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April 20, 2012

Ms. Kirsten Walli, Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Sir or Madam:

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

On behalf of the Canadian Federation of Independent Business ("CFIB"), we thank the Board for the opportunity to provide our members' views and respectfully submit the following points regarding the Renewed Regulatory Framework for Electricity ("RRFE").

Our submission will include:

A. Who is CFIB

B. RRFB – CFIB's Vision and Context

C. Distribution Network Investment Planning (EB-2010-0377) and Regional Planning for Electricity Infrastructure (EB-2011-0043)

D. Performance & Incentives (EB-2010-0379)

E. Rate Setting & Mitigation (EB-2010-0378)

In our submission, CFIB has made a concerted effort to follow the format used for the March Stakeholder conference. We have also answered the Board's questions raised in the Board's letter, Provision for Written Comments by Stakeholders, dated April 5, 2012 - Attachment A: Issues for Comment. Although not an explicit section, reference to Smart Grid (EB-2011-0004) issues are included within.

CFIB looks forward to working with the Board in support of the guiding principles for Ontario's electricity framework, including access to safe and reliable electricity at affordable prices that are economically sustainable.

A. WHO IS CFIB

CFIB is a not-for-profit public interest entity, representing the interests of more than 108,000 owners of small and medium-sized businesses, distributed across all industry sectors and all regions of Canada. Approximately 42,000 of those CFIB members are located in Ontario.

Small and medium-sized businesses have a significant impact on Ontario's energy profile. Approximately 81% of Ontario businesses employ fewer than 5 people. Thus, small and medium-sized businesses account for more than half of Ontario employment and nearly half of GDP.

CFIB's members mirror and reflect the regional and economic diversity of Ontario, as they include many commercial sectors such as agriculture, natural resources, construction, manufacturing, wholesale, retail, transportation, arts and information, finance, insurance, real estate and leasing, professional services, enterprises and administrative management, social services, hospitality, personal, miscellaneous services and others. CFIB members will be affected by investments in conservation, generation, distribution, and transmission that will be needed to maintain a clean and reliable electricity system for Ontarians and by the cost of those investments as reflected in rates.

In particular, CFIB's main concerns in considering the immediate and long-term plans for Ontario's electricity system are the two factors that affect its members' ability to operate competitive, profitable businesses in Ontario: **reliability of service and price**. These concerns mirror the Board's statutory mandate to protect the interests of consumers with respect to matters pertaining to electricity pricing and reliability.

In a recent survey of CFIB members[1], focused on their energy needs and costs, 88% identified price stability as the most important aspect of Ontario's electricity policy and decision-making identified.

While 47% of those surveyed stated that their energy use has remained the same over the past three years, 85% have seen their energy costs increase – with 32% seeing a 'strong increase' and 53% seeing a 'moderate increase'.

[1] A survey conducted by CFIB of its members. 3280 responses were obtained in writing or online.

B. RENEWED REGULATORY FRAMEWORK – CFIB'S VISION and CONTEXT

The RRFE consists of the following five initiatives:

- Distribution Network Investment Planning (EB-2010-0377): addresses how the Board might ensure that ***distributor investment plans*** are demonstrably economically efficient and 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.

- Approaches to Mitigation for Electricity Transmitters and Distributors (EB-2010-0378): addresses approaches and supporting tools to help mitigate the effects of unavoidable and significant rate and/or bill impacts.

- Defining and Measuring Performance of Electricity Transmitters and Distributors (EB-2010-0379): addresses how the Board might create conditions which will foster the cost-effective and efficient implementation of Board-approved ***network investment plans by transmitters and distributor***s through the establishment of appropriate standards for performance and efficiency, the provision of appropriate incentives, and the review of utility performance.

- Developing Guidance for the Implementation of Smart Grid in Ontario (EB-2011-0004): examines issues associated with the implementation of ***Smart Grid***.

- Regional Planning for Electricity Infrastructure (EB-2011-0043): addresses promotion of the cost-effective ***development of electricity infrastructure*** through coordinated planning on a regional basis between licensed distributors and transmitters.

Although the issues ranged widely in the stakeholder presentations, including such issues as the role of CDM in bill mitigation, CFIB has understood the concerns of the Board to centre around the issue of capital investments in the distribution and transmission systems, including those:

- To meet the requirements of load growth and addition of customers;

- To maintain the system and replace aging equipment;

- To support connection of renewables; and

- To implement the Smart Grid.

CFIB understands that Hydro One as the transmission company and most distributors have expressed a need to invest significant amounts in their systems to meet these goals, and some distributors appear to be facing the replacement of infrastructure installed in the 1950's and 1960's. When added to the upward pressures on bills that result from the addition of new generation, especially renewables, the addition of those investments to utility rate bases may result in increased rate levels that can be characterized as "rate shock".

The existing distribution rate approval regime, consisting of a cost of service application at four-year intervals with a formula-driven rate change in the intervening years, has the effect of making distribution rate increases a series of steps—very small rate changes for three years, followed by a significant increase in the cost of service year.

Before responding to the suggested questions on a point by point basis, CFIB would like to set out the essence of its viewpoint related to regulation of electricity by the Board, and in the rates faced by its members as Ontario small businesses.

1. CFIB supports the regulatory process.

While CFIB certainly endorses the goal of cost-effectiveness in the regulatory process, CFIB is nonetheless reassured that consumers are protected by the periodic detailed review of the prudency of their costs by an independent and expert agency (the Board) and by the process that allows stakeholders to examine the support offered by the utility and ask questions. While statistics and benchmarks are undoubtedly useful in focusing regulatory attention, CFIB does not believe that they can replace an informed review of a utility's individual circumstances, or that utilities should be barred from presenting their case in the face of unforeseen and significant changes in their circumstances.

