlying principles are as follows:

- **Cost Causality** – The transmission customers that cause the costs to new or reinforced infrastructure should bear those costs.
- **Beneficiary Pays** – Those transmission customers that benefit from a new or upgraded infrastructure should pay their share of the costs.

The current regulatory framework presents several stakeholder concerns that need to be addressed. These concerns can be summarized as follows:

- **TSC Section 6.3.6** – This section is an expression of the concept that an individual customer ought not to bear any unique responsibility for projects within established plans for things such as additions or improvements to the system for reliability and integrity improvements which have already been identified and planned for by the transmitter, except for any additional costs associated with the advancement of the improvements at the request of the customer. The OEB recognizes that there can be ambiguity in relation to the application of Section 6.3.6.
- **Capacity** – A key aspect of the transmission planning process in Ontario in relation to connection assets is a transmitter's available capacity procedure. The TSC requires each transmitter to have an available capacity procedure as part of its overall connection procedures. Sections 6.2.6 and 6.2.9 of the TSC require a transmitter to determine the total assigned capacity and monitor the available capacity on its connection facilities, from time to time, as required. Under the current regime, focus tends to be on short-term capacity planning while optimal investments require long-term planning.
- **Customers** – The load customers of transmitters are typically divided into two groups namely directly connected distributors and directly connected industrial customers. Currently, these two types of transmission customers are essentially treated in the same manner in the TSC. However, some stakeholders have suggested that these two groups should be treated differently from a transmission connection cost responsibility perspective as distributors grow in an "organic" fashion where industrial customers experience "discrete" changes.

Solution:

This section of the renewed regulatory framework deals with the issues of cost responsibility and regional planning in relation to load customer connections. More specifically, the primary focus should be on distribution system connections, which themselves are affected by generation connections at the distribution level. The regional planning consultation is most closely related to the Distribution Network Investment Planning (EB-2010-0377) component of the RRF, which is concerned with distribution system planning and prioritization. This regional planning consultation, for its part, will examine the more specific circumstance of how a particular infrastructure need can be addressed through regional planning among utilities.

As the current framework has limited experience, no regional planning requirements, and no tying to outcomes, the OEB proposal is to update the TSC and/or develop a regulatory framework for regional planning in a manner that is consistent with the principles articulated above. Details of this proposal are as follows:

- **Reclassification of Line Connection Assets** – As indicated above, the TSC does not include a provision to take into account the evolutionary nature of the transmission system and the changing functions of certain line connection assets. There are also a number of 115kV lines that are defined as line connection assets but often perform network functions that benefit many transmission customers. The OEB proposes to reassign or reclassify these assets to meet the principles of cost causality and beneficiary pays.
- **Cost Responsibility** – An alternate approach to reclassification is to develop a framework for the implementation of regional planning that addresses the above issues as well as changes to the current cost responsibility rules in the TSC. The OEB believes that a coordinated joint planning approach between transmitters and distributors is desirable in order to achieve OEB objectives. A regional planning framework would focus on the following:
    - The reclassification of a relatively small subset of certain connection assets
    - The requirement for joint planning between distributors and transmitters
    - A suggested five-year horizon for filing requirements
    - Projects would be determine based on the best combination of transmission and distribution solutions with highest NPV
    - Filing requirements would be developed for regional plans
    - Generators would be consulted before the regional plan is finalized
    - Distributors would provide transmitters a near-term and long-term load forecast every 5 years
    - Regional plans filed by one utility but involving other utilities may need to be revised (may require consulting among utilities)
    - A regional plan may occur in advance of filing any rate application

CHEC Position:

CHEC does not support the principles of cost causality and beneficiary pays, except where it involves a direct customer connection. Under these principles, transmission changes could be devastating at the distribution level. However, CHEC does support the concept of pooled assets component and cost recovery in transmission charges.

CHEC generally supports the new framework for the implementation of regional planning but there is a concern regarding the additional requirements this puts on the LDC's. Careful consideration would have to be given to the definition of a "region" as well as determining methodologies that maximize the efficient use of

LDC resources. Integration with other initiatives may be necessary in order to make this process cost effective.

CHEC does support the OPA's concept for regional planning. A team based, collaborative long-term planning process with OPA oversight is seen as a value added concept. While there are some commonalities across regions, each generator, transmitter and distributor is unique in terms of its electricity requirements, anticipated growth, economic development potential, age and configuration of existing infrastructure, resource and demand management opportunities, and community acceptance of proposed solutions. Generators, transmitters and distributors must be kept as distinct entities for these reasons.

CHEC would also support the following:

- *The issue of transmission cross-subsidisation needs to be addressed. It is not fair for some customers that pay for extra low voltage charges when Hydro One switches feeders between transformer stations. The customers that have higher incidents of feeder switching cross subsidize those customers that don't. Hydro One's low voltage charges should be charged on a monthly overall system peak to eliminate this type of cross-subsidization.*
- *Regional boundaries must be clearly defined and should not be decided based solely on existing municipal or district boundaries.*