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ELECTRICITY

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This web page last updated August 20, 2007

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DISTRIBUTED ELECTRICITY GENERATION

By C. Rhodes

GENERATION TYPES:
Historically most electricity was generated via hydro-electric dams or via thermal-electric generating stations. Most of the readily accessible sites that are suitable for large hydro-electric dams have already been harnessed. Fossil fuel thermal-electric generators are a problem because they are the principal source of CO2 that causes global warming. Nuclear thermal-electric generators have proven to be quite expensive, and have associated with them complex waste management issues. In order to obtain electricity without the aforementioned problems attempts are being made to use distributed energy sources.

DEFINITION:
Distributed electricity generation involves taking advantage of economic and environmentally acceptable sources of energy for electricity generation where ever and whenever they occur. Much of the potential distributed electricity generation has a random power versus time profile that is determined by sun light, wind velocity, river flow or by the rate of use of heat. The reliability of distributed electricity generation rests on there being both energy storage and a large number of statistically independent distributed generators. Behind the meter energy storage at the generator can be used to modify the net generation profile to match the available transmission profile. Behind the meter energy storage at the load can be used to modify the net load profile to match the available transmission profile. Energy storage may also be used to provide reactive power when and where required.

DISPATCH CONTROL:
If distributed electricity generation forms a large fraction of total electricity generation, then part of the generation and part of the load should be interruptable and under dispatch control. Time-Of-Use (TOU) rates should be used to encourage generation and load profile matching. Some generation must be contractually constrained off at certain times in order to match seasonal load variations.

ELECTRICITY SYSTEM BENEFITS:
In June 2006 the government of Ontario made a public commitment to double the contemplated fraction of the electricity requirement met by conservation and renewable sources and to gradually phase out coal fired generation.

From the point of view of the Ontario electricity ratepayer a kWh generated behind the meter of an end user is a kWh that does not have to be remotely generated, does not have to be stored, does not have to be transmitted, and does not have to be distributed. It makes economic sense for the government of Ontario, acting on behalf of the electricity ratepayers, to offer an incentive for environmentally acceptable behind the meter distributed generation subject to the amount of the generation being measured and the cost of the incentive, including its administration, being less than the difference between the cost per kWh for new environmentally acceptable electrical energy and the Hourly Ontario Electricity Price (HOEP). At some future time, when the electricity rates to end users have increased enough to fully fund both the total cost of new environmentally acceptable generation and the total cost of its related transmission and distribution, then the need for distributed generation incentives will end.

DISTRIBUTED GENERATION CAPITAL FINANCING:

Distributed generators are usually owned by corporate entities. These entities generally expect to earn a 30% per annum return on share capital. They evaluate distributed generation measures based on that benchmark, although they will often leverage share capital with 50% debt financing provided that there is certainty of a positive cash flow.

Any distributed generation facility can be characterized by an initial capital cost C. In order to finance that facility the owner generally requires a minimum ongoing energy cost saving, net of fuel and consumeables, of about .04C per month. Typically .01C per month is applied to operating, maintenance, and repair costs and .03C per month is applied to meeting blended principal and interest financing payments. In practise, a significant energy retrofit involves payments to engineers, suppliers and trades several months in advance of when the corresponding energy cost savings are actually realized by the facility owner, so the actual simple payback period realized by the owner is about three years. If the simple payback period exceeds three years the owner will usually choose not to proceed with the project because the owner has alternative uses for capital that earn a higher rate of return. For this type of project the owner's actual blended cost of funds is about 20% per annum and the equipment must operate as projected for at least five years for the owner to break even.

DISTRIBUTED GENERATION TYPES:

Two significant sources of distributed generation energy are wind and co-generation. It is helpful to examine the costs of both types of distributed generation. The mathematical development for other forms of distributed generation is analogous.

RECENT MAJOR WIND PROJECTS:

Recent examples of major wind projects are the Melancthon II Wind Project and the Erie Shores wind Farm. The published data for these projects is:

MELANCTHON II WIND PROJECT:
Contracted Capacity: 132 MW

Anticipated Annual Output: 350,000 MWh / year
Project Cost: $265,000,000
Ongoing Cost: .0254 X Project Cost / year
Anticipated Average Power: 350,000 MWh / 8766 h = 39.927 MW
Anticipated Average Capacity Factor = 39.927 MW / 132 MW = .3025
Anticipated Capital Cost Per Average W = $265 M / 39.927 MW = $6.64 / W

ERIE SHORES WIND FARM:
Contracted Capacity: 99 MW
Anticipated Annual Output: 278,000 MWh / year
Project Cost: $186,000,000
Anticipated Average Power: 278,000 MWh / 8766 h = 31.71 MW
Anticipated Average Capacity Factor= 31.71 MW / 99 MW = .3203
Anticipated Capital Cost Per Average W = $186 M / 31.71 MW = $5.86 / W

This author believes that the costs for these two projects have been front loaded for tax shelter purposes.

NET REVENUE CALCULATION:
Let Er be the electricity energy rate paid to the project in $ / kWh generated.
Use the figures for Melancthon II as a guide.
The annual gross income is:
350 X 10^6 kWh X Er
The claimed ongoing cost is:
.0254 X $265 X 10^6 / annum = $6.730 X 10^6 / annum

Let C be the unamortized capital.
Let I be the effective fractional interest rate per unit time.
Let T be time.
Then the net annual revenue R available to repay capital C is given by the differential equation:
R = - dC / dT = $(350 Er - 6.730) X 10^6 - I C

At T = 0, C = $265 M.
If the project is amortized over the initial contract period, at T = 20 years, C = 0.
The differential equation is of the general form:
dC / dT = I C - B
where B = $(350 Er - 6.730) X 10^6

MINIMUM ACCEPTABLE ENERGY RATE:
At T = 0 it is crucial that the net annual revenue R be positive or the capital C will never be repaid. Hence the minimum kWh rate Er that the project can support must satisfy the equality:
I = $(350 Er - 6.730) X 10^6 / C

The effective interest rate for a privately funded wind project is typically:
I = .20 / annum = 20% / annum.
The financing typically consists of a blend of half equity at 32% / annum and half debt at 8% / annum for an average cost of 20% / annum (I = .20). These effective interest rates include financing related accounting, legal and placement

fees that typically reduce the before corporation tax equity yield to 30% and the debt yield to 6%.

Rearranging the above equation gives:
(C X I) / 10^6 = $(350 Er - 6.730)
or
Er = (1 / 350) X [6.730 + ((C X I) / 10^6)]
= $.1706 / kWh
Hence to start the pay down process:
Er ~ $.18 / kWh
Thus a practical large scale wind generator project without energy storage needs to earn $.18 / kWh generated to be economically viable.

With reference to the web page titled "Equipment Financing" the initial costs of the wind generator installation must be kept below $2500 / (average kW generated).
Sites where the wind is insufficient to meet this financial criteria are simply not economically viable for private sector owned wind generation.

WIND ENERGY STORAGE:
Wind energy, without energy storage, does not reliably contribute to meeting the daily peak electricity demand. The cost of an electro-chemical storage system is about $2500 / kW ($1000 / kW for constant voltage inverter and $1500 / 12 kWh for electro-chemical energy storage). In order for the generator and storage system to be economic they must earn earn an average of $.36 / kWh. In these circumstances the on-peak rate paid to the generator could be $.60 / kWh for 84 hours per week and the off-peak rate paid to the generator could be $.18 / kWh for 84 hours per week. The rate differential of:
$.60 / kWh - $.18 / kWh = $.42 / kWh
must fund the energy storage system. Due to energy loss within the storage cycle the energy storage income is effectively reduced to:
.75 X $.42 / kwh = $.315 / kWh

Assume that the energy storage system stores 12 kWh / kW. The required annual revenue to finance the energy storage system and its maintenance is:
.04 / month X $2500 / kW X 12 months / annum = $1200 / kW annum
The actual annual revenue is:
$.315 / kWh X 12 kWh /kW day X 365 days / annum = $1379.70 / kW annum

Thus to a first approximation the amount paid to privately financed non-fossil fuel generators will have to be about $.60 / kWh during on-peak hours, about $.18 / kwh during off-peak hours and must be subject to the requirement that the average on-peak power output exceeds the average off-peak power output. There should be no payment for off-peak energy that causes the average off-peak power output to exceed the average on-peak power output.

Then the cost of an average base load kWh from wind, financed via the private sector, is:
($.60 / kWh + $.18 / kWh) / 2 = **$.39 / kWh**
This price can be somewhat mitigated if the owner can take full advantage of

Capital Cost Allowance (CCA) Class 43.2 and other energy efficiency incentives.

If the government purchases the equipment at the time of installation these rates can be reduced to $.30 / kWh during on-peak hours and $.09 / kWh during off-peak hours. Then the cost of an average base load kWh from wind is:
($.30 / kWh + $.09 / kWh) / 2 = **$.195 / kWh**

Thus the average value of new base load electricity from non-fossil fuel generation financed by government guaranteed debt is about **$.195 / kWh**

The aforementioned calculations effectively demonstrate that wind energy only has value when compared to other new sources of non-fossil fuel energy. Wind energy is not economically viable when compared to the Hourly Ontario Electricity Price (HOEP) which contains fossil fuel, old low cost hydro and subsidized nuclear components.

