NAVIGANT CONSULTING

REGULATED PRICE PLAN – COST TRACKING

MONTHLY VARIANCE EXPLANATION (NOVEMBER 06 – FEBRUARY 07)

This document has been prepared at the request of the Ontario Energy Board (OEB, or the "Board"). The Board's objective is to better inform interested stakeholders and consumers about the Regulated Price Plan (RPP) and the factors that have contributed to the difference between the forecast price that RPP consumers currently pay and the actual cost to supply those consumers. An appendix is included which provides monthly values for the key contributing factors. This document is updated on a monthly basis when all of the information becomes available.

All of the statistics presented in this report are taken or derived from publicly available information sources. Neither Navigant Consulting nor the OEB has audited this information. Any revisions by the providers of the actual data will be included in future updates of this report.

This report is available on the Regulated Price Plan (RPP) Web page of the OEB Web site at www.oeb.gov.on.ca (see quick link under "Major Key Initiatives"). Any technical questions regarding this report can be directed to Chris Cincar at 416-440-7696 or Russell Chute at 416-440-7682.

Regulated Price Plan consumers pay a stable price for electricity that was set in advance by the Board. The initial RPP prices went into effect on April 1, 2005 and remained in place for a thirteen month period (April 2005 through April 2006). New RPP prices were established by the Board on May 1, 2006 and remained in place through October 31, 2006. On October 11, 2006, the Board announced new RPP prices which were effective November 1, 2006. This report will focus on the ability of the current RPP prices to recover the cost of supplying RPP consumers, as well as the extent to which the new prices recover the outstanding variance as of October 31, 2006.[1]

Under Ontario's current hybrid electricity market structure, there are essentially three sources of supply for the RPP:

1. Generating facilities subject to regulated prices, or under contract to the Ontario Power Authority (OPA) or the Ontario Electricity Financing Corporation (OEFC);
2. Certain Ontario Power Generation (OPG) facilities which are subject to a revenue cap; and
3. Generating facilities that receive the wholesale spot market price.

[1] The current RPP tiered prices are 5.5 cents per kWh (for consumption below the tier threshold) and 6.4 cents per kWh (for consumption above the tier threshold). The tiered prices were previously 5.8 cents per kWh and 6.7 cents per kWh for Tier 1 and Tier 2, respectively.

The first two groups of generating facilities described above (i.e., subject to regulated prices, or under contract, and certain OPG facilities subject to a revenue cap) supply electricity into Ontario's wholesale electricity market and are paid the wholesale spot market price for the electricity they supply to the grid. However, under current regulations, the final revenues for these two groups are different from the spot market price as described below:

- Generating facilities subject to regulated prices or under contract to the OPA or OEFC are paid, or must reimburse, any difference between the average monthly revenue earned for their output on the spot market and their contract price or regulated price. This difference is passed through to consumers through the "Provincial Benefit" (or "Global Adjustment").

> **Example:**
>
> If the spot market price of electricity in a given period was 6 cents per kWh and the average contracted or regulated price (for generating facilities under contract or subject to regulated prices) was 5 cents per kWh, these generating facilities would have to reimburse 1 cent per kWh, on average, to consumers for the electricity they supplied to the Ontario market during that period. This has the effect of reducing their average revenues from 6 cents per kWh to 5 cents per kWh. Conversely, if the spot market price was 4 cents per kWh, these generating facilities would be paid an additional 1 cent per kWh by consumers through the Provincial Benefit to bring their average revenues to 5 cents per kWh.

- Similarly, regulations require that OPG generation facilities subject to a revenue cap must reimburse any difference between the average revenue earned on their generation output and their revenue cap (average of 4.6 cents per kWh) to consumers. This payment is called the "OPG Rebate" (often also referred to as the OPG Non-Prescribed Asset Rebate, or "ONPA rebate"). For the first year, May 1, 2006 to April 30, 2007 revenues from the same group of assets will be capped at 4.6 cents per kWh[2]. Similar to the initial RPP prices, an estimate of the OPG Rebate continues to be included in the new RPP prices.

