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29 May 2008

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

Re: EB-2007-0031 Staff Discussion paper Distribution Rate Design – GEC Comments

Please find attached GEC's comments in this matter.

Sincerely,

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EB-2007-0031

GEC Comments on Board Staff Discussion Paper:

Rate Design for Recovery of Electricity Distribution Costs

Prepared by: Susan Geller, Resource Insight Inc.

The Board Staff Discussion Paper requests comment on a number of issues. The Green Energy Coalition's comments focus on a subset of these issues, namely:

- Distribution rate design,
- Rate design for load displacement generation,
- Mechanism for revenue stability, and
- Revenue recovery of distribution system losses

Distribution Rate Design

The Board Staff Discussion Paper regards Ontario's large-scale investment in Smart Meters as an opportunity to develop and implement efficient rate designs that were not feasible before now:

> This represents a significant opportunity for rate design in the newly re-metered industry. The simplifications, assumptions, and proxies that have been used in rate design as a result of lack of metered data need to be re-examined. This is the chance to ask what a rate design would look like if the Board was starting with a blank page. (Discussion Paper, p. 14)

> This project has been undertaken primarily because the widespread implementation of smart meters in Ontario will mean that some of the assumptions and proxies used in the current rate design are no longer necessary. (, Executive Summary, pp.1 & 2)

"[S]tarting with a blank page" and first principles, with participation from stakeholders, the Staff Discussion Paper considers several distribution rate design options, including:

- a fixed monthly customer charge that recovers 100% of the costs (considered for single phase secondary customers),
- a demand charge using the customer's peak hourly demand as the billing determinant (considered for single phase secondary, three phase secondary, and primary customers) or a demand charge fixed at the customers' contract demand (considered for primary customers);
- a demand ratchet (considered for primary customers);
- Time-of-Use (TOU) energy rates, with the possibility of a third period consisting of super-peak hours (considered for single phase secondary customers).

The Staff's Discussion Paper leans toward implementing demand charges and higher fixed charges as the best option for customers with Smart Meters. In our respectful submission, this position is based on an unrealistic and internally inconsistent understanding of:

- The factors driving distribution system investment, and
- The effectiveness of each rate design option.

Increases in the fixed charge portion of bills (demand and customer charges) may serve a utility's desire for revenue stability, but they are antithetical to the goal of conservation, cost-based rate design, reduction of distribution costs, and non-disruptive impacts on customer bills. Smart Meters should be used to benefit Ontario consumers, not to expand the implementation of an ineffective pricing signal.

The Green Energy Coalition recommends that the Board order that Time-of-Use rates be implemented for customers on Smart Meters and that distribution costs should continue to be recovered entirely through energy charges (as they currently are). The TOU charges should vary by period of the day and season, as cost-justified. The TOU rate should consist of three daily time periods; the third could be a relatively narrow "critical peak" period, which contained the highest-cost hours. For reasons discussed below, this rate design best reflects cost causation and provides the best incentives to conserve especially at high-cost, high-load times when distribution equipment is heavily loaded.

Where TOU rates are implemented for General Service classes, demand charges and ratchets should also be eliminated, and the recovery of distribution costs should be shifted from demand charges to on-peak energy charges.

Cost Causation

According to the Paper, Board Staff accepts that the causal relationship between load and distribution investment has the following three aspects: First, in the Staff's view, demand drives distribution costs. The Discussion Paper, however, lacks a consistent explanation of how "demand" determines cost.[1] For example, the Paper states variously that distribution capacity costs are driven by:

- customers' contribution to annual coincident peak demand (1-CP) (p. 37).
- customers' contribution to the highest instantaneous demand, not by the highest hourly demand (1-CP). Furthermore, the instantaneous demand may occur outside the hour of the CP (p. 40).
- customers' contributions to the multiple peak loads on the various components of the distribution system, not by the single system coincident peak. These peaks are likely to occur at different times (p. 40):

[1] Since the Paper's discussion of cost causation contains internal inconsistencies, this summary may misinterpret Staff's actual positions.