NATURAL GAS CO-GENERATION:
This author's practical experience in 1999 based on 11 representative major buildings was that a budget of about $200,000 was required to design, supply and install a reliable 100 kW natural gas cogeneration retrofit. As shown on the web page titled "Equipment Financing", financing this equipment to run at an 80% load factor requires an electricity price of $.137 / kWh plus fuel and consumeable costs.

For thermal load following CHP systems (an attractive behind the meter distributed generation opportunity for multi-residential buildings), for every kWh of incremental electricity generation an additional kWh of heat must be provided to the generator's prime mover. In most cases the fuel is natural gas which is burned at an efficiency of about 80%. The cost of the incremental extra heat which is converted to mechanical and then electrical energy is about:
$.57 / m^3 X 1 m^3 / 10.4 kWh X 1 / .8 = $.0685 / kWh

For natural gas fuelled systems there is also the issue of consumption of the prime mover. The prime mover may be a reciprocating engine that at 100 kW costs about $32,000 to replace and that lasts 16,000 hours or may be a recuperated combustion turbine that costs $64,000 to replace but that lasts 32,000 hours. In either case the prime mover is a consumeable that costs:
$32,000 / (100 kW X 16,000 H) = $.02 / kWh

There is also a problem of consequential damages. That is, a prime mover failure may damage a generator, or a generator failure may damage a prime mover, or an electrical/electronic failure may damage mechanical equipment. When consequential damages, oil, filters, etc. are taken into consideration it is prudent to use a non-fuel consumeable cost of $.04 / kWh.

Hence a co-generation system only makes economic sense for a building owner if he can achieve an 80% average load factor and if he receives an average price for co-generated electricity of:
$.137 / kWh + $.0685 / kWh + $.04 / kWh = **$.2455 / kWh**
This rate can be slightly mitigated via CCA Class 43.2 and via demand charge reduction. Generally the government has no interest in purchasing equipment

that is as maintenance intensive and building integral as a co-generation system. In addition, a co-generation proponent needs long term price protection against increases in the cost of natural gas.

THE METERING ISSUE AND ITS SOLUTION:

A significant problem affecting co-generation is that the existing OEB approved transmission/distribution rates for large buildings (over 50 kW peak demand) act as a disincentive for behind the meter combined heat and power (CHP) generation in these buildings. In most large buildings it is physically impractical or cost prohibitive to connect a generator directly to the grid. It is much more practical to connect internal generators behind the LDC electricity meter. The output of such generators has the effect of reducing the number of kWh registered by the LDC electricity meter.

The problem is that, with present Ontario Energy Board (OEB) approved Local Distribution Company (LDC) electricity rates, when a behind the meter generator is shut down for service or for lack of heat load the building's peak kW or peak kVA meter registers a peak, causing the building owner to be billed for extra kW or kVA equal to the entire generator capacity. This extra billing presently makes behind the meter generation in large buildings uneconomic. The long term solution to this problem is to change the electricity rate structure so that the building owner is billed for transmission/distribution in proportion to his cumulative daily kVAh (calculated using 24 hour intervals) instead of his monthly peak kVA or monthly peak kW. This new billing methodology is simple to implement with an electronic meter. This methodology is fair to the LDC, and provides the building owner with financial incentives to keep his power factor high, his harmonic distortion low and to flatten his load profile.

However, it may take years to implement these rate structure and metering changes via the existing Ontario Energy Board (OEB) approval process. During the transition period it is contemplated that LDCs will continue to bill customers using existing meters. Customers that implement internal self generation measures should be given priority for supply and installation of new electronic meters that measure cumulative daily kVAh and for access to transmission/distribution rates that depend on the availability of cumulative daily kVAh metering. These new electricity meters must also measure the number of kWh exported from the grid to the customer and and the number of kWh imported by the grid from the customer. Since the grid export rate per kWh is higher than the grid import rate per kWh, customers increase their energy costs as well as their kVA costs if they present reactive loads to the grid.

This web page last updated August 20, 2007.

ONTARIO ENERGY BOARD

DISTRIBUTED GENERATION: RATES AND CONNECTION
BOARD FILE NO. EB-2007-0630

By Charles Rhodes, Xylene Power Ltd.

INTRODUCTION:
Ontario needs major private sector investment in non-fossil fuel Distributed electricity Generation, natural gas co-generation and Energy Storage to meet the electricity supply shortage that is anticipated during the next decade.

The Ontario Energy Board (OEB) by a letter dated July 13, 2007 initiated a consultation process that is expected to culminate in a rates and connection policy framework for Distributed Generation (DG).

The OEB has made available a report titled: "Discussion Paper on Distributed Generation (DG) and Rate Treatment of DG" dated June 2007. This report was prepared by EES Consulting.

The OEB has also made available a Staff Discussion Paper on Distributed Generation: Rates and Connection EB-2007-0630

Unfortunately, apart from standby power rates, these documents do not address the fundamental issues that determine the economic viability of Distributed Generation in Ontario.

This website shows the reasons why Distributed Generation is presently not economic in Ontario and indicates the specific issues that the OEB must address to correct this problem.

BACKGROUND:
The income from a Distributed Generator in Ontario is determined by:
1. The Hourly Ontario Electricity Price (HOEP);
2. An incentive supplementary to the HOEP paid by the Ontario Power Authority (OPA);
3. Costs paid by the generator for use of the transmission/distribution system;
4. Costs and incentives related to energy storage at the Distributed Generator site;
5. The customer load profile at the Distributed Generator site.

As of August 2007, there are major problems with the methodology for determining: HOEP, the incentive supplementary to the HOEP paid by the OPA and transmission/distribution cost allocations. The whole issue of energy storage and related regulated Time-Of-Use (TOU) energy rates has not been addressed by the OEB. Meanwhile, Ontario is facing an increasing shortage of non-fossil fuel electricity generation. Large amounts of non-fossil fuel electricity generation, natural gas co-generation and related energy storage are required to enable closure of coal fueled electricity generation plants, to replace end-of-life nuclear plant and to meet anticipated electricity load increases.

The Ontario Power Authority (OPA) has developed a metering methodology for its Renewable Energy Standard Offer Program (RESOP) that totally circumvents the existing electricity rate structure. The OPA has proposed a different metering methodology that explicitly relies on HOEP for its Clean Energy Standard Offer Program (CESOP).

A major problem with the present implementation of the RESOP is that the time profile of the RESOP generation output does not match the provincial electricity load profile. Presently there is insufficient financial incentive for RESOP generators to use energy storage to modify their output power profiles to match available transmission capacity and the provincial load profile. A major problem with both the RESOP and the CESOP is that the incentive payments offered by the OPA are not sufficient to attract large scale private sector investment.

TASKS FOR THE OEB:
The immediate task for the OEB is to determine an economically viable interim incentive rate structure supplementary to HOEP that is sufficient to attract large scale private sector investment into non-fossil fuel electricity generation, high efficiency fossil fuel electricity generation and related energy storage. The incentive offered per kWh generated should be dependent on the fossil carbon emissions / kWh, the extent to which the generation contributes to meeting the daily and annual peak electricity demands, future changes to HOEP, future changes to transmission/distribution cost allocations, the Consumer Price Index and the prime interest rate.

Another challenge for the OEB is to implement changes to HOEP such that eventually there is no need for a distributed generation incentive supplementary to HOEP.

Another challenge for the OEB is to implement changes in the methodology used to allocate transmission/distribution charges to remove existing practical obstacles to implementation of distributed generation and related energy storage while fairly compensating owners of transmission/distribution for use of their facilities.

Another challenge for the OEB is to implement regulated TOU energy rates that will encourage the private sector to invest in both Distributed Generation (DG) and Energy Storage (ES).

Another challenge for the OEB is to implement an electricity rate that substantially reduces the nuclear related stranded debt. This debt reduction is required to mitigate future electricity price escalation.

HISTORY:
The existing electricity rate structure in Ontario has evolved from the previous century during which Ontario Hydro was an integrated developer, generator, transmitter, and distributor with almost 300 allied municipal distributors. During the 1960s Ontario Hydro signalled to its commercial customers that energy was almost too cheap to measure. At that time Ontario Hydro relied principally on peak demand metering for its revenue. As late as 1970 Ontario Hydro was still offering commercial customers 10 year contracts at $.01 per kWh and $6.00 per kW per month. Major building developers were encouraged to incorporate thermal energy storage into their building designs to minimize peak demand charges.

However, in the 1970s the cost of energy started to rapidly increase. Between 1970 and 2005 the price of a kWh increased more than sixfold. About 1981 Ontario Hydro identified to the OEB that Ontario Hydro intended to shift from demand based metering to Time-Of-Use energy metering. Between 1985 and 1999 various TOU rates were implemented. These rates led to extensive electricity conservation and fuel substitution. Co-generation systems were installed in a number of major buildings.

During the late 1990s Ontario Hydro held its wholesale electricity rate constant in spite of increased debt service costs. By 2001 Ontario Hydro and its successors accumulated over $20 billion in stranded nuclear debt.

Around the year 2000 there was extensive reorganization in the electricity sector. Ontario Hydro was broken up. The stranded debt was taken over by a government owned finance company. Municipal utilites, fearing loss of rate base, based their transmission/distribution charges on peak demand. Regulated TOU rates were abandoned. The cost of natural gas increased. Private sector generators were forced out of business by artificially low electricity rates that did not recover actual costs. Building owners decommissioned existing thermal energy storage systems because the electricity rate structure did not support the costs of their ongoing operation, maintenance and repair.