2. ***CFIB supports a businesslike approach to capital planning***.

Decisions regarding utility capital planning must address two key issues: (a) what capital projects should be undertaken; and (b) what is the best timing to undertake them? As well as pure replacement decisions, businesses look for capital investment opportunities that have a business case—i.e. that are expected to support increases in revenue or decreases in operating costs. CFIB would like to see business case support for capital project proposals to the degree that these are applicable.

As to the best timing, this is when total cost can be minimized. That takes into account life cycle costs – trading off early replacement against risk of failure and/or expensive maintenance, and also the cost of capital. Business typically sees a time of low interest rates as the right time to make a needed capital investment. Fortunately, in view of all the other pressures on electricity cost, this is such a time.

3. ***CFIB supports bill mitigation through cost-effective management by utilities, and through a rate increase mechanism that more evenly increases rates over time***.

CFIB does not support mechanisms that borrow from the future through deferral of costs. Furthermore, CFIB does not believe that increases driven at the generation level should prevent a utility from carrying out cost-effective, needed investments, which are approved by the Board on the grounds of engineering requirements or a business case.

While CFIB understands that much of the expected generation cost increase is outside the mandate of the OEB, we believe that the bill effects of those programs should receive separate scrutiny, and not have their effects blurred by mitigation mechanisms applied to distribution costs.

4. ***CFIB is concerned about bill levels to its members.***

Over and above the average effects of electricity cost pressures, small business customers are impacted by two additional issues. At the generation level, time of use rates raise bill levels for customers whose timing for most of its load must inevitably be normal business hours (i.e. the peak periods).

Unlike a residential customer who can defer cooking or laundry into the off-peak, small and medium businesses have very little flexibility. In a recent survey of CFIB members, focused on their energy needs and costs, ninety-two percent of CFIB members surveyed confirmed that they are unable to switch their time of use.

At the distribution level, the revenue/cost ratios for small general service classes are often well above unity, and can be maintained there as long as they are within the wide range allowed by the Board. CFIB would urge that there be more work done by the LDCs and/or the OPA to help with load shifting, but unless significant improvement can be achieved without changes to the "given" of business hours, a move to increase the peak/off-peak differential would be a source of hardship to many members. CFIB also urges the Board to encourage a gradual move toward unity in revenue/cost ratios for distribution rates. Where the revenue/cost ratio relationship among customer classes is extreme, CFIB proposes that the mechanism in IRM years include the possibility of a planned and Board-approved adjustment so that transitions are smooth and not unduly postponed.

VISION

CFIB's vision of the regulatory regime is that it protects customers with independent scrutiny of utilities' investment plans with regard to prudence, timing, and business case. We believe that the establishment of clear goals and principles to guide investment plans, and the requirement for modern asset assessment approaches supported by independent expert opinion should guide the

Board in clarifying requirements for utility filings. We believe that statistics and benchmarks, where applied, should be at a detailed (project) level as well as general, but should not override a well-presented case of need for the investment, and of the costs that will be incurred in a specific situation.

We strongly support the involvement of stakeholders including customers in regulatory review processes, but principles and policies as to what will receive approval should keep expediency in the settlement process from driving compromises that are unwise in the long term.

CFIB concurs with other stakeholders that approval of a multi-year capital plan is needed to allow the regulated transmitters and distributors cost-effective implementation with assurance of recovery, and to replace a more even phase-in of the costs into rates instead of the present steep steps at four-year intervals.

CFIB suggests that regional planning issues, if in dispute among the participants, could be brought to the Board to review alternative solutions and develop individualized cost-sharing approaches where appropriate.

With regard to performance, while CFIB supports a program of general customer service quality measures, our comments today focus on ***the need to develop performance measures that relate specifically to a utility's use of good planning practices, incorporation of customer feedback, and ability to bring their approved capital projects in on time and within budget.*** CFIB suggests that where possible, benchmarks be developed for the actual cost of certain typical activities, to be used as a guideline to prevent budgeting ambiguity. A financial incentive could apply when challenging cost budgets and time plans are met. More information should be gathered as to the value of reliability and power quality to different communities and types of customers to guide decisions as to the level of investment appropriate to support service levels, including investments in the Smart Grid.

We believe that at a general level, the necessary changes are:

- Incorporation of a multi-year capital plan approval into the cost of service process;

- Incorporation of the costs of the approved projects into the annual (IRM) rate formula, along with any planned and approved changes to phase in changes to revenue/cost ratios or harmonization;

- Development of process and cost benchmarks for asset assessment, planning, budgeting and project implementation;

- Development of key principles that are referenced in a utility's justification of its plan;

- Potential developments to incent good planning, budgeting and project implementation; and

- Development of processes to bring a regional planning issue to the Board and resolve cost allocation issues on a basis that is fair in the specific case.

C. DISTRIBUTION NETWORK INVESTMENT PLANNING (EB-2010-0377) and REGIONAL PLANNING for ELECTRICITY INFRASTRUCTURE (EB-2011-0043)

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?

CFIB understands that this facet of the review is focused on planning at the distribution system level. We have, however, included some comments that apply to transmission system planning for two reasons. First, many planning situations involve potential trade-offs between a transmission level solution and a distribution level solution. Neither should any process involving planning to address a local supply constraint ignore the options offered by local generation and by CDM. Second, the transmission sector has evolved with best practices in system planning that could be used to good effect at the distribution level, although clearly on a smaller scale.

As consumers of electricity, CFIB's members are primarily concerned with good service at reasonable cost. For those members, the planning process and selection of projects should focus on those objectives. The question refers to the reliability and quality "that customers demand". A good understanding of the levels of service that customers want and are willing to pay for should therefore be at the core of system planning decisions.

