April14, 2008

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319, Suite 2700
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Dear Ms. Walli:

Re: 3rd Generation Incentive Regulation for Electricity Distributors

Board File No. EB-2007-0673

Attached are comments I have prepared as a member of the working group on 3rd Generation Incentive Regulation, representing the Association of Major Power Consumers in Ontario.

Paper copies are being sent by express courier.

Yours truly

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Comments
3rd Generation Incentive Regulation for Electricity Distributors
OEB File: EB-2007-0673

Introduction

This commentary is provided in support of the Board's efforts to establish a robust and effective incentive regulation mechanism for LDCs.

The first section provides AMPCO's particular perspective as a consumer organization, followed by specific comments organized according to the structure of the staff report.

AMPCO Interest and Perspective

The majority of AMPCO members are served by distributors. For these customers, distributor charges represent a significant and growing portion of their energy cost. For companies that compete globally to survive, it is vital that their monopoly suppliers operate as efficiently as possible. To this end, AMPCO is a committed stakeholder in any process that will affect the economic efficiency of electricity distribution.

While large users have specific usage characteristics that sometimes differentiate their interests from other customer groups, this is not the case with incentive regulation. All customers have an interest in their distribution utility becoming as efficient as possible.

The interest of customers is on the total cost of distribution. While much of the working group discussion has been around incentives for operational efficiency, the revenue requirements of distributors tend to be driven equally or more by the rate base. For example, in Hydro One's current application for 2008 distribution rates, revenue requirements driven by OM&A costs are projected at $478M, while costs driven by the rate base (including capital taxes and ROE) total $550M[1].

Any incentive regime designed to promote the economic efficiency of the distributor must include effective incentives to limit growth in the rate base to an economic optimum.

Changes in the distributor environment resulting from smart meters, CDM, distributed generation (DG) and other factors are increasing a rate base that must be supported by (projected) decreasing sales volumes. This will inevitably result in decreasing asset utilisation and higher rates. This makes it all the more important to limit growth in the rate base to what is economically efficient.

The objective of good regulation, whether COS or IRM, should be to provide results equal to what a competitive market would produce.

[1] Hydro One Prefiled Evidence for EB-2007-0681, Ex E1/Tab 1/Schedule 1, Table 1.

AMPCO's members are accustomed to being price takers in competitive markets, forced to succeed or fail according to how well they can keep their costs below the prices they get. The risk/reward environment that comes with a competitive marketplace is a strong incentive for continuously improving productivity. As an example, the Total Factor Productivity of the Canadian Mining Industry grew an average of 3% annually over the period 1984-1998 while general manufacturing in Canada exhibited 1.7% growth in the same period.[2]

AMPCO believes quite strongly that, the closer that regulation mimics the business pressures of competition; the more regulated companies will improve their total productivity.

Managers of businesses in competitive environments have significant freedom of action in how they achieve their objectives, including the balancing of risk and reward. To the extent good regulation does mimic competition, it must also provide utility managers the latitude to take greater risk in return for greater reward. Part of the challenge of an IRM must be to present distributors with the opportunities and risks that competition provides. Done properly, this means the Board should consider it acceptable if one or more distributors fail as a business, so long as the assets remain in service. The Board's mandate to preserve the financial viability of the sector should not be taken as a requirement to protect all the companies in the sector.

Specific Comments

These comments are organized by the same section numbering used in the staff discussion paper. Where a section number is not referenced, there is no comment.

2. A Long-Term View of Incentive Regulation

2.1 Criteria for 3rd Generation IR

A practical framework should pass a net benefit test that includes **all** costs, the opportunity cost for all parties and the unrecoverable costs of intervenors and other stakeholders.

2.2 Building a Comprehensive and Sustainable Framework

We agree with the objective to build on the data that has been collected since 2002. This will require persistent effort to ensure data remain as consistent as possible in definition and interpretation. This will not be easy; the working group and stakeholder meetings highlighted significant differences in capitalization practice among distributors. The implementation of international accounting standards in 2011 may result in other changes, especially as it affects capitalization of overheads. Moreover, the staff paper on EDSQI has noted differences in interpretation of outage measurement standards.

3. Issues and Options for 3rd Generation IR

3.1 Capital Investment

[2] Presentation to House of Commons Standing Committee on Industry by the Mining Association of Canada February 15, 2000 (http://www.mining.ca/www/_news/news_299.php)

The treatment of capital investment in an incentive regime is perhaps the most contentious issue that has been discussed in both the working group and the stakeholder meetings.