During the period 2001 to 2007 the government of Ontario collected interest on the stranded debt via a $.007 / kWh surcharge on all billed electricity consumption, but did not significantly reduce the stranded debt principal.

In early 2005 the government of Ontario formed the Ontario Power Authority (OPA), with a mandate to purchase electricity from private sector generators. Almost simultaneously the electricity industry became much more aware of the negative consequences of the increasing carbon dioxide concentration in the atmosphere. The largest single source of excess atmospheric carbon dioxide is combustion of fossil fuels for electricity generation. However, the OPA has found that the Hourly Ontario Electricity Price (HOEP) is not sufficient to attract major private sector investment in non-fossil fuel electricity generation.

The OPA has implemented the Renewable Energy Standard Offer Program (RESOP), but at the 2007 RESOP base rate of $.11 per kWh for 20 years the project takeup rate has been very small as compared to the total requirement for new non-fossil fuel generation. A major limitation of the present implementation of the RESOP is that there is insufficient financial incentive to cause RESOP generators to shift their electricity outputs to times of daily peaks in the provincial electricity demand.

ENERGY STORAGE:
There is a further issue that wind and tidal energy generators at remote locations need behind the meter daily energy storage to level their net generation rates, so as to minimize their transmission capacity requirements. Furthermore, as the dependence on non-fossil fuel generation increases more energy storage behind load customer meters will be required to match the load profile to the transmitted energy supply profile. There are substantial costs associated with energy storage that were not anticipated in the RESOP formulation. A subtle but important technical issue is that the RESOP generation and related energy storage should be configured so that the generator can ride through transient grid faults and does not rely on other generation to black start.

REQUIRED INCENTIVE AND RATE CHANGES:
The immediate task facing the OEB is to implement rate changes and distributed generation and energy storage incentives that are sufficient to attract large scale private sector investment in non-fossil fuel electricity generation and related energy storage. Failure of the OEB to adequately address this matter will lead to an electricity shortage in the Province of Ontario.

Issues that should be considered by the OEB include but are not limited to:
a) Application of a coal prohibitive fossil carbon emissions tax or its financial equivalent to the HOEP;
b) Proper allocation of past nuclear debt and future nuclear costs to the HOEP;
c) Charging all generators for transmission/distribution use on the same terms as general load customers, thus increasing the HOEP and reducing load customer transmission/distribution charges;
d) Use of cumulative daily kVAh meters instead of peak demand meters for fair allocation of transmission/distribution costs. These meters are applicable to a network containing distributed loads with embedded distributed generation. These meters encourage use of energy storage by both generators and load customers while preventing excessive costs to owners of distributed generation and energy storage related to short term maintenance shutdowns;
e) Implementation of high differential time-of-use (TOU) rates in the regulated energy sector to encourage use of energy storage at both generator sites and load sites;
f) Long term rate guarantees for parties willing to build distributed generation and/or energy storage;
g) Recognition that the cost of private sector capital for financing fixed assets for electricity generation and energy storage is much greater than the cost of government guaranteed debt.
h) Recognition that past vascillations of the government of Ontario caused many parties who

invested in Distributed Generation and Energy Storage to lose money. In the near term an expectation of substantial profit will be required to motivate these parties to reinvest.

INTENT:

This website attempts to portray the long term changes to the HOEP and transmission/distribution rates that are essential to ensure Ontario's future electricity supply.

This web page last updated August 20, 2007.

XYLENE POWER LTD.

ELECTRICITY SYSTEM

By C. Rhodes

DEFINITION:
The term "Electricity System" encompasses all the components of the means by which we obtain electicity. Without limiting the generality of the definition the electricity system includes energy sources, generation, transmission, energy storage and recovery, distribution, metering, development, operating, maintenance, administration and regulation.

IMPORTANCE:
During the last 100 years electricity has become more and more important in our daily lives. The electricity system in Ontario has been so reliable that we tend to take it for granted. Today we almost totally depend on reliable grid supplied electricity for all kinds of critical functions including but not limited to: pumping potable and sewage water, enabling and controlling winter heating, providing lighting, transportation, summer cooling, refrigeration and power for industrial processes.

ENVIRONMENTAL ISSUES:
The reliability of the electricity system in Ontario is now under serious threat arising from a long term failure of the electricity industry and related governmental bodies to pay sufficient attention to environmental issues. As long as the electricity was obtained from hydro-electric dams at remote locations, and the environmental effects were largely confined to fish habitat and fish migration, there was relatively small public opposition to electricity system development. However, by about 1970 much of the economic hydro-electric potential in Ontario had been developed and other sources of electricity were constructed.

These other sources of electricity were primarily thermal-electric plants, where the source of heat was either combustion of a fossil fuel or a nuclear reaction. The fossil fuel plants emit toxic products of combustion and green house gases. The nuclear plants, if not carefully operated and maintained, have the potential of releasing dangerous radioactive isotopes. Both coal and nuclear plants have significant waste disposal issues.

URBAN POWER TRANSMISSION:
In urban areas much of the green house gas emissions come from combustion of fossil fuels in vehicles and from building heating plant. The technologies that can displace fossil fuel energy with non-fossil fuel energy require that much more

electricity be delivered to urban areas. The existing municipal plans do not provide sufficient right-of-way for the required new electricity transmission corridors. Hence, in order to substantially reduce urban greenhouse gas emissions, large amounts of urban property must be expropriated to form new power transmission corridors.

SYSTEM DETERIORATION:
The aforementioned problems with thermal-electric generation and urban transmission have led to the electricity industry being subject to intense public scrutiny. Fear of public reaction to electricity system development has made elected politicians unable or unwilling to make timely decisions related to new generation and transmission projects. As a result the electricity system has deteriorated to such an extent that Ontario presently relies on both large amounts of coal fueled electricity generation and electricity imports from the USA for meeting the electricity load on hot summer days. Most of the existing electricity utility staff are devoted to operating and maintenance. There is an infrastructure replacement backlog. There are few trained human resources available to undertake major new generation and transmission projects.

DEPENDENCE ON COAL:
Successive delays by politicians have caused the Ontario electricity system to become dependent on coal for daily load following generation. The problem has been compounded by implementation of the Hourly Ontario Electricity Price (HOEP) which is strongly influenced by the low price of coal without fossil carbon emissions tax. The HOEP causes more expensive emission free generation technologies to be rejected in favour of low cost coal. Both federal and provincial politicians have been unwilling to directly face the issue of implementing a coal prohibitive fossil carbon emissions tax in order to correct the HOEP problem.

DISTRIBUTED GENERATION:
In order to provide electricity without a severe environmental impact, much effort in recent years has gone into investigating generating electricity from non-fossil fuel and high efficiency natural gas distributed energy sources. These distributed energy sources include co-generation, wind, run-of-river hydro, solar, micro-nuclear, tidal power, etc. However, all of these distributed energy sources have the common problem that the time profile of their generation outputs does not match the time profile of the provincial electricity load. **In order to effectively utilize these distributed energy sources, part of their electricity output must be converted into some other form of energy for storage purposes and then reconverted back into electricity at a later time.**

There is a notable exception, which is generation of electricity from biofuels. Biofuels have the advantage that they can be used to provide energy when and where required with minimal environmental impact. However, this very feature makes biofuels in high demand as transportation fuels, so biofuels are generally uneconomic for stationary electricity generation.

The government of Ontario has indicated that it plans to close coal fueled electricity generation to prevent both toxic and CO_2 emissions. In order to financially enable construction of replacement distributed generation ahead of coal generation closure it is necessary for the OEB to implement a non-fossil fuel electricity generation incentive. This incentive must reflect the reality that the alternative is the full cost of new nuclear generation. The last major new nuclear project in Ontario, commenced about 30 years ago, cost more than $4000 / kW. Any new nuclear project will require training an entire new army of construction, operating and maintenance personnel, so it is unrealistic to contemplate a full cost of less than $6000 / kW. A full cost of $8000 / kW is more likely. Hence non-nuclear non-fossil fuel electricity generation fitted with sufficient energy storage to provide a nearly constant output is realistically worth at least $6000 / kW to the electricity ratepayer, and the OEB approved non-fossil fuel generation incentive should reflect this reality.

PRIVATE SECTOR CAPITAL:
The Ontario Power Authority (OPA) seeks to purchase kWh rather than fixed assets from private sector distributed generation. Consequently the generation facilites must be funded by the private sector without government guarantees. Absent all government guarantees the blended cost of capital increases from approximately 6.7% / annum to approximately 20% / annum. Few who have not been personally involved in funding power system construction, operation and maintenance fully appreciate this issue. The consequence is to approximately double the cost of a new build kWh. Presently new generation construction in Ontario is stalled on this issue.

The OEB is going to have to face and deal with this issue. There is no magic solution. The government of Ontario is sitting on $20 billion of stranded nuclear debt that has not been passed onto the rate payers. This debt makes it difficult or impossible for the government of Ontario to guarantee further debt financing for major electricity projects. In order to mitigate the cost of new build generation and new transmission the OEB will have to implement a substantial electricity rate increase to rapidly pay down the stranded debt. In order to enable economical new generation this rate increase will have to be applied principally to existing central generation. Part of this rate increase could be in the form of a fossil carbon emissions tax applied to fossil fueled generation.

ENERGY STORAGE:
The practical methods of storing energy for later recovery and use are river fed reservoirs, pumped storage, electro-chemical storage, kinetic energy storage and electromagnetic storage.