The primary effect of these regulations is that the cost of supplying electricity to RPP consumers from the first two sources – 1) generating facilities subject to regulated prices, or under contract to the OPA or OEFC that pay the Provincial Benefit; and 2) certain OPG generation facilities subject to a revenue cap that pay the OPG Rebate – is essentially fixed at a price that was expected to be below the average spot price for electricity. This reduces the average cost of

[2] Output sold by OPG through the OPA Pilot Auction (PA) is excluded from the 4.6 cent per kWh cap and instead is subject to a higher revenue cap of 5.1 cents per kWh. On May 1, 2007 the cap will rise to 4.7 cents per kWh and on May 1, 2008 it will increase again to 4.8 cents per kWh.

supply for all consumers and also reduces consumers' exposure to variability in spot market prices, since the cost of supply from the spot market is not fixed (i.e., changes every hour).

The new RPP prices, which went into effect on November 1st, are based on forecasts of many different factors, the most important of which are: 1) the relative amount of electricity coming from each of the three electricity supply sources; and 2) the price of electricity purchased from the spot market; and 3) the outstanding variance at the end of the initial RPP period.

The actual supply cost for the RPP depends on many factors; the most important of which are the same as those used to forecast the RPP price, namely: 1) the relative amount of electricity coming from each of the three supply sources; and 2) the price of electricity purchased from the spot market. If these factors differ from those in the forecast issued by the Board, the *actual* RPP supply cost will differ from the *forecast* RPP supply cost.

The forecast and actual values for the key factors influencing the RPP supply costs are compared below as follows.

1. The first set of values are related to the spot market price of electricity.
2. The second set of values are related to generating facilities subject to regulated prices or under contract to the OPA or OEFC that pay the Provincial Benefit.
3. The third set of values are related to certain OPG facilities subject to a revenue cap that pay the OPG Rebate.
4. The fourth set of values are related to the difference between the forecast and actual values for the cost of RPP supply and the revenues generated by the RPP.

The difference between the RPP revenues and the RPP supply cost is defined as the "RPP variance" for the period in review. Lastly, a chart showing the forecasted and actual cumulative outstanding RPP variance at the beginning of and at the end of each month in the current RPP period is presented along with a table showing the forecasted and actual cumulative outstanding RPP variance at the end of this month. For the purposes of this report, "*Initial RPP Period*" refers to April 1, 2005 through April 30, 2006, "*Previous RPP Period*" refers to May 1, 2006 through October 31, 2006 and "*Current RPP Period*" refers to November 1, 2006 onwards.

1. Spot Market Prices and Key Drivers of Spot Prices

Simple Average Spot Market Price

This comparison shows the cost of electricity purchased from the spot market (without consideration of the Provincial Benefit and OPG Rebate) for a consumer that used the same amount of electricity in each hour. This price would apply to a relatively small subset of consumers. Actual spot market prices were lower than forecast due largely to lower than forecast natural gas prices, mild weather conditions for most of the winter and lower RPP demand.

Simple Average Cost of Electricity

Current RPP Period (November 1, 2006 through February 28, 2007)	
Forecast	6.5 cents per kWh
Actual	4.8 cents per kWh
Percent Difference	27% lower

RPP-Load Weighted Average Spot Market Price

This comparison similarly shows the cost of electricity purchased from the spot market (without consideration of the Provincial Benefit and OPG Rebate). However, in this case, it is for a consumer (e.g., residential) whose usage pattern is the same as the average RPP consumer (higher electricity consumption during the peak periods, such as winter evenings, when prices are higher). The actual RPP load-weighted spot market price is lower than forecast for the same reasons as described above for the simple average spot market price.

RPP-Load Weighted Average Cost of Electricity

Current RPP Period (November 1, 2006 through February 28, 2007)	
Forecast	7.0 cents per kWh
Actual	5.1 cents per kWh
Percent Difference	27% lower

Natural Gas Price

This comparison shows natural gas prices. Natural gas is the fuel source for generating facilities that set the spot market price for electricity for a portion of hours throughout the day, so natural gas prices have a significant impact on electricity prices. If natural gas prices are higher than forecast, the cost of electricity from these generating facilities and the spot market price of electricity will be higher than forecast.