For ratepayers, what matters is the total distributor revenue requirement, since this drives customer cost. An incentive mechanism must effectively influence both operating cost and capital expenditures.
A "hybrid" regulatory regime that combines cost of service regulation for capital requirements with incentives for operational efficiency would inevitably lead to a distributor bias towards over-investment.

The issue of whether or not special consideration for capital is required depends on the need for a significant change in the level of capital investment. If the relative portion of capital versus OM&A holds steady, the IRM approach proposed by PEG should not require modification.

Distributor representatives have noted several reasons why capital investment may need to increase significantly. These investment requirements have separate drivers and require separate examination.

Smart meters are the best defined of the capital issues. Costs are well understood for each utility. Since rebasing will precede IRM, the implementation of smart meters should be built into capital expenditure levels for any distributor that has not already completed its installations prior to IRM. There are two other issues related to smart meters. The first is that, for any distributor that has not completed installing smart meters before IRM, there should be a reduction in capital requirements during any multi-year IRM. The second is that smart meters should drive a reduction in labour cost for meter reading. Aside from the projected CDM benefits that justify smart meters, they represent an allocative shift of resources away from operations and into rate base.

The effect of distributed generation (DG) on investment requirements is not yet well understood, for several reasons. First, different types of DG impose different requirements on the distribution system, depending on capacity relative to the local distribution load and on such factors as intermittency in the case of wind and solar power. Second, DG is not likely to be distributed evenly across all distributors. It may well be that most urban distributors will experience minimal impact from DG, while rural distributors feel the brunt of the DG integration requirement, especially for wind power. Finally, the impact of DG on an IRM will be affected significantly by the allocation of connection cost, which issue has yet to be addressed.

Ageing assets are a commonly cited reason for a capital investment module in IRM. This may be justified, but should only be accepted when validated by comprehensive data. Asset age or ageing is not itself a justification for increases in investment; justification needs to rest on physical evidence of asset condition and performance deterioration.

There was also an issue raised that might be characterized as "lumpy" capital requirements. Two particular examples were given. One involved the very large capital requirements associated with the cost of building transformer stations. The other involved the need for replacement of major information systems, especially customer billing systems that need to be upgraded to accommodate smart metering.

Transformer stations are not distribution assets per se and do not need to be built by distributors. Any distributor building a TS is presumably doing so in the knowledge not that the asset is needed but that the distributor will be better off financially by constructing it at its own cost. Distributors have the option of relying on the transmitter to supply transformation.

For most distributors, customer systems exhibit a similar decision profile to transformer stations. Service providers supply customer billing functionality to a large number of Ontario distributors. For most, investing capital in a customer system asset is a decision, not a necessity. Moreover, most customer system replacements should be built into distributors' capital plans in the rebasing prior to IRM.

Finally, it has not yet been established that service quality requirements will increase to the point they drive increased investment and rates. This is being examined in EB-2008-001, which is still at the discussion paper stage. To date, no evidence has been put forth suggesting that customers overall are demanding or willing to pay for substantially increased service levels.

The reason for the foregoing discussion is to illustrate that at least some of the concerns that distributors have concerning capital investment may be addressed through the rebasing prior to IRM or may be localized to a subset of the distributor population.

For distributors forced to make exceptional and large new investments, an adjustment mechanism may be needed. However, these case should be treated as an exceptions and not the norm, with a commensurate evidentiary burden.

Of the alternative capital investment treatments Dr. Kaufmann presented, preference should be given to those that can be practically implemented, provide incentives for distributors to forecast accurately and discourage alternating IRM with rebasing.

The basic approach used by OFGEM to incent a careful and accurate investment forecast has several attractions and merits further examination. The concept of an information quality incentive (IQI) is compelling, as it provides a means for needed capital investments to be approved while addressing the fundamental problems of information rents and the natural incentive to expand the rate base. Understandably, multi – year COS with IQI will not be practical for many smaller distributors.

However, for the six large distributors that account for 72% of the provincial asset base and 60% of the customers being served, this may be a practical approach[3].

Approaches that require ongoing prudence reviews and capital cost trackers may add an unacceptable burden on distributors, stakeholders and the Board, and may not be effective. The problem with information rent would still be present.

Unit cost approaches lack adequate benchmarking and are difficult in any event, given the variety of conditions in Ontario. Especially for Hydro One and to a lesser extent Toronto Hydro, this approach could end with a distributor's projected costs being benchmarked against its own past costs, due to a lack of external comparators.

Accelerated cost recovery should be rejected. Most distribution assets are long-lived and accelerated cost recovery violates the principle of inter-generational equity. Equally important, accelerated recovery may incent inefficient investments. For example, an opportunity for accelerated cost recovery of a new transformation station could produce an inappropriate preference for distributor over transmitter ownership.