RIVER FED RESERVOIRS:
If a river fed reservoir feeds a hydraulic turbine, and the reservoir has sufficient area, the flow through the turbine at night can be set at 0.5 X the average river flow and the flow through the turbine during the day can be set at 1.5 X the average river flow. This arrangement results in a 3:1 change in the downstream water flow rate and results in an electricity generation rate during the day which is three times the electricity generation rate during the night. This arrangement is a good way of realizing daily load following generation provided that the daily

change in downstream water flow is acceptable.

PUMPED STORAGE:
With pumped storage when there is a surplus of electricity water is pumped up hill from a low level reservoir to a high level reservoir, storing gravitational potential energy. When there is a deficiency of electricity water runs back downhill from the high level reservoir to the low level reservoir to generate electricity. A pumped storage system can typically economically store energy for hours, days or even weeks. An example of a large pumped storage system is the Grand Coulee Dam in Washington State, USA and its up-river seasonal storage dams in British Columbia. In past years this system was used to meet electricity peak demand as far east as Chicago. A disadvantage of pumped storage is that there is usually an associated major transmission cost. There are also daily changes in water flow and water level which may have significant ecological consequences.

ELECTRO-CHEMICAL STORAGE:
With electro-chemical storage surplus electricity is stored in a high efficiency battery. When there is a deficiency of electricity the chemical energy is converted to 3 phase AC using a constant voltage static inverter. The battery systems that are suitable for this purpose include sodium-sulfur, sodium-aluminum chloride (zebra) and various types of flow batteries. An electo-chemical energy storage system can economically store energy for about one day. Electro-chemical energy storage is presently used on a large scale in Japan, and on a smaller scale in trial installations in the USA and Ireland. An important advantage of electro-chemical storage is that it can be located at distributed generation sites and at urban load sites, greatly reducing transmission costs. **However, electro-chemical energy storage systems will not be built unless the electricity rate structure provides the storage system owner adequate financial reward for the reduction in transmission costs enabled by the energy storage system.**

KINETIC ENERGY STORAGE:
With kinetic energy storage surplus electricity is stored as kinetic energy in a flywheel. When there is a deficiency of electricity the kinetic energy in the flywheel is converted back into electricity. The energy is typically stored from seconds to minutes. Flywheel energy storage systems are primarily used to dampen voltage oscillations on electricity transmission/distribution systems.

ELECTROMAGNETIC STORAGE:
With electromagnetic storage electrical energy is stored in a combination of electric and magnetic fields and is released in a controlled manner a few milliseconds later. The primary purposes of electromagnetic energy storage are for AC/DC/AC power conversion and for power factor correction.

AC/DC/AC power conversion is implemented at power system boundaries and in support of underwater cables or very long transmission lines.

Power factor correction is used to shift the voltage and current waveforms into phase with one another. Power factor correction maximizes the amount of power that can be delivered to a load via a transmission/distribution system that is subject to specific voltage and current limits and maximizes the power transfer efficiency. Practical implementation of power factor correction in a transmission network with time varying reactive parameters is a complex undertaking, with potential severe complications related to attached nuclear generation safety shutdown if the network is suddenly reconfigured while under high load. Over reliance on power factor correction generally leads to system instability and unreliability. Reliability is enhanced by designing and building the transmission/distribution system so that it does not have to rely on active power factor correction to stay within safe operating limits.

A related issue that has not been adequately addressed by the OEB is requiring distributed generators to be self excited to reduce their requirement for downstream electromagnetic energy storage and to reduce their dependence on other generation for black-startup.

CHILLED WATER STORAGE:
With chilled water storage an electrically powered cooling system is run during off-peak periods to generate a large stratified tank full of chilled water. This chilled water is used for space cooling during on-peak periods. Thus electrical load is effectively transferred from the on-peak period to the off-peak period. **However, chilled water storage systems will not be built unless there is long term electricity rate stability and sufficient difference between the on-peak and off-peak electricity rates to justify the required capital investment.**

COST OF ENERGY STORAGE:
As long as a major fraction of the total generation was hydraulic or fossil fuel based and was provided by an integrated electricity supplier such as Ontario Hydro, the electricity rate regime paid little attention to the issue of properly valuing energy storage. However, as the availability of fossil fuel energy and controllable hydro-electric energy decreases, the importance and hence value of controllable energy storage increases. This issue is gradually being discovered by the Ontario Power Authority as it investigates the costs of the dedicated peaking generation required to allow taking existing coal fuelled generation out of service.

FUNDING ENERGY STORAGE:
Any energy storage system relies on there being enough difference between the value of the discharged energy and the value of the input energy to finance the storage system energy losses, as well as the capital, operating and maintenance cost of the energy storage system. **This financial criteria sets a larger value on the stored energy for on-peak use than is presently recognized by the Ontario Power Authority (OPA) and the Ontario Energy Board (OEB). This financial constraint must be taken into account in any future determination of regulated Time-Of-Use (TOU) electricity energy rates.**

ALLOCATION OF TRANSMISSION/DISTRIBUTION COSTS:
The existing monthly peak demand charges must be eliminated to encourage energy storage and on-peak behind the meter electricity generation. **A new transmission/distribution rate regime, based on cumulative daily kWAh,**

should be established. This new rate regime would rely on the statistical independence of shutdowns in behind the meter electricity generation, energy storage and load control equipment rather than on continuous 100% operational availability of that equipment at each site.

Major generators usually have multiple generation units at each generation site. Typically, at any instant in time, 20% of these units are shut down for repair or maintenance. Small generators usually do not have multiple generation units and should not be unduly penalized for short term equipment shutdowns. If transmission/distribution costs unduly penalize small generators for short term equipment shutdowns, these small generators simply will not exist.

If energy storage systems have to pay transmission/distribution costs for energy flowing in both directions these energy storage systems will not be economic. In order to be economic energy storage systems usually must be located behind the generation or load meters.

Distributed Generation and Energy Storage systems involve complex mechanical equipment and controls that need frequent repair and maintenance. In order to permit equipment repair and maintenance without undue cost penalty the existing peak kVA meters must be replaced by cumulative daily kVAh meters.

SUMMARY:

In order to financially enable non-fossil fuel Distributed Generation it is necessary for the OEB to implement a non-fossil fuel generation incentive which values a kWh of nearly constant output non-fossil fuel distributed generation at close to the full cost of a kWh from new build nuclear generation. In setting this incentive the OEB must recognize the full blended cost of capital in the private sector.

In order to implement Distributed Generation on a large scale it is necessary to implement energy storage at both generation sites and load sites. For this energy storage to be economically viable for its owners there must be high differential TOU electricity energy rates guaranteed by credible long term contracts.

In order to permit reasonable maintenance of distributed electricity generation and energy storage equipment existing peak kVA meters and peak kW meters must be replaced by cumulative daily kVAh meters. In order to put all generation on a level playing field major generators must be subject to the same cumulative daily kVAh metering and transmission/distributon cost allocation as are distributed generators.

This web page last updated August 16, 2007.

XYLENE POWER LTD.

ELECTRICITY NETWORK

By C. Rhodes

BACKGROUND:
The Ontario Power Authority (OPA), in its 2005 Supply Mix Report, identified that Ontario needs to build more than 24,000 megawatts of electricity generation capacity by the year 2025. The Supply Mix Report implicitly assumed continued use of fossil fuels for electricity demand peak coincident electricity generation, industrial, transportation and heating applications. However, when the constraints imposed by local and global warming are taken into account, these implicit assumptions are faulty. The reality is that the required electricity generation capacity will be much larger than was contemplated in the 2005 OPA Supply Mix Report.

ACTUAL ELECTRICITY LOAD:
There is an increasing annual peak electricity load in Ontario that on August 1, 2006 exceeded 27,000 megawatts. This annual peak electricity load is anticipated to continue increasing due to:
a) An increasing population;
b) An increasing use of mechanical cooling due to GHG atmospheric warming;
c) An increasing cost of fossil fuels that is causing electricity to be used to displace fossil fuels in industrial, transportation and heating applications.

The OPA has failed to adequately take these issues into account in preparing its long term electricity load forecast. The only certain way to meet the load growth is to adopt an electricity price structure that is sufficient to fund the full cost of environmentally acceptable new generation and its related transmission and distribution. Since the cost of new transmission and distribution may exceed the cost of new generation, it is highly desirable to remove obstacles to implementation of **distributed generation** so as to minimize overall costs.

GENERATION CATEGORIES:
The electricity supply can be viewed as a linear sum of the following generation categories:
1. Renewable Base Load Generation - This category includes wind turbine generators and run of river hydraulic generators. It is assumed that Time-of-Use (TOU) energy rates and cumulative daily kVAh transmission/distribution rates will cause wind generators to install sufficient electro-chemical energy storage behind their meters to make their outputs similar to the outputs of run-of-river hydraulic generators. Both types of generation have high average outputs in the early

spring and low average outputs in the late summer. In both cases the annual variation in the average output is about 3:1. In both cases the generation normally operates at full available capacity 24 hours per day.

2. Base Load Nuclear Generation: This category consists of nuclear generators that operate at a constant output, 24 hours per day.

3. Daily Load Following Generation: This category consists of solar generation, river fed reservoirs and base load generation with daily energy storage. The energy that is not required at night is used to charge the energy storage. The stored energy is released during the following day. During moderate weather the daily load following generation supplies the power difference between the minimum night time electricity demand and the maximum daytime electricity demand. If daily energy storage is not available this generation must be economic at a 50% load factor.

