GENERAL METHODOLOGY FOR ALLOCATION OF TRANSMISSION/DISTRIBUTION COSTS AMONGST DISTRIBUTED GENERATORS AND LOAD CUSTOMERS

Feb. 11, 2008

Re:Review of Cost Responsibility Policies for Connection to Electricity Transmission Systems
OEB File Number: EB-2008-0003

The following information has been available at www.xylenepower.com in various editions for almost two years. During 2006 I realized that there was a need for development of a method for proper allocation of transmission/distribution costs amongst distributed generators and electricity consumers in Ontario. An essential feature of this cost allocation methodology was to encourage distributed generation but discourage wasteful use of the transmission/distribution system by both generators and end users.

A problem with the existing cost allocation methodology is that wind generators tie up three to six times more transmission capacity per kWh delivered to the load than do nuclear generators. There is presently no rate incentive for wind generators to use electro-chemical energy storage to mitigate this problem.

At the load customer end the existing method of allocating transmission/distribution costs is a disincentive for small behind the meter generators and thermal energy storage systems because it inequitably penalizes building owners for brief equipment shutdowns required for routine maintenance.

To circumvent these problems I developed a general methodology for fair allocation of transmission/distribution costs amongst distributed generators and loads. This methodology requires the use of electronic metering programmed to calculate and cumulate a parameter known as daily kVAh. Daily kVAh is 24 hours X (kVA calculated over a 24 hour time period). It was not practical to adopt this methodology until the development of modern micro-controller based electronic meters.

I urge all parties to support the adoption of this fair and equitable means of allocating transmission/distribution costs.

I am presenting below excerpts from www.xylenepower.com that show the mathematical derivation of this methodology.

Sincerely,

Charles Rhodes, P.Eng., Ph.D.

TRANSMISSION / DISTRIBUTION:

One objective of this web page is to set out the essential principles of a practical AC electricity network consisting of central generators, a high voltage power transmission system, numerous independent local distribution companies (LDCs), distributed electrical loads with energy storage and embedded distributed electrical generation with energy storage. The importance of identifying these essential principles at this time is that they define the future path for the Ontario Power Authority (OPA), the Ontario Energy Board (OEB), the Independent Electricity System Operator (IESO) and the Ministry of Energy (MOE) for changing Ontario from an electricity system based on a few large central generators owned and operated by a few parties to an electricity system based on a large number of distributed power generation units of varying sizes owned and operated by many parties. Many of the distributed generators may be located behind load customer meters.

PRINCIPLES:

The proposed distributed electricity network for energy exchange rests on the following general principles:

EQUITY:

1. All parties connected to the electricity grid should have equal access. The metering and billing methodology should be the same for all parties, regardless of who they are, their size and whether they source or sink electrical energy at any instant in time. Major generators must pay for transmission/distribution on the same basis as distributed generators and end use customers in order to put all parties on a level playing field. Allocating part of the cost of transmission/distribution to major generators will increase the Hourly Ontario Electricity Price (HOEP) but should reduce end users' transmission/distribution charges by the same amount. The increase in HOEP will encourage more energy conservation by end users.

2. Electricity conservation and green house gas (GHG) free in-fence electricity generation are indistinguishable on the grid and hence should be treated equally by the rate structure.

3. Unless the power factor is exactly unity, every party connected single phase to the grid alternately sources and sinks energy during a cycle period due to the non-zero phase angle between the voltage and current. Thus, most residential consumers are both energy receivers and energy transmitters. The net energy transferred, as indicated by a normal induction type kWh meter, is the difference between the total energy received and the total energy transmitted. For some customers the net energy received is a very poor indicator of the distribution resources used. For example, if a residential customer has a behind the meter wind turbine without energy storage, his net energy received may be close to zero but he may still use a significant fraction of the distribution resources. The metering system must be fair to the customer, the Local Distribution Company (LDC) and the other customers of the LDC.

ENERGY EXCHANGE:

4. The electricity meter on each connection to the grid should separately register and display the cumulative kWh exported by the grid and the cumulative kWh imported by the grid. These separate registers are required to monitor cumulative energy transfers and to properly apportion energy losses within the distribution

system.

5. Each electricity meter should have additional memory registers to show the energy imported by the grid and the energy exported by the grid during each TOU measurement interval during the billing period.

TRANSMISSION/DISTRIBUTION COST ALLOCATION:

6. The rate structure and metering should provide a financial incentive for all parties connected to the grid to do all necessary to achieve high power quality and high transmission / distribution utilization efficiency without reliance on complex and difficult to enforce regulations.

7. Efficient use of the transmission / distribution system should be financially rewarded. The transmission / distribution system operates most efficiently when each connected party transfers power to or from the transmission / distribution system at a constant rate with unity power factor.

