Before the Ontario Energy Board

Consultation on Distribution Revenue Decoupling

Comments of the GEC on the PEG Paper

The following submissions summarize GECs view of the issues and offer suggestions for added study that would inform the Board Staff discussion paper:

Single Fixed/Variable (SFV):

SFV reduces efficiency incentives and should be rejected outright for that reason alone. SFV would preclude innovative rate structures that could utilize Ontario's investment in advanced metering to foster efficiency.

SFV requires the maintenance of LRAMs which are difficult and costly to administer for a large number of utilities. LRAMs are limited in scope in that they do not shield the LDC from conservation impacts of third party programs which could benefit from LDC cooperation.

SFV is also unfair, since costs vary with customer size and contribution to peak loads on distribution and transmission equipment. Board staff may wish to have Dr. Lowry's report expanded to address this later concern.

Full Decoupling:

Full decoupling addresses the disincentive for all load reducing measures and efforts, not simply those typically considered in LRAMs. It also avoids the need for the complicated regulation that an LRAM approach requires. Given the fluid and multi-party nature of CDM and DSM delivery in Ontario, consideration of decoupling is very timely.

Without decoupling, LDCs have an interest in keeping fixed charges high to minimize volume risk. This reduces the conservation price signal. At several points during his presentation Dr. Lowry mentioned that the fixed charges of Ontario distributors were significantly higher than typical U.S. LDC fixed charges. In the case of the electric LDCs there is reason to believe that Dr. Lowry's observation is reflective of a real error in the estimation of the fixed costs. In the RP-1999-0034 proceeding GEC filed the evidence of Paul Chernick of Resource Insight Inc. that, *inter alia,* discussed the derivation of the fixed charge in the draft rate handbook. Appendix B of that evidence is attached to this submission. From the discussion therein it appears quite clear that the fixed charge was derived as a residual value (after deduction of Incremental Distribution Charges or 'IDC') and was based on a false assumption about a value included in an earlier Ontario Hydro study that Mr. Chernick had available to him (and that was not examined in the 0034 proceeding). Mr. Chernick's evidence suggests that the IDC value was likely an underestimate and the resulting fixed charge value will be accordingly overstated by more than 100%.

In the case of the gas LDCs, the fixed customer charges are presumably based on cost allocation studies, but such studies involve numerous judgements. Given the attraction of high fixed charges to LDCs it is not unreasonable to assume that there will be a systematic tendency to allocate costs disproportionately to fixed customer costs. If full decoupling is utilized, the risk of such a bias can be avoided.

Board Staff may wish to expand the scope of Dr. Lowry's report to address the issue of the appropriateness of current customer fixed charges (for both gas and electric LDCs) given the concerns noted above.

With full decoupling the Board and the LDCs (both electric and gas) would be free to consider, experiment with, and implement other rate structures that would better foster conservation. Given the importance of conservation in government policy, the immense investment already made in advanced metering, the Board's conservation mandate, and the broad public interest, obtaining the flexibility to use rate design to foster energy efficiency should be accorded a high value.

Accordingly, Board Staff may wish to expand the scope of Dr. Lowry's report to cover the experience in other jurisdictions with alternative rate designs to encourage conservation and to canvass other theoretical studies of that potential.

Decoupling would reduce utility risk and should therefore lower the cost of capital. The variance mechanism to hold the LDCs harmless could have a soft cap with a multi-year recovery period to maintain smooth rates.

Board Staff may wish to expand the scope of Dr. Lowry's report to quantify the potential benefit to customers of a lower cost of capital due to the reduced revenue risk that decoupling would provide.

Partial Decoupling:

Partial decoupling does not create the same flexibility for innovative rate design. Further, it does not avoid the need for an LRAM with all its complications and debate and its limited scope.

Full decoupling is simple, and removes financial disincentives for all forms of CDM, cogeneration, progressive rate design, provincial and local standards and codes, fuel-switching etc..