Higher than forecast natural gas prices were a primary contributor to higher than forecast electricity prices in the spot market during the initial RPP period. Preliminary analyses show that for every 10% increase in natural gas prices, Ontario electricity spot market prices would increase by approximately 6%.

Natural gas prices for the current RRP period remained considerably lower than forecast. This contributed to the lower than forecast spot market prices.

Natural Gas Prices ($USD)

Current RPP Period (November 1, 2006 through February 28, 2007)	
Forecast	$9.79 / MMBtu
Actual	$7.23 / MMBtu
Percent Difference	26% lower

NB - 1 MMBtu (Million British Thermal Units) ≅ 1.055 GJ (Gigajoules) ≅ 27.5 m^3 (cubic meters) of Natural Gas

Weather, Cooling Degree Days (>24°C)

Degree days for a given day represent the number of Celsius degrees that the mean temperature is above or below a given base. This comparison shows the number of cooling degree days above 24°C per month in the city of Toronto (Lester B. Pearson Int'l Airport). If the temperature is less than or equal to 24°C, then the number will be zero.[3] Values above 24°C are used primarily to estimate the cooling requirements of residential consumers. For example, if the mean daily temperature is 30°C, the number of cooling degree days would be 30°C –24°C = 6.

During the initial RPP period, the number of such days far exceeded normal conditions. During the previous RPP period, weather also played a role as the level of cooling degree days was above normal. The number of cooling degree days is zero, as expected under normal conditions.

Cooling Degree Days (>24 °C)

Current RPP Period (November 1, 2006 through February 28, 2007)	
Forecast	0
Actual	0
Difference	0

Weather, Heating Degree Days (>15°C)

During the winter heating season, the number of *heating* degree days replaces *cooling* degree days as an important factor driving electricity demand and spot market prices. Heating degree days are calculated in the same manner as cooling degree days. However, instead of depicting cooling requirements, they offer an indication as to the heating requirements of consumers in Ontario.

This comparison shows the number of heating degree days below 15°C in the city of Toronto (Lester B. Pearson Int'l Airport). If the temperature is higher than or equal to 15°C, then the number will be zero. The number of heating degree days for the full forecast period remained lower than expected. This is due to the mild conditions experienced for most of the winter season. The month of February was one of the coldest in recent history and the number of heating degree days exceeded expectations for that particular month.

Heating Degree Days (<15 °C)

Current RPP Period (November 1, 2006 through February 28, 2007)	
Forecast	2,147
Actual	1,891
Difference	256 lower

[3] 18°C is another common base temperature used to determine cooling degree days. Navigant Consulting and the OEB share the view that 24°C is more representative of when residential consumers use air conditioning.

2. Generating Facilities that Pay the Provincial Benefit

The two main generation supply sources that pay the Provincial Benefit are OPG's nuclear generating stations and OPG's regulated (baseload) hydroelectric generating stations.

OPG Nuclear Output

This comparison shows the output (or production) of OPG's nuclear plants. The actual amount of electricity produced by these generation facilities was substantially lower than forecast by the Board. The lower than expected output is a result of several nuclear units being placed on outages. The Board has taken outages into account when preparing the forecast. However, the planned outage schedules are brought forward or postponed, extended or shortened, or are otherwise subject to change, depending on the operational needs of the specific generation units. Output was much closer to forecast (6% lower) for the month of February, relative to the November to January period (23% lower).

OPG's Nuclear Output

Current RPP Period (November 1, 2006 through February 28, 2007)	
Forecast	17.3 TWh
Actual	14.0 TWh
Percent Difference	19% lower

NB - 1 TWh = 1 billion kWh and is roughly equivalent to the electricity used by 100,000 homes in a year.