8. One of the properties of a balanced 3 phase constant resistive load is that its power drain from the grid is constant. Hence for such a load the instantaneous power is equal to the average power. This is the most efficient way of coupling to the grid and should attract the lowest distribution charges per kWh of energy transferred.

9.Inefficient use of the transmission / distribution system should be financially penalized. If a customer presents a reactive impedance or harmonic distortion to the grid then that customer should be allocated a larger fraction of the distribution costs.

10. The higher the fluctuations in power transfer rate, the less efficiently the transmission / distribution system is utilized. If a customer presents a resistive impedance to the grid that varies over a 24 hour period that customer should be charged more for distribution per kWh than is a customer that takes the same amount of energy at a constant energy transfer rate.

11. The metering technology used should be able to resolve power harmonics up to the 30th harmonic of the power line frequency in order to measure significant harmonics generated by power inverters. These harmonics cause heat losses in the transmission/distribution system.

12. The aforementioned grid connection issues should be addressed through the use of cumulative daily kVAh metering. Monthly peak demand and monthly peak kVA metering is unacceptable because peak monthly metering acts as a disincentive to customer owned behind the meter generation and energy storage.

13. A single phase consumer's fair share of the distribution costs during a particular measurement time interval is proportional to:
Root-Mean-Square (RMS) load current(amps) X RMS voltage(kV).
The RMS current and voltage values are both always positive, so their product is always positive and has units of kVA. This principle is not new. It has been used for many decades by electricity distribution companies for allocating costs. The methodology set out herein is simply a generalization of that principle. The RMS

current is proportional to the fraction of the current capacity of the distribution system that is used by the customer. The RMS voltage indicates the operating voltage of the distribution system. The product:
(RMS current) X (RMS voltage)
indicates the amount of distribution system transformer and power transmission capacity that the customer is using. A three phase customer can be viewed as being similar to three single phase customers.

14. Daily kVA is calculated in the same manner as single cycle kVA except that the RMS calculation period is extended from (1/60) second to 24 hours. This time period extension makes the calculated daily kVA penalize load variations during the 24 hour period. The daily kVA measurements are multiplied by 24 hours and are summed over a monthly billing period to produce an output in kVAh for billing purposes.

15. If Customer "A" presents a constant resistive impedance to the grid over a 24 hour period, then the calculated daily kVAh for Customer "A" is the same as the daily kWh. If Customer "B" uses the same amount of energy, but consumes all that energy within an 8 hour period, during those 8 hours the current squared increases 9 fold. The average current squared for Customer "B"over the 24 hour period increases 3 fold. The RMS current over a 24 hour period increases by (3)^0.5 = 1.732. Thus the transmission/distribution charges experienced by Customer "B" are 1.732 times the transmission/distribution charges experienced by Customer "A". Viewed another way, Customer "B" has the opportunity of reducing his transmission/distribution charges by up to:
((1.732 -1) / 1.732) X 100% = 42.3%
by installation of a behind the meter energy storage system. If Customer "B" implements the energy storage system he will make further cost savings because much of the energy that he purchases will be obtained off-peak rather than on-peak.

16. The daily kVAh calculation time interval (24 hours) is very long compared to one cycle period to encourage efficient utilization of distribution and transmission. If the rate of power transfer to or from the grid is not uniform over the 24 hour calculation period the customer is charged more for transmission/distribution. This billing methodology encourages wind generators and customers with peaky loads to build energy storage on site behind their meters to reduce variations in the rate of power transfer to and from the grid. This billing methodology is also fair to behind the meter co-generation and energy storage because the cost consequences of brief equipment shutdowns for routine maintenance are relatively small.

17. Each electricity meter should calculate and display the single cycle RMS phase voltages Va, Vb, Vc and both the single cycle and 24 hour RMS phase currents Ia, Ib, Ic. Each electricity meter should also calculate and display the daily kVA for each 24 hour period. The daily kVAh for each day should be stored in memory, and the daily values stored during the billing period should be summed and displayed for distribution / transmission cost allocation purposes.

18. At points where a transmission system and a distribution system interconnect, each system is responsible for the fraction of the other system's costs determined by the kVAh meter located at the connection between the two systems.

DAILY kVA AND kVAh

By C. Rhodes

INTRODUCTION:

Cumulative daily kVAh metering can be applied to generators and loads of all sizes for fair allocation of transmission/distribution costs. With cumulative daily kVAh metering a customer can be sometimes a load and sometimes a generator without any changes in the metering arrangement.

This web page reviews basic electrical engineering concepts that can be found in many electrical engineering textbooks and then introduces the concepts and features of daily kVA and daily kVAh metering. The daily kVAh cumulated over a month is a good measure for allocating transmission/distribution costs in a transmission/distribution system involving distributed generation.