The Ontario Power Authority has carried out a very thorough planning exercise in the past years through the IPSP process[2]. It gives a very detailed look "across the sector" covering generation, transmission, demand management, conservation covering a sufficient timeline. In parallel Hydro One undergoes planning exercise on a five year horizon. Its methodology includes five stages: (i) Establishment of strategic direction and goals; (ii) development of economic outlook and forecast assumptions; (iii) development of investment proposals; (iv) prioritization and selection of investments; and (v) development of the work programs.

Thus, the skill sets and practices required to achieve planning for "the level of reliability and quality of supply that consumers demand" appear to be in place in the Ontario electricity sector. However, clear requirements for the planning processes necessary to support regulatory approvals may optimize the regulatory framework.

This is what has happened in the United States in the recent past. Orders 890 and 1000 of the Federal Energy Regulatory Commission ("FERC") made it mandatory to include in the Tariffs of each entity a planning obligation articulated around nine concepts: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation.

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[2] CFIB participated in, and provided submission, on that process.

Most entities already had planning procedures that covered most of these concepts. But three aspects usually required amendments or updates to make them fully compliant, namely: (i) economic studies, (ii) cost allocation and (iii) regional planning.

These are the three areas that in our view can best bring about the optimization sought. In addition to challenges of ensuring planning best practices at the distribution level, the oversight process needs to address the implementation side once funding is approved to execute the plan.

Investments into distribution systems are comprised of four major components:

(a) Sustainment – investments into renewal and replacement of existing assets to manage failure of assets in service at a level where they do not significantly impact reliability or public safety.

(b) System expansions and extension - Investments into capacity upgrades to remove and eliminate constraints in grid that prevent connection of new loads or green energy generators.

(c) Smart Grid development – to introduce remote monitoring, automation and control for improving reliability and power quality to meet the changing customer needs for higher levels of reliability and power quality.

(d) Relocation of utility lines (installed in public right of ways) to meet the road widening requirements.

To optimize planning across the sector for distribution assets, it is highly desirable to have a standardized methodology to determine the optimal size and optimal timing of investments. A risk based approach that **determines the level and timing of investments into asset sustainment by comparing level of risk against the cost of risk mitigation**, results in optimal planning for investments into asset sustainment.

Investments into system expansion and extensions require development of master plans based on small area load forecasts. Close coordination between LDCs and local and regional municipalities is expected to result in accurate and reliable demand growth forecasts, since the local municipalities have access to information on land use plans. Planning for investments into relocation of utility lines can also be improved through coordination between LDCs and local and regional municipalities.

To optimize investments into Smart Grid developments requires on-going R&D activity at province wide level that incorporates electricity user surveys to accurately assess changing customer needs and technology scans to determine what recent technological advancements can be cost effectively deployed to improve reliability and power quality to meet the customer's needs.

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(c) Smart Grid development – to introduce remote monitoring, automation and control for improving reliability and power quality to meet the changing customer needs for higher levels of reliability and power quality.

Investments into asset sustainment and smart grid development can be optimized using the same methodology as described above for distribution systems. The load forecasts prepared by LDCs can be integrated to forecast loading of transmission system.

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

A first element that needs to be addressed is the concept of “Region”. The definition of Region provides some flexibility in order to be useful in optimizing planning, and ensuring that the relevant stakeholders are involved. If the Region is defined for planning purposes as the service territory affected, or potentially affected by supply constraints or the solutions to those constraints, the parties involved may be Hydro One, several distributors, and several municipalities or regional municipalities. The definitions of the Region for electricity planning purposes may change over time. We believe that what is of greater importance in the concept of Region is that it may help to insure adequate flow of information from overlapping jurisdictions with different agendas and responsibilities in the same territory, or rather, “generic region” since the territories might not coincide perfectly from one agency to another.

We believe that this flow of information including “planned land use” information from the municipal level is of great importance for the integration of network improvements and the identification of potential issues. For a successful integration one cannot limit the planning effort to a limited “engineering” view.

To meet the reliability, cost-effectiveness and regulatory predictability, the coordinated regional planning process should regroup the knowhow of the OPA and the IESO, for the elaboration of a base case. This base case would determine whether all reliability criteria are met for both resource and transmission adequacy in each year.

If reliability criteria are not met in one year further analysis should determine whether additional resources or transmission capacity expansion are required. At this stage of the process the experts should not seek to identify specific additional facilities.

For the development of this “Reliability Needs Assessment”, market participants and land users should provide the data necessary for the study. This input would include the existing and planned additions to the transmission system, proposals for merchant transmission facilities, generation additions and retirements, demand response programs, all long term transmission requests made, transmission network topology, and limitations imposed by existing and proposed environmental legislation.

For this exercise, the transmission owners and network distributors need to submit their plans so the IESO/OPA may review them to assess if they will meet the reliability needs, recommend an alternate means to resolve the needs from a regional perspective, where appropriate, or indicate that it is not in agreement with a proposed addition.

The reliability needs so assessed, should then go through a review process, in front of an entity such as the IESO Technical Panel, to get both a new technical and commercial input. In the event that a dispute arises relating to the conclusions or recommendations of the reliability needs assessment, such dispute may be referred to the OEB for resolution.

To provide the required exposure to insure that the market place understands the identified reliability needs, the IESO/OPA will proceed with stakeholder process with presentation to market committees, industry sectors, and public venues.

The aim of this process would be to produce a reliability plan including a determination for the implementation of a regulated solution to ensure system reliability. Implementation would require that the responsible transmission providers and affected distributors as well as the market be solicited to submit specific projects to materialize the solution. This way, the ratepayer may benefit of the efficiency of the competitive process.

As indicated above, investments into distribution systems for capacity increase and line extensions or for line relocations can be optimized through a closer coordination between the LDCs and local and regional municipalities. A closer coordination between these entities will not only improve the accuracy of small area load forecasts, but will allow the required 3 to 5 year time horizon for LDCs to plan and construct system expansion and line extension or relocations to meet customer needs.