OPG Regulated (Baseload) Hydroelectric Output

This comparison shows the amount of electricity produced by OPG's regulated hydroelectric plants (DeCew Falls, Sir Adam Beck, and R.H. Saunders). The output from these facilities is primarily baseload, i.e. they are generally producing electricity all of the time (24 x 7). Overall, the actual output of these generating facilities is slightly lower than the forecast by the Board.

OPG's Baseload Hydroelectric Output

Current RPP Period (November 1, 2006 through February 28, 2007)	
Forecast	6.4 TWh
Actual	6.3 TWh
Percent Difference	1% lower

NB - 1 TWh = 1 billion kWh and is roughly equivalent to the electricity used by 100,000 homes in a year.

Provincial Benefit

This comparison shows the forecast versus actual Provincial Benefit (also referred to as the "Global Adjustment"). The forecast value of the Provincial Benefit is already included in the current RPP prices.

Provincial Benefit (Global Adjustment)

Current RPP Period (November 1, 2006 through February 28, 2007)	
Forecast	0.6 cents per kWh
Actual	-0.4 cents per kWh
Difference	1.0 cents lower

Unlike the spot market price, the Provincial Benefit does not differ based on when a consumer's electricity consumption occurs. In other words, it is the same unit value for all Ontario electricity consumers whether they consume more electricity during "on-peak" (e.g., daytime) periods when spot market prices are higher or they consume more electricity during "off-peak" (e.g., night) periods when spot market prices are lower.

The Provincial Benefit is a net charge to consumers for the period November '06 through February '07. This is primarily due to low spot market prices.

3. Generating Facilities that Pay the OPG Rebate (or ONPA rebate)

The two supply sources that pay the OPG Rebate are OPG's coal-fired generating plants and OPG's unregulated hydroelectric generating plants.

OPG Coal-fired Output

This comparison shows the output of OPG's coal-fired generating plants. The output from OPG's coal-fired facilities is strongly correlated with demand in Ontario. Higher demand implies greater output from OPG's coal-fired facilities, while lower demand implies less output from the same facilities. After being substantially below the Board's forecast in November through January (31% lower), coal-fired output was 6% above forecast during February, as February was the first month since November in which demand exceeded expectations (4% higher). These results illustrate that strong correlation discussed above.

OPG's Coal Fired Output

Current RPP Period (November 1, 2006 through February 28, 2007)	
Forecast	11.7 TWh
Actual	9.1 TWh
Percent Difference	22% lower

NB - 1 TWh = 1 billion kWh and is roughly equivalent to the electricity used by 100,000 homes in a year.

OPG Unregulated (Non-Prescribed) Hydro Electric Output

This comparison shows the output of OPG's unregulated hydroelectric generating facilities. The large majority of this output comes from "peaking" capacity which only tend to operate during periods of high demand. The remainder is "baseload" capacity which is operating more or less continuously all of the time (24 x 7).

The actual output of these generators is substantially higher than the output forecast by the Board for the current period.

OPG's Unregulated Hydroelectric Output

Current RPP Period (November 1, 2006 through February 28, 2007)	
Forecast	4.2 TWh
Actual	5.2 TWh
Percent Difference	22% higher

NB - 1 TWh = 1 billion kWh and is roughly equivalent to the electricity used by 100,000 homes in a year.

OPG Rebate (estimated)

This comparison shows the OPG Rebate. The overall estimated OPG Rebate is lower than forecast. This is a result of lower than forecast spot market prices. The forecast value of the OPG Rebate is already included in current RPP prices.

OPG Rebate

Current RPP Period (November 1, 2006 through February 28, 2007)	
Forecast	0.8 cents per kWh
Actual	0.2 cents per kWh
Difference	-0.6 cents lower

Under new Government regulations, this revenue cap (and rebate) was extended for three years, with revenue from these assets currently limited to 4.6 cents per kWh from May 1, 2006 through April 30, 2007. On May 1, 2007 the cap will increase to 4.7 cents per kWh and on May 1, 2008 will increase again to 4.8 cents per kWh for the subsequent 12 month period.

4. RPP Supply Costs and Revenues

The RPP supply cost represents the cost and amount of electricity for RPP consumers associated with each of the three sources of generation supply discussed above (see page 1) and is calculated as the spot market price of electricity, less the Provincial Benefit and OPG Rebate.