WYE CONNECTION:

A wye electricity service presents three AC phases with 120 degree (2 Pi / 3 radians) phase separations. The voltage reference point is the junction of the wye, which is normally close to or at ground potential. The phase voltages are measured with respect to this junction. If the individual phases are denoted by a, b, c, the instantaneous phase voltages are Vai, Vbi, Vci and the instantaneous phase currents are Iai, Ibi, Ici. The instantaneous power Pai fed to load phase a is:

Pai = (Vai X Iai).

If the voltage source is the electricity grid, to a good approximation the voltage is sinusoidal. Hence:

Vai = Vaio sin(WT)

where:

Vaio = peak voltage on phase a

W = 2 Pi F

Pi = 3.1415928

F = 60 Hz

T = time in seconds relative to an arbitrary initial time

sin = sine

The RMS voltage Va is defined as:

Va = [Integral from T1 to T2 of (Vai^2 dT)/ (T2 - T1)]^0.5

The RMS current Ia is defined as:

Ia = [Integral from T1 to T2 of (Iai^2 dT)/ (T2 - T1)]^0.5

For a sinusoidal voltage Vai the cycle period is (2 Pi / W) giving:

Va = [Integral from T1 to T1 + (2 Pi / W) of [Vaio sin(WT)]^2 dT / (2 Pi / W)]^0.5
= Vaio / (2)^0.5

For a linear but reactive load the corresponding instantaneous current is given by:
Iai = Iaio sin(WT - Phi)
where:
Iaio = the peak instantaneous current
Phia = phase angle in radians between the Vai and Iai wave forms

For a sinusoidal current Iai the cycle period is (2 Pi / W) giving:
Ia = [Integral from T1 to T1 + (2 Pi / W) of [Iaio sin(WT - Phi)]^2 dT / (2 Pi / W)]^0.5
= Iaio / (2)^0.5

The instantaneous power on phase a is defined as:
Pai = Vai Iai
It can be shown that for sinusoidal voltages and currents the average power on phase a is:
Pa = Va Ia cos(Phia)
In this expresion:
cos(Phia) = Power Factor

For a 3 phase wye fed system the total instantaneous power P is defined as:
P = Pai + Pbi +Pci
= (Vai X Iai) + (Vbi X Ibi) + (Vci X Ici)
where:
Vbi = instantaneous voltage on phase b
Ibi = instantaneous current on phase b
Vci = instantaneous voltage on phase c
Ici = instantaneous current on phase c

If the voltages and currents are sinusoidal it can be shown that the total average power Pt on all three phases is:
Pt = Va Ia cos(Phia) + Vb Ib cos(Phib) + Vc Ic cos(Phic)
where:
Vb = RMS voltage on phase b
Ib = RMS current on phase b
Phib = phase angle between Vbi and Ibi
Vc = RMS voltage on phase c
Ic = RMS current on phase c
Phic = phase angle between Vci and Ici

For the special case of balanced sinusoidal voltages and currents:
Va = Vb = Vc = V
and
Ia = Ib = Ic = I
and
Phia = Phib = Phic = Phi

Thus:
Pt = 3 V I cos(Phi)

Note that even in a perfectly balanced system the total power on each phase is less than or equal to the product of the RMS voltage multiplied by the RMS current due to the factor cos(Phi). In general cos(Phi) is less than or equal to unity.

The quantity **(Va Ia + Vb Ib + Vc Ic)** is the normally measured kVA and is referred to herein as the **single cycle kVA**. For sinusoidal voltages and currents the single cycle kVA equals the power Pt in kW if:
Phia = Phib = Phic = 0

DELTA CONNECTION:
Recall that the instantaneous power P is given by:
P = Iai Vai + Ibi Vbi + Ici Vci
For a three phase delta connected customer, at any instant in time the instantaneous phase currents Iai, Ibi, Ici conform to:
Ici = -Ibi - Iai
Substituting into the three phase formula for P gives:
P = Iai (Vai - Vci) + Ibi (Vbi - Vci)
The corresponding expression for kVA is: kVA = Ia (Va - Vc) + Ib (Vb - Vc)
where:
(Va - Vc) is the RMS value of (Vai - Vci)
and
(Vb - Vc) is the RMS value of (Vbi - Vci)

Hence the fair share of the distribution costs for a delta connected load during a particular time interval is proportional to:
[(Ia(Va - Vc) + Ib (Vb - Vc)]

CONSTANT TORQUE:
An important property of a balanced 3 phase system is that:
P = Pt = constant
Hence the torque on a three phase generator driving a balanced load is constant. Similarly the torque exerted by a three phase motor is nearly constant.

