# “Lessons from LTC experience in semi-liberalized markets: the case of Ontario ”

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# Electricity Restructuring Ontario

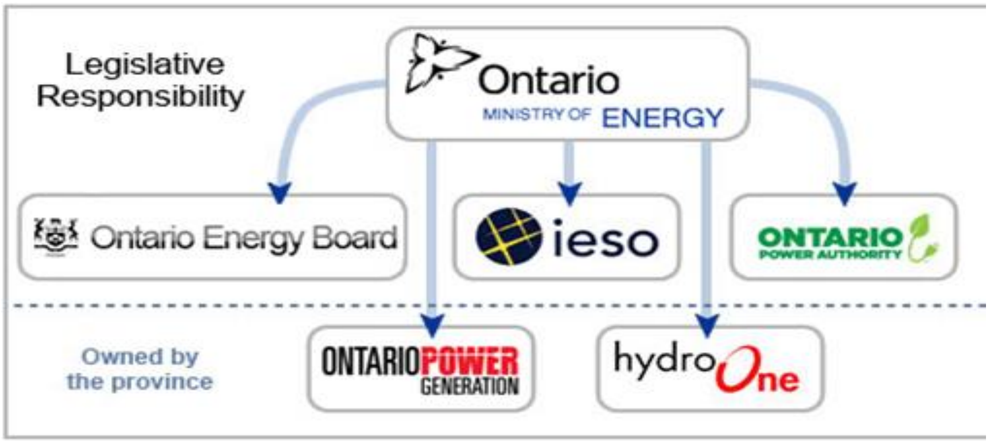
## 1998 - 2002 Electricity restructuring and privatization

- HEPC split into three private companies :
  - Ontario Power Generation (for production)
  - Ontario Hydro Services (transmission networks, remote distribution
  - Independent Market Operator (st planning, dispatch, wholesale markets)

## 2002 – 2006 Adjustment Process for the new model

- Shrinking supply despite rising demand and population highlighted the need for a long term planning process to cover supply mix, regional distribution, growth forecasts and environmental goals.
- Creation of the OPA (Ontario Power Authority) to fill this role.
- Supply Mix Advice Report in 2005
- OPA sets up new procurement process for long term contracts in 2006 to stimulate investment in new capacity to meet the plan targets

# The Contract Process




- **Capacity Planning**
  The OPA defines a long term plan by type of power source and service region and opens capacity for development.
- **Supplier Qualification**
  There is a supplier qualification process for all new suppliers.
- **Bidding**
  Candidates present proposals for capacity development covering time to build, technical characteristics, project management and operations management.
- **Ongoing Operation**
  The producer must have his capacity available and produce when called upon by the dispatch operator. The producer is paid by OPA at the contract price.
- **Quality Control and Evaluation**
  There are quality standards and an evaluation process.

# Contract Prices Examples

## All Contracts

- Long term contracts with confidential prices and rules for price increases over time
- Penalties for missing project schedule and for failure to provide capacity when called
- Contracts are exclusive with OPA except for certain exceptions for ancillary services

## Thermal average contract length 20 years

- Link to capacity through 'deemed production'* which is used in place of actual production because the producer doesn't control dispatch.
- There is also a minimum revenue requirement that triggers complements or paybacks.
- Mix between an energy only contract and a capacity mechanism.
- Link to cost and also a reference price for gas based on a reference hub.
- Bidding process distinguishes simple, combined cycle and combined heat and power

** Deemed production is expected average volume as defined in contract*

| | | |
|---|---|---|
| **Hypothetical example for St Clair - Sarnia - capacity of 577 MW** | | |
| | | |
| | 7900$/MW month | |
| | $4 558 300 | minimum revenue requirement |
| | | |
| | deemed production - January | |
| | 107322 | MWH assuming 6 hrs a day at 577 |
| | $5 366 100 | $50/mwh - part of the 807 800 of excess paid back to OPA |
| | | |
| | deemed production - July | |
| | 71548 | MWH assuming 4 hrs a day at 577 |
| | $3 577 400 | $50/MWH OPA tops up this payment with 980 900 to meet minimum |

# Contract Prices Examples

**Renewables** 6-10 years new techno, 20 established, 50 large hydro

- Feed in Tariffs for new renewables (power from waste, some PV)
- Some FIT for small hydro, especially peaking units and storage
- Established large hydro based on cost plus reference prices (similar to former regulated prices) with mechanisms to cover dispatch gaps and minimum revenues
- Established wind and solar shifting to a new mechanism more in line with established hydro

**FIT/microFIT PRICE SCHEDULE (January 1, 2014)**

| Renewable Fuel | Project Size Tranche* | Price (¢/kWh) | Escalation Percentage** |
|---|---|---|---|
| Solar (PV) (Rooftop) | ≤ 10 kW | 39.6 | 0% |
| | > 10 kW ≤ 100 kW | 34.5 | 0% |
| | > 100 kW ≤ 500 kW | 32.9 | 0% |
| Solar (PV) (Non-Rooftop) | ≤ 10 kW | 29.1 | 0% |
| | > 10 kW ≤ 500 kW | 28.8 | 0% |
| On-Shore Wind | ≤ 500 kW | 11.5 | 20% |
| Waterpower | ≤ 500 kW | 14.8 | 20% |
| Renewable Biomass | ≤ 500 kW | 15.6 | 50% |
| On-Farm Biogas | ≤ 100 kW | 26.5 | 50% |
| | > 100 kW ≤ 250 kW | 21.0 | 50% |
| Biogas | ≤ 500 kW | 16.4 | 50% |
| Landfill Gas | ≤ 500 kW | 7.7 | 50% |