4. Seasonal Load Following Generation: This category consists of nuclear base load generation that is constrained off on a seasonal basis and hydraulic generation from storage dams that hold back very large lakes of water. Seasonal load following generation supplies the power difference between the low daily average load in April and September and the high daily average load on a cold winter day or a hot summer day. This generation category also supplies or absorbs the difference between projected annual electricity requirements and actual annual electricity requirements. This generation must be controlled on an hour by hour basis and must be economic at about a 50% load factor. There are constraints on seasonal hydraulic generation imposed by maximum and minimum limits on downstream river flows.

5. Directly Controlled Load Following Generation: This category consists of generation that is directly controlled moment by moment by the Independent Electrical System Opertor (IESO) in order to regulate the system voltage and frequency. Ideally this controlled generation operates at about a 50% load factor. This controlled generation may actually consist of a mix of daily load following generation and seasonal load following generation. The daily load following generation may be subject to daily energy storage constraints. The seasonal load following generation may be subject to seasonal energy storage constraints.

6. Reserve Generation: This category of generation normally does not operate at all except for test purposes. Normally the load factor of reserve generation is zero. However, reserve generation must be ready to function immediately with no advance notice to make up for any failure of other generation to operate as planned.

GENERATORS' COMPENSATION RATES:

The importance of the above categories of generation lies in the generators' compensation rates. Renewable base load generation is the least expensive per kWh but is also the least flexible source of electricity. Seasonal load following generation must be economic at about a 50% load factor. Reserve generation is the most expensive form of generation per kWh but is the most reliable source of electricity. The higher reliability generation is contractually constrained off much of the time, so such generators must be paid to finance equipment that is seldom utilized.

The concept of market based electricity rates entails paying more per kWh at some times than at others and entails paying more per kWh to some generators than others. On a day by day basis, for each hour the total electricity demand is estimated by the Independent Electricity System Operator (IESO) and then that demand is met by the IESO purchasing available electricity supply for that hour starting with the least expensive source and working upwards until the projected demand is met. **However, this electricity purchasing system as presently implemented has a number of serious problems. Presently the electricity purchasing system does not include a fossil carbon emissions tax, there are hidden government subsidies for nuclear power, there are hidden government financing guarantees, major generators do not pay for transmission/distribution, there is insufficient competition for supply of seasonal hydraulic generation, reserve generation is very expensive and there is insufficient development of discretionary loads and discretionary generation to limit electricity energy price swings.**

ELECTRICITY MARKET PROBLEMS:

1. CARBON TAX: Absence of a fossil carbon emissions tax encourages consumption of coal. There should be a coal prohibitive fossil carbon emissions tax which is reasonably estimated to be $100 per emitted CO2 tonne.

2. STRANDED DEBT RETIREMENT: The charge for stranded debt retirement is not sufficient to pay down the nuclear debt and does not properly allocate the cost of nuclear generation.

3. MAJOR GENERATORS ARE NOT PAYING FOR TRANSMISSION/DISTRIBUTION: The major generators are not paying their share of transmission/distribution charges which causes the HOEP to be too small.

4. MAJOR GENERATORS HAVE GOVERNMENT GUARANTEED CAPITAL FINANCING: The major generators that existed prior to the breakup of Ontario Hydro usually had government guaranteed debt capital financing which reduced their long term costs as compared to a generator without such debt guarantees.

5. LACK OF COMPETITION: All the seasonal hydraulic generation is owned by one party, Ontario Power Generation (OPG). There is no price competition until: Price per kWh of seasonal generation approaches:
(cost per kWh of nuclear base load generation) / (load factor of seasonal generation).

6. EXPENSIVE RESERVE GENERATION: Since the load factor of reserve generation is very small its cost per kWh is extremely high. The supply of reserve generation becomes such a business gamble that there is not be enough of it for electrical system reliability. The system reliability then rests on electricity supply contracts that permit service interruption.

7. DISCRETIONARY LOADS AND DISCRETIONARY GENERATION: In order to limit the amplitude of price swings in the electricity market and increase system

reliability it is necessary to develop a group of customers that will consistently increase load or cease distributed generation when the price of electricity is low, a group of customers who will consistently decrease load or generate more electricity when the price of electricity is high, and a group of energy storage owners who will purchase electricity at a low price and sell electricity at a high price.

TOU RATES:

Examples of customers who will consistently buy electricity at a low price are owners of plug-in hybrid vehicles or chilled water storage systems. These same customers will decrease electricity usage at a high price. An example of generators who will consistently sell electricity only at a high price are owners of hydro electric generators with only daily storage. Examples of customers who will buy electricity at a low price and sell it at a high price are owners of electro-chemical energy storage systems and pumped energy storage systems.

In order to encourage development of these customer groups it is necessary to adopt regulated Time-Of-Use (TOU) electricity energy rates with sufficient on-peak / off-peak price differential to allow these customer groups to exist and financially prosper. Thus far the OPA and the OEB have paid little attention to this issue.

A problem with regulated TOU energy rates is that some parties benefit and others do not. Parties that can take advantage of inexpensive off-peak electricity rate benefit, but other parties experience increases in their average electricity cost. Hence, TOU electricity energy rates should be implemented with care.

A useful strategy for balancing the generation and load for grid voltage and frequency regulation is to offer 24 hour interruptable electricity at a discount from normal TOU rates. The purchasers of such electricity are parties that can tolerate ongoing frequent power interruptions. These parties may include:
a. Parties in the electrolysis and electrolytic refining business that have processes that can tolerate rapid large supply power variations;
b. Owners of plug-in hybrid vehicles and owners of parking lots for such vehicles;
c. Owners of energy storage systems;
d. Owners of chilled water storage systems

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 shall 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 in order to put all generators on a level playing field. The cost of the transmission/distribution for major generators will increase the Hourly Ontario Electricity Price (HOEP) but should reduce end users' transmission/distribution charges by the same amount.

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 an induction kWh meter with no ratchet, 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 LDC and the other customers of the LDC.

ENERGY EXCHANGE:
4. The electricity meter on each connection to the grid shall 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 also requires additional memory registers to show the energy imported by the grid and the energy exported by the grid during each TOU interval during the billing period.

TRANSMISSION/DISTRIBUTION COST ALLOCATION:
6. The 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 shall 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 shall 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.

12. The aforementioned grid connection issues are addressed through the use of cumulative daily kVAh metering.

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

15. If a customer presents a constant resistive impedance to the grid, then the

calculated daily kVAh is the same as the daily kWh measured by an induction type kWh meter.

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 electro-chemical energy storage on site behind the meter 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 are relatively small.

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

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

This web page last updated August 16, 2007.

XYLENE POWER LTD.

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 realestate 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.

This web page last updated August 6, 2007.

XYLENE POWER LTD.

ELECTRICITY METERING

By C. Rhodes

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

SYSTEM DESCRIPTION:
A distributed power system can be viewed as a collection of 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 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 sepatate 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 consuming little or no net energy.

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 paying a much lower rate for transmission/distribution than are electricity consumers and small distributed generators. The inequality in apportionment of transmission/distribution costs 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 consumer owned 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 any particular distribution subsystem 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 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 may be only a single energy source, such as a behind the meter generator, that normally minimizes the connection kVA. Within a one month billing period this generator will likely need to be briefly shut down for mechanical or heat load service. During that service period the building will experience a kVA peak. Hence the practical effect of monthly peak kVA metering is to unduely transfer costs to customers with behind the meter generators when their generators are shut down for maintenance or due to loss of thermal load. Hence, monthly peak kVA metering is a major obstacle to economic application of 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 increase Ke and to 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 may lead to more rather than less total electricity usage and hence may increase the total required generation capacity.

In the absence or 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 vascillating 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 were built with thermal energy storage. During the 1980s and 1990s these storage systems were taken out of service when the electricity rates were changed such that these storage systems no longer provided a significant financial benefit for the building owner. Major building owners require a financial benefit and certainty regarding the long term future of TOU electricity rates before they will make the capital and operating expenditures on chilled water 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 to fundamentally fix the electricity rate structure and then to offer building owners and developers firm electricity rate contracts, guaranteed by the Province of Ontario, with at least 10 year terms.

This web page last updated August 10, 2007.

XYLENE POWER LTD.

ELECTRICITY COST APPORTIONING

By C. Rhodes

INTRODUCTION:
This web page addresses transmission, distribution and nuclear 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:
$Pg = Pj + Pk + \ldots$
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 + ...) Cht = Cht / 2
= (2/3) Chi + (1/3) (Cji + Cki + ...)

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**

NUCLEAR DEBT RETIREMENT:
By 2001 Ontario Hydro and its successor companies had accumulated about $20 billion in stranded debt that could not be serviced from the government set electricity rates that pertained in 2001. For five years to 2006 the people of Ontario paid a "stranded debt retirement charge" of $.007 per kWh on every electricity kWh consumed in the province. The blunt reality is that this assessment of $.007 / kWh is not sufficient to pay the interest on the stranded debt. This payment of $.007 / kWh has not caused reduction in the stranded debt principal. In order to reasonably discharge the stranded debt from a surcharge on kWh consumed it is necessary to triple the debt retirement charge from $.007 per kWh to $.021 per kWh.

However, a surcharge on all electricity consumed amounts to a subsidy for nuclear generation at the expense of other non-fossil fuel generation. Since nuclear generation accounts for about half the electricity generated in Ontario, a much better accounting treatment is to charge the entire debt retirement amount to existing nuclear generation. Thus the nuclear generation component of the Hourly Ontario Electricity Price (HOEP) would increase by:
2 X $.021 / kWh = $.042 / kWh
and the average HOEP would increase by about **$.021 / kWh** just due to proper accounting for the nuclear debt.