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

At the most general level, the Board might achieve these goals:

(a) By requiring distributors and transmitters to a common, standardized planning methodology based on closer coordination between distributors, transmitters and local and regional municipalities.

(b) By requiring distributors to provide their load forecasts to the transmitters, who should be responsible for producing load forecasts at the transmission level for optimal planning of investments into transmission systems.

CFIB also suggests that changes be considered where the interpretation of Codes prevents an opportunity to reduce costs by making an investment at the time that would be most economic. An example is section 6.3.6 of the Transmission Code.

It appears that certain transmission projects are identified at an early stage by entities such as Hydro-One. These are complex projects requiring a proper integration with the environment. One of the elements required in these linear projects are corridors. The cost of such projects could be reduced by enabling the transmission provider to acquire options on land at the time that the best transmission route from an engineering standpoint is identified in the planning process.

Presently, the requirement for of acquiring and using diligently seems to prevent this from happening. When the transmission provider gets to the point where the capital contribution can be made by the beneficiaries the corridor identified at the early stages of the process is no longer available and costs move up.

The text of section 6.3.6 states that “the transmitter shall not require a customer to make capital contribution for a connection facility that was otherwise planned by the transmitter” should be interpreted as enabling the transmission provider to acquire options on land it may need for projects once it has identified the portion of lands it may require and enable them to roll these costs in their base rate at that time.

This would benefit the ratepayer by enabling the transmission provider to avoid having to resort to alternatives later on in time that would be more costly.

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

CFIB represents independent businesses across Ontario, and is therefore primarily concerned that the allocation of costs should reflect both immediate and wider societal benefits. CFIB is concerned that a single rule for cost responsibility may not reflect cost responsibility fairly in all situations.

There is, in our submission, a key distinction between the situation of industrial customers and distributor customers. An industrial customer is making a business decision as to whether it is economic to carry out a particular activity in a particular location, and the costs of new transmission facilities are part of the costs of that choice. To make other customers absorb the costs of transmission facilities for an industrial, without an associated benefit, distorts the business case of the industrial customer in evaluating the opportunity. However, for a distributor, no choice of activity or location is involved, and the allocation of costs to a distributor does not help to optimize economic decisions. The transmission system as it exists today reflects past decisions made to deliver service across the province at the lowest total cost. The costs of updating the system to reflect changing patterns of load growth is therefore at least in part the shared responsibility of all consumers.

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

With regard to sustainment investments, the Board can improve its confidence in the plans by requiring distributors and transmitters to employ a standardized methodology, using risk based approaches to prioritize investments and determine the size and timing of investments.

Where major reliability investments or capacity expansions at the transmission level are concerned, greater opportunity to for the Board to consider competing solutions from both utilities and the market would contribute the filter of competition for the assessment of investments and also provide a benchmark as to costs.

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

The terminology "Smart Grid investments" may cover quite broad and diverse objectives, as well as a variety of projects. Given the lack of any specific definition as to what constitutes an eligible smart grid investment, a key part of the assessment should be whether the size and timing of such investments is appropriate and commensurate with the customer needs. If the investment receives approval on the basis that it is appropriate, considering the needs of customers, it should be incorporated into the rate base for recovery of the cost by the utility.

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?

As a stakeholder representing consumers, CFIB is primarily concerned that the development and approval of utility plans should be focused on giving the consumers the level of service they require at the lowest possible cost—that is, the highest value for their money. This means that the tools and methods should support the selection of the right projects, at the right time. We therefore recommend that requirements be established that incorporate analysis approaches that evaluate the projects themselves, while considering the dimension of customer value.

For investments into asset sustainment, Distributors and Transmitters could be required to employ Board approved models for determination of asset health indices and probability of asset failures to establish the optimize size and timing of investments. For investments into capacity expansion and line extensions, Distributors and Transmitters could be required to employ Board approved models for load forecasts to determine anticipated capacity constraints and the size and timing of investments.

i. Risk-Based Analysis

A majority of the investments in fixed assets are triggered by either declining performance in the areas of supply system reliability, power quality or safety; or increasing operating and maintenance costs associated with aging assets; or anticipated growth in demand requiring capacity upgrades. In any of these cases, investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal operation. Optimal operation of the system is achieved when "right sized" investments into renewal and replacement (capital investments) and into asset repair, rehabilitation and preventative maintenance are planned and implemented based on a "just-in-time" approach. The objective of the asset management strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

A risk based asset management strategy determines the risk of asset failure based on the condition of the asset, which is commonly measured with the help of a yard stick of "Asset Health Indices". The methodology attributes a value to the risk based on consequences of asset failure and identifies the optimal risk mitigation alternative through an evaluation of available options. Asset management covers the full life cycle of a fixed asset, from preparation of the asset specification and installation standards to the scope and frequency of preventative maintenance during the assets service life, and finally to the determination of the assets end-of-life and retirement from service. At each stage of an asset's life cycle, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs) and lowest operating costs. The best-in-class asset management strategies employ integrated processes that allow optimal levels of financial and operating performance to be achieved, using transparent and objective criteria that can easily be audited and inspected by the Board.

The following diagram shows the relationship between capital costs and on-going costs associated with risk of failure, in determining the total cost of an asset replacement strategy. The objective is to select the strategy that minimizes total cost over time.