**Nuclear**

- Still on regulated prices (cost plus based) new nuclear paused so mechanism not defined

# Interfaces

- **Existing Producers and New Procurement**
  Transition process – Regulated process for OPG, existing NUG contracts, moving to new process over 10 years
- **Interface Suppliers , OPA**
  Suppliers report capacity availability and production (monthly reporting )and receive payments from OPA at contract price.
- **Interface IESO, OPA, Distributors**
  IESO dispatch based on HOEP (spot price) using merit order and marginal cost logic. Pass through OPA to IESO to retailers at adjusted HOEP. OPA carries Global Adjustment Account with differences between adjusted HOEP and contract price.
- **Interface Distributors, Final Users**
  Mostly regulated retail prices and municipal distribution but some new private retail suppliers. Prices adjusted over time to cover Global Adjustment Mechanism.
- **Adjustments in Prices and Contracts**
  Supplier contracts contain provisions to adjust prices based on fuel prices and reference cost data, plus some guaranteed increases over time. Note that wholesale market price fluctuations (HOEP) are managed and absorbed by IESO and OPA and ultimately passed on to final users.

# Evaluation of Contract Program

**Program Goals**

- Stimulate investment in new capacity to meet long term plan
- Implement conservation and environmental initiatives
- Provide low cost reliable electricity supply

**Investment - 5/5**

- Good response rate for bids, many new entrants – especially in gas and renewables
- Capacity goals met with the desired mix
- Program viewed positively by investors outside Ontario

**Conservation and Environment - 4/5**

- Managed expansion of renewables, including non-hydro
- Replaced coal with gas to meet environmental goals
- Not clear where nuclear will go – on hold
- Program to integrate demand response and storage with dispatch

**Low Cost - 3/5**

- Primary source of complaints is price related (GAM passed on to consumers)
- Cost impact of renewables subsidies offset with cost risk of expanding reliance on gas
- GAM leaves deferred liabilities on OPA books with risk of future cost pressure (see 2012 in appendix)

# Conclusions

- Contract program is effective at stimulating investment in desired mix.
- Only production is ‘open’ – distribution and retail remain regulated.
- Financial risk transferred to OPA – vulnerable to a durable disconnect between HOEP and contract prices.
- Impact of centralized dispatch on interaction with other markets (import/export) not clear. (Is the market signal still heard?)

# Appendices

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# A: Statistics on OPA contracts

The Ontario system is a mix of contracted power and a competitive wholesale market, but the contracted market is the dominant force covering over 80% of supply.

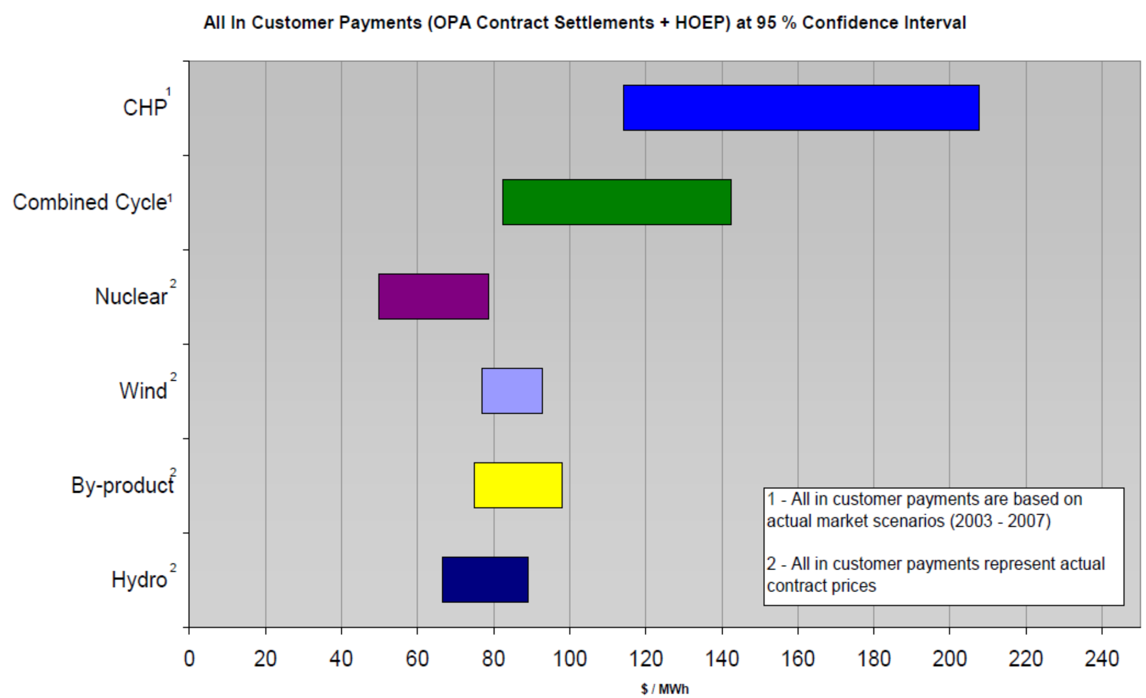
**Breakdown of Total Contract Capacity as of June 30, 2013**