3.2 Lost Revenue Due to Changes in Consumption

The reference forecast by the OPA for Ontario (including transmission connected industrial customers, but excluding exports and imports) suggests that, in the absence of specific CDM programs, Ontario demand and energy will each increase slowly, by about 8 TWhr of annual energy consumption from 2007-2015 and 1817 Mw in peak summer demand (weather normal)[4]. These figures suggest a reference case of energy and demand output that is slowly increasing, with a slight downwards trend in load factor.

However, the major TFP growth factor in weighting distributor output is customer count. Housing stock is probably the best data surrogate for this, and the IPSP reference case projects it to increase at an average annual rate of 1.4% in the period 2005-2010 and 1.2% in the period 2010-2015[5]. Whatever actions the OPA may take in the CDM area, customer counts will be unaffected.

With respect to CDM effects, the government directed targets are for a reduction of 1,350Mw in demand between 2007 and 2010 and a further 3,600MW by 2025, compared to the reference case. If one assumes the 3rd generation IRM is not embedded until 2010, then the 2010-2025 target is the one that is germane to considerations of TFP influence.

[3] Ontario Energy Board 2006 Yearbook of Electricity Distributors, pie charts on pages 4 & 10
[4] IPSP, Exhibit D/Tab 1/Schedule 1/Attachment 2, Tables 12 & 13.
[5] IPSP, Exhibit D/Tab 1/Schedule 1/Attachment 2/Table 19

The 2010-2025 target calculates out to an average 3600/15 = 240MW reduction in Ontario peak demand per year. Also, the IPSP identifies cumulative annual energy savings from CDM of 11.871 TWhr by 2015[6]. Netting out the reference case, this suggests that 2015 energy consumption will be about 4 TWhr below 2007 levels, or about 2.5% lower than today. Since a significant amount of this reduction will have been achieved by 2010 (3277MW by YE 2009[7]), the effect on the energy portion of distributor output should work out to about 0.4% a year or less. The same calculation would hold for demand.

While these numbers are small and can be readily addressed by various means, such as an LRAM, they remain significant. However, government directives and OPA plans do not constitute a fait accompli, when the actual outcome is to be driven by a change in customer behaviour, which may or may not conform to the wishes of the planners. It would be presumptive to assume success in the plans of the OPA until evidence appears that the programs are effective.

A prudent approach would suggest having some mechanism in place that can flexibly accommodate declines in energy delivery or demand. Distributors have been universal in their concern that reductions in electricity use by customers, either for due to "natural" CDM, or successful CDM and fuel switching programs, needs to be addressed in any regulatory regime.

The EDA proposal for an RSAM (revenue cap) makes sense from the customer perspective, providing it is implemented with effective controls to prevent asset harvesting or service reductions. An RSAM could also benefit customers by allowing un-conflicted distributor support of CDM and should effect adjustments in ROE to reflect the reduction in business risk faced by the shareholder. Moreover, an RSAM that dealt only with actual versus forecast revenue would remove any issues around forecast gaming or weather normalization methods.

The issue of rate volatility under a revenue cap has been raised frequently as an issue for this type of regulation.

Concern about rate stability may be an artifact of expectations rooted in the time when the energy price was relatively stable and much of the growth in the rate base was financed through capital contributions. However, today there are many factors converging to increase volatility in overall energy costs and distributor regulation is one of the least of these. Volatility in the price of the commodity itself can lead to semi-annual rate adjustments for the RPP customers and hourly price changes for the rest. Smart meters will facilitate another source of price volatility, as TOU rates are introduced and evolve over time. This is a reality that customers cannot avoid.

[6] IPSP, Exhibit D/Tab 4/Schedule 1/Attachment 3/Table 5
[7] IBID

A particular concern was raised about the impact on distributor rates if a large customer were to leave. This has already happened, but there is no regulatory regime that can prevent some impact on the remaining customers. The problem is aggravated if the distributor has used the large customer to subsidize other customers. The difference between a price cap and a revenue cap for these situations is likely to be more a temporal issue, although a price cap might shift some risk to the distributor that a revenue cap would not.

If rate volatility is truly a significant objection to a revenue cap or RSAM, then there could be other mechanisms to mitigate it.

3.3 Distributor Diversity

In Ontario, less than 10% of the distributors supply 60% of the customers. Combined, over 60% of the distributors serve less than 10% of total customers. Only 9 LDCs serve more than 2% of Ontario's customers each.

