Aegent
ENERGY ADVISORS INC.

Ontario Electricity Total Bill Impact Analysis
August 2010 to July 2015

About Aegent Energy Advisors

Aegent Energy Advisors Inc. ("Aegent") is a consulting company providing independent, objective advice to large energy buyers on all aspects of their electricity and natural gas procurement. Aegent specializes in helping buyers to reduce commodity cost, manage commodity price risk, and optimize utility contracts.

More on Aegent can be found at www.aegent.ca.

Background

With all of the changes the Ontario electricity industry is undergoing, it is clear there will be future cost increases and resulting customer impacts. Related to the Ontario Energy Board ("OEB") process for considering Hydro One's application for transmission rate increases for 2011 and 2012 (EB-2010-0002), Canadian Manufacturers and Exporters ("CME") commissioned Aegent to develop a total bill impact analysis of increases over the next five years. CME takes the position that the total bill impact of any specific utility rate application the OEB considers cannot be evaluated by simply considering utility-specific changes to line items in the electricity bill and holding everything else constant. Rather, there is a need to consider the total bill impact of what a particular utility is proposing in conjunction with everything else in the electricity bill that is simultaneously changing.

CME asked Aegent to provide this analysis because Aegent has experience in estimating total bill impacts of this nature. An example of this type of analysis was released by Aegent in March 2010 in a report. A copy of this is attached at Tab A.

This document provides a discussion of the method Aegent has applied and the results of the analysis. These materials have been prepared by Mr. Bruce Sharp of Aegent. Mr. Sharp, whose curriculum vitae is attached at Tab B, will testify to support this analysis.

The information upon which this analysis is based includes information published by the Ontario Power Authority ("OPA"), the Independent Electricity System Operator ("IESO"), Ontario electricity distributors, and rate case filings with the OEB made by Hydro One Networks Inc. ("Hydro One") and Ontario Power Generation Inc. ("OPG"). Almost all of these entities, except some of the electricity distributors, are owned by the Government of Ontario, and all are entities over which the OEB exercises regulatory authority.

Aegent does not have access to the five (5) year Business Plans of these entities. Accordingly, where necessary, this analysis provides Aegent's estimates, based on assumptions that it considers to be reasonable and conservative, of the electricity price implications of the five (5) year Business Plans of these entities that will have an influence on elements of the electricity bill. Aegent readily acknowledges that entities such as the OEB or the Ministry of Energy and Infrastructure ("MEI" or the Ministry of Energy), with an ability to access the five (5) year Business Plans of the OPA, IESO, Hydro One, OPG and other transmitters and distributors the OEB regulates, are in a position to provide any information that is needed to better align Aegent's estimates with the contents of those five (5) year Business Plans.

It is possible that the OEB and/or the MEI have already prepared total bill impact reports of the type presented in this analysis. If they are conducting total bill impact studies, then the results of those studies or reports should be made public. They are urgently needed by manufacturers and other consumers for business planning purposes.

Time Period Covered

This analysis assumes that there will be no lag in the bill impact of utility cost increases for a particular year for which the OEB sets prospective test period rates. Cost increases derived from information on file with the OEB are assumed to have an effect on the bill in each particular year for which those costs are either forecast or estimated to be incurred. For other cost increases, including those linked to procurements by the OPA, the analysis assumes that there will be a lag between the contracting commitments made by the OPA and the total bill impact of those procurement arrangements. The analysis assumes that commitments made between August of one year and July of the ensuing year will affect electricity bills in that ensuing year, so that costs reflected in OPA publications pertaining to the period August 2010 to July 2011 will be reflected in the analysis for the year 2011. Procurement commitments made by the OPA in the period between August 2011 and July 2012 will be reflected in the analysis for the year 2012. The same method is applied to estimate cost increases for 2013, 2014, and for early 2015.