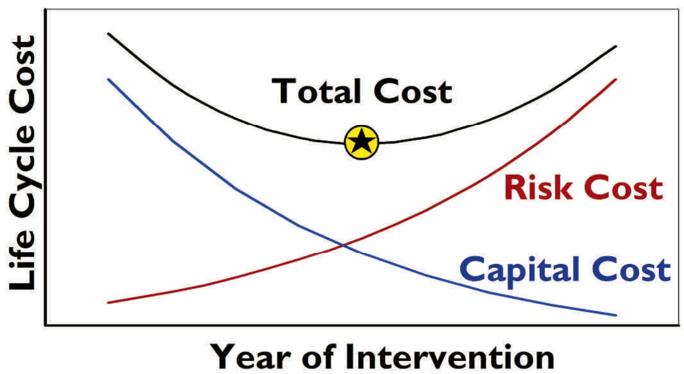

Figure 1 - Total cost of an asset replacement strategy
Source: S. Otal, METSCO Inc.

As an example, PAS-55, a specification for asset management, was developed by British Standards Institute (BSI) and offers one of the best in class strategies for risk management associated with fixed assets of electricity distribution systems.

The following diagram summarizes a practical matrix to sift through a large number of assets, typically employed on transmission and distribution systems, to objectively identify assets that present the highest risk of in-service failures, so that the investments could be targeted into assets that present the highest risk. Numeric health indices, typically normalized to a scale of 100, are commonly used to express the health and condition of assets, and this allows separation of the assets in good condition that require minimal risk mitigation from those in poor condition, requiring a higher level of investments. This exercise allows development of an investment plan that could be implemented over a 5-10 year period.

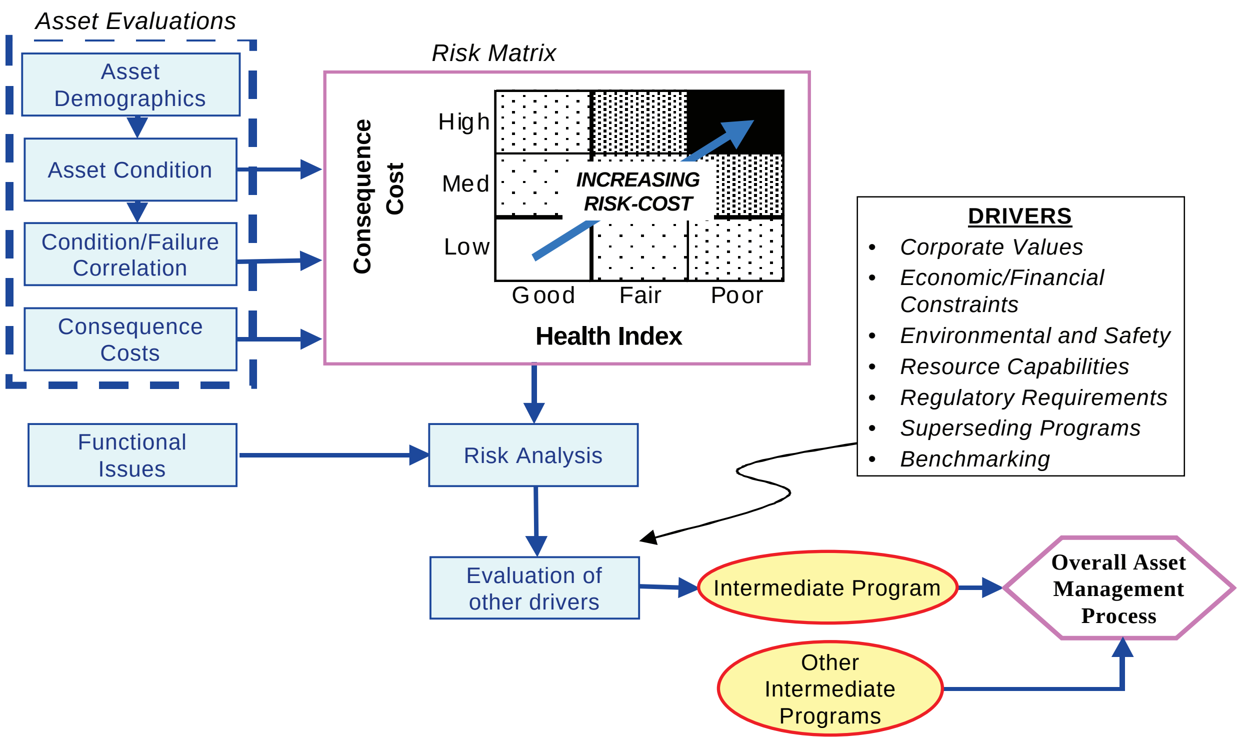

Figure 2 – Identification of assets that present the highest risk of in-service failures
Source: S. Otal, METSCO Inc.

ii. Value-Based Reliability Planning

The optimal level of investments aimed at improving reliability of regulated assets can be objectively determined by analyzing the economic efficiency of investments. An investment into reliability improvement is considered to be economically efficient if and only if the costs incurred to improve reliability of a specific asset are less than the value of benefit achieved or the value of economic loss avoided. This approach to utility investment planning has been a subject of many studies and is commonly referred to as “Value-Based Reliability Planning”.

Value-Based Reliability Planning compares the incremental cost of improving reliability of transmission or distribution assets with the incremental benefit of reliability improvements, with both the costs and the benefits focusing on the costs and benefits to customers. The incremental societal benefits are calculated by including the value of customers’ benefit due to reliability improvement. The value of customers’ benefits is quantified by the customers’ willingness to pay for reliability improvements and is established through customer surveys or analysis of customers’ costs during power interruptions of varying durations. The cost of system improvements is usually established using engineering cost estimates.

A recent study completed in 2009 by Ernest Orlando Lawrence Berkeley National Laboratory on behalf of the U.S. Department of Energy analyzed customers' costs during interruptions ad developed customers' damage functions to illustrate the use of value based reliability planning methodology in determining economic efficiency of investments. Two such customer damage functions related to small general service customers and residential customers are shown below in Figures 3 and 4.[3] CFIB has been advised that similar surveys from Canadian jurisdictions are also available, which could be updated for use in evaluation of economic efficiency of investments; but we would be willing to cooperate with the Board in developing a survey that would gather input from our members.