The diversity in distributor demographics speaks to the need for some choice of regulation mechanisms. It would be unfair to the majority of Ontario customers if the regulatory regime were straight jacketed by a "one size fits all" approach designed to speed the regulatory process or excessively lighten the regulatory burden on all distributors.

An approach providing for a basic IRM mechanism based on inflation, TFP growth and a stretch factor, along with an option to modify the formula based on special circumstances (e.g., DG-driven investment requirements or a need for significant asset replacement) might work for all. Smaller distributors in stable circumstances could opt for the simple formula approach, while those with the need and resources to pursue a more complex arrangement (such as multi-year COS with IQI), could do so.

It is also logical to provide some term flexibility to an IRM. However, given the significant changes expected in the industry in the next few years, a limit of five years may be advisable.

3.4 Alternative Approaches

Comprehensive Multi-Year Cost of Service Approach

As discussed previously, the Board should not be constrained from providing the best regulation for the majority of customers in pursuit of a single solution for all distributors. There is considerable attraction in a sliding scale approach with an information quality incentive available to all but perhaps most attractive to the larger companies.

Hybrid Approach

This model should be rejected for the reasons noted by on Table 1, especially that it would incent allocative inefficiency.

Comprehensive Price Cap Index Approach

This approach may work well, but the details are important. A mechanism for stabilization of revenue should the energy or customer forecast turn out high or low would enhance this approach by reducing risk to both customers and the distributor and by removing incentives for forecast gaming.

4 Elements of a Core Plan

4.1 Form

While we believe a mechanism such as the RSAM proposed by the EDA might be better suited, a properly implemented comprehensive price cap index is a workable mechanism for an IRM.

4.2 Term

As noted earlier, 3 to 5 year terms seem reasonable for the first pass of a third generation regime.

4.3 Inflation Factor

The use of an industry specific GDP – IPI, with appropriate weighting for capital, seems correct. The formula example provided could be adjusted to reflect varying weights for capital and labour.

Additional consideration of capital due to planned construction of transmission assets should not be considered for distribution IRM.

There may be a problem in applying a uniform capital price sub index if the distributor is using lower depreciation rates than the 5.67% used in 1st generation PBR. A utility using a lower rate may benefit inappropriately if differences are not considered.

Overall, the staff recommendation on inflation seems correct.

4.4 Productivity Factor

The basic approach of setting an X-factor for each distributor or distributor cohort is reasonable. The breakout of the X-factor into a TFP growth estimate and a "stretch" or X factor is also logical. After this point, opinions vary widely.

The setting of the TFP estimate has been contentious, especially the proposal to use American data in the absence of adequate Ontario data. It is easy to understand why a distributor would be hesitant e to accept data from another jurisdiction.

However, there are several reasons to trust the American data:

- It consists of many years of data, enough to smooth out contrary trends. Moreover, American FERC accounting standards have been in place longer than USofA and are likely trustworthy as a result.

- The American data are, to our understanding, representative of distribution utilities. The electrical distribution business in Canada is very similar if not virtually identical to that in the US, except perhaps with regards to property taxation.
- Material, equipment and information systems inputs are basically served by the North American market, so there should be little difference in escalation factors (notwithstanding currency exchange).
- Labour is to some extent internationally mobile, especially in skilled trades, although labour inputs may cost more in the USA.
- Outputs are as similar as inputs, right down to voltage standards, billing practices and service reliability index calculations.
- Longer term, the national productivity relationship between the USA and Canadian economies has held very steady, although there are periodic fluctuations.
- Dr. Kaufmann has gone to some pains to screen out companies that may not have input/output characteristics similar to LDCs.

One argument against using American data is that American utilities tend to be more technology-intensive than their Canadian counterparts. No specific evidence was produced in support of this, but it may be accurate. However, if it is, it would suggest that American utilities lead Canadian ones in terms of fixed TFP at any given time. If the argument that historical high productivity gains limit future opportunity is valid (uncertain), then American utilities should have experienced lower TFP growth in the past few years than Ontario distributors.

Overall, the use of American TFP data until a 10 year Ontario trend is established seems a reasonable way to start.

Discussions on stretch factors also revealed considerable differences of opinion. PEG's proposal suggested a zero stretch factor for the top tier of performers, with less productive cohorts being given progressively higher targets to meet. The PWU and CLD presentations appeared to favour a convergence approach, whereby average performers had a zero stretch factor, the best performers had a negative stretch factor (i.e., X-factor would be less than TFP trend), and the lowest performers would have a positive stretch factor.