…the distribution system does not experience a single coincident peak. Rather the timing of the coincident peak may differ for different elements of a distributor's system. For example, individual feeders may peak at different times, and for a distributor with multiple connections to the transmission system, the peaks for each connection are unlikely to coincide. (p. 40)

- The sum of customers' maximum possible (not actual) loads, with adjustment for load diversity:[2]

> The most direct driver of distribution system costs is the aggregate capacity of its customers. Even if peak demand is typically below the capacity that is appropriate to use for design purposes to ensure that the system achieves acceptable reliability standards, the most direct cost driver is required capacity, not actual demand in any particular year … Distributors could then reinforce and expand their systems as necessary to accommodate the "contract" demand of their customers, taking into account diversity benefits in determining the required system capacity to meet the requirements of their customers. (p. 44)

Second, in the Staff's view, distribution system costs are "almost entirely fixed in the short run…" (p. 35). And while the Staff recognizes that increased usage of the distribution system increases costs in the long run, it is unclear on the relationship between variable costs and variable rates, and between customer behaviour and distribution investment:

> The long term variable costs arise out of the five to ten year (and longer) planning horizon. Given that rates are set over a much shorter period, it is not clear that there is a connection between long run variable costs and variable rates. In other words, Board staff are unsure of the economic link between customer behaviour and distribution investment. (p. 32)

Third, the Staff assume that energy use does not affect distribution costs:

> …reducing total energy consumption does not impact directly on future distribution costs, except to the extent that an overall reduction in electricity results in reduced peak demand (p. 36)

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[2] Maximum possible load is not a useful measure of a customer's cost responsibility *because* of load diversity.

Aside from being internally inconsistent, the Staff Paper's conceptual model of distribution cost causation consists of the very "simplifications, assumptions, and proxies …used in rate design" that must be re-examined. The Staff Paper's approach has at least three important flaws. First, while the Staff Paper acknowledges that the cost-causal distribution peaks occur at different times on different distribution components, the Paper intermittently falls into the error of assuming that all the distribution costs from the service drop to the substation vary with a single measure of peak load (e.g., p. 40). The customer's non-coincident peak load determines the required size of its service drop; the customer's load during the hours of high loads on its line transformer(s) (which it may share with several or even dozens of other customers) determines its contribution to the line transformer costs; the customer's load during the hours of high loads on the feeder that serves it (including contingency loads when the principal feeder or an adjacent feeder fails) determines the customer's contribution to feeder costs; the customer's load during the hours of high loads on the substation that serves it (including contingency loads) determines the customer's contribution to substation costs; and so on.

Second, the Paper ignores the effect of energy, especially energy use in high-load hours and off-peak load on high-load days, on distribution investment and outages, in the following ways:

- The number of high-load hours determines risk of load loss following equipment failure, and hence drives redundant investment for reliability.
- The number and extent of overloads determines the life of the insulation on lines and in transformers (both in substations and in line transformers), and hence the life of the equipment. A transformer that is very heavily loaded for a couple of hours a year, and lightly loaded in other hours, may well last 40 years or more, until the enclosure rusts away. A similar transformer subjected to the same annual peaks, but to many smaller overloads in each year, may burn out in 20 years.
- All energy in high-load hours, and even all hours on high-load days, affects heat buildup and hence
    - the sagging of overhead lines, which often defines the thermal limit on lines,

    - the aging of insulation in underground lines and transformers, and
    - the ability of lines and transformers to survive brief load spikes on the same day.
- Line losses depend on load in every hour (marginal line losses due to another kWh of load generally exceeds the average loss percentage in that hour).

Appendix A provides a more detailed explanation of the effect of energy on the cost and sizing of transformers.

Third, there is no basis for the uncertainty expressed in the Staff Paper regarding whether variable rates will reduce load and thus the costs of long-lived distribution investments.[3] Clearly, higher variable rates (especially tail-block energy charges) will encourage efficiency and the careful use of power. The Board Staff's recent report on TOU commodity costs confirms that TOU rates induce conservation[4]. Current rates affect customer's short-term decisions regarding long-lived equipment, so higher energy rates today will affect loads many years into the future. The resulting reductions in loads will extend the life of existing equipment and defer the need for reinforcements. Reducing loads can

- reduce the number of line transformers that will fail in the next heat wave;
- improve reliability on overloaded equipment;
- reduce the sizing of replacements for failed equipment, by reducing current and expected load;
- free up existing distribution capacity for other customers and other loads, allowing LDCs to defer the construction of some reinforcements that would otherwise be required in a year or two;

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[3]The source of Staff's uncertainty is not clear. It is possible that the Staff Paper is suggesting that recovering distribution costs through energy charges is philosophically inappropriate, simply because the costs do not vary *immediately* in response to load levels, as would fuel costs, for example. The costs of distribution are real, and driven by loads, even if the effects are delayed by a year or a few years; the timing of the benefits of reduced load is not relevant to these rate-design issues.