The results to this point are available from numerous basic electrical engineering text books. The following results are not readily available elsewhere:

DAILY kVA:
Recall that the definition of single cycle kVA involved the calculation of RMS voltage Va and the calculation of RMS current Ia over a single cycle period (1 second / 60). The concept of daily kVA is to calculate kVA over 24 hours instead of over (1 second / 60). Using modern microprocessor instrumentation it is straight forward to calculate daily RMS voltage and current values where the calculation period instead of one cycle period is:
24 hours = 86,400 seconds = 5,184,000 X (1 second / 60)

The daily RMS voltage Vad is given by:

Vad = [Integral from T1 to T2 of (Vai^2 dT')/ (T2 - T1)]^0.5
where T2 - T1 = 86,400 seconds. In order to evaluate this integral numerically dT' is chosen to be 1 second / 3600, which is sufficient for sampling the 30th harmonic of 60 Hz.

The expression for Vad can be simplified using the substitution:
Va^2 = [Integral from T to T + dT of (Vai^2 dT')/ dT)]
where dT = 1 second / 60
Then:
Vad = [Integral from T1 to T2 of (Va^2 dT)/ (T2 - T1)]^0.5
where T2 - T1 = 86,400 seconds. This integral is easier for the layman to understand. Furthermore, provided that Va is accurate this integration result is almost independent of minor variations in dT. Hence this formula is easy to numerically evaluate.

Similarly the daily RMS current Iad is given by:
Iad = [Integral from T1 to T2 of (Iai^2 dT')/ (T2 - T1)]^0.5
where T2 - T1 = 86,400 seconds. In order to evaluate this integral numerically dT' is chosen to be 1 second / 3600, which is sufficient for sampling the 30th harmonic of 60 Hz.

The expression for Iad can be simplified using the substitution:
Ia^2 = [Integral from T to T + dT of (Iai^2 dT')/ dT)]
where dT = 1 second / 60
Then:
Iad = [Integral from T1 to T2 of (Ia^2 dT)/ (T2 - T1)]^0.5
where T2 - T1 = 86,400 seconds. This integral is easier for the layman to understand. Furthermore, provided that Ia is accurate this integration result is almost independent of minor variations in dT. Hence this formula is easy to numerically evaluate.

For the special case of:
Vaio = constant
Iaio = constant
then:
Va Ia = Vad Iad
and for the special case of:
Vbio = constant
Ibio = constant
then:
Vb Ib = Vbd Ibd
and for the special case of:
Vcio = constant
Icio = constant
then:
Vc Ic = Vcd Icd
Thus if the single cycle RMS voltages and currents are both constant throughout a 24 hour period the daily kVA equals the single cycle kVA. However, if the single

cycle RMS voltages or the single cycle RMS currents are not constant throughout the 24 hour period then the daily kVA is not equal to the single cycle kVA. The daily kVA creates the desired metering function which causes flat loads to have lower connection costs than peaky loads that draw the same amount of energy per day.

Consider a practical example. Suppose a 1 kW resistive load operates for 24 hours. The energy consumed is 24 kWh. At an RMS voltage of 120 volts the RMS current is:
1000 W / 120 v = 8.333 A
The single cycle kVA value is:
.120 kV X 8.333 A = 1.0 kVA
Since the single cycle RMS voltage and the single cycle RMS current are constant, in this case:
daily kVA = single cycle kVA = 1.0 kVA.

Now suppose that the same 24 kWh of energy is drawn by a 3 kW resistive load that operates for 8 hours of the 24 hour period. The energy consumed is:
3 kW X 8 h = 24 kWh
The RMS voltage is constant at 120 volts.
During the 8 hour load on period the single cycle RMS current is:
3 X 8.33 A = 25 A
The daily RMS current is given by:
{[(16 h X (0 A)^2) + (8 h X (25 A)^2)] / 24 h}^0.5
= {(25 A)^2 / 3}^0.5
= {(8.333 A)^2 X 3}^0.5
= 8.333A X (3)^0.5
Hence the daily kVA value is:
120 V X 8.333 A X (3)^0.5
= 1 kVA X (3)^0.5
= 1.732 kVA

Notice that concentrating the energy into an 8 hour period instead of spreading it out over a 24 hour period had the effect of increasing the daily kVA from 1.0 kVA to 1.732 kVA. By comparison a single cycle peak kVA recording meter would have registered 3 kVA. **However, that 3 kVA measurement would have been the same regardless if the 3 kVA peak was hit once or 20 times a month.**

DAILY kVAh:
We can now introduce a unit of:
daily kVAh = 24 h X (measured daily kVA)
Note that if the load is resistive and constant 24 hours per day, then:
measured daily kVAh = measured kWh in a 24 hour period
However, if the load is time varying:
measured daily kVAh > measured kWh
The cumulative daily kVAh is a good proportional indicator of the grid connection costs for both loads and generators.