The RPP revenues represent the total revenues generated from the two tiered pricing structure of 5.5 cents per kWh (for consumption below the tier threshold) and 6.4 cents per kWh (for consumption above the tier threshold).

The difference between the forecast and the actual RPP supply cost is accumulated and tracked in a variance account (held by the OPA) to be either *credited* to RPP consumers (if a positive variance) or *charged* to RPP consumers (if a negative variance).

RPP Unit Supply Cost

The RPP unit supply cost is lower than forecast for November through February 2007.

RPP Unit Supply Cost

Current RPP Period (November 1, 2006 through February 28, 2007)	
Forecast	5.7 cents per kWh
Actual	5.3 cents per kWh
Percent Difference	6% lower

The RPP unit supply cost presented above excludes the Variance Recovery Factor (included in RPP prices) which is currently 0.144 cents per kWh.

RPP Total Supply Cost

The actual *total* RPP supply cost is lower than forecast. This is a result of lower than forecast RPP demand as well as lower than forecast RPP *unit* supply cost.[4]

RPP Total Supply Cost

Current RPP Period (November 1, 2006 through February 28, 2007)	
Forecast	$1,486 million
Actual	$1,334 million
Percent Difference	10% lower

RPP Unit and Total Revenues

The RPP unit revenue was roughly 1% higher than forecast. This is a result of a higher percentage of consumption at the higher tier price than originally forecast.

RPP Unit Revenues

Current RPP Period (November 1, 2006 through February 28, 2007)	
Forecast	5.7 cents per kWh
Actual	5.8 cents per kWh
Percent Difference	1.0% higher

The actual RPP revenue was roughly 2% lower than forecast; mainly due to lower than forecast RPP demand.

RPP Total Revenues

Current RPP Period (November 1, 2006 through February 28, 2007)	
Forecast	$1,476 million
Actual	$1,442 million
Percent Difference	2% lower

[4] The RPP total supply cost also includes the stochastic adjustment factor, which is not included in the unit supply cost. For an explanation of the stochastic adjustment factor, please see the RPP Price Report issued on Oct 11, 2006 on the Board's website at http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_regulatedpriceplan_baseline.htm.

RPP Variance[5]

The RPP Variance represents the difference between the revenues collected from RPP consumers and the cost to supply RPP consumers (i.e., RPP supply cost).

The outstanding variance from the initial RPP period as of April 30, 2006 was negative $417 million. In the subsequent months, the outstanding variance was reduced significantly. In establishing the current RPP prices, the outstanding variance was forecast to be $106 million as at the end of October 2006. The actual outstanding variance on October 31, 2006 was $127 million, primarily due to lower than forecast RPP demand and, given the very low spot prices in September and November, higher than expected contract payments under the Global Adjustment (or "Provincial Benefit").[6] Certain of these contract payments made to Bruce Power under the terms of its agreement[7] with the Ontario Power Authority were recovered from Bruce Power in February 2007, which mitigated the outstanding variance discussed above.

The current RPP prices incorporate a Variance Recovery Factor of 0.144 cents per kWh to pay down the forecast outstanding variance from the previous RPP period to zero over the twelve month period from November 2006 through October 2007. The chart below presents the forecasted and actual monthly variance outstanding in the current RPP period, as well as the outstanding variance at the end of the *initial* RPP period and the *previous* RPP period.