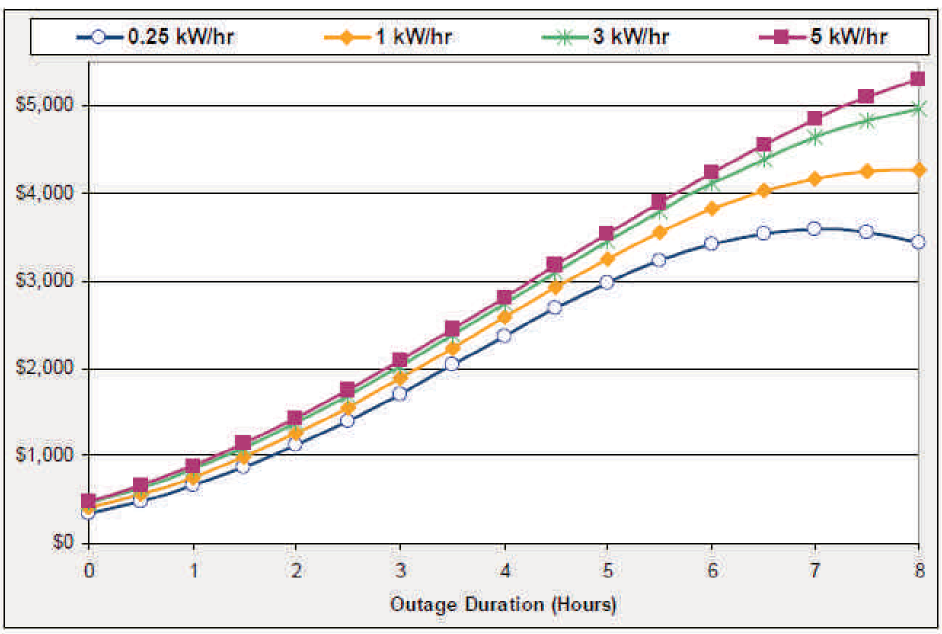

Figure 3 - Small Commercial and Industrial Customers Damage Functions – Summer Afternoon[3]

[3] "Estimated Value of Service Reliability for Electric Utility Customers in the United States" Michael J. Sullivan, Matthew Mercurio, Josh Schellenberg.

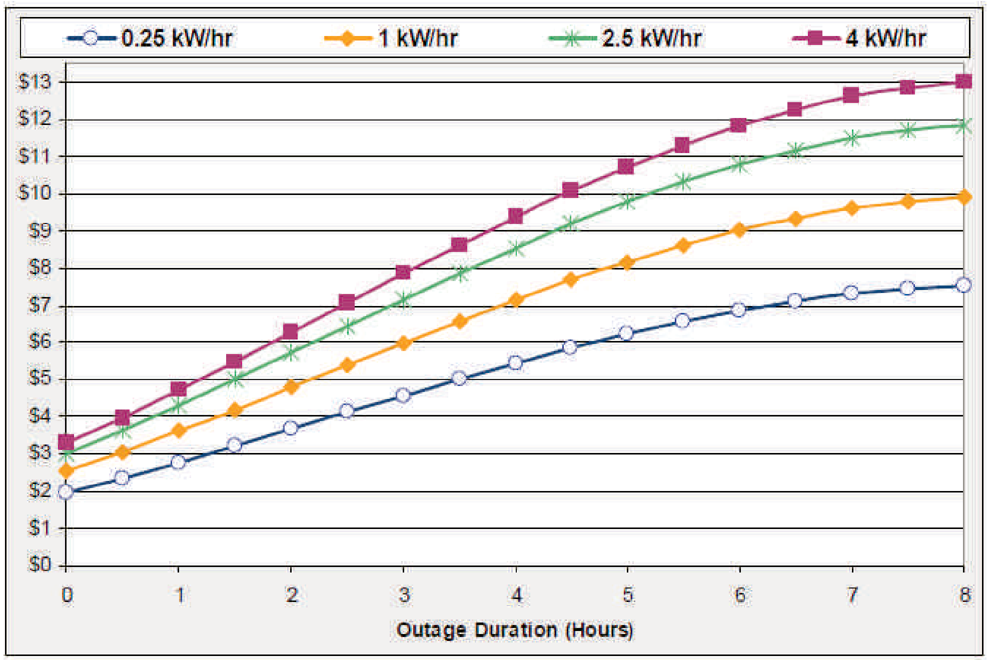

Figure 4 - Residential Customer Damage Functions - Summer Weekday Afternoon[3]

D. PERFORMANCE & INCENTIVES (EB-2010-0379)

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

We propose that the indicators of performance should be linked with the following outcomes:

- Customer perception of value for money
- The reliability of the service
- The optimization of operations
- Uptake of CDM programming
- Control of the costs of operation
- Social and environmental responsibility including health and safety

In a sector that is regulated the performance "outcomes" should aim at providing value to customers, as well as assuring compliance with requirements that are in legislation. Responses to surveys and comments from our members indicate that small businesses in Ontario perceive that recent electricity cost increases have not been accompanied by any improvements in value. Their assessment is that the value received for their electricity bill is therefore declining.

While cost is one of the key elements, it is not the only element. One possible option is to adopt a "balanced scorecard" approach to benchmarking, so that a variety of dimensions of customer service and customer value are taken into account.

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

As an association representing consumers, CFIB's position is that the highest priority should be on the measurement of customer satisfaction and perception of value for money. Specific quantitative measures of utility performance should be selected to correspond with the key dimensions of customer service, including, but not limited to reliability.