FEATURES OF CUMULATIVE DAILY kVAh METERING:

1. Cumulative daily kVAh meters can be applied to generators and loads of all sizes for fair allocation of transmission/distribution costs.
2. Cumulative daily kVAh meters cumulate so that a building that has multiple load peaks in a month is charged more for its grid connection than a building that has only a single load peak during the month.
3. The use of cumulative daily kVAh simplifies meter reading and administration issues. Bills and real estate transactions can easily be settled to the nearest day.
4. Cumulative daily kVAh metering mitigates the cost effect of load swings that occur only one or two days per month but captures the cost effect of load swings that occur almost every day.
5. Use of daily kVAh cumulated monthly instead of peak kVA would have the effect of slightly shifting the rate burden from low load factor to high load factor customers, which would encourage more energy conservation.
6. All the existing advantages of single cycle kVA metering that encourage high power factor and low harmonic content are retained.
7. Like peak kVA metering, cumulative daily kVAh metering encourages high load factor.
8. Unlike peak kVA metering, cumulative daily kVAh metering allows brief equipment shutdowns for maintenance purposes without an undue cost penalty to the building owner.

GENERAL BENEFITS OF CUMULATIVE DAILY kVAh METERING:
1. The cumulative daily kVAh electricity meter calculates the RMS values over a 24 hour time interval to encourage efficient utilization of distribution and transmission.
2. If the rate of power transfer to or from the grid is not uniform over the 24 hour RMS calculation period use of cumulative daily kVAh metering will cause the generator/load to be charged more per kWh for grid access.
3. Use of cumulative daily kVAh metering would encourage wind generators to build electro-chemical energy storage on the generator site to reduce variations in net power output.
4. Cumulative daily kVAh metering is fair to behind the meter co-generation because it mitigates the cost effect of short generator shutdowns for maintenance or repair.
5. Cumulative daily kVAh metering is believed to be fairly applicable to generators and loads of all sizes ranging from small apartment suites to the largest nuclear generation stations.
6. If a customer presents a constant resistive impedance to the grid, then the calculated daily kVA is the same as the average power in kW sensed by an induction type kWh meter.
7. If a customer presents a reactive impedance or harmonic distortion to the grid then the calculated daily kVA is greater than the average power in kW, causing that customer to be allocated a larger fraction of the distribution costs.
8. If a customer presents a resistive impedance to the grid that varies over the 24 hour RMS calculation period, that customer will be charged more for distribution per kWh consumed than is a customer that consumes the same amount of energy at a constant rate.

9. The contemplated metering technology for measuring daily kVAh is readily able to resolve voltage and current harmonics up to the 30th harmonic of the power line frequency. Generally power transformers effectively filter out higher frequency harmonics.
10. The daily kVAh for each 24 hour period is calculated, cumulated and displayed for distribution / transmission cost billing purposes. As part of this calculation the single cycle RMS voltages Va, Vb, Vc and the single cycle RMS currents Ia, Ib, Ic are calculated and are available for display.
11. The use of daily kVAh metering would encourage installation of behind the meter energy storage and and behind the meter electricity generation to minimize swings in the power transfer rate to and from the grid.
12. The use of daily kVAh metering allows LDCs to fairly recover their costs from net metering customers.

ELECTRICITY METERING

By C. Rhodes

OBJECTIVE:
The objective of this web page is to identify the metering methodology necessary for proper implementation of a distributed power system in Ontario.

SYSTEM DESCRIPTION:
A distributed power system can be viewed as a collection of transmission/distribution subsystems. Each distribution subsystem consists of an assembly of passive components such as wires, transformers, switches, fuses, capacitors and inductors that interconnect energy sources and energy sinks. All electricity entering or leaving each subsystem is metered. The same type of metering is used at points where different subsystems interconnect. Generally each distribution subsystem is owned and/or managed by a separate legal entity.

kWh METERING:
Let T designate time. At the commencement of a billing interval T = Ta. At the end of the billing interval T = Tb.
The law of conservation of energy requires that between times Ta and Tb:
Eit = El + Es + Eet
where:
Eit = total electrical energy imported into the distribution subsystem,
El = total electrical energy lost within the distribution subsystem,
Es = total electical energy stored within the distribution subsystem,
Eet = total electrical energy exported from the distribution subsystem.

In most transmission/distribution systems, over periods of time that are long compared to a cycle period (1 second / 60), Es = 0. Since El > 0, Eit > Eet. In order to evaluate El and hence compute the relative values of Eit and Eet it is necessary to measure all the components of Eit and all the components of Eet. Thus each electricity meter must have separate registers for the components of Eit and Eet that it measures.

The kWh registers record the energy that flows through connections to the distribution system. However, net energy flow is a poor indicator for apportioning distribution system costs. For example, an external reactive load connected to a distribution system can cause high distribution costs even though the reactive load consumes very little energy. Similarly a residence with a behind the meter wind turbine can cause significant distribution costs while drawing little or no net energy from the electricity grid.