From the point of view of the load customer the net increase in electricity costs related to nuclear debt retirement would be:
$.021 / kWh - $.007 / kWh = **$.014 / kWh**

From the point of view of the distributed generator the increase in revenue related to proper allocation of nuclear debt retirement costs would be:
$.021 / kWh

This web page last updated August 20, 2007.

XYLENE POWER LTD.

EQUIPMENT FINANCING

By C. Rhodes

INTRODUCTION:
This web page addresses the financing costs that must be met in order to effectively implement private sector distributed generation within the Province of Ontario.

FINANCING CONSTRAINTS:
The existing large generators in Ontario were mostly financed by debt instruments that were guaranteed by the government of Ontario. The required rate of return on such government guaranteed financing is only about 1/3 of the required rate of return on private sector mixed equity and debt financing with no outside guarantees.

Let the capital cost of new base load generation and accompanying energy storage per average kW generated while running be C. Assume that the unit runs 80% of the time per year (Load Factor = 0.8). For each such kW of base load generation capacity the unit produces:
1 kW X .8 X 8766 h / year = 7012.8 kWh / year.

Private sector investors have a Return-On-Investment (ROI) requirement which is generally a simple return on capital C of .04C per month or .48C per year. Of this amount .01C per month is set aside for administration, operation, maintenance and repair expenses leaving .03C per month for interest payments and capital amortization. The value Vp of a kWh required to attract private sector investment is then given by:
(.04 X 12 X C) = 7012.8 kWh X (Vp - F)
where F is the cost of fuel and other consumeables per electrical kWh generated. Note that for natural gas fueled engines and combustion turbines the engine or the turbine can be viewed as a consumeable item, becuase the operating life of such units (2 years to 4 years) under base load conditions is small compared to the contract period (20 years).

Assume that F ~ 0 as with wind, hydraulic and nuclear generation.
Then:
Vp = .48 X C / 7012.8 kWh

By comparison governments are generally satisfied with a simple payback of .02C per month or .24C per year. Of this amount .01C per month is set aside for equipment operation, maintenance and repair leaving .01C per month for debt

service. The corresponding value Vg of a kWh required to attract government investment is:
Vg = .24 X C / 7012.8 kWh

The following table summarizes Vp and Vg as a function of C for non-fossil fuel generation:

C ($ / kW)	2000	3000	4000	5000	6000
Vp ($ / kWh)	.137	.2055	.274	.3425	.411
Vg ($ / kWh)	.0685	.10275	.137	.17125	.2055

Note that the amount available for debt service in the private financing case is .03C per month whereas the corresponding amount with government financing is .01C per month. Thus the rate of return on capital investment required by private sector investors is three times the rate of return on investment required by governments. The distinction between private sector capital and government capital is that private sector capital must compete for capital against other non-energy investment opportunities whereas government capital is designated for a specific application and is not required to make a profit for the investors (taxpayers). In Canada there is presently some mitigation of Vp via Capital Cost Allowance (CCA) Class 43.2. However, this mitigation would likely be cancelled by the federal government if numerous investors took advantage of it.

This issue of the cost premium for private sector financing has not yet been adequately appreciated by either the Ontario Power Authority (OPA) or the present government of Ontario.

Note that as the load factor goes down the required $ / kWh increases. Thus even with government guaranteed financing, a peaking generator with a load factor of 20% and a capital cost of $2000 / kW requires a per kWh price of:
(80% / 20%) X $.0685 / kWh = **$.274 / kWh**
plus fuel and other consumeables.

Hence the availability of energy storage to displace low load factor peaking generation is a crucial issue in minimizing overall costs.

The required generator compensation is proportional to the initial capital cost per average kW of power output and is inversely proportional to the load factor. This author's personal experience was that in 1998 - 1999 the true capital cost of natural gas fueled behind the meter electricity generation with heat recovery was about $2000 / kW. All forms of non-fossil fuel electricity generation are more expensive.

The source of the aforementioned required return-on-investment constraints and the required provision for ongoing operating, maintenance and repair costs is this author's 25 years of experience designing, selling, financing and implementing energy systems for both government and private sector customers.

This web page last updated August 16, 2007.

XYLENE POWER LTD.

ELECTRICITY RATE STRUCTURE AND GENERATOR COMPENSATION

By C. Rhodes

ONTARIO ELECTRICITY RATE STRUCTURE PROBLEMS AND THEIR SOLUTIONS:
Many parties have advocated that Ontario adopt a distributed electricity generation system with private sector owned generation to minimize risk for the ratepayers. The rate structure of this system should effectively incorporate a fossil carbon emissions tax. However, the electricity rates presently approved by the Ontario Energy Board (OEB) are not consistent with the return-on-investment required by privately owned distributed generators. Furthermore, these rates do not penalize fossil carbon emissions to the atmosphere.

TRANSMISSION/DISTRIBUTION COST ALLOCATION:
The first major problem with the existing rate structure is that large generators such as Ontario Power Generation (OPG) and Bruce Power have free use of transmission/distribution whereas small behind the meter generators do not have free use of transmission/distribution. The hidden cost of providing large generators with free use of transmission/distribution is an obstacle to implementation of both energy conservation and distributed generation. If the Ontario Energy Board (OEB) forced large generators to pay for transmission/distribution at the same rate per kVAh as small electricity customers, then as shown on an adjacent web page titled "Electricity Cost Apportioning", major generators would have to add about $.013 / kWh onto their energy rate in order to have the cash flow to pay Hydro One Networks. Hence the Hourly Ontario Energy Price (HOEP) would increase by about $.013 / kWh. Then Hydro One Networks and the Local Distribution Companies (LDCs) could lower their transmission/distribution charges to end users by the same $.013 / kWh. For electricity consumers that made no change the net effect is zero. However, for those customers that implement generation that exports energy to the grid, the value of that exported energy increases by:
2 X $.013 / kWh = **$.026 / kWh**

ENERGY STORAGE:
The second problem with the existing rate structure is that it does not sufficiently reward RESOP generators for contributing generation that meets the daily peak electricity demand and does not sufficiently reward consumers for reducing load coincident with the daily peak demand. Achieving these objectives requires high

differential Time-Of-Use (TOU) rates and energy storage equipment.

Experience with wind turbines indicates that the average hourly output can vary over a 25:1 range through a day. In order to usefully contribute to the daily demand peak wind generators require adjacent energy storage facilities. Such energy storage facilities will not be built unless there is a significant TOU rate incentive. The TOU rate differential should approximately track daily variations in the HOEP and must be sufficient to fund the energy storage.

In order to reduce transmission requirements wind generators must be billed for transmission/distribution use in proportion to daily kVAh. The daily kVAh billing provides an incentive to operate the energy storge system for efficient use of the transmission/distribution system.

There is also merit in offering a discounted load customer rate for power that can be frequently interrupted under dispatch control without notice. Such interruptable power can displace expensive controlled generation for grid voltage and frequency stabilization. Potential applications for such power are charging the batteries of plug-in hybrid vehicles and charging energy storage systems.

STRANDED NUCLEAR DEBT:
The third major problem with the existing Ontario electricity rate structure is that stranded debt related to old nuclear facilities is charged to all electricity users rather than just the old nuclear generators and the charge is not sufficient to reduce the stranded debt. The costs of servicing this stranded debt should be met from revenue earned by existing nuclear generation facilities. This revenue should be sufficient to discharge the stranded debt in a reasonable time frame (< 10 years). As shown on the web page titled "Electricity Cost Apportioning" the required increase in the nuclear generation price is about $.042 / kWh and the consequent effect on the average HOEP is about **$.021 / kWh**.

Furthermore, new non-fossil fuel generation will likely be even more expensive than existing nuclear generation, so it is unrealistic to continue with an electricity price that is not sufficient to fully fund the existing base load nuclear generation.

FOSSIL CARBON EMISSIONS TAX:
The fourth problem with the existing electricity rate structure is that the energy portion of this rate structure is derived from the HOEP which in turn is strongly affected by the cost of electricity obtained by combustion of coal and other fossil fuels. In order to encourage construction of non-fossil fuel generation to displace coal it is necessary to compensate owners of this non-fossil generation at the rate that would prevail if fossil fuels were subject to a coal prohibitive carbon tax. Various parties, including this author, have independently calculated that the minimum effective fossil carbon emissions tax required to displace coal is about $100 per emitted CO_2 tonne. This amount translates into a cost adder for coal fueled electricity generation of about $.12 / kWh. Since coal is about 20% (1/5) of total Ontario electricity generation, the required increase in the average HOEP just due to application of a fossil carbon emissions tax to coal combustion is:
$.12 / 5 = $.024 / kWh.
When similar adjustments are made for oil and natural gas fueled electricity

generation, the net effect of applying a coal prohibitive fossil carbon emissions tax to electricity generation in Ontario is to increase the average HOEP by about: **$.03 / kWh**.

Even if a fossil carbon emissions tax is not implemented in Ontario in the near term, it is essential to reward new non-fossil fuel generators as if such a fossil carbon emissions tax were in place, in order to build up a supply of non-fossil fuel generation that can gradually replace existing coal fueled generation. It is also important that this non-fossil fuel generation be fitted with energy storage and controls so that the IESO can modulate the net generation output to match the grid load.