Board Staff may wish to expand the scope of Dr. Lowry's report to quantify the potential difference in the benefit to customers of a lower cost of capital due to the reduced revenue risk that decoupling versus partial decoupling would provide.

Existing Decoupling for gas LDCs:

The current Gas IRMs are versions of partial decoupling and have separate LRAMs.

Gas LRAM has been complicated and on occasion, divisive. It is desirable that the LDCs be supportive of the full range of conservation efforts at play in the marketplace. Decoupling would avoid the risk of LRAM disputes and better serve this goal.

The concerns expressed above in regard to high fixed charges being a barrier to rate design innovation apply equally to the gas sector. Complete and simplified decoupling would reduce utility concerns about rate design changes.

Given that the Board and parties are now considering incentive mechanisms that may not require detailed analysis of cubic meter savings that are attributable to the LDC, there may be regulatory efficiency in eliminating the LRAM in favour of a unified decoupling approach.

Finally, the current partial decoupling mechanisms do not appear to fully shield the LDCs during the rate year from volume changes in some rate classes due to the activities of third parties. Union's average use adjustment and variance account covers only its general service customers (81% of revenues) although Enbridge's appears to cover 96%. Third party DSM, and the need to ensure LDC cooperation with such third parties, is an increasingly relevant consideration in Ontario and all customer segments should be considered.

Concerns about the reduced incentive to engage in marketing:

Dr. Lowry pointed out that decoupling would reduce the incentive for the LDCs to market and this may have an undesirable impact where the load would be advantageous to the economy or environment, such as may be the case for dual fuel capable industries or electric vehicles. These are specific examples of a concern that arises due to the failure of energy pricing to include externalities. There are of course many more examples where marketing hurts the environment or reduces economic efficiency because it fails to consider externalities. If government policy supports encouragement of a particular environmentally or economically advantageous application, an approach similar to CDM can be utilized – either a government or LDC program can be offered to support the end use or a rate can be designed for the purpose (such as a range rate for dual fuel users that in effect incorporates a credit for reduced externalities when the market price of the commodities so requires, or a rate to charge up electric vehicles in low demand periods). In short, targeted and thus regulated marketing would be more environmentally and economically valuable than unregulated broad marketing that is blind to environmental impacts. Finally, it should be noted that the gas LDCs are owned or controlled by entities with an interest in the upstream industry and will still have a corporate interest in marketing.

GEC thanks the Board and its staff for the opportunity to provide these comments. All of which is respectfully submitted this 14th day of May, 2010.

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Excerpt from evidence of Paul Chernick filed by GEC in RP-1999-0034

Appendix B: Incremental Distribution Costs

The *Draft Handbook* proposes that the variable portion of distribution rates be set at incremental distribution cost (IDC), in $/kW for rates that have demand charges, and in $/kWh for other rates. As laid out in Appendix A to the *Draft Handbook,* the IDC in $/kWh would be the same for all rate classes, and would be based on a $0.0062/kWh incremental distribution cost, which Appendix A describes as having been "derived in a 1980's joint Ontario Hydro-MEU study." The joint study is not otherwise cited or described. Appendix A claims (repeatedly) that this "is the only value currently available," suggesting that the authors did not have access to the source document that derived the $0.0062/kWh value.[1]

Appendix A asserts that the $0.0062/kWh value "includes system losses," without specifying whether these include the generation and transmission costs of losses, or just the losses between various pieces of distribution equipment and the end user. Nor does the *Draft Handbook* specify the losses supposedly included in the $0.0062/kWh.[2] Appendix A proposes that each utility's most-recent five-year average system loss percentage, multiplied by some unspecified cost categories, be removed from the $0.0062/kWh, to estimate the IDC. The *Draft Handbook* does not explain how the same $0.0062/kWh could contain different loss values for different utilities. Without any derivation, Appendix A asserts that the default value for the loss correction should be $0.0025/kWh.