PEAK kVA AND PEAK kW METERING:

Historically electricity utilities with central generation have used measurements of:

kVA = [root mean square (RMS) current X RMS kilovolts]

to apportion distribution costs. In recent years both Hydro One Networks and Toronto Hydro have apportioned their costs amongst >50 kW customers in proportion to monthly peak KVA or monthly peak kW averaged over periods varying from 5 minutes to 1 hour.

There are several fundamental problems with this peak KVA or peak kW metering methodology.

1. Major electricity generators are presently not paying for transmission/distribution usage as are electricity consumers and small distributed generators. Major generators presently have no economic incentive to use energy storage for more efficient use the transmission/distribution system. The inequality in apportionment of transmission/distribution costs and the lack of generator responsibility causes electricity energy to be priced too low and consumer transmission/distribution charges to be priced too high. This improper pricing acts as an obstacle to energy conservation and consumer owned energy storage and distributed generation. To remedy this problem the grid should be viewed as a medium for exchange of energy from any party to any other party. Since any party within a particular distribution system can alternately source and sink energy, the transmission/distribution rate per daily kVAh should be the same for all parties within that subsystem, regardless of who the party is, and the size and direction of the power flow.

2. Peak kVA and peak kW metering does not recognize the statistical independence of temporary shutdowns in behind the meter energy storage and energy generation. A distribution system will have a large number of energy sources and energy sinks. However, on any one connection to this distribution system there is usually only a single energy storage system or a single behind the meter generator, that normally operates to minimize the connection kVA. Within a one month billing period this apparatus will likely need to be briefly shut down for routine electrical, mechanical or heat load service. During that service period the building will often experience a kVA peak. Hence the practical effect of

monthly peak kVA metering is to unduely transfer costs to customers with behind the meter energy storage systems or generators when this equipment is shut down for routine maintenance. Hence, monthly peak kW and peak kVA metering is a major obstacle to economic application of energy storage and distributed generation.

3. Use of monthly peak kVA or monthly peak kW meters reduces the financial benefit to the customer of saving a marginal kWh. Hence this type of meter acts as a disincentive for electrical energy conservation.

4. One of the reasons that electricity distribution utilities adopted peak kVA and peak kW metering is historical. Prior to the availability of microprocessor based electronic meters, peak kVA and peak kW metering was implemented using a simple mechanical ratchet advanced by the kVA or kW meter needle. At the time peak kWh and peak kVA metering was first implemented Ontario Hydro and the municipal LDCs had the common objective of encouraging more use of electricity, not less.

CUMULATIVE kVAh METERING:

In order to avoid the aforementioned problems with peak kVA and peak kW metering this author recommends the use of daily kVAh metering in its place. A measurement of:

daily kVAh = (RMS current calculated over a 24 hour interval) X (RMS voltage calculated over the same 24 hour interval) X 24 h

provides a good indication of the amount of distribution resources used on a particular day.

The electricity meter should display the calculated value of daily kVA for each day and should have a register for cumulative daily kVAh during the month.

The reasons for using cumulative daily kVAh for determining transmission/distribution cost allocation are as follows:

1. An electronic kVA meter can easily be modified to output daily kVA and daily kVAh;
2. Daily kVAh does not require a precise absolute time reference;
3. Daily kVAh rewards good power factor;
4. Daily kVAh rewards low harmonic content;
5. Daily kVAh rewards uniform power transfer rates;
6. Daily kVAh reduces the cost impact of short term power transfer rate variations due to random mechanical equipment repair and maintenance;
7. Daily kVAh penalizes ongoing daily variations in power transfer rate.

FORM OF ELECTRICITY BILL:

An electicity bill for a billing interval takes the form:

Bill = - Ki (Eib - Eia) + Ke (Eeb - Eea) + Kr (Rb - Ra)

where:

Subscript a indicates the beginning of the billing period;

Subscript b indicates the end of the billing period;

Ei = Cumulative energy imported into the distribution system;

Ee = Cumulative energy exported from the distribution system;

Ki = positive constant with units of \$ / kWh;
Ke = positive constant with units of \$ / kWh;
R = Cumulative kVAh registered;
Kr = positive constant with units of \$ / kVAh

An important issue with this billing formula is that if there is a time varying behind the meter generator, such as a wind turbine, that causes the sums of the first two energy terms to cancel out, the LDC still gets paid for distribution usage via the term:
Kr (Rb - Ra).

Consider all the meters that are connected to a particular distribution system. Define:
Eit = total of all the (Eib - Eia) readings
Eet = total of all the (Eeb - Eea) readings

The law of conservation of energy requires that for Hydro One normal density residential customers:
Eit = 1.092 Eet
Distributor non-profit on energy requires that:
Ki Eit = Ke Eet
Hence:
Ke / Ki = Eit / Eet = 1.092

Note that if a non-generating customer presents a pure resistive load to the distribution system then:
(Eib - Eia) = 0.