EFFICIENT USE OF TRANSMISSION/DISTRIBUTION:
The fifth problem with the existing rate structure is that it does not reward generators for efficient use of transmission/distribution. Recent experience with wind turbines indicates that the average hourly wind turbine output can easily vary over a 25:1 range through a month. In order to efficiently utilize transmission/ distribution wind turbines require adjacent energy storage facilities. These energy storage facilities will not be built unless there is a significant rate incentive. This rate incentive has two components, a Time-Of-Use (TOU) kWh rate and transmission/distribution use daily kVAh rate. A cumulative daily kVAh meter is required to fairly allocate transmission/distribution costs.

REPLACEMENT OF PEAK DEMAND METERS:
A related problem with the existing electricity rate structure is that existing transmission/distribution costs for commercial customers in most LDC service areas are based on monthly peak kVA or monthly peak kW instead of cumulative daily kVAh. The practical effect of monthly peak kVA or monthly peak kW billing is to excessively penalize small behind the meter generators, thus eliminating these generators from the electricity market. Such generators typically need to be shut down for generator mechanical service or thermal load mechanical service about twice per month. However, since the service times are random and statistically non-coincident, typically less than 10% of the recorded monthly peak demand billed to the building owner as a result of generator shutdown is actually billed to the LDC by Hydro One transmission. This discriminatory billing by the LDC typically devalues behind the meter generation by a further:
$.01 to $.02 per kWh
generated, depending on the generator operating cycle. The metering methodology and LDC rate structure must be changed if distributed power generation is to be realized. As an interim measure, until cumulative kVAh meters are available, the connection charge applied to commercial customers with behind the meter generators should be proportional to the metered monthly peak demand reduced by the average kW generated while the generator is operating.

OPPOSITION BY UTILITIES:
A related problem with the existing rate structure is that changes to this rate structure will be strongly opposed by LDCs, Hydro One and OPG unless the package of rate changes is implemented in a manner that leaves these parties

financially whole. The lead opponent of large scale distributed generation is Toronto Hydro. With reasonable transmission/distribution rates, widespread implementation of co-generation in high rise residential buildings within Toronto would likely reduce Toronto Hydro's gross annual revenue by over $100,000,000. This financial estimate is based on the actual performance of co-generation systems that were installed in high rise residential buildings during the period 1996 to 2000. Toronto Hydro, Hydro One and OPG will likely take the position that absent corresponding electricity rate increases that leave them financially whole, they are unable to absorb revenue losses of that magnitude.

REPLACEMENT OF TRANSMISSION/DISTRIBUTION INFRASTRUCTURE:
During the last 20 years there has been under investment by the Province of Ontario in electricity transmission and related rural distribution. The surplus capacity that existed in the early 1990s has been taken up by a growing population and delayed maintenance. The problem of locked in power at the Bruce Nuclear Generation Station has re-emerged after being dormant for over a decade. The Ontario Power Authority (OPA) is facing immediate multi-billion dollar expenditures on transmission system upgrades that will have to be financed by via increases in transmission/distribution rates.

COST OF CAPITAL:
In various speeches executives of the OPA have indicated that it is the intention of the OPA to obtain new generation from multiple parties at guaranteed long term rates. Such guarantees require the use of private capital instead of taxpayers and ratepayers funds. The return on investment required by such private capital is typically three times the return on investment required by government guaranteed borrowing. The use of private capital will substantially increase the cost of electricity but will introduce competition and will prevent governments from accumulating further public debt relating to electricity generation. It remains to be seen whether or not the OPA will actually implement programs that attract significant private capital. The present Renewable Energy Standard Offer Program (RESOP) base rate of $.11 / kWh is not sufficient to attract private capital on the scale necessary to solve Ontario's electricity supply problems. Also the present implementation of RESOP does not reliably contribute to the daily and annual peak generation requirements.

Distributed generation, new nuclear generation and energy storage cannot be built on the scale required until the cash flow received by the owners of the new generation and energy storage is sufficient to fund construction and operation of these new facilities.

OTHER CHARGES:
Toronto Hydro also bills end use customers $.0015 / kWh as a Market Transition Charge and $.0062 / kWh as a charge for Wholesale Market Operations including Rural Rate Protection.

ADJUSTED END USER ELECTRICITY RATE:
Thus, after the above mentioned rate adjustments, the average cost of electricity to an end user will be:

$.062 / kWh + $.013 / kWh + $.0157 / kWh + $.021 / kWh + $.030 / kWh + $.0015 / kWh + .0062 / kWh
= **$.1494 / kWh plus GST.**
Costs related to transmission infrastructure replacement and funding the IPSP are additional to this amount.

RATE CHANGES AND INTERIM INCENTIVES:
It may take many years to fully implement all of the aforementioned rate changes. It will take many more years for the effects of past government capital financing to work their way out of the HOEP. **In the interim the OPA and the OEB should encourage construction of distributed non-fossil fuel generation by directly paying non-fossil fuel generators.** The approximate amount of the required payment for generation with daily energy storage is set out on the web page titled "Equipment Financing". **This non-fossil fuel distributed generator compensation should be subject to the requirement that there is sufficient on-site energy storage at the generator that the average power output during the designated On-Peak hours is more than the average power output during the billing month.**

Consider a combination of non-fossil fuel generation and energy storage technologies that costs $5000 per average kW output and that is available 80% of the time. The cost per kWh can be viewed as the following decomposition:
+ $.062 / kWh (present average HOEP)
+ $.013 / kWh (transmission/distribution cost transferred to HOEP)
+ $.0157 / kWh (transmission/distribution paid by distributed generator)
+ $.021 / kWh (nuclear debt retirement transferred to HOEP)
+ $.030 / kWh (fossil carbon emissions tax effect on HOEP)
+ $.17125 / kWh (private sector financing premium for $5000 / kW, 80% load factor, no fuel)
+ $.0015 / kWh (market transition)
+ $.0062 / kWh (regulation)
= $.32065 / kWh

This amount compares to a calculated amount of:
+ $.3425 / kWh (private sector financing, $5000 / kw, 80% load factor, no fuel)
+ $.0157 / kWh (transmission/distribution paid by distributed generator)
+ $.0015 / kWh (market transition)
+ $.0062 / kWh (regulation)
= $.3659 / kWh

These calculations show that the cost of a kWh from new base load privately financed non-fossil fuel distributed generation with a capital cost of $5000 / kW is in the range **$.32065 / kWh to $.3659 / kWh**

The payment amounts in excess of HOEP should diminish over time as the aforementioned rate structure problems are eliminated and HOEP increases. Eliminating the discriminatory peak demand charges may require the OPA to also make temporary interim payments to the LDCs to keep them financially whole.

IMPLEMENTATION:

These payment changes to generators could be immediately implemented by the OEB by amending the RESOP and CESOP. Resolving these generator payment issues is primarily a matter of political will.

These payment rate changes would put existing central generators and new distributed generators on a level playing field and would enhance the reliability of the Ontario electrical grid by encouraging development of non-fossil fuel distributed generation where ever that generation makes economic sense. However, before plunging ahead it would be prudent for the OEB to consider the long term cost to the ratepayers of privately owned distributed generation.

The OEB may wish to express its view to the government and to the ratepayers at large regarding the stated plans of the OPA to use private sector financing in place of government financing, because the effect of the private sector funding premium is to almost double the long term cost of electricity in Ontario. It may be more prudent for the OEB to insist that the stranded debt be rapidly paid off so that Ontario can return to use of government guaranteed debt for funding major electricity projects.

This web page last updated August 18, 2007.

ELECTRICITY

OPA STANDARD OFFER PROGRAMS

By C. Rhodes

DEFINITION:
A Standard Offer Program (SOP) is a program under which small generators are paid a standard rate for the electricity that they generate and export to the electricity grid. A Standard Offer Program provides an administratively practical means of implementing distributed electricity generation. The standard offer may include time dependent rates that provide a price bonus for electricity that is consistently delivered coincident with the daily peak load on the electricity grid. In principle a standard offer program could provide a further price bonus for use of self excited generators and for allowing the Independent Electricity System Operator (IESO) control of the net power output.

BENEFITS:
The benefits of a Standard Offer Program (SOP) are that it can be used to circumvent existing electricity rate structure problems and it can provide a means for a small generator to obtain a limited amount of commercial financing based on a SOP contract with the Ontario Power Authority (OPA). Under an SOP contract the OPA guarantees to take and pay, at a specified rate, for the electricity generated.

ONTARIO PROGRAMS:
The Ontario Power Authority (OPA) made a small positive step forward by implementing a Renewable Energy Standard Offer Program (RESOP) to encourage the construction of distributed renewable electricity generation. The OPA has also announced its intent to implement a Clean Energy Standard Offer Program (CESOP).

The present RESOP details are available at OPA RESOP.

The contemplated CESOP details are available at OPA CESOP.

The major problems with the present and contemplated implementation of these these programs are:
1. The payments offered are not sufficient for commercial viability;
2. The present program implementation will not significantly contribute to the amount of non-fossil fuel generation that Ontario requires;
3. The programs do not recognize the benefit to transmission of high generator capacity factor;
4. The programs do not adequately recognize the benefit to the entire electricity

system of reliable generation coincident with the daily electricity demand peaks.
5. The cost of financing implicit in these programs is very high.

The underlying problem is that the RESOP and CESOP payment rates were intuitively derived from the Hourly Ontario Electricity Price (HOEP), which is itself an illusion.