[4] Staff Discussion Paper - Regulated Price Plan - Time-of-Use Prices: Design and Price Setting Issues - EB–2007-0672 - April 17, 2008

- defer the costs of planning and purchasing for long lead-time projects; and
- reduce the cost of building reinforcements that can be downsized.

Rate Design Options:

The Staff Paper's discussion of the advantages and disadvantages of each rate design option is, in our submission, similarly flawed.

Fixed Charges

The Board Staff paper gives several rationales for recovery of distribution through fixed charges: [5] (1) distribution costs are fixed in the short run, (2) fixed charges provide revenue stability, (3) fixed charges are simple to implement and easily understood by customers (p. 35).

The Board should reject the use of fixed charges to recover load-related distribution costs for the following reasons:

- They do not reflect cost causation. As explained above, distribution costs are not fixed in the short run, long-term distribution planning is affected by short term changes in load, and customers' long run end use choices are affected by short term rates.
- Fixed charges provide no efficiency incentive.
- Fixed charges are inequitable, overburdening the smaller customers in the rate class. The Discussion Paper suggests subclassifying customers by "capacity" to limit the inequities, but this approach is only a crude and flawed substitute for cost-based variable charges.
- Revenue stability concerns can be dealt with without implementing rate structures that discourage efficient use of resources.
- Fixed charges will not achieve rate simplicity because while simple to determine, they will not make sense to customers. Knowing that loads drive

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[5] The Staff Paper distinguishes between permanently "fixed" charges (which can differ by size of customer) and demand charges, which are fixed during the month (absent a ratchet) once the customer incurs its maximum demand.

utility costs, customers will be frustrated that they cannot control their distribution rates by reducing usage.

Demand Charges

The Staff's endorsement of demand charges appears to be based on the view that demand drives distribution costs. The Discussion Paper specifies at least four different ways by which demand determines distribution capacity needs: distribution costs are driven by (1) system coincident peak (1-CP) or (2) system instantaneous peak or (3) the multiple peaks on various points of the distribution system or (4) the sum of customer's maximum possible demand adjusted for diversity. Customer undiversified maximum demand is *not* considered a cost determinant. Nevertheless, the Staff Paper endorses the use of customer maximum demand as a billing determinant (the conventional demand charge), for the following reasons:

- It is not "practical" to implement an effective cost-based price signal:[6]

> A variable charge based on demand will provide a price signal to limit peak usage during the period used as the basis for the demand charge. Annual coincident peak demand (1-CP) is the ideal representative billing determinant in theory, but has practical limitations. It is a weak price signal since consumers do not know when the coincident peak will occur and therefore, they can do little to avoid it. In addition, use and demand not coincident with the peak has no associated cost so there is no conservation signal. (p. 37)

- The demand charge is simple for customers to understand:

> …This approach would provide a very simple and understandable signal to consumers to manage their use so as to limit their peak usage whenever it occurs. (p. 40)

If, as the Staff believes, it is not practical to implement rates that provide customers with an accurate price signal, using customer maximum demand as a proxy is definitely the wrong solution. Indeed, the Staff's reasons for rejecting its "ideal representative billing determinant" apply to customer maximum demand as

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[6] The 1-CP is not the ideal bill determinant, as discussed in the Cost Causation section of these Comments.

well. Demand charges are a particularly ineffective means for giving price signals, for the following reasons:

- Distribution capacity needs are driven by diversified demand at all levels of the system, not by billing demand or by the single annual system coincident peak (1-CP). The peaks of the customers sharing a particular distribution component are unlikely to occur at the same time. The Board Staff recognizes that distribution planners take load diversity into account in determining capacity requirements. (p. 44)
- The peaks on the secondary system, line transformer, primary tap, feeder, and substations occur at varying times. The Board Staff agrees that:

  > … the distribution system does not experience a single coincident peak. Rather the timing of the coincident peak may differ for different elements of a distributor's system. For example, individual feeders may peak at different times, and for a distributor with multiple connections to the transmission system, the peaks for each connection are unlikely to coincide. (p. 40)