| | Total | Under Development | Commercial Operation |
|---|---|---|---|
| **Renewables** | | | |
| Bio-energy | 364 | 255 | 109 |
| Solar PV | 1,998 | 1,184 | 814 |
| Wind | 5,752 | 3,595 | 2,158 |
| Non-Hydroelectric - Sub-total (MW) | 8,114 | 5,003 | 3,081 |
| Hydroelectric | 2,389 | 722 | 1,720[3] |
| **Renewables - Sub-total (MW)** | **10,503** | **5,756** | **4,801** |
| **Natural Gas and Other Fuel Sources** | | | |
| Combined Heat and Power (CHP) | 420 | 6 | 414 |
| Simple Cycle and Combined Cycle (SC/CC) | 8,288 | 1,189 | 7,099 |
| Energy from Waste (EFW) | 23 | 20 | 3 |
| **Natural Gas and Other - Sub-total (MW)** | **8,731** | **1,215** | **7,516** |
| **Nuclear** | | | |
| Bruce A | 3,000 | - | 3,000 |
| **Nuclear Sub-total (MW)** | **3,000** | **-** | **3,000** |
| **Total Contract Capacity (MW)** | **22,234** | **6,970** | **15,317** |

*From web site of the OPA http:/www.powerauthority.on.ca/*

# B: Contract Structure and Prices

- **Renewables**
  FIT and RESOP subsidy programs with pre-defined prices by type of production.
- **Nuclear**
  No new capacity in plan but the management of existing capacity was outsourced.
- **Gas and Other**
  Zoom on the 'deemed production' mechanism on next slide.




*From web site of the OPA http:/www.powerauthority.on.ca/*

# C: Thermal Generation

**Table 13: Natural Gas and Other Fuel Sources – Simple Cycle and Combined Cycle as of March 31, 2013**

| Contract Facility | Contract Capacity (MW) | Commercial Operation/Term Commencement Date | Contract Expiry Date |
|---|---|---|---|
| Brighton Beach Power Station | 541.3 | 01-Jan-06 | Q3 2024 |
| Goreway Station | 839.1 | 04-Jun-09 | Q2 2029 |
| Greenfield Energy Centre | 1,005.0 | 16-Oct-08 | Q4 2028 |
| GTAA Cogeneration Plant | 90.0 | 01-Feb-06 | Q1 2026 |
| Halton Hills Generating Station | 641.5 | 01-Sep-10 | Q3 2030 |
| Lennox Generating Station | 2,000.0 | 01-Jan-13 | Q3 2022 |
| Portlands Energy Centre | 550.0 | 22-Apr-09 | Q2 2029 |
| Sarnia Regional Cogeneration Plant | 444.0 | 01-Jan-06 | Q4 2025 |
| St. Clair Energy Centre | 577.0 | 30-Mar-09 | Q1 2029 |
| Sudbury District Energy Cogeneration Plant | 5.0 | 01-Jan-06 | Q4 2024 |
| Sudbury District Energy, Hospital Cogeneration | 6.7 | 01-Jan-06 | Q4 2024 |
| Trent Valley Cogeneration Plant | 6.7 | 01-Jan-06 | Q4 2015 |
| York Energy Centre | 393.0 | 09-May-12 | Q2 2032 |
| **Subtotal** | **7,099** | | |

# D: Detail on Gas Contracts showing Capacity and Owner

**Current Facilities**

**Facilities in commercial operation (7,099 MW)**

| | | |
|---|---|---|
| Brighton Beach Power Station (541.3 MW) – Windsor | 541,30 | Coral Energy Canada Inc (ATCO) |
| Goreway Station (839.1 MW) – Brampton | 839,10 | Goreway Station Partnership |
| Greenfield Energy Centre (1005.0 MW) – Sarnia | 1005,00 | Greenfield Energy Centre LP (MIT Power and Calpine) |
| GTAA Cogen Plant (90 MW) – Mississauga | 90,00 | Greater Toronto Airports Authority |
| Halton Hills Generating Station (641.5 MW) - Halton Hills | 641,50 | TransCanada Corporation |
| Lennox Generating Station (2,000 MW) - Napanee | 2000,00 | Ontario Power Generation Inc |
| Portlands Energy Centre (550.0 MW) – Toronto | 550,00 | Portlands Energy Centre LP (OPG and TransCanada) |
| Sarnia Regional Cogen Plant (444 MW) – Sarnia | 444,00 | TransAlta Energy Corporation |
| St. Clair Energy Centre (577.0 MW) – Sarnia | 577,00 | St. Clair Power LP (Invenergy LLC) |
| Sudbury District Energy Cogen Plant (5 MW) – Sudbury | 5,00 | Toromont Energy Ltd. |
| Sudbury District Energy Hospital Cogen (6.7 MW) – Sudbury | 6,70 | Toromont Energy Ltd. |
| Trent Valley Cogen Plant (6.7 MW) – Trenton | 6,70 | Sonoco Products (linked to IESO) |
| York Energy Centre (393.0 MW) - Northern York Region | 393,00 | York Energy Centre LP, Veresen Inc. |
| Total | 7099,30 | |

**Projects under development (1,189 MW)**

| | | |
|---|---|---|
| Green Electron Power Project (289 MW) - Sarnia | 289,00 | Greenfield South Power Corporation |
| Napanee Generating Station (900 MW) - Napanee | 900,00 | TransCanada Energy Ltd. |

* Data from OPA site plus individual corporate sites

# E: Zoom on Gas Contracts

The contract includes **both a fixed and variable component**, with a link to capacity through the concept of 'deemed production' which is used in place of actual production because the producer doesn't control dispatch. This provides an **interesting mix between an energy only contract and a capacity mechanism**. As for **price levels**, there is a **link to cost** and also a **reference price for gas** based on a reference hub.