For about 20 years the true cost of non-fossil fuel electricity generation in Ontario has been concealed from the general public. The concealing accounting mechanisms are so complex that many senior persons in the energy sector do not understand them. Successive provincial governments have failed to properly address this issue. Meanwhile Ontario accumulated over $20 billion in unfunded electricity debt. Electricity in Ontario is still sold far below its intrinsic value. Correcting this situation requires a succession of substantial electricity rate increases which politicians are loath to face. However, the reality is that if this issue is not promptly faced Ontario will experience enormous escalations in electricity prices.

The present "Hourly Ontario Electricity Price" (HOEP) is too low and hence discourages electricity conservation, distributed generation and prudent investment in new major generation and transmission.

HOEP PROBLEMS:
The average HOEP is too low because:
1. There is no fossil carbon emissions tax;
2. The costs of paying down stranded nuclear debt are not included in the HOEP;
3. The costs of government guaranteed electricity system financing are hidden;
4. Major generators are not paying for transmission/distribution;
5. The inherent value of seasonally stored hydro-electric power is not properly reflected in the HOEP.
6. The full cost of reserve generation is not well reflected in the HOEP.

The HOEP is far too low for the average HOEP to be commercially viable as a RESOP or CESOP base payment rate.

NEW METHODOLOGY:
A better means of establishing the RESOP and CESOP base rates is to use the same effective rate as is arrived at on a competitive basis for large non-fossil fuel generation projects such as hydro-electric dams or new nuclear facilities that do not include government funding guarantees of any type.

OBJECTIVE:
The objective of this web page is to identify the rate changes and incentives that are required to achieve maximum economic distributed electricity generation in Ontario while minimizing emissions of green house gases. The importance of identifying these rate changes and incentives 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).

RESOP:

The present implementation of the RESOP allows generators using renewable energy sources to operate at random times and sell the electricity that they generate to the grid at a fixed rate. However, the present RESOP does not adequately reward reliable generation that is coincident with the provincial electricity demand peak and pays too much for electricity that is generated but not stored at times of low electricity demand. The existing RESOP implicitly assumes that there is available uncommitted external energy storage via fossil fuels or hydraulic storage for system balancing. However, as coal fueled electricity generation is closed, the available amount of low cost system balancing capacity will decrease.

Another problem with the present RESOP program is that RESOP generators are not required to be self excited or IESO controllable. Hence these RESOP generators add to grid instability.

When the OPA originally proposed the Renewable Energy Standard Offer Program there was some uncertainty regarding the most appropriate base rate, and the OPA chose a low base rate believing that it could always raise the base rate at a later date. However, the OPA failed to address the possible political consequences of the government going into a provincial election with a RESOP base rate that is too low for large scale commercial viability.

Since the original announcement of the RESOP program various practical issues relating to wind power have been studied in detail. Wind generation without energy storage has several major problems.

1. The first problem is that the reliable wind generation that is coincident with the annual peak electricity load is almost zero. Most good wind generation sites are located close to the shores of large water bodies. The wind at such locations reverses direction twice in every 24 hours. At the times of the wind direction reversals the wind generation drops to almost zero. In order to provide reliable power coincident with the daily electricity demand peak wind generators must be complemented by energy storage systems.

2. The second problem is that the average wind generation in the summer is less than 20% of the peak wind generation in the winter. Hence wind generators without on-site energy storage use transmission very inefficiently. In order to contain the costs of transmission wind generators must be fitted with on-site electro-chemical energy storage and voltage source inverters.

3. The third problem is that the daily peaks in wind generation tend to occur at times when the provincial electricity load is close to minimum. In order to be economically beneficial the wind energy needs to be stored and then released during the daily electricity demand peak. Again on-site electro-chemical energy storage and voltage source inverters are required to address this problem.

4. The fourth problem is that most wind generators currently in use in Ontario are not self excited and are not controllable by the IESO. These generators increase the grid instability. This problem can be solved by adding electro-chemical energy storage and a voltage source inverter to each wind generator.

CONCLUSION:
In order to provide major benefits to the electricity system wind generators require on-site energy storage. The financial analysis on this web site indicates that private sector financed RESOP wind generation that will reliably contrbute to the daily and annual peak load costs about $.39 / kWh. Of this amount about $.18 / kWh must be paid for the energy generation and a further $.21 / kWh must be paid for the energy storage and inverter system to time shift the energy output onto the daily electricity demand peak.

The financial analysis indicates that the present RESOP payment rates of about $.11 / kWh are far too small and that new nuclear power or out of province hydro-electric power, if available at an all inclusive cost of less than $.18 / kwh, is a bargain.

It appears that **if there is an Ontario government financing guarantee the cost of reliable wind power can be reduced to about $.195 / kWh**. It is important to further investigate this matter because this cost has the potential of capping the future cost of new nuclear power.

The RESOP presently circumvents rate structure and metering issues through the use of multiple interval meters that are connected such that a building with behind the meter generation is billed as if the generation were not present. The generator is treated as a separate LDC account. The problem with this solution is that it is administratively too complex and too expensive to be economically applied to micro-generators.

COST OF ELECTRICITY FROM RENEWABLE SOURCES:
The OPA has concluded that the market price for electrical energy that is supplied at random times from a self financed wind generator is $.11 / kWh generated. The OPA is providing a bonus of $.0352 / kWh for electricity that a generator consistently supplies coincident with the peak load on the grid. If the peak hours are defined as 11 AM to 7 PM Monday to Friday, the net effect of this bonus is to raise the average cost of base load electricity from renewable sources to:
[((168h - 40h) X $.11/kWh) + (40h X $.1452/kWh)]/ 168h = $.11838 / kWh.

This author is of the view that payment rates offered by the OPA are no where near sufficient to attract the required investment in on-peak generation. This author is of the view that wind generation without energy storage and without government financing guarantees requires a payment rate of $.18 / kWh and that base load wind energy without government financing guarantees requires a payment rate of $.39 / kWh. If government financing guarantees are available these rates drop to $.09 / kWh without energy storage and $.195 / kWh with daily energy storage.

It is believed by this author that in calculating the RESOP base rate the OPA assumed that the generator had nearly free access to the electricity grid. If the change in transmission/distribution rate structure proposed on this website is adopted a RESOP generator will likely have to pay for transmission/distribution at an effective rate of about $.0157 per kWh delivered to the grid. Hence the RESOP base rate will have to be increased by about $.0157 per kWh just to offset the cost of transmission/distribution borne by distributed generators.

NEW STANDARD OFFER PROGRAM BASE RATE:
An alternative method of determining the appropriate RESOP base rate is to obtain a long term all inclusive cost for new nuclear electricity or out of province hydro electricity plus related transmission, and then to increase this rate by the cost of transmission/distribution billed to the generator.

CONCLUSION:
This analysis indicates that the present implementation of the OPA Renewable Energy Standard Offer Program (RESOP) is not commercially viable.

Another issue not addressed in the above analysis is the potential increment in base rate required to compensate for loss of economy of scale. The cost to rate payers of this increment in base rate may be offset by savings due to reduced transmission costs for smaller and more distributed RESOP generators. When this increment is taken into account the RESOP base rate will likely need to be:
$.20 / kWh
to achieve large scale implementation of RESOP wind generation without accompanying energy storage.

A distributed generator that is not participating in the RESOP can potentially mitigate its grid connection costs by being installed behind the meter of a building that has an electrical service of sufficient size to accept the maximum generator output. By this means the net power flowing to and from the grid is minimized and hence LDC imposed transmission/distribution charges are minimized. Provided that there is no peak kVA or peak kW metering, this technique may result in a larger financial benefit to the generator than is presently available via the RESOP.

RATE CHANGES:
As set out on this website under the heading "Electricity Rate Structure and Generator compensation", even with Ontario government guaranteed distributed generator financing, in order to provide fair compensation to distributed non-fossil fuel generators, adjustments for misallocated transmission/distribution charges, misallocated debt reduction costs and carbon tax will cause the electricity energy rate to increase to:
($.062 / kWh + $.013 / kWh + $.021 / kWh + $.030 / kWh) = $.126 / kWh
and will cause the end user transmission/distribution and debt reduction charges to decrease to:
($.0157 / kWh + $.000 / kWh) = $.0157 / kWh.

CLEAN ENERGY STANDARD OFFER PROGRAM:
Natural gas fueled co-generation could be provided under a Clean Energy Standard Offer Program (CESOP). The corresponding CESOP base rate would have to be about **$.2455 / kWh.** This rate may need further adjustment to reflect future increases in transmission and distribution costs borne by the generator.

CESOP RULES AND REGULATIONS:

The rules of the proposed distributed generation incentive program for behind the meter generation are simple:

1. The carbon emissions to the atmosphere related to electricity generation must be less per kWh than the emissions of a combined cycle natural gas fuelled generation plant;
2. The facility main electricity meter should have a cumulative daily kVAh register instead of a monthly peak kVA meter or peak kW meter;
3. The output of the behind the meter generator must be fitted with a dedicated sealed revenue accuracy kWh meter.
4. The amount paid to the building owner is given by the formula:
Amount
= ($.2455 / kWh) X kWh generated.
5. The metering must be configured so that the building owner pays for generated electricity that he consumes at the HOEP rate.
6. The amount paid to the building owner should be subject to ongoing adjustments to reflect changes in the price of natural gas, the cost of living, and electricity transmission/ distribution costs.

This web page last updated August 20, 2007.