In 2006 the energy rate was:
Ke = \$.067 / kWh
Hence:
Ki = Ke / 1.092
= \$.067 / 1.092 kWh
= \$.061355 / kWh

In 2006 for residential customers the quantity:
(Rb - Ra) was approximated by (Eeb - Eea).

In 2006 for residential customers the quantity Kr was about:
Kr = \$.0458 / kWh.

RATE CHANGES:
As shown elsewhere on this web site under the heading Electricity Cost Apportioning, in order to enable significant distributed power generation in Ontario it will be necessary to make major generators pay for grid access which will increase Ke and decrease Kr.

TIME-OF-USE (TOU) ENERGY RATES:
It is contemplated by the Ministry of Energy that in the future the regulated values of Ke and Ki will be made time dependent to better reflect the market price for electrical energy. The billing formula becomes a summation over all the

Time-Of-Use (TOU) intervals in the billing period. A time dependent regulated energy price should encourage preferential consumer use of off-peak electricity, which should reduce swings in the Hourly Ontario Electricity Price (HOEP). However, implementation of TOU rates will likely lead to more rather than less total electricity usage and hence will increase the total required generation capacity.

In the absence of TOU energy rates the daily variation in the total load allows some generators to go off line during the night for preventive maintenance. If these generators are committed for off-peak generation, additional reserve generation may be required to permit normal scheduled equipment maintenance.

Another possible result with TOU rates is that contemplated savings on generation equipment may be more than offset by increased energy rates for many customers. Implementation of TOU rates will likely increase the average cost of electricity for parties that are not able to take advantage of the lower cost off-peak electricity.

This author's personal experience was that Ontario lost the benefits of TOU rates by years of vacillating about electricity rates and then failing to adopt and maintain TOU electricity rates that reasonably recover actual costs. During the 1960s and 1970s many large buildings in Metro Toronto were built with thermal energy storage. During the 1980s and 1990s these thermal energy storage systems were taken out of service when the electricity rates were changed such that continued operation of these thermal energy storage systems no longer made economic sense for the building owners. Major building owners require a projected positive cash flow and certainty regarding long term electricity rates before they will make the capital and operating expenditures on thermal energy storage systems, electro-chemical energy storage systems, behind the meter generation, etc. that TOU rates are intended to promote. From the point of view of major building owners, the Ontario government and the OPA have zero credibility with respect to their claims regarding future electricity rates. In order to restore that credibility it will be necessary for the OEB to fundamentally fix the electricity rate structure and then for the OPA to offer building owners and developers firm electricity rate contracts, guaranteed by the Province of Ontario, with at least 10 year terms.

ELECTRICITY COST APPORTIONING

By C. Rhodes

INTRODUCTION:

This web page addresses transmission, distribution and stranded electricity debt retirement costs that must be re-apportioned to effectively implement private sector distributed electricity generation within the Province of Ontario.

ELECTRICITY GRID:
The electricity grid in Ontario is actually a collection of interconnected distribution systems that are owned and maintained by separate parties. Most of the major generators are connected to the high voltage transmission system that is maintained by Hydro One. This high voltage transmission system is in turn connected to many lower voltage distribution systems that are maintained by Local Distribution Companies (LDCs). Rural Local Distribution Systems are also often operated and maintained by Hydro One. Most end users obtain their electricity from LDCs.

At every point where electricity enters or leaves the high voltage transmission system there is a meter. Similarly at every point where electricity enters or leaves a local distribution system there is a meter. There are some unmetered loads such as street lighting, but generally the LDCs have accurate records as to the number, size and performance characteristics of these loads. For the purposes of calculations presented herein these loads can be considered as metered.

The high voltage transmission system can be considered to be a distribution system with generators and LDCs as customers that exchange energy.

Each LDC has a distribution system with the transmission system that is maintained by Hydro One as one customer and with distributed generators and end consumers of electricity as the other customers. The LDC's customers exchange energy amongst themselves.

DEFINITION OF TERMS:
Cht = total cost that Hydro One must apportion amongst its customers;
Chi = costs directly related to the high voltage transmission system;
Cjt = total costs that LDCj must apportion amongst its customers;
Cji = costs directly related to LDCj;
Ckt = total costs that LDCk must apportion amongst its customers;
Cki = costs directly related to LDCk

Pg = central generator output power fed to Hydro One transmission;
Pj = power flowing from Hydro One transmission to LDCj;
Pk = power flowing from Hydro One transmission to LDCk;
Pjt = total power indicated on all LDCj electricity meters;
Pkt = total power indicated on all LDCk electricity meters.