The standard and metrics should where possible be consistent with those used across Canada and North America, to enable a comparison with companies outside Ontario where possible. However in selecting and interpreting these measures, the scale, geographic conditions and customer mix (largely urban for most Ontario distributors) needs to be taken into account. For some elements of customer service, such as site visits, telephone response and clearing problems, it is possible that metrics can be adopted and benchmarked outside the utility industry.

The standards and metrics that could be applied to both transmission providers and distributors should be adopted, for example the ratio of hours of interruption of service to clients versus the totality of clients served, or System Average Interruption Duration Index ("SAIDI"), in the Distribution Code but not present in the Transmission Code.

These common elements of performance measures should be integrated to both Codes as a core element. This would enable a benchmarking with the utilities active in the North East or Canada.

The existing performance benchmarks should also remain in both Codes enabling a historical look at performance. Should it be assessed that new standards of performance supplant the existing standards, a transition period should enable the accumulation of data to preserve this ability to compare on a certain time frame the performance.

Similarly a classification by gravity or importance of incidents should be added to both Codes. This classification could be catalogued according to importance: an incident causing the loss of a load would be grade 1; an incident causing the loss of equipment would be grade 2, and; all other incidents regrouped as grade 3.

A new standard for cost performance that may be of interest would consist in having the ability to compare costs to the underlining components used. In other words comparing costs of specific activities to the price of the component needed to pay for them. For example, the cost for the construction or replacement of a substation or pylon could be measured in relation to a basket of key components including different variables such as the price of steel, an index of labour costs, an index price for cement, and so on. Each component would have a specific weight or size in the basket of reference. This would show the relation between the costs of the utility for specific activities and a generic reference curve. In turn this could be used to measure the efficiency of all utilities involved in similar activities.

The basket of reference may not need to be a perfect mirror of the costs since its use would be to apply a constant for purposes of comparison.

Benchmarking work conducted on behalf of the Board[4] strongly indicated that the same average unit cost levels are not achievable by all Ontario distributors, given the differences in location, geography, size, and the nature of the existing system. However, "back office" costs could more easily be compared across distributors with different distribution systems. CFIB has some concern for the differences of opinion that appear to exist among experts as to the quality of data, and whether it is a good basis for analysis, even after more than a decade of regulation by the Board.

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)?

There are known characteristics of organizations that are essential to their level of performance:

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[4] by the Pacific Economics Group, in 2008.

High-performance organizations tend to establish clear visions that are supported by flexible and achievable strategic plans. The clarity of the strategic plan is an essential component.

One characteristic of high-performing regulated entities, in keeping with the "outside world", involves the quality of the customer-based approach and how they treat their customers. Strong performance reflects the fact that the organization uses customer information as the most important factor for developing new products and service.

One potential metric to evaluate the level of performance of the regulated entity could involve the uptake of conservation and demand management ("CDM") programs by its customers. Higher rates of inclusion and acceptance of CDM programs will demonstrate which regulated entities are focusing on the customer's needs.

It is also vital to evaluate the portfolio of CDM programs to ensure that they are actually effective in helping the participating customers achieve the result of lower bills, to ensure the expansion of availability of effective programs, and to reduce costs by cancelling ineffective programs.

In these challenging economic times, CFIB members need to see initiatives that reflect the special challenges of small business, including more focused conservation information and direct support to small and medium-sized businesses by industry sector.

Of CFIB members surveyed, 62 percent identified energy conservation as major concern, and placed conservation at the top of a list of relevant energy and environmental issues (including recycling, water, and climate change). 77 percent of small and medium-sized businesses surveyed have already implemented conservation measures including changes to lighting, thermostats, building alterations, investments in improved technologies, and changes to layout/production or timing.

If the investments are forced upon small businesses without a positive business case, they will put additional pressure on the ability of the businesses to sustain profitability for the employers and employment for the staff. Thus, the customer and regulated entity need to work together to determine the most efficient mechanisms for advancing CDM. The rate of acceptance of new CDM programs by customers may be one potential indicator of measuring performance of regulated entities. Furthermore, small businesses differ widely in their types of appliances and hours of operation. A convenience store is different from a restaurant, a hair salon, a dry cleaner or an office. As such, unless CDM measures are specific, it is possible that they will address only part of the problem.

CFIB strongly recommends that initiatives be developed that are focused on small business AND within the control of small business to implement. Specifically, high performing entities need to incorporate strategies and technologies that are tailored to different types of small business, and that are effective in achieving results for the customers.

CFIB respectfully recommends that performance be measured using the following criteria:

(a) Customer Service

- Prompt and courteous telephone response
- One-call resolution to almost all customer billing and service problems
- Accurate bill
- Convenient service hours
- Very few outages, service quickly restored
- Satisfactory power quality for high-tech applications
- Availability of communications in the traditional languages of the community, where applicable
- Prompt connection of new services
- Convenient bill payment options
- Delivery of a variety of effective, cost efficient CDM programs for all customer classifications

(b) Cost Performance

- TFP better than average for selected comparable and neighbouring distributors
- Better than average unit costs for "inside" customer service and administrative functions
- Better than average ratio of employees to staff
- Management of capital projects on time and on budget

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 staff discussion paper regarding on this topic refers to what is being considered by the United Kingdom's Office of Gas and Electricity Markets ("Ofgem"), as far as methodologies for the development of an approach for the removal of what is called "network risk" (page 57 of Staff Discussion Paper on Defining & Measuring Performance of Electricity Transmitters & Distributors).

This type of incentive appears appropriate for a regulated entity. The traditional risk/reward dynamic, where an increased risk provides an increased reward, makes no sense in a regulated rate of return world. Once a rate of return is fixed, there is no reason to develop an intelligent risk-taking culture that would enable the entity to increase profits.