The combination of the undocumented $0.0062/kWh value, the undocumented claim that it includes losses, and the undocumented selection of $0.0025/kWh in losses produces an estimated IDC of $0.0037/kWh, which the *Draft Handbook* then applies in ratemaking. Since this IDC is a small portion of distribution costs, Appendix A proposes to recover nearly half of the general-service revenues and 70% of the residential revenues through the fixed monthly service charge.

I believe that the study to which the *Handbook* refers is "Estimation of Incremental Capacity Costs for Municipal Utilities," (R-87-7), August 1987, by Peter Choynowski of Hydro's Rate Economics Section. That study conducted a series of regression analyses of peak load and distribution costs, both capital and O&M. The study reduced its estimate of capital costs 30%, to take out a rough (and I think overstated) estimate of capitalized overhead costs, and included no overheads on O&M. Following this adjustment, the study estimated the IDC to be $32.95/kW-yr for the municipal utilities. At a 60% municipal load factor, $32.95/kW-yr is

[1] This is particularly obvious in the derivation of an IDC for the rates with demand charges, where Appendix A starts with the IDC in $/kWh, rather than the $/kW rate from which it must have been derived.

[2] Again, the authors do not appear to have seen the derivation of the $0.0062/kWh.

equivalent to $0.0062/kWh. So the Choynowski study appears to be the source of the $0.0062/kWh.

Note that this IDC estimate includes no losses and is in 1987 dollars. At the very least, the IDC estimate in the *Handbook* should be revised by inflating the $0.0062/kWh about 20% to year-2000 dollars, and omitting the adjustments for losses. These modest corrections would bring the IDC to about $0.0075/kWh, twice the value recommended in the *Handbook*.

The Choynowski study also appears to understate the true IDC, by removing capitalized overheads.[3] Most of these overheads are related to employee benefits, supervision, and other costs that vary with the amount of T&D construction. Retaining overheads in capital, and adding them to O&M, would increase the IDC 30%, to about $56.50/kW-yr or $0.01/kWh. This is very similar to the IDC estimated by Hydro's Branch Comptroller for Hydro's rural retail service territory, and cited by Choynowski: $51.09/kW-yr in 1987 dollars, or about $61/kW-yr in 2000 dollars.

These are still average IDC values over all classes. Secondary customers have higher incremental distribution costs than to those served at primary voltage, while customers served directly off the subtransmission systems should have very low IDCs. Adding 32% to reflect the higher cost of secondary distribution brings the IDC for small customers to $74.50/kW-yr, or about $0.0142/kWh, nearly four times the value used in the *Handbook*. [4]

This corrected IDC value would result in entirely variable rates, with no fixed service charge, when applied to the examples in Appendix A for residential customers (Table 2-10) and general service (Table 3-5). Rather that using the flawed and unsupported assumptions in the *Handbook,* perhaps the default for distribution rate design should simply be that all distribution charges should be collected through the variable rate.

As an aside, the suggestion in Appendix A of the *Handbook* that all variable distribution costs be recovered through the demand charge for classes with such charges is sub-optimal. Demand charges only reflect the customer's own peak demand, not its demand at the time of the peak load on the feeder, substation, or subtransmission system. It is the loads on equipment that drive distribution costs, not customer non-coincident peaks. For any given monthly demand, a customer with higher energy use (and hence more hours with higher loads) is more likely to contribute to peak loads on equipment than one with lower energy use. Rates intended to

[3] As noted above, I doubt that capitalized overheads are as much as 30%. This is much higher than for the US distribution utilities I surveyed.

[4] For a derivation of ratio of secondary to average IDC, see my report "Estimation of the Costs Avoided by Potential Demand Management Activities of Ontario Hydro," 12/92, filed in the DSP proceeding.

recover these costs should therefore include an energy-sensitive component.[5] In addition, energy use directly increases distribution costs, by accelerating wear on lines and transformers, and requiring larger-capacity equipment to withstand frequent high loads and long periods of high usage. Distribution energy charges should not be set to zero for any rate that uses the distribution system.

[5] This is hardly a new idea. See Bary, C.W., *Operational Economics of Electric Utilities*, Columbia University Press 1963.