- Demand charges provide little or no incentive to control or shift load from those times which are off the customers' peak hours but which are very much on the distribution peak hours. Customers can avoid demand charges by redistributing load within the peak period. Some of those customers will be shifting loads from their own peak onto higher load hours, thereby causing customers to increase their contribution to maximum or critical loads on the local distribution system, the transmission system, or the regional generation system.
- Demand charges can excessively penalize customers, since even a single failure to control load results in the same demand charge as if the same demand had been reached in every day or every hour.
- Demand charges are difficult to avoid; Determining which way to redistribute load is inherently difficult, since the customer must know (1) its usage in the current hour, under normal and various alternative operating conditions and its maximum hourly usage earlier in the billing month; (2) forecasts of its usage later in the billing month, under normal and various alternative operating conditions; (3) where ratchets may be binding, forecasts of its usage later in the winter; and (4) must have the technological and

operational capability to redistribute load. Hence, while customers can avoid demand charges by actions that merely redistribute load within the peak period, without reducing (and even increasing) critical loads on the distribution and transmission system, those actions are difficult to implement effectively and the charges are difficult to avoid.[7]

- In order to avoid demand charges, customers will need to install equipment to monitor loads, interrupt discretionary load, and schedule deferrable loads. Rather than promoting cost-effective conservation at high-cost times, or shifting of load from system peak periods, demand charges encourage customers to waste resources on the arbitrary tasks of flattening their personal maximum loads, even if those occur at low-cost times.
- Shifting revenues into demand charges will reduce energy charges and encourage increased electric use, some of which will likely fall in the peak period.

Demand Ratchets

Demand ratchets worsen the adverse effects of demand charges in the following ways:

- In the months when the customer’s demand is within a certain percentage of the annual maximum, demand charges are fixed and therefore will provide no incentive to conserve at any time during the month.
- Ratchets excessively penalize the customer for a kWh increase in its annual maximum billing demand, because that increase can affect the billing demand in other months.
- Ratchets provide confusing and misleading signals to customers,
- Ratchets reduces customers’ control over their bills, and
- Ratchets result in disruptive bill impacts, especially for a customer who unintentionally establishes a new maximum demand.

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[7] The Board Staff pointed out similar concerns with a rate using 1-CP billing determinants.

Time-of-Use Rates

The Green Energy Coalition recommends that all customers on Smart Meters be served under an energy-only TOU rate, with at least three periods including a narrow “critical peak” period, which would provide a useful signal of the highest cost hours. The “critical peak” period would include the monthly coincident peaks, the multiple peaks on the various components of the distribution system and the other high-load, high-cost hours most responsible for distribution capacity investment. This TOU rate design will encourage reduction of usage in high-load periods, when distribution equipment is heavily loaded.

The Staff includes the energy-only TOU rate as an option, but only for the single phase secondary class, not for three phase secondary customers also currently on energy-only rates. Demand charges and ratchets do not serve any purpose in TOU rates, do not provide an effective price signal and frustrate customers, and therefore should not be introduced into the rates of customers currently on energy-only rates. In existing demand rates as well, distribution cost recovery should be gradually shifted from demand charges to on-peak energy charges to provide a more effective price signal.

Rate Design for Load Displacement Generators

The Staff paper includes a TOU rate with a high on-peak charge as an option for load displacement generators, but expresses a concern that the rate “does not entirely address the issue of revenue for assets ‘standing by’ or risking system stability from unscheduled outages (p. 69).” A customer with an embedded generator may impose some costs beyond those of a non-generating customer with the same net load, but those costs are likely to be much lower than the costs imposed by a customer with the same gross load and no generator. Charging generating customers as if they had no generation is punitive. Distributors do not install and reserve facilities to meet the maximum demand of each of these customers.[8] System design takes load diversity into account. For example, customers with self-generation may have a high maximum demand at some odd hours when the generator happens to be out of service but very low loads at the times of maximum load on the distribution equipment. System designers do not assume that all non-embedded generators will experience unscheduled outages at the same time.