***5.2.1. Current contract structures for gas-fired generators in Ontario***

*With the exception of contracts for non-utility generators (NUGs), which are currently held by the Ontario Electricity Financial Corporation (OEFC), contracts for gas-fired generators are held by the OPA. 116 These contracts are settled through a **Deemed Production Model** format. This involves "a combination of a **monthly fixed component** (or revenue requirement) and the **monthly variable cost** to generate an expected (or deemed) production of electricity, based on a set of contractual parameters."117 According to a report prepared for the OEB, the average net revenue requirement for projects developed under the Clean Energy Supply RFP118 (as well as "early mover" projects119) is $7,900 per megawatt month. 120 The OPA is responsible for contingent support payments covering the difference between this amount and the "deemed" energy market revenues (i.e. the market revenues generated based on the dispatch parameters in the contract).121 Conversely, **if deemed revenues ever exceed the revenue requirement**, the generator must make a **revenue sharing payment to OPA**.*
*As the IESO notes, "in the **absence of the ability of the firm to influence HOEP***, the OPA **payment**—whether from or to the OPA—is **independent of the firm's actual production choices**. …production decisions are not based on the criteria for deeming."122 The criteria for determining deemed production include variable energy cost — one element of which is the **gas price at the Dawn hub**.123 OPA also holds a contract for the ongoing operation at OPG's Lennox generating station.124*
** Hourly Ontario Energy Price*

Source: from page 35 of Weis and Partington, Pembina Institute, 'Behind the Switch: Pricing Ontario Electricity Options', July 2011

# F: Detail on Hydro Contracts showing Capacity and Owner

| | | | |
|---|---|---|---|
| | **Current Hydro Facilities (not all facilities are individually listed)** | | |
| | **Facilities in commercial operation (1,716 MW)** | | |
| MW | | Owner | Date built |
| 47 | Andrews GS (47 MW) - Montreal River | Brookfield | |
| 162 | Aubrey Falls GS (162 MW) - Mississagi River | Brookfield | |
| 9 | Calm Lake GS (9 MW) - Bennett Township: Rainy River | H2O Power | |
| 52 | Clergue GS (52 MW) - St. Mary's River | Brookfield | |
| 45 | Dunford GS (45 MW) - Michipicoten River | Brookfield | |
| 10 | Fort Frances GS (10 MW) - Fort Frances: Rainy River | H2O Power | |
| 23 | Gartshore GS (23 MW) - Montreal River | Brookfield | |
| 8 | Glen Miller GS (8 MW) - Trenton: Trent River | Glen Miller LP | 2005 |
| 12 | Harris GS (12 MW) - Magpie River | Brookfield | 2009 |
| 15,7 | Healey Falls GS (15.7 MW) - Trenton: Trent River | Ontario Power Generation | 2010 |
| 7,2 | Heywood GS (7.2 MW) - St. Catharines: Twelve Mile Creek | St. Catherine Hydro | 1985 |
| 18 | Hogg GS (18 MW) - Montreal River | Brookfield | |
| 23 | Hollingsworth GS (23 MW) - Michipicoten River | Brookfield | |
| 29 | Iroquois Falls GS (29 MW) - Iroquois Falls: Abitibi River | H2O Power | |
| 38 | Island Falls GS (38 MW) - Smooth Rock Falls: Abitibi Rive | H2O Power | |
| 1 | Kagawong GS (0.8 MW) - Kagawong: Kagawong River | Kagawong Power | 2010 |
| 29 | Lac Seul/Ear Falls GS (29 MW) - Ear Falls: English River | Ontario Power Generation | |
| 4,1 | London Street GS (4.1 MW) - Peterborough: Otonabee Riv | Peterbourough Utilities | 1884! |
| 14 | Lower Sturgeon GS (14 MW) - Timmins: Mattagami River | Ontario Power Generation and UMH Energy | 2010 |
| 62 | MacKay GS (62 MW) - Montreal River | Brookfield | |
| 46 | Rayner & GS (46 MW) - Wharnclife: Mississagi River | Brookfield | |
| 22 | Scott Falls GS (22 MW) - Michipicoten River | Scott Falls | |
| 22 | Twin Falls GS (22 MW) - Iroquois Falls: Abitibi River | H2O Power | |
| 23 | Umbata Falls GS (23 MW) - Marathon: White River | Umbata Falls LP Begetekong Power Corporation | |
| | Feed-in Tariff (5.5 MW) - facilities are not individually listed | | |

| | | |
|---|---|---|
| **Hydro Projects under development (721 MW)** | | |
| Harmon GS (78 MW) - Kapuskasing: Mattagami River | Ontario Power Generation | expansion of facility from 1960's |
| Kipling GS (78 MW) - Kapuskasing: Mattagami River | Ontario Power Generation | expansion of facility from 1960's |
| Little Long GS (67 MW) - Kapuskasing: Mattagami River | Ontario Power Generation | expansion of facility from 1960's |
| Smoky Falls GS (215 MW) - Timmins: Mattagami River | Ontario Power Generation | expansion of facility from 1920's |
| Yellow Falls (16 MW) - Smooth Rock Falls: Mattagami Ri | Boralex | |
| Feed-in Tariff (179.9 MW) - facilities are not individually listed | | |
| Renewable Energy Standard Offer (0 MW) - facilities are not individually listed | | |

* Data from Invenergy web site

# G: Zoom on Hydro Contracts

- On January 21, 2013 and June 26, 2013 the Minister of Energy directed the OPA to implement standard offer programs for the continued development of hydroelectric capacity.
- Key elements from directives include:

  (i) **Municipal stream**

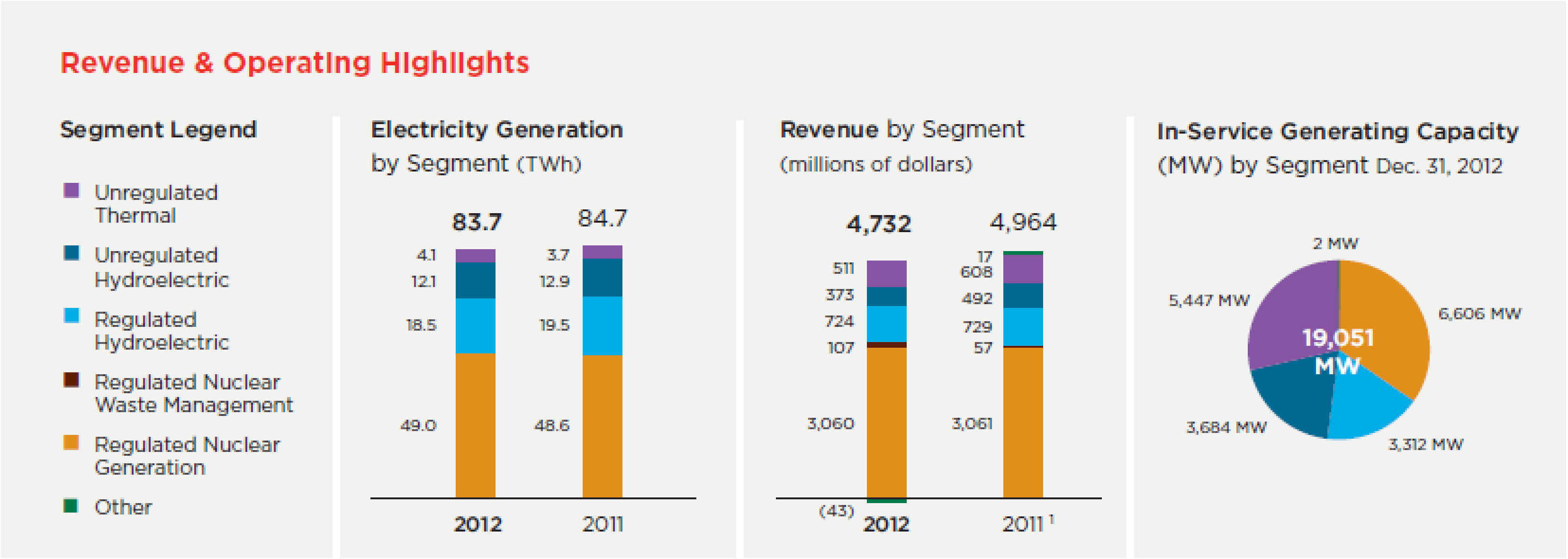
  - undertake a procurement for up to 10 MW for new build distribution-connected hydroelectric projects > 500kW and < 5MW, under a municipal stream for eligible municipal waterpower projects

- Base Price is $141/MWh
  - Opportunity to receive Economic Efficiency Priority Points by submitting reduction to Base Price
  - 0.1 Priority Points per $1/MWh reduction in Base Price
- The reduced price will be used as the HESOP Contract Price
- Projects will receive a time differentiated price under the HESOP Contract
  - On-Peak Performance Factor = 1.35
  - Off-Peak Performance Factor = 0.90
- Price Escalation: Contract Price is subject to an annual escalation of 20% on the basis of CPI increases following Commercial Operation Date

http://www.powerauthority.on.ca/sites/default/files/page/HESOP_Webinar_Oct%208%202013.pdf

# H: Ontario Power Generation

selected data from their 2012 financial reporting



# I: Ontario Power Generation

## selected data from their 2012 financial reporting

### OPG's Reporting Structure

OPG receives a regulated price for electricity generated from most of its baseload hydroelectric facilities and all of the nuclear facilities that it operates. This comprises electricity generated from the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and the Pickering and Darlington nuclear facilities (collectively, the "Prescribed Facilities"). The operating results related to these regulated facilities are described under the Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, and Regulated – Hydroelectric segments. For the remainder of OPG's hydroelectric facilities, the operating results are described under the Unregulated – Hydroelectric segment. The operating results from the thermal facilities are discussed in the Unregulated – Thermal segment. A description of all OPG's segments is provided under the heading, *Business Segments*.

### Unregulated Generation

The electricity generation from OPG's unregulated assets receives the Ontario electricity spot market price, except where a cost recovery or an Energy Supply Agreement ("ESA") is in place.

The Lambton and Nanticoke generating stations are subject to a Contingency Support Agreement with the Ontario Electricity Financial Corporation ("OEFC"). The agreement was enacted to enable the recovery of costs associated with these coal-fired generating stations after implementation of OPG's strategy to reduce Carbon Dioxide ("$CO_2$") emissions. Capacity provided by and production from, the Lennox generating station, are subject to an agreement with the Ontario Power Authority ("OPA"). Refer to section *Recent Developments – Lennox Generating Station Supply Agreement* for details.

OPG currently has Hydroelectric ESAs with the OPA for the Lac Seul and Ear Falls generating stations, the Healey Falls generating station, the Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations, and the Lower Mattagami River project. Payments under the Lower Mattagami Hydroelectric ESA will commence when the first incremental unit comes into service.