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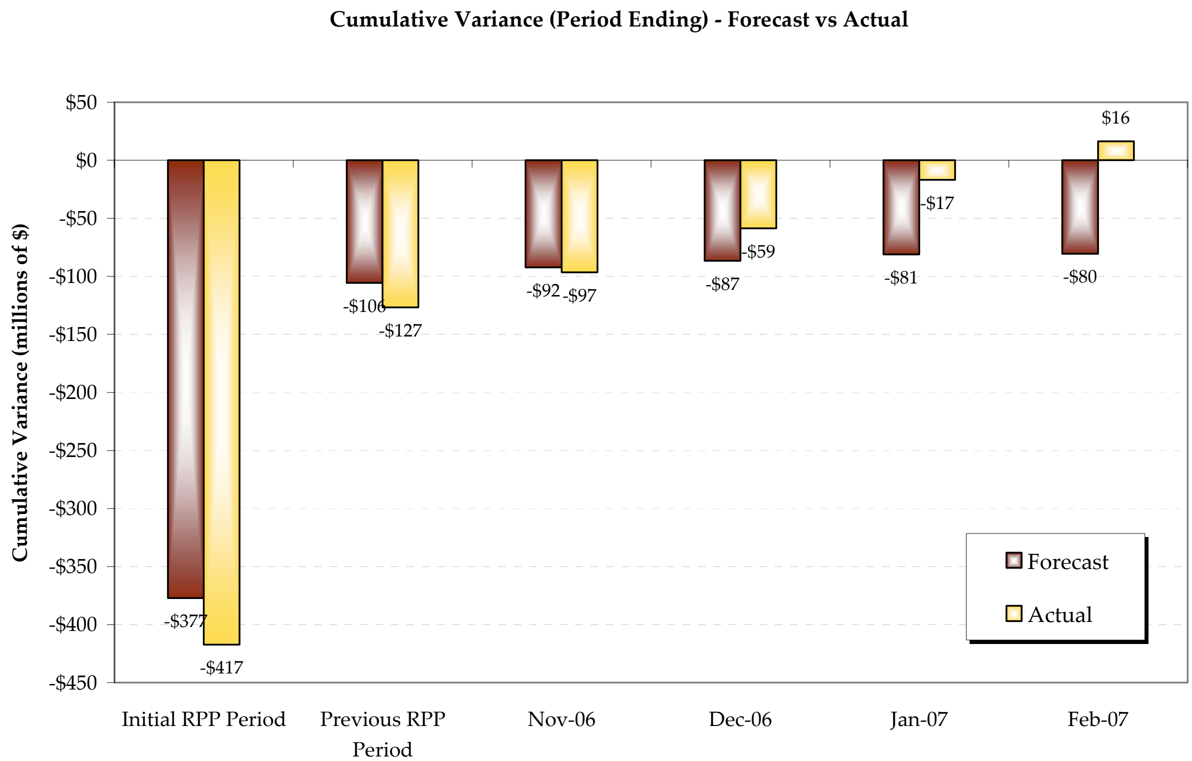
[5] The RPP variance includes interest incurred by the OPA for balances held in the variance account, as required by the Board's RPP Manual.

[6] The actual outstanding net variance at the end of October 2006 has been slightly revised upwards to $126.8 million from $126.2 million taking into account the actual quarterly payment of the OPG rebate for the period August '06 – October '06. In the absence of the actual OPG rebate amount, monthly rebate estimates are substituted in order to determine the outstanding net variance amount.

[7] *Bruce Power Refurbishment Implementation Agreement*, between Bruce Power L.P. and Bruce Power A L.P. and the Ontario Power Authority, October 17, 2005.



The total net variance accumulated in the OPA variance account is roughly positive $16 million. Compared to the forecast total variance of roughly negative $80 million, this yields a positive unexpected variance of $96 million i.e., the outstanding variance from the previous RPP periods has been recovered and the variance account has a positive balance of $16 million at the end of February 2007. As the chart above illustrates, this is the first month since the introduction of the RPP in which the net variance balance has been positive and, therefore, completes the recovery from the significant negative variance built-up during the summer of 2005 when Ontario experienced extreme weather conditions.

RPP Variance - Overall

(Apr 1, 2005 through February 28, 2007)	
Forecast	-$80 million
Actual	$16 million
Difference	$96 million

The positive $16 million net RPP variance corresponds to the "Net Variance Account Balance" identified on the OEB's Final RPP Variance Settlement Amount web page.[8] This value is taken to be the surplus amount after the estimated accrued OPG Rebate (attributable to RPP

[8] http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_regulatedpriceplan_variance.htm

consumers) is taken into account. The difference between the forecast and actual net RPP variance at the end of the RPP period will be used to reset the variance recovery factor when RPP prices are adjusted. RPP price adjustments are now implemented by the Board every six months, if required, on November 1st and May 1st.