Cost Increase Elements

The following cost increase elements, shown with the residential bill areas they fall under, were evaluated:

cost increase element	bill area	table
Feed-In-Tariff (FIT)	Electricity (Provincial Benefit)	1a, 1b, 1c
Renewable Energy Standard Offer Program (RESOP)	Electricity (Provincial Benefit)	2
Renewables (other)	Electricity (Provincial Benefit)	3
Bruce Power (existing)	Electricity (Provincial Benefit)	4
Bruce Power (new)	Electricity (Provincial Benefit)	5
OPG	Electricity (Provincial Benefit)	6
Natural Gas	Electricity (Provincial Benefit)	7
Non-Utility Generators (NUGs)	Electricity (Provincial Benefit)	8
Conservation and Demand Management (CDM)	Electricity (Provincial Benefit)	9
Transmission	Delivery or Regulatory	10a, 10b, 10c
Distribution (non-Green Energy Act)	Delivery	11
Distribution (Green Energy Act)	Delivery or Regulatory	12

Excluded Cost Increase Elements - Already in Effect

The following cost increase elements have already come into effect for residential consumers:

a) Two-tier RPP rate increase – This increase came into effect May 1, 2010. For consumers using 800 kWh per month, this increase amounted to $ 7.10/MWh (12 month impact).
b) TOU RPP increase – This has affected some residential consumers, with most to follow. The cost increase is in the order of $ 4/MWh.
c) Special Purpose Charge – Effective May 1, 2010 many or most local distribution companies began collecting this from customers. The rate/increase is $ 0.38/MWh.
d) HST – Introduction of the Harmonized Sales Tax on July 1, 2010 resulted in the sales tax on electricity increasing from 5 % to 13 % -- a residential bill impact. The additional 8 % adds about $ 9/MWh to an approximate, previous GST-exclusive residential unit rate of about $ 115/MWh.

The total of items a) to c) is about $ 11.50/MWh (no HST) or $ 13/MWh with HST. In combination with item d), the total bill impact of the items already in effect is about $ 22/MWh. This is an increase of about 18% from a previous GST- inclusive unit price of about $ 120/MWh. Increases included in this analysis are additive, though there is some overlap with these excluded items (in the order of $ 3/MWh).

Excluded Cost Increase Elements - Other

The following elements were not included in the analysis as they have non-uniform and/or uncertain impacts:

a) Industrial "time-of use" rates – This concerns the reallocation of Global Adjustment / Provincial Benefit costs, from a postage-stamp basis to one determined by coincident peak demands.
b) Coincident peak allocation of future transmission costs – Similar to the Global Adjustment/Provincial Benefit reallocation noted above, the same could occur with transmission. Even with transmission rates rising rapidly, there are less total dollars involved and so if this occurs the ultimate (into 2015) increase would likely be less than $ 0.50/MWh.
c) IESO Smart Grid investment – These costs may arise in the future but as of this date the IESO has not identified any significant related costs in its most recent Business Plan (2010 - 2012).
d) Ancillary services – The integration of a huge amount of new generation will most likely lead to significant operating challenges, which in turn will result in increased ancillary services (including operating reserve and regulation service) costs.

General Methodology

The following general methodology was used in analyzing each cost increase element:

a) Calculate cost in reference time period prior to first increase period, if applicable ($ million)
b) Calculate cumulative cost in forecast periods ($ million)
c) Cumulative increase for each forecast period is value or value less reference period value ($ million)
d) Use IESO total annual energy consumption forecast (and escalated) values (TWh)
e) Calculate cumulative unit cost increase values ($/MWh)
f) Increases will manifest themselves through increases to the Global Adjustment/Provincial Benefit, transmission distribution and possibly regulatory charges.

Methodology Details

The following methodologies were used in analyzing groups of or individual cost increase elements:

<u>FIT, RESOP, Renewables (other), Bruce Power (new)</u>

- For each period, subtract reference spot price from contract price to arrive at premium over spot price in $/MWh
- Estimate MW quantities added each period
- Calculate cumulative MW quantities to end of each period
- Use capacity factors and 8,760 hours in year to arrive at cumulative MWh to the end of each period
- Cumulative $, to end of period = cumulative MWh, to end of period x $/MWh
- Cumulative increase $ = cumulative $ (all "new" so no reference required to prior to Aug10)

<u>Bruce Power (existing)</u>

- For each period, subtract reference spot price from contract price to arrive at premium over spot price in $/MWh
- Use current, uniform MW quantity in each period
- Apply capacity factors and 8,760 hours in year to arrive at cumulative MWh in each period
- Cumulative $ to end of each period = cumulative MWh x $/MWh

- Cumulative increase $, to end of each period = cumulative $, in each period less cumulative $, prior to Aug10