# J: OPG data on HOEP

## selected data from their 2012 financial reporting

Average Sales Prices and Average Revenue

The average sales prices and average revenue for 2012 and 2011 were as follows:

| *(¢/kWh)* | **2012** | **2011** |
|---|---|---|
| Weighted average hourly Ontario electricity price ("HOEP") | **2.4** | 3.1 |
| Regulated – Nuclear Generation | **5.5** | 5.5 |
| Regulated – Hydroelectric | **3.5** | 3.5 |
| Unregulated – Hydroelectric | **2.4** | 3.2 |
| Unregulated – Thermal | **2.6** | 3.3 |
| Average revenue for all electricity generators, excluding OPG [1] | **8.6** | 8.4 |
| Average revenue for OPG [2] | **5.1** | 5.3 |

[1] Revenues for other electricity generators are computed as the sum of hourly Ontario demand multiplied by the HOEP, plus total global adjustment payments, plus the sum of hourly net exports multiplied by the HOEP, less OPG's generation revenue.

[2] Average revenue for OPG is comprised of regulated revenues, market based revenues, and other energy revenues primarily from cost recovery agreements for the Nanticoke, Lambton and Lennox generating stations, and revenue from Hydroelectric ESAs.

The average sales prices for the Regulated – Nuclear and Regulated – Hydroelectric segments for 2012 reflect the OEB's March 2011 decision establishing new regulated prices effective March 1, 2011. These regulated prices were discussed in OPG's 2011 annual MD&A under the heading, *Revenue Mechanisms for Regulated and Unregulated*

Average sales prices for OPG's unregulated segments decreased for 2012, compared to 2011. This was primarily due to the impact of significantly lower Ontario electricity spot market prices. The decrease in the HOEP for 2012 was primarily due to lower natural gas prices, offset slightly by the impact of lower hydroelectric generation.

Lennox Generating Station Supply Agreement

In December 2012, the OPA and OPG executed a long-term Lennox ESA for the period from January 1, 2013 to September 30, 2022. The agreement allows the station to recover its costs, including a reasonable return. The agreement replaced the Lennox Generating Station Agreement, in effect from October 1, 2009 to December 31, 2012, which allowed for the recovery of the station costs.

# K: Brookfield Renewables

renewable power. In November 2009, we signed a 20-year PPA with the Ontario Power Authority ("**OPA**") for the previously uncontracted output from our Ontario hydroelectric generating assets, representing approximately 2,300 GWh per year. The contract has a base price plus additional payments in respect of on-peak generation, both of which escalate annually at a predetermined rate. In addition, we are entitled to retain any ancillary revenues generated by the facilities.

### Financial Position & Operating Results

| Generation (GWh) | Long-term Average[1] Year ended December 31, 2010 | 2009 | Actual Production[1] Year ended December 31, 2010 | 2009 |
|---|---|---|---|---|
| Conventional hydroelectric generation | | | | |
| Canada | **4,344** | 4,360 | **2,901** | 4,179 |
| United States | **6,060** | 6,004 | **6,154** | 6,844 |
| Brazil | **3,017** | 2,702 | **2,655** | 2,680 |

| Revenues and Operating Results ($U.S. millions) | Invested Capital[1] As at Dec. 31, 2010 | Dec. 31, 2009 | Revenues Year ended December 31, 2010 | 2009 | Operating cash flow[2] Year ended December 31, 2010 | 2009 |
|---|---|---|---|---|---|---|
| Conventional hydroelectric generation | | | | | | |
| Canada | **$ 4,353** | $ 4,624 | **$ 248** | $ 266 | **$ 131** | $ 183 |
| United States | **4,813** | 5,845 | **512** | 543 | **370** | 411 |
| Brazil | **2,319** | 2,045 | **271** | 215 | **186** | 149 |

2010 Canada 57$/MWH 2009 Canada 61$/MWH

# L: GAM From OPA Annual Report 2012

Electricity supply contracts include nuclear, clean and renewable generation facilities. Generation charges account for changes in the mix of fuel sources and total installed capacity under contract in operation and for differences between HOEP and the rates paid to contracted generators for electricity in Ontario. These "top up" contract payments increased in 2012 as the value of HOEP continued to decrease. In 2012, total electricity generation charges increased 18 percent over 2011. The lower HOEP and new renewable generation contracts contributed to the majority of the increase in generation charges.