The Green Energy Coalition recommends the TOU rate option, with a "critical-peak" period limited to the hours in which the distribution system is likely to experience its maximum demand. If the current TOU energy-only rate design is not adequate for a large generation customer, a demand charge can be added, but it must be based on the customer's contribution to the distribution peak (e.g., on a feeder or substation), not on its non-coincident demand. For large customers with distributed generation, it may be practical to meter load hourly and charge the customer for its contribution to system costs based on its load coincident with the feeder and/or substation peak, or at time of contingencies that stress the local system. In the unusual situation that an embedded generator is so large that its outages are the dominant factor determining peak load on its distribution feeder (or more rarely, the substation), the distributor should be permitted to negotiate a cost-based contract with the customer, which may include provisions for load interruption or load control. (For a more detailed discussion of rate design for load displacement generators, see EB-2007-0630 – Comments of Paul Chernick on DG Issues (filed by GEC).

Revenue stability mechanism

Revenue-cap regulation, often referred to as "revenue decoupling," provides a consistent approach for dealing with revenue losses caused by the demand response to rate design innovations and load-displacement generation and as well as revenue losses (or gains) caused by other factors such as weather, economic conditions, changes in power-supply costs, national and provincial policy

[8] With the exception of the customer's specific interconnection facilities (service drops, meters, dedicated transformers), which are covered through a combination of monthly customer charges and connection charges.

initiatives, and other factors. The difference between allowed and actual revenues would be amortized and rolled into annual rate adjustments.

Revenue Recovery of Distribution System Losses

Using an hourly markup for losses is appropriate for HOEP customers billed on hourly rates and a markup varying by TOU period for customers billed on TOU rates. Since the markup would reflect average losses during a given time period, this method of recovering losses will not give the full marginal-cost price incentive.

Appendix A: The Effect of Energy Use in High-Load Periods on the Cost and Sizing of Transformers.

At least three energy-use factors determine the cost and sizing of transformers. The first two—the number of hours in the day in which the transformer operates near its peak period and the load factor on the transformer—affect the maximum load the transformer can tolerate without catastrophic overheating. The third factor is the effect of periodic overloads on useful transformer life.

Instantaneous peaks do not determine distribution capacity needs. Short peaks and low off-peak currents allow the transformer to cool between peaks, so that it can tolerate a higher peak current. The limit for very short-duration loads (e.g., 30 minutes) is generally stated as 200% of rated capacity, while utility practice for high load factors (e.g., 80%) and long peak periods (e.g., 8 hours) often limits loadings to 100%–120% of rated capacity, especially for underground service.

Thus, only about half the installed transformer capacity would be necessary to meet the brief peak loads measured by demand charges, were it not for the neighboring hours of high utilization and the relatively high off-peak loads on peak days. Even considering only system reliability criteria, only 50%–60% of transformer capacity can be attributed to the single-hour peak load.

Energy usage also affects the service life of transformers, due to overheating of the insulation. For example, a transformer that is overloaded by 20% for eight hours (due to high load, or failure of another transformer in a network) will lose about 0.25% of its useful life. With ten overloads annually at this level, the transformer would last 40 years, by which time accidents, corrosion, and other problems would likely lead to its retirement. Long overloads and higher load levels increase the rate of aging per overload, and frequent overloads lead to rapid failure of the transformer.

In a low-load-factor system, these high loads will occur less frequently, and the heavy loading will not last as long. If the only high-demand hours were the ones on which the peak loads are based, the chances of a first contingency coinciding with the peak would be small, and most transformers would be retired for other reasons before they experienced many overloads. In this situation, larger losses of service life per overload would be acceptable, and the short peak would allow greater overloads for the same loss of service life.

With high load factors, there are many hours of the year when the transformers are at or near full loads.[9] Thus, the size of the transformer must be increased to limit overloads to the small amount that is compatible with acceptable loss of service life per overload for this frequency of overloads, or the transformer will burn out far too rapidly.

Load factor has similar effects on the sizing of underground transmission, primary, and secondary lines. Since heat builds up around the lines, the length of peak loads and the amount of load relief in the off-peak period affects the sizing of underground lines. An underground line may be able to carry twice as much load for a needle peak as for an eight-hour peak with a high daily load factor. To reduce losses and the build-up of heat, utilities must install larger cables, or more cables, than they would to meet shorter loads.[10] Since the number and sizing of underground lines is a function of load factor, a portion of the cost of the lines should be recovered through energy charges, even if demand charges could reasonably measure the contribution of customer loads to peak demands on distribution equipment.

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[9] In networks, failure of other transformers or lines will frequently cause overloading at such times.

[10] Both lines and transformers are sized, in part, to reduce the costs of energy losses.