OPG, NUGs

- Subtract reference spot price from contract price to arrive at premium over spot price in $/MWh
- Use annual TWh quantities for each period
- Calculate premium-over-spot $ in period = $/MWh x MWh
- Increase $ to end of period = premium-over-spot $ in period less same, prior to Aug10

Natural Gas

- Estimate MW quantities added each period
- Calculate cumulative MW quantities to end of each period
- Estimate contingent support payment rates ($/MW/year)
- Cumulative $ to end of each period = cumulative MW x $/MW/year
- Cumulative increase $ = cumulative $

CDM

- Estimate expenditures in each period
- Cumulative increase $, to end of each period = cumulative $, to end of period less cumulative $, prior to Aug10

Transmission

- Determine / estimate Rates Revenue Requirement in reference and each forecast period
- Cumulative increase $, to end of each period = cumulative $, to end of period less cumulative $, prior to Aug10

Distribution (non-GEA)

- Use 2009 total Ontario LDC distribution revenue (OEB's 2009 Yearbook of Electricity Distributors)
- Estimate annual increase percentages
- Calculate increased annual revenues
- Cumulative increase $, to end of each period = revenue, each period less revenue, 2010

Distribution (GEA)

- Use Hydro One Distribution Green Energy Act data to extrapolate total Green Energy Act investment by all Ontario LDCs
- Determine / estimate Rates Revenue Requirement in reference and each forecast period
- Cumulative increase $, to end of each period = cumulative $, to end of period less cumulative $, prior to Aug10

Commodity Price Assumptions

For this analysis we define the total commodity price for electricity as being comprised of the spot price of electricity and the Global Adjustment (the "GA"). By spot price we generally refer to the arithmetic average price of electricity, also referred to as the Hourly Ontario Energy Price ("HOEP"). The GA is also referred to as the Provincial Benefit on local distribution company ("LDC") – served customers' electricity bills).

HOEP-GA Interaction

There is a clear interaction between the spot price of electricity and the GA. When spot prices fall, the GA rises and vice versa. This occurs because the government and its agencies have entered into electricity supply arrangements that cover off a very large majority of Ontario electricity supply requirements. The majority of these contracts included fixed prices (some with escalators). With the huge amount of contracted generation coming in to service over the next five years, virtually no new supply will be un-contracted and so this interaction will become even stronger.

The dynamic is more complex than that but for the purposes of this analysis we assume that the combination of HOEP and the GA are generally fixed. This means that a lower spot price is offset by a correspondingly higher GA and vice versa.

Uniform Forecast of HOEP

We also assume that HOEP is fixed during the forecast period. This simplifies the analysis related to most of the generation-related elements, by taking away the need to forecast and incorporate HOEP and the GA for each year analyzed. Even if different HOEP forecast values were used for each period, HOEP-GA interaction assumption would have an offsetting impact, resulting in the same reference total commodity price and rendering varying annual HOEP values moot.

Reference Spot Market Prices

Based on the monthly behavior of HOEP and the GA over the last six to twelve months, we estimate the current, total commodity price to be approximately $ 65/MWh, comprised of HOEP at $ 38/MWh and the GA at $ 27/MWh. For most of the new generation sources with fixed-price contracts, we assume they will be paid $ 38/MWh from the spot market and then be “made whole” through payments funded through the GA. Solar and NUG projects are the exception – as they produce energy during higher-priced daylight and on-peak hours. We assume they will be paid $ 48/MWh from the spot market, with the remainder funded through the GA.

Other Assumptions

This analysis includes a number of assumptions. Some relate to forecast years beyond test periods documented in OEB rate cases; in those cases we assumed similar and/or moderate increases in future years. In all cases we have tried to be reasonable and err on the side of being conservative, i.e. the low side.

One major assumption of note is the amount of FIT generation that will come into service during the forecast period. For our analysis, we assume a total of 10,500 MW of FIT generation will come online by July 2015. This is comprised of 8,000 MW of FIT applications received by the OPA as of April 2010 and 2,500 MW of Samsung wind and solar projects.

Incremental Surplus from New Generation

Using near-term IESO forecasts and similar escalation rates, we estimate that annual Ontario energy consumption will grow by 6.2 TWh between 2010 and 2015. By 2015, the new generation (FIT, remaining RESOP, other renewable, new Bruce Power) identified in this analysis will produce an approximate 41 TWh (25.9 + 1.4 + 1.5 + 12.0) of incremental annual energy.