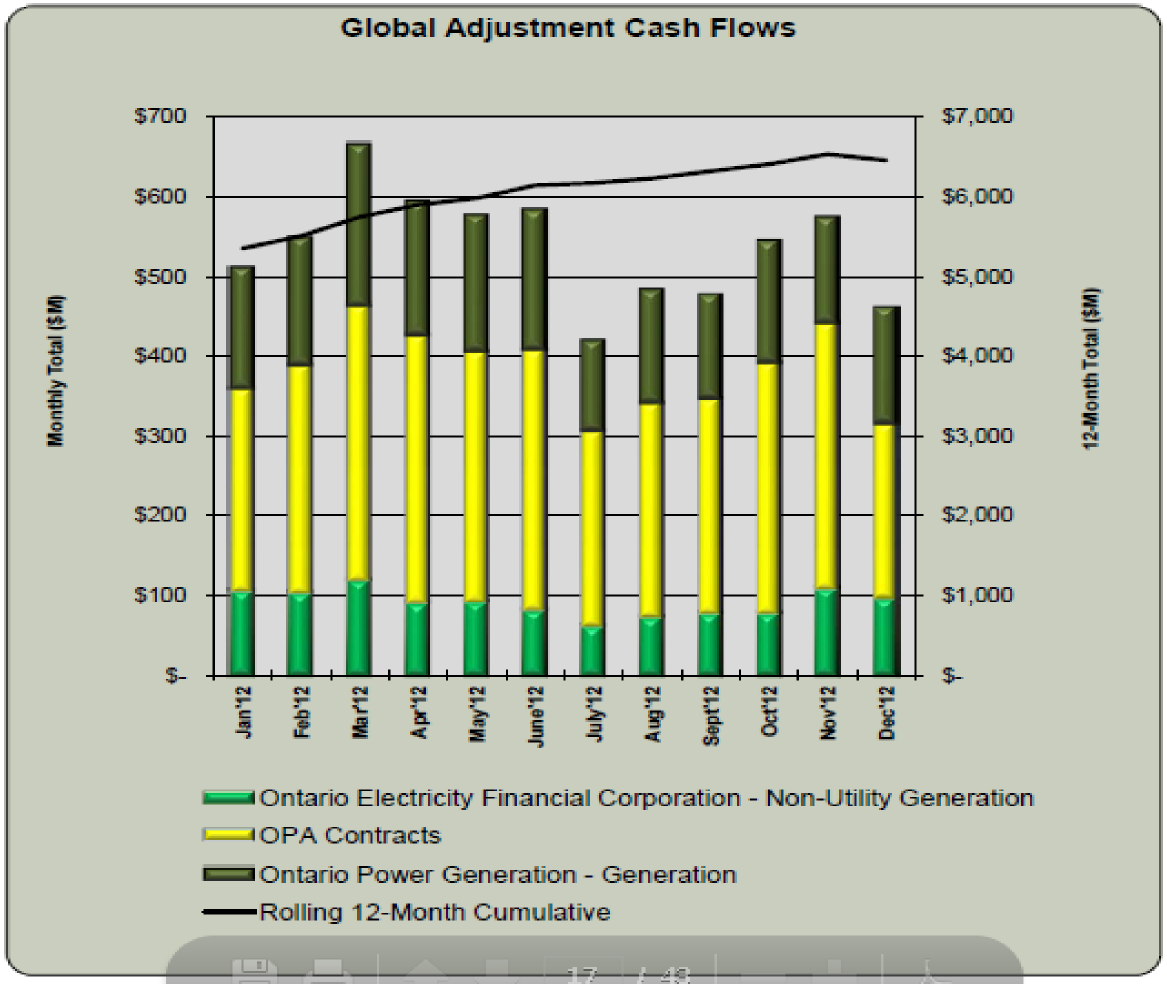
## Global Adjustment Mechanism (GAM)

GAM accounts for differences between HOEP and the rates paid to regulated and contracted generators for electricity in Ontario. It also includes amounts paid for conservation and demand management programs, as well as green energy initiatives. As a result, elements of GAM may be positive or negative, depending on the fluctuation of prices in the wholesale electricity market. GAM applies to all consumers in Ontario, including business customers who pay the dispatch market price (HOEP) and customers who have signed a contract with a licensed electricity retailer. For customers who subscribe to the Regulated Price Plan (RPP), it is factored into the rate set by the OEB.

The global adjustment reflects the difference between the dispatch market price and:

- regulated rates paid to Ontario Power Generation's (OPG's) nuclear and hydroelectric baseload generating stations
- payments made to suppliers that have been awarded contracts through the OPA, such as new gas-fired facilities, renewable facilities (e.g., FIT and microFIT program projects) and demand response programs
- contracted rates administered by the Ontario Electricity Financial Corporation (OEFC) paid to existing generators.

# M: GAM Cash Flows
From OPA Annual Report 2012



# N: GAM Details
# From OPA Annual Report 2012

**Accounts receivable:**

| | December 31, 2012 | December 31, 2011 | January 1, 2011 |
|---|---|---|---|
| Market contracts | | | |
| Generation contracts | $ 474,424 | $ 326,049 | $ 187,789 |
| Conservation contracts | 54,382 | 87,077 | 98,059 |
| Renewable energy contracts | 12,555 | 2,156 | 1,126 |
| | 541,361 | 415,282 | 286,974 |
| Other | 262 | 820 | 1,232 |
| HST/GST Receivable | 5,340 | - | 917 |
| | $ 546,963 | $ 416,102 | $ 289,123 |

**Other financial assets and liabilities:**

Other financial assets, liabilities and deferrals arise as a result of the *Electricity Act, 1998* and the regulations thereunder and are reflected by the balances in the Regulated Price Plan (RPP), retailer contract settlement deferral accounts, government procurement deferral account and the global adjustment account. In the absence of rate-regulated accounting, these amounts would have flowed through the statement of operations when incurred.

| | December 31, 2012 | December 31, 2011 | January 1, 2011 |
|---|---|---|---|
| Other financial assets | $ - | $ - | $ 15,689 |
| Other financial liabilities | (289,918) | (25,788) | (49,966) |

**RPP variance accounts**

While prices for RPP consumers are set every six months by the OEB based upon a forecast of the cost of power over the next year, it is likely that there will be a difference between the actual and forecast cost of supplying electricity to all RPP consumers. When the hourly Ontario energy price (HOEP) is greater than the RPP, the OPA pays the excess amount and records a financial asset as the electricity market funds paid are receivable from the market. When the HOEP is less than the RPP, the OPA receives the difference and records a financial liability as the funds received will be returned to the market. The OPA tracks this variance in the RPP variance account. The Ontario Power Generation (OPG) rebate is equivalent to the difference between the revenue limit for specific OPG generating facilities and the revenue OPG actually received in the IESO wholesale spot market for that generation.

| | 2012 | 2011 |
|---|---|---|
| OPG rebate contribution | $ (602,736) | $ (602,750) |
| Total RPP variance before interest | 299,896 | 562,467 |
| Interest earned | 12,922 | 14,495 |
| | $ (289,918) | $ (25,788) |

# O: More GAM details
# From OPA Annual Report 2012

**Global adjustment account**

The OPA has a legislated responsibility to record the transactions flowing through the global adjustment mechanism. The global adjustment and settlement accounts have been created for this purpose. The nature of the global adjustment transactions result in a zero balance in the account on a monthly basis. The information and explanation below provide transparency for the transactions flowing through the global adjustment mechanism.