COST APPORTIONED TO CENTRAL GENERATORS:
Assume that there is no electricity generation within the LDCs. This is the special case that approximately pertains at this time in Ontario due to a rate structure that acts as a disincentive for LDC connected distributed generation.
If transmission loss is neglected, conservation of energy requires that:
Pg = Pj + Pk + ...
If distribution loss in LDCj is neglected, conservation of energy requires that:
Pj = Pjt/2
If distribution loss in LDCk is neglected, conservation of energy requires that:

$Pk = Pkt/2$

Assume that costs are apportioned amongst customers in proportion to absolute measured power. This is a simplification for demonstration purposes.

The cost billed to Hydro One transmission by LDCj for use of the LDCj distribution system is:
$(Pj / Pjt)\ Cjt$.
The total cost billed to Hydro One transmission by LDCb for use of the LDCb distribution system is: $(Pk / Pkt)\ Ckt$.
Thus the total cost Cht that Hydro One transmission must apportion amongst its customers is given by:
$Cht = Chi + (Pj / Pjt)\ Cjt + (Pk / Pkt)\ Ckt + \ldots$
$= Chi + (1/2)\ (Cjt + Ckt + \ldots)$

The total cost Cjt that LDCj must apportion amongst all its customers is given by:
$Cjt = Cji + (Pj /(Pg + Pj + Pk + \ldots))\ Cht$
The total cost Ckt that LDCk must apportion amongst all its customers is given by: $Ckt = Cki + (Pk /(Pg + Pj + Pk + \ldots))\ Cht$
Thus:
$Cjt + Ckt + \ldots$
$= Cji + Cki + \ldots + ((Pj + Pk + \ldots)/(Pg + Pj + Pk + \ldots)\ Cht$
$= Cji + Cki + \ldots + Cht/2$

Substituting this equation into the previous equation for Cht gives:
$Cht = Chi + (1/2)\ (Cjt + Ckt + \ldots)$
$= Chi + (1/2)\ (Cji + Cki + \ldots + Cht/2)$

Rearranging this equation gives:
$(3/4)\ Cht = Chi + (1/2)\ (Cji + Cki + \ldots)$

Multiply both sides of this equation by (2/3) to get:
$Cht / 2 = (2/3)\ Chi + (1/3)\ (Cji + Cki + \ldots)$

Hence the cost billed by Hydro One transmission to the central generators is:
$(Pg /(Pg + Pj + Pk + \ldots)\ Cht = Cht / 2$
$\mathbf{= (2/3)\ Chi + (1/3)\ (Cji + Cki + \ldots)}$

SUMMARY:
This important result states that, subject to the assumptions that there is negligible generation within the LDCs and that transmission and distribution losses are negligible, the central generators must bear 2/3 of the high voltage transmission system costs and 1/3 of the lower voltage system distribution costs. Hence, end users and distributed generators that are directly connected to LDCs must bear 1/3 of the high voltage transmission system costs and 2/3 of the lower voltage system distribution costs, so that the transmission and distribution systems achieve 100% cost recovery.

HYDRO ONE NON-ENERGY RATE:

For normal density Hydro One customers the average transmission and distribution loss is 9.2%. For customers with monthly peak demands less than 50 kW the existing grid connection charges are currently broken down by distribution, debt retirement, transmission and regulation. On the basis of Ontario Energy Board (OEB) approved Hydro One 2006 rate for normal density residential customers the incremental cost per kWh is typically:
($.0218(distribution) + $.0070(debt retirement)) + 1.092(distribution loss) X ($.0094(transmission) + $.0062(regulation))
= $.0288 + 1.092($.0156)
= $.0458 /kWh plus GST.
If there was no distribution loss this number would be:
$(.0218 + .0070 + .0094 + .0062) / kWh = $.0444 / kWh

TORONTO HYDRO NON-ENERGY RATE:
The corresponding 2006 Toronto Hydro rate is:
($.0103(transmission) + $.0184(distribution) + $.0015(market transition) + $.0062(regulation) + $.0070(debt reduction)) / kWh = $.0434 / kWh

Note that the two rate structures have total non-energy charges that agree to within $.001 / kwh

REALLOCATED TRANSMISSION/DISTRIBUTION COSTS:
For General Service customers in Toronto with monthly demands less than 50 kW Toronto Hydro in 2006 indicated that the transmission charge was $.0103 / kWh and the distribution charge was $.0184 / kWh. Hence the amount of these charges that should be borne by the central generators is given by:
(2/3)($.0103 / kWh) + (1/3)($.0184) = **$.013 / kWh**
and the amount that should be borne by distributed generators and end users is given by:
(1/3)($.0103 / kWh) + (2/3)($.0184) = **$.0157 / kWh**

The reallocated transmission/distribution costs will increase the Hourly Ontario Electricity Price (HOEP) by about $.013 / kwh and should decrease load customer transmission/distribution costs by about $.013 / kWh. This reallocation has the effect of increasing the value of electricity from distributed generation that is exported to the grid by:
2 X $.013 / kWh = **$.026 / kWh**