Generation that will or could be retired or otherwise out of service in the next few years includes coal (10 TWh in 2009) and nuclear (OPG’s Pickering B: 2,160 MW at a capacity factor of 85% ~ 16 TWh), for a total of about 26 TWh. Not included in this number is the inevitable contribution of energy from incremental natural gas generation, required for system operability and other purposes.

That leaves an incremental surplus of at least 15 TWh. Possible consequences of this surplus include:

a) Displacement of OPG's unregulated generation
b) Displacement of Bruce Power or renewable output, both with possible take-or-pay implications
c) Significantly increased surplus base load generation
d) Significantly increased (and subsidized) exports

Concerning the potential for renewable-related take-or-pay or curtailment events, if just 10% or 2.9 TWh of new renewable energy output by 2015 had to be dispatched off and still paid the above-market premium (an average of over $ 140/MWh), the impact would be $ 406 million. It should be noted however that in the context of this analysis this would not be additional as the above-market cost is already accounted for.

Results

Throughout the analysis we have used nominal (i.e. non-constant) dollars.

Cumulative Increase, Total Dollars ($ million)

The cumulative total dollar increase from 2011 to early 2015 is $ 7.739 billion. The cumulative dollar increase for each element and in total, on a year-by-year basis, is shown below:

element	**2011**	**2012**	**2013**	**2014**	**early 2015**
Feed-In-Tariff (FIT)	$ 481	$ 963	$ 1,444	$ 2,646	$ 3,848
Renewable Energy Standard Offer Program (RESOP)	$ -	$ 110	$ 220	$ 330	$ 330
Renewables (other)	$ -	$ 7	$ 36	$ 66	$ 96
Bruce Power (existing)	$ 14	$ 29	$ 43	$ 58	$ 74
Bruce Power (new)	$ -	$ 377	$ 404	$ 443	$ 461
OPG	$ 234	$ 304	$ 166	$ 166	$ 237
Natural Gas	$ 57	$ 86	$ 111	$ 111	$ 192
Non-Utility Generators (NUGs)	$ 94	$ 197	$ 158	$ 258	$ 170
Conservation and Demand Management (CDM)	$ 105	$ 187	$ 226	$ 265	$ 267
Transmission	$ 189	$ 299	$ 505	$ 704	$ 1,012
Distribution (non-Green Energy Act)	$ 80	$ 163	$ 206	$ 249	$ 293
Distribution (Green Energy Act)	$ 156	$ 310	$ 465	$ 615	$ 759
total	**$ 1,411**	**$ 3,032**	**$ 3,986**	**$ 5,911**	**$ 7,739**

Annual Energy

The following Ontario total annual energy consumption values were used. The 2011 value is the IESO's most recent weather-normalized forecast. We used the same energy quantity for 2012 – 2015 as we believe that increased conservation and demand management efforts will offset load growth that would otherwise take place.

for	**2011**	**2012**	**2013**	**2014**	**2015**
Ontario annual energy, TWh	142.9	142.9	142.9	142.9	142.9

Cumulative Increase, Unit Cost, ($/MWh)

The cumulative unit cost increase from 2011 to early 2015 is $ 54.15/MWh (no HST) and $ 61.19/MWh with HST. The GST/HST-exclusive cumulative increases for each element and in total, on a year-by-year basis, are shown below:

element	2011	2012	2013	2014	early 2015
Feed-In-Tariff (FIT)	$ 3.37	$ 6.74	$ 10.11	$ 18.52	$ 26.93
Renewable Energy Standard Offer Program (RESOP)	$ -	$ 0.77	$ 1.54	$ 2.31	$ 2.31
Renewables (other)	$ -	$ 0.05	$ 0.25	$ 0.46	$ 0.67
Bruce Power (existing)	$ 0.10	$ 0.20	$ 0.30	$ 0.41	$ 0.52
Bruce Power (new)	$ -	$ 2.64	$ 2.83	$ 3.10	$ 3.22
OPG	$ 1.63	$ 2.13	$ 1.16	$ 1.16	$ 1.66
Natural Gas	$ 0.40	$ 0.60	$ 0.78	$ 0.78	$ 1.35
Non-Utility Generators (NUGs)	$ 0.66	$ 1.38	$ 1.11	$ 1.80	$ 1.19
Conservation and Demand Management (CDM)	$ 0.73	$ 1.31	$ 1.58	$ 1.85	$ 1.87
Transmission	$ 1.32	$ 2.09	$ 3.53	$ 4.92	$ 7.08
Distribution (non-Green Energy Act)	$ 0.56	$ 1.14	$ 1.44	$ 1.74	$ 2.05
Distribution (Green Energy Act)	$ 1.09	$ 2.17	$ 3.26	$ 4.30	$ 5.31
total	**$ 9.87**	**$ 21.22**	**$ 27.90**	**$ 41.36**	**$ 54.15**