The global adjustment and settlement accounts record charges that flow between the OPA and the IESO. The account flows include the amounts paid and received for: Demand Response 2, Demand Response 3, non-utility generation, regulated nuclear generation balancing amount and regulated hydro electric generation balancing amount. These accounts are settled simultaneously by the IESO. The account also records the amounts paid and received for OPA contracts (standard offer, generation and conservation/demand management, Feed-In Tariff and hydroelectric contract initiatives) which the OPA settles on a monthly basis with the IESO.

**6) Accounts payable and accrued liabilities:**

| | | December 31, 2012 | December 31, 2011 | January 1, 2011 |
|---|---|---|---|---|
| Accrued contract settlements | $ | 211,522 | 12,942 | 189,002 |
| HST/GST payable | | - | 128 | - |
| Other accrued liabilities | | 263,317 | 308,925 | 107,252 |
| | | **474,839** | **321,995** | **296,254** |

The OPA receives its fee revenue from the IESO. The fee revenue is approved by the OEB and collected each month by the IESO from ratepayers through a usage rate applied to Ontario domestic electricity consumption. Fee revenue for 2012 was $76,298 (2011 - $76,388). In addition, the OPA and the IESO have agreements set up for the settlement of amounts paid and received for the global adjustment account, RPP on behalf of various market participants (see note 5). At December 31, 2012, the OPA had a net receivable of $264,304 (December 31, 2011 - $326,049 and January 1, 2011 - $187,789). The OPA also incurred $388 in 2012 (2011 - $844) for IESO professional services.

# P: Invenergy Project Finance Success

Invenergy

**Invenergy Closes Refinancing**
**For St. Clair Energy Centre**

CHICAGO, Illinois - (September 3, 2013) – Today, Invenergy LLC ("Invenergy") announced the successful refinancing of the St. Clair Energy Centre ("St. Clair"), a 584 MW combined cycle, natural gas-fired energy generation facility in Ontario, Canada.

St. Clair Energy Centre is located near the town of Sarnia, approximately seventy miles northeast of Detroit, Michigan. St. Clair is jointly owned by affiliates of Invenergy and Stark Investments. The facility is operated and maintained by Invenergy Services Canada ULC, an affiliate of Invenergy.

CHICAGO, IL – (June 6, 2013) – Invenergy is pleased to announce that it has been named Project Finance Borrower of the Year by *Power Finance & Risk* ("*PF&R*"), part of the publication's tenth annual industry honors program, the Power Finance Deals & Firms Awards.

According to *PF&R*, "the industry has spoken", with Invenergy among the companies "recognized by their peers for excellence." This is the first year in which award winners were determined by online polling of borrowers, investors, bankers, and advisors throughout the Americas. Previously, honorees were selected by editorial staff at *PF&R*, a publication of the Power Intelligence information service. The new voting process took place over a period of two months, in April and May of 2013.

* Data from Invenergy web site

# Q: Contractual provisions for repair of defects

Owned by OPA but operated by Bruce Power
This is a PPP
Article below shows incentives in contract to fix problems

**Nuclear Power Contract**

The Bruce Nuclear facility, located on Lake Huron in Tiverton, Ontario, is the largest nuclear facility in North America in terms of output with a total output capacity of 6,224 MW (net) and 6,610 MW (gross). It houses two nuclear generating stations – Bruce A and Bruce B – and each generating station has four CANDU reactors.

## Bruce Power Update, August 2012

On May 7, 2012, scheduled equipment checks and testing by Bruce Power found a problem with a newly serviced non-nuclear component which has delayed re-starting Unit 2 at Bruce A nuclear station. A review by Bruce Power traced the cause of the problem to an error in the original design drawings used to manufacture the component. On May 25, Bruce Power asked the OPA to recognize that the problem was beyond the company's reasonable control (force

Outside technical and legal experts carried out the due diligence on Bruce Power's findings. In separate reviews, two technical experts confirmed the error and concluded it existed prior to Bruce Power acquiring the equipment and was therefore beyond the control of Bruce Power and prevented the company from meeting its July 1 in-service date. As a result, Bruce Power will continue to receive the contract price (6.8 cents per kWh) for the electricity it currently generates by the operating Bruce A units.

There are no added costs to ratepayers. None of the repair and maintenance costs will be paid for by the ratepayer or taxpayer. Once the two refurbished units are in-service, OPA will analyze the work schedule and determine if there were any delays not associated with fixing the non-nuclear problem. Bruce Power will not be paid for any such delays, as per Bruce Power's contract.

The price of energy under the Bruce contract provides good value to ratepayers. It is low-cost, reliable and flexible base-load generation for the province. Nuclear energy remains an important part of Ontario's energy supply and an important part of getting out of coal by 2014.

* Data from Bruce Power web site