A risk reduction approach on a long term horizon should be incentivized. This approach would dovetail well with the suggestion of having a five year capital plan. Proper planning for operation and maintenance should bring about a reduction of costs.

Example:

On a short term basis such an approach may increase costs for the implementation of such a program and this may deter some entities from proceeding with such plans. Thus an incentive should be introduced. For example, a program of enabling to shift costs from "catch up" maintenance to "preventive maintenance" should be rewarded, if the investment is repaid with lower costs on a present value basis. With a growing number of assets coming closer to end of use life, refurbishing will be a priority. This may entail having to have distributors report back on the actual savings achieved by comparison with those forecast in the business case analysis.

Regulation could include a requirement for categorization of assets according to condition of operation from each license holder. This would bring about a regulatory need for inspection providing key data with an obligation to report. From this information, preventive maintenance programs could be developed along with the identification for critical maintenance needs due to "neglect" (not repairs stemming from events such as forest fires or plane crashed destroying equipment).

One indicator that could be created would track the improvement of the ratio of costs to be incurred for "catch up" maintenance versus costs to be incurred for "preventive" maintenance would.

Improvement of this ratio would be rewarded. The reward should help the utility to further accelerate or facilitate its catch up program. The maintenance programme would need to be pre-planned and approved for the period until the next cost of service application.

Such programs would include timelines and budgets for deliverables. The costs incurred would then be related to the budgets and timeline and full recovery allowed for the portion exceeding budgets enabling earlier delivery thus helping move the ration "catch up" versus "prevention".

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

There is a natural alignment of the interests of utilities and their customers when customer value is being created. CFIB's members are telling us that they perceive a reduction in value because of increasing electricity costs without a corresponding increase in service. CFIB therefore does not support a structure that allows utilities to qualify for incentives when there is no improvement in customer value. Rather than a mechanistic program that attempts to provide utilities with opportunity to improve earnings through cost reductions, CFIB would favour development of a program that reflects some of the broader, and especially, customer-focused improvements listed above. A performance program that includes several dimensions, of which financial performance is one, is frequently referred to as “balanced scorecard”. Balanced scorecard approaches are well documented in business management literature, and could serve as a basis for development of a performance assessment and incentive program.

E. RATE SETTING & 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?

CFIB would suggest that approval of the multi-year investment plan be part of the utility's cost of service application, in-so-far as possible. Where only one utility is involved (i.e. where there is no element of a new regional plan) this will allow the continuation of a system where review of utilities' cost of service is distributed over time for the Board, and allow one utility's plans, activities and costs to be reviewed as part of a single proceeding. Between cost of service years, the adjustment to rates would include changes to reflect escalation and a productivity target at present, but also the inclusion of the new capital approved under the multi-year plan. The disadvantage is that when there is a regional planning issue, all the utilities affected may have different cost of service years. Either there must be a mechanism to incorporate the effects of an approved regional plan into an individual utility's rate base between cost of service years, or the schedule for re-basing needs to be aligned to synchronize the regulatory cycle of neighbour utilities.

One issue is how long the multi-year investment plan should be. Either a four-year span could be adopted to match the existing IRM and cost of service cycle, or the regulatory cycle could be lengthened to match a five-year investment plan term. With provision to incorporate significant new investments into rates, the utilities may not be averse to a longer cycle, and the longer cycle may help the Board in resourcing the necessary additional reviews.

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?

CFIB understands that utilities faced with immediate needs for significant capital investment, and who have more than one or two years to wait for rebasing will want an interim mechanism to apply. CFIB would be concerned by a process that involves the uncertainty of after-the-fact approvals. Perhaps an expedited process could be allowed on an interim basis, to address approval of projects of significant size. Once the formula for incorporation of capital increments between cost of service years has been developed, this could apply to specific approved capital increments for utilities that have not yet had a rebasing year under the new requirements.

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?

A possible option is to consider process (best practices) benchmarking and the benchmarking of those costs that are most comparable across utilities regardless of location (for example, customer service, billing, workforce management). Best practices benchmarking, carried out cooperatively, could help utilities learn from one another and from utilities outside Ontario.

CFIB suggests that a benchmarking practice that encourages cooperation in cost reduction, rather than competition within a ranking structure, would help in ensuring that the whole industry, and customers across the province, benefit from the efficiency innovations that are developed.

One of the approaches that many utilities have used to date to control costs is sharing of functionality with its municipality or with affiliates. In some functions, such as joint billing with water services, the savings can be considerable. It is suggested that the Board carefully reconsider provisions of the Affiliate Relationships Code that are potential barriers to this type of saving, and implement changes that allow equitably shared scale economies to continue to be realized.

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?

CFIB does not support the idea that a utility's application should be subject to a less thorough scrutiny because of the utility's previous efficiency ranking or other benchmarking results.

However, CFIB does endorse the idea that utilities should be encouraged to meet all the requirements in their filings that allow for efficiencies in review by Board Staff and by the Board itself. A quality and complete filing will reduce costs in the regulatory process. CFIB suggests that from existing information about the costs and efforts at the Board for processing an application, some sort of standard could perhaps be developed. If costs associated with the review can be reduced by a fully compliant filing, the resulting savings could be shared between utility customers and the shareholder on some basis.

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?

With a four-year or five-year plan in place, there will be improvement in the phase-in of rate increases because the step effect of the current regime will be eliminated. The approval of the plan and cost at the time of rebasing will allow the utility to present its forecast of revenue requirement for each year, and suggest a smoothing over that period that may, depending on the timing of the investments, include some pre-recovery and some deferral, if the increase in any one year would exceed a pre-determined percentage of the whole bill.

CFIB does not support deferral of recovery of new costs at the transmission and distribution levels in order to cushion escalations at the generation level.

All of which is respectfully submitted by CFIB. We once again thank the Board for the opportunity to provide our members' views

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