Unit Cost Impacts

Non-Residential

Unit costs can vary greatly, depending on load characteristics and LDC rates.

Based on the forecast total unit cost increase and depending on the reference unit cost, by early 2015, non-residential consumers would see their total unit cost rise by 47% - 64% (over the increase already experienced in 2010). This is equivalent to an average, annual, compounded increase of 8.0% – 10.4% (again, over the increase already experienced in 2010).

The table below shows the unit cost impacts for August 2010 reference unit costs ranging from $ 85/MWh to $ 115/MWh. This range has been selected as being representative of the total bill unit cost that small to large manufacturers currently pay. Note that all unit rates shown in the table below exclude GST/HST.

cumulative increase	$ 9.87	$ 21.22	$ 27.90	$ 41.36	$ 54.15	% increase, Aug10 - Jul15	
August 2010	2011	2012	2013	2014	early 2015	total	average annual (compounded)
$ 85.00	$ 94.87	$ 106.22	$ 112.90	$ 126.36	$ 139.15	63.7%	10.4%
$ 90.00	$ 99.87	$ 111.22	$ 117.90	$ 131.36	$ 144.15	60.2%	9.9%
$ 95.00	$ 104.87	$ 116.22	$ 122.90	$ 136.36	$ 149.15	57.0%	9.4%
$ 100.00	$ 109.87	$ 121.22	$ 127.90	$ 141.36	$ 154.15	54.2%	9.0%
$ 105.00	$ 114.87	$ 126.22	$ 132.90	$ 146.36	$ 159.15	51.6%	8.7%
$ 110.00	$ 119.87	$ 131.22	$ 137.90	$ 151.36	$ 164.15	49.2%	8.3%
$ 115.00	$ 124.87	$ 136.22	$ 142.90	$ 156.36	$ 169.15	47.1%	8.0%

Residential

This metric is included in this analysis as it is one the board is familiar with and regularly applies. Unit costs can vary greatly, depending on LDC rates.

Based on the forecast total unit cost increase and depending on the reference unit cost, by early 2015, residential consumers would see their total unit cost rise by 38% - 47% (over the significant increase already experienced in 2010). This is equivalent to an average, annual, compounded increase of 6.7 – 8.0% (again, over the significant increase already experienced in 2010).

The table below shows the unit cost impacts for August 2010, HST-inclusive reference unit costs ranging from $ 130/MWh to $ 160/MWh.

cumulative increase	no HST	$ 9.87	$ 21.22	$ 27.90	$ 41.36	$ 54.15	% increase, Aug10 - Jul15	
	with HST	$ 11.15	$ 23.97	$ 31.52	$ 46.74	$ 61.19		
with HST							total	average annual (compounded)
August 2010		2011	2012	2013	2014	early 2015		
$130.00		$ 141.15	$ 153.97	$ 161.52	$ 176.74	$ 191.19	47.1%	8.0%
$135.00		$ 146.15	$ 158.97	$ 166.52	$ 181.74	$ 196.19	45.3%	7.8%
$140.00		$ 151.15	$ 163.97	$ 171.52	$ 186.74	$ 201.19	43.7%	7.5%
$145.00		$ 156.15	$ 168.97	$ 176.52	$ 191.74	$ 206.19	42.2%	7.3%
$150.00		$ 161.15	$ 173.97	$ 181.52	$ 196.74	$ 211.19	40.8%	7.1%
$155.00		$ 166.15	$ 178.97	$ 186.52	$ 201.74	$ 216.19	39.5%	6.9%
$160.00		$ 171.15	$ 183.97	$ 191.52	$ 206.74	$ 221.19	38.2%	6.7%