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APPENDIX A –KEY VARIANCE DRIVERS, MONTHLY VALUES

Presented in this appendix are the monthly values for the factors discussed in the body of this document. As well, one additional summary table is provided for RPP total demand which was not previously discussed in this report. As mentioned in the main body of the report, "*Initial RPP Period*" refers to April 1, 2005 through April 30, 2006, and "*Previous RPP Period*" refers to May 1, 2006 through October 31, 2006.

1. Spot Market Prices and Key Drivers of Spot Prices

Simple Average Spot Market Price

cents per kWh	Initial RPP Period	Previous RPP Period	Nov-06	Dec-06	Jan-07	Feb-07	Current RPP Period to date
Forecast	5.5	6.0	5.6	6.4	7.2	6.9	6.5
Actual	6.5	4.5	5.0	3.9	4.4	5.9	4.8
% Difference	18%	-25%	-11%	-38%	-39%	-15%	-27%

RPP Load Weighted Average Spot Market Price[9]

cents per kWh	Initial RPP Period	Previous RPP Period	Nov-06	Dec-06	Jan-07	Feb-07	Current RPP Period to date
Forecast	6.0	6.6	6.0	6.9	7.7	7.3	7.0
Actual	7.0	5.0	5.1	4.3	4.7	6.3	5.1
% Difference	16%	-24%	-15%	-37%	-40%	-14%	-27%

RPP Demand

TWh	Initial RPP Period	Previous RPP Period	Nov-06	Dec-06	Jan-07	Feb-07	Current RPP Period to date
Forecast	81.0	37.2	6.1	6.6	6.9	6.1	25.7
Actual	81.1	34.6	5.7	6.1	6.9	6.4	25.0
Difference	0.1%	-7%	-8%	-7%	0%	4%	-3%

Natural Gas Price

$/MMBtu	Initial RPP Period	Previous RPP Period	Nov-06	Dec-06	Jan-07	Feb-07	Current RPP Period to date
Forecast	$7.08	$7.84	$8.22	$9.86	$10.54	$10.58	$9.79
Actual	$8.89	$6.14	$7.65	$7.11	$6.50	$7.74	$7.23
% Difference	26%	-22%	-7%	-28%	-38%	-27%	-26%

[9] Actual values are calculated based on LDC reported monthly RPP revenues and costs for RPP supply which was provided by the IESO. The LDCs report these RPP revenues and costs before month-end, and are based on an estimate for the current month plus any reconciliation required for prior submissions. The forecast values were developed based on an estimate of the consumption pattern for RPP consumers.

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Weather, Cooling Degree Days (> 24 °C)

> 24 °C	Initial RPP Period	Previous RPP Period	Nov-06	Dec-06	Jan-07	Feb-07	Current RPP Period to date
Normal	17	17	0.0	0.0	0.0	0.0	0.0
Actual	81	52	0.0	0.0	0.0	0.0	0.0
% Difference	363%	198%	0%	0%	0%	0%	0%

Weather, Heating Degree Days (< 15 °C)

< 15 °C	Initial RPP Period	Previous RPP Period	Nov-06	Dec-06	Jan-07	Feb-07	Current RPP Period to date
Normal	3,517	346	355.6	554.4	659.9	577.3	2,147.2
Actual	2,894	291	292.4	407.5	547.3	643.9	1,891.1
% Difference	-18%	-16%	-18%	-26%	-17%	12%	-12%

2. Generators that Pay the Provincial Benefit

The tables below show the total output from OPG's regulated generation facilities. However the regulation specifies that any aggregate output above a threshold of 1,900 MW for OPG's regulated hydroelectric generation facilities in any given hour is eligible to receive the spot price, and hence does not contribute to the Provincial Benefit.

