Regulated Price Plan

Price Report

November 1, 2013

to

October 31, 2014

Ontario Energy Board

October 17, 2013

Executive Summary

This report contains the electricity commodity prices under the Regulated Price Plan (RPP) for the period November 1, 2013 through October 31, 2014. The prices were developed using the methodology described in the Regulated Price Plan Manual (RPP Manual).

In accordance with the applicable regulation, the Board must forecast the cost of supplying RPP consumers and ensure that RPP prices reflect this cost. RPP prices are reviewed by the Board every six months to determine if they need to be adjusted.

In broad terms, the methodology used to develop RPP prices has two essential steps:

1. Forecasting the total RPP supply cost for 12 months, and
2. Establishing prices to recover the forecast RPP supply cost from RPP consumers over the 12-month period.

The calculation of the total RPP electricity supply cost involves several separate forecasts, including forecasts of:

- the hourly market price of electricity;
- the electricity consumption pattern of RPP consumers;
- the electricity supplied by those assets of Ontario Power Generation (OPG) whose price is regulated;
- the costs related to the contracts signed by non-utility generators (NUGs) with the former Ontario Hydro and the costs associated with certain OPG coal facilities[1];
- the costs of the supply contracts, and conservation and demand management (CDM) initiatives of the Ontario Power Authority (OPA); and
- the net variance account balance (as of October 31, 2013) carried by the OPA.

The market-based price for electricity used by RPP consumers reflects both the hourly market price of electricity and the electricity consumption pattern of RPP consumers. Residential consumers, who represent most RPP consumption, use relatively more of their electricity during times when total Ontario demand and prices are higher (than the overall Ontario average) and relatively less when total Ontario demand and prices are lower (than the overall Ontario average). This consumption pattern makes the average market price for RPP consumers higher than the average market price for the entire Ontario electricity market.

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[1] In addition to the contracts with the NUGs, OEFC is also the counterparty to a contingency support agreement with OPG in relation to two of its generation facilities identified in O. Reg. 427/04 (Payments to the Financial Corporation re Section 78.2 of the Act). Payments made to OPG under this agreement are related to the carbon dioxide (CO_2) limits that began to apply to OPG effective January 1, 2009.

Average RPP Supply Cost

The hourly market price forecast was developed by Navigant Consulting Ltd. (Navigant). The forecast of the simple average market price for 12 months from November 1, 2013 is $19.67/ MWh (1.967cents per kWh). After accounting for the consumption pattern of RPP consumers, the average market price for electricity used by RPP consumers is forecast to be $21.56/ MWh (2.156cents per kWh).

The combined effect of the other components of the RPP supply cost is expected to increase this per kilowatt-hour price. The collective impact of the other components is summarized by the Global Adjustment. The Global Adjustment reflects the impact of the NUG contract costs, which are above market prices, the regulated prices for OPG's prescribed baseload nuclear and hydroelectric generating facilities, which may be above or below market prices, and the cost of supply contracts held by the Ontario Power Authority (OPA), most of which are above market prices. The cost associated with CDM initiatives implemented by the OPA is also included, as are amounts approved by the Board in respect of Board-approved CDM programs undertaken by electricity distributors. The Global Adjustment also reflects payments made to OPG's Nanticoke and Lambton facilities, under an agreement with the Ontario Electricity Financial Corporation (OEFC), related to the CO_2 limits that began to apply to OPG effective January 1, 2009. The forecast net impact of the Global Adjustment is to increase the average RPP supply cost by $67.93/ MWh (6.793cents per kWh).

Another factor to be taken into account is that actual prices and actual demand cannot be predicted with absolute certainty; both price and demand are subject to random effects. Two adjustments are made to account for this forecast variance. A small adjustment is made to the RPP supply cost to account for the fact that these random effects are more likely to increase than to decrease costs. This adjustment was determined to be $1.00 / MWh (0.100 cents per kWh). Without this adjustment, the RPP would be expected to end the year with a small debit variance.

An additional adjustment factor is required to "clear" the expected balance in the OPA variance account as of October 31, 2014. The current surplus balance was accumulated because of higher than forecast RPP revenues and lower than forecast supply costs since May 1, 2013. The forecast adjustment factor to clear the existing variance balance is a credit (decrease in the RPP price) of $1.50/ MWh (0.150cents per kWh).

The resulting average RPP supply cost is $89.00/ MWh. The average RPP price (RPA) is 8.900cents per kWh. This is summarized in Table ES-1.

Table ES-1: Average RPP Supply Cost Summary (for the 12 months from November 1, 2013)

RPP Supply Cost Summary		
for the period from November 1, 2013 through October 31, 2014		
		Current
Forecast Wholesale Electricity Price		$19.67
Load-Weighted Price for RPP Consumers ($ / MWh)		$21.56
Impact of the Global Adjustment ($ / MWh)	+	$67.93
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	($1.50)
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$89.00**

Inevitably, there will be a difference between the actual and forecast cost of supplying electricity to all RPP consumers. This difference is referred to as the unexpected variance and will be included in the RPP supply cost for the next RPP period.

RPP consumers are not charged the average RPP supply cost. Rather, they pay prices under price structures that are designed to make their consumption weighted average price equal to the average supply cost. There are two RPP price structures, one for consumers with conventional meters (Tiered Pricing) and one for consumers with eligible time-of-use (or "smart") meters who pay time-of-use (TOU) prices.

Regulated Price Plan (TOU Pricing)

Consumers with eligible time-of-use (or "smart") meters that can determine when electricity is consumed during the day will pay under a time-of-use price structure. This currently applies only to consumers of those utilities that have implemented time-of-use prices. The prices for this plan are based on three time-of-use periods per weekday[2]. These periods are referred to as Off-Peak (with a price of $RPEM_{OFF}$), Mid-Peak ($RPEM_{MID}$) and On-Peak ($RPEM_{ON}$). The lowest (Off-Peak) price is below the RPA, while the other two are above it.

The resulting time-of-use (TOU) prices for consumers with eligible time-of-use meters are:

- $RPEM_{OFF}$ = 7.2cents per kWh (64% of TOU load);
- $RPEM_{MID}$ = 10.9cents per kWh (18% of TOU load); and,
- $RPEM_{ON}$ = 12.9cents per kWh (18% of TOU load).

These prices reflect the seasonal change in the TOU pricing periods which will take effect on November 1, 2013 and May 1, 2014. TOU pricing periods are:

- *Off-peak* period (priced at $RPEM_{OFF}$):
  - *Winter and summer weekdays*: 7 p.m. to midnight and midnight to 7 a.m.

[2] Weekends and statutory holidays have one TOU period: Off-peak.

  - *Winter and summer weekends and holidays*:[3] 24 hours (all day)
- *Mid-peak* period (priced at $RPEM_{MID}$)
  - *Winter weekdays (November 1 to April 30)*: 11 a.m. to 5 p.m.
  - *Summer weekdays (May 1 to October 31)*: 7 a.m. to 11 a.m. and 5 p.m. to 7 p.m.
- *On-peak* period (priced at $RPEM_{ON}$)
  - *Winter weekdays*: 7 a.m. to 11 a.m. and 5 p.m. to 7p.m.
  - *Summer weekdays*: 11 a.m. to 5 p.m.

Regulated Price Plan - Tiered Pricing

RPP consumers that are not on TOU pricing pay prices in two tiers; one price (referred to as $RPCM_{T1}$) for monthly consumption up to a tier threshold and a higher price (referred to as $RPCM_{T2}$) for consumption over the threshold. The threshold for residential consumers changes twice a year on a seasonal basis: to 600 kWh per month during the summer season (May 1 to October 31) and to 1000 kWh per month during the winter season (November 1 to April 30). The threshold for non-residential RPP consumers remains constant at 750 kWh per month for the entire year.

The resulting tiered prices for consumers with conventional meters are:

- $RPCM_{T1}$ = 8.3cents per kWh, and
- $RPCM_{T2}$ = 9.7cents per kWh.

Based on consumption over the 12-month period ending September 30, 2013, approximately 57% of RPP tiered consumption was at the lower tier price ($RPCM_{T1}$) and 43% was at the higher tier price ($RPCM_{T2}$). This ratio is expected to remain the same in the upcoming RPP period. Given these proportions, the average price for conventional meter RPP consumption is forecast to be equal to the RPA.

The average price a consumer on TOU prices will pay depends on the consumer's load profile (i.e., how much electricity is used at what time). As discussed above, RPP prices are set so that a consumer with an *average* load profile will pay the same average price under either the tiered or TOU prices, as shown in Table ES-2.[4] This average price is equal to the average RPP unit supply cost (equal to the RPA) of 8.9¢ / kWh.

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[3] For the purpose of RPP time-of-use pricing, a "holiday" means the following days: New Year's Day, Family Day, Good Friday, Christmas Day, Boxing Day, Victoria Day, Canada Day, Labour Day, Thanksgiving Day, and the Civic Holiday. When any holiday falls on a weekend (Saturday or Sunday), the next weekday following (that is not also a holiday) is to be treated as the holiday for RPP time-of-use pricing purposes.

[4] The percentages of total consumption by TOU period in Table ES-2 are based on consumption data for consumers on TOU pricing provided by the IESO. Data from the October 2012 through September 2013 period is used, taking into account the change in the TOU schedule.

Table ES-2: Price Paid by Average RPP Consumer under Tiered and TOU RPP prices

Tiered RPP Prices	Tier 1		Tier 2	Average Price
Price	8.3¢		9.7¢	8.9¢
% of Tiered Consumption	57%		43%	
Time-of-Use RPP Prices	**Off-Peak**	**Mid-Peak**	**On-Peak**	**Average Price**
Price	7.2¢	10.9¢	12.9¢	8.9¢
% of TOU Consumption	64%	18%	18%	

Major Factors Causing the Change in RPP Prices

The forecast average supply cost for RPP consumers increases by $5.05/ MWh in the current forecast compared to the previous forecast. Two factors account for this change:

- Underlying cost factors – the load weighted price for RPP consumers plus the global adjustment - increase the average supply cost by $2.33/MWh; and,
- The decrease in the variance account credit balance $2.71/MWh.

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1. Introduction

Under amendments to the *Ontario Energy Board Act, 1998* (the *Act*) contained in the *Electricity Restructuring Act, 2004*, the Ontario Energy Board (OEB or the Board) was mandated to develop a regulated price plan (RPP) for electricity prices to be charged to consumers that have been designated by legislation and that have not opted to switch to a retailer or to be charged the hourly spot market price. The first prices were implemented under the RPP effective on April 1, 2005, as set out in regulation by the Ontario Government. This report covers the period from May 1, 2013 to April 30, 2014. The RPP prices set out in this report are intended to be in place for that same period.[5] However, the Board will review these RPP prices in six months to determine whether they need to be adjusted.

The Board has issued a Regulated Price Plan Manual (RPP Manual) that explains how RPP prices are set. The Board relies on a forecast of wholesale electricity market prices, prepared by Navigant as a basic input into the forecast of RPP supply costs as per the RPP Manual methodology.

This Report describes how the Board has used the RPP Manual's processes and methodologies to arrive at the RPP prices effective November 1, 2013.

This Report consists of four chapters as follows:

- Chapter 1. Introduction
- Chapter 2. Calculating the RPP Supply Cost
- Chapter 3. Calculating RPP Prices
- Chapter 4. Expected Variance

1.1 Associated Documents

Two documents are closely associated with this Report:

- The *Regulated Price Plan Manual* (RPP Manual) describes the methodology for setting RPP prices; and,
- The *Ontario Wholesale Electricity Market Price Forecast For the Period November 1, 2013 through May 31, 2015* (Market Price Forecast Report),[6] prepared by Navigant, contains the Ontario wholesale electricity market price forecast and explains the material assumptions which lie behind the hourly price forecast. Those assumptions are not repeated in this Report.

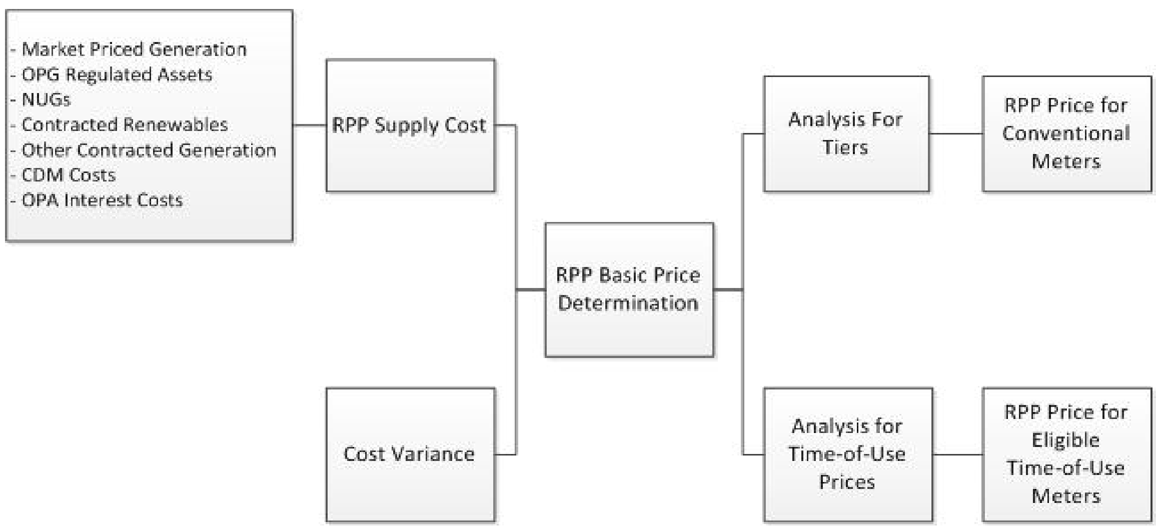
[5] In accordance with the RPP Manual, price resetting is considered for implementation every six months. If there is a price resetting following a Board review, the Board will determine how much of a price change will be needed to recover the forecast RPP supply cost *plus or minus* the accumulated variance in the OPA variance account over the next 12 months. In addition to the scheduled six month review, the RPP Manual allows for an automatic "trigger" based adjustment if the unexpected variance exceeds $160 million within a quarter.

[6] The Market Price Forecast Report is posted on the OEB web site, along with the RPP Price Report, on the RPP web page.

1.2 Process for RPP Price Determinations

Figure 1 below illustrates the process for setting RPP prices. The RPP supply cost and the accumulated variance account balance (carried by the Ontario Power Authority or OPA) both contribute to the base RPP price, which is set to recover the full costs of electricity supply. The diagram below illustrates the processes to be followed to set the RPP price for both consumers with conventional meters and those with eligible time-of-use meters (or "smart" meters).

Figure 1: Process Flow for Determining the RPP Price



Source: RPP Manual

This Report is organized according to this basic process.

2. Calculating the RPP Supply Cost

The RPP supply cost calculation formula is set out in Equation 1 below. To calculate the RPP supply cost requires forecast data for the terms in Equation 1. Most of the terms depend on more than one underlying data source or assumption. This chapter describes the data or assumption source for each of the terms and explains how the data were used to calculate the RPP supply cost. More detail on this methodology is in the RPP Manual.

It is important to remember that the elements of Equation 1 are forecasts. In some cases, the calculation uses actual historical values, but in these cases the historical values constitute the best available forecast.

2.1 Defining the RPP Supply Cost

Equation 1 below defines the RPP supply cost. This equation is further explained