The main argument for a convergence approach seems based on the assertion that distributors that have been the best performers in the past will be unable to keep up even with average TFP growth in the future. On the surface, there may be some validity to this argument, since productivity improvements within industries tend to exhibit some ebb and flow over time.

However, for an IRM to substitute for a competitive environment, it's structure should promote behaviours that succeed in competitive environments where companies operate as price takers. In such environments, where AMPCO members operate, pressure to reduce cost while raising output is constant for all players, regardless of their relative competitive position. This is true across resource industries (e.g., mining, forestry), basic industries (e.g., steel, paper) and manufacturing (e.g., automobiles). For example, Toyota is every bit as driven to improve productivity as Ford is, even though Toyota may enjoy a competitive advantage in this area.

From this perspective, the idea that the best companies should be allowed to back off does not make sense. If accepted, the convergence argument would drive a race to the average.

Finally, the discussions around TFP and the proposed stretch factors seem based on a flawed assumption. That is, that current average LDC productivity is good (or at least good enough). This is a questionable assumption considering that the companies involved are almost all government owned monopolies operating in an environment that has not allowed them to fail, and have for decades been regulated with what was basically a cost of service rate setting paradigm.

The above point is not meant to disparage the people in Ontario's LDCs; they are generally a very capable group. It is simply that it is unrealistic to expect competitive levels of performance when competition is absent. Past performance improvements are a poor indicator of future potential.

In sum, the proposals from PEG for the X-factor seem to be a modest but sound first step.

The "menu" proposal to allow some distributors to accept higher performance improvement targets in return for a potential higher rate of return has merit. It may be true that there are distributors who know of productivity improvement opportunities they have not exploited, but would do so to gain windfall profit. Whether this is true or not really doesn't matter; if the result is lower cost to the customer without service or asset deterioration, then everyone wins.

4.5. Provision for Incremental Capital Investment

The discussions earlier in this submission note the concern about dilution of incentives and the growth of rate base.

As noted, the evidentiary bar for exceptional capital investment should be kept high and it would also seem prudent to keep the materiality threshold high (5% or greater). The use of an incremental module should be limited to those investments and project characteristics that can be reasonably established to be outside management's ability to prudently avoid.

The text of the staff discussion reveals significant unease with such a module and this concern is shared. Whether customers pay more than they should due to technical inefficiency or allocative inefficiency is irrelevant to the customer. A capital module would need to be managed with great caution.

4.6 Treatment of Unforeseen Events (Z-factor)

It is probably best to treat Z-factor events on a case by case basis. There is no particular reason why capital consequences should not be considered as well as OM&A. Prescriptive treatment might preclude the examination of all the consequences of the unforeseen event, including the tendency to defer planned work when responding to emergencies.

Cost allocation by revenue is not appropriate, since unforeseen events tend to affect assets. If the event is material, cost allocation based on asset use would be appropriate.

Recovery though rate riders is a valid approach for the OM&A portion.

Generally, a company should be prepared to handle all but the most severe events without seeking outside recourse. Aside from the 1998 ice storm or the Stelco bankruptcy, it is hard to think of an event that should have forced a special hearing.

4.7 Off Ramps

The opportunity to access an off ramp should be symmetrical for both customers and distributors. The 6% suggestion may be too broad, but the principle is sound. Weather normalization of earnings should only be allowed if there is an ESM related to weather induced revenue windfalls.

4.8 Earnings Sharing Mechanism

Earnings sharing mechanisms (ESMs) have counterparts in private business, whereby suppliers may be incented to achieve cost reductions by being allowed to keep a portion of the benefit. Some manufacturing and services businesses operate in this way, especially when the customer wants to ensure the supplier is motivated to improve.

Whether an ESM is necessary or not in an IRM regime is uncertain and depends on the level of uncertainty about costs and productivity opportunity. Given that the first round of IRM will follow a COS rebasing and that a price cap regime is recommended, ESMs may be advisable beyond a reasonable dead band of ROE.

Ultimately, an ESM limits customer risk. To the extent that other aspects of the IRM effectively limit customer risk (see prior comment on weather correction of revenue), an ESM is less necessary. Generally, an ESM should be seen as a last backstop, half loaf solution when the regulatory regime has been unsuccessful in optimizing risk and reward for the distributor.

ESMS also limit distributor opportunity and in doing so could act to limit performance incentives.

An asymmetrical ESM trigger of +2% of ROE may be appropriate for the first round of IRM. The Board may wish to consider a sliding scale ESM, with an upper limit on ROE.

4.9 Service Quality

Existing Service Quality standards should be continued through the first run of IRM, unless there is convincing evidence that customers are generally dissatisfied with current performance.

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