OPG Nuclear Output

TWh	Initial RPP Period	Previous RPP Period	Nov-06	Dec-06	Jan-07	Feb-07	Current RPP Period to date
Forecast	50.6	22.2	4.1	4.4	4.6	4.2	17.3
Actual	49.5	24.3	3.0	3.5	3.6	3.9	14.0
% Difference	-2%	9%	-27%	-21%	-22%	-6%	-19%

OPG Regulated Hydroelectric Output

TWh	Initial RPP Period	Previous RPP Period	Nov-06	Dec-06	Jan-07	Feb-07	Current RPP Period to date
Forecast	19.7	9.8	1.6	1.6	1.6	1.5	6.4
Actual	19.3	8.9	1.5	1.7	1.6	1.5	6.3
% Difference	-2%	-9%	-5%	3%	-1%	-1%	-1%

Provincial Benefit (or "Global Adjustment")

cents per kWh	Initial RPP Period	Previous RPP Period	Nov-06	Dec-06	Jan-07	Feb-07	Current RPP Period to date
Forecast	0.2	0.4	(0.0)	0.4	1.1	0.7	0.6
Actual	0.7	(0.5)	(0.4)	(1.0)	(0.7)	0.6	(0.4)
Difference	0.4	(0.9)	(0.4)	(1.5)	(1.8)	(0.1)	(1.0)

3. Generators that Pay the OPG Rebate (or "ONPA rebate")

The tables below show the total output from OPG's non-prescribed generation facilities. However, under the existing regulation, approximately 15 percent of the total output from these facilities is not subject to the revenue cap (and rebate).

OPG Coal-fired Output

TWh	Initial RPP Period	Previous RPP Period	Nov-06	Dec-06	Jan-07	Feb-07	Current RPP Period to date
Forecast	36.2	14.5	2.8	2.9	3.2	2.9	11.7
Actual	30.0	13.3	1.8	1.6	2.6	3.0	9.1
% Difference	-17%	-8%	-34%	-44%	-17%	6%	-22%

OPG Unregulated (Non-prescribed) Hydroelectric Output

TWh	Initial RPP Period	Previous RPP Period	Nov-06	Dec-06	Jan-07	Feb-07	Current RPP Period to date
Forecast	19.7	7.2	1.1	1.1	1.1	1.0	4.2
Actual	15.7	5.7	1.3	1.4	1.4	1.1	5.2
% Difference	-20%	-20%	13%	23%	34%	20%	22%

OPG Rebate

cents per kWh	Initial RPP Period	Previous RPP Period	Nov-06	Dec-06	Jan-07	Feb-07	Current RPP Period to date
Forecast	0.5	0.5	0.5	0.8	0.9	0.9	0.8
Actual	0.5	0.1	0.2	0.0	0.1	0.4	0.2
Difference	0.0	(0.4)	(0.3)	(0.8)	(0.8)	(0.5)	(0.6)

4. RPP Unit and Total Revenues

The RPP unit revenue for November 2006 onwards is calculated as the weighted average price of electricity consumed by RPP consumers at the two tiered prices (5.5 and 6.4 cents per kWh) less the variance recovery factor of 0.144 cents per kWh. The actual unit revenue was roughly 1% higher than forecast.

cents per kWh	Initial RPP Period	Previous RPP Period	Nov-06	Dec-06	Jan-07	Feb-07	Current RPP Period to date
Forecast	5.3	5.8	5.8	5.7	5.7	5.7	5.7
Actual	5.4	5.7	5.7	5.8	5.8	5.8	5.8
% Difference	1%	-1%	0%	1%	1%	1%	1%

The differential between *forecast* and *actual* RPP demand combined with the differential between *forecast* and *actual* RPP unit revenues results in the difference between the *forecast* and *actual* total RPP revenue.

million $	Initial RPP Period	Previous RPP Period	Nov-06	Dec-06	Jan-07	Feb-07	Current RPP Period to date
Forecast	$4,300	$2,158	$353	$377	$394	$352	$1,476
Actual	$4,358	$1,991	$325	$354	$395	$367	$1,442
% Difference	1%	-8%	-8%	-6%	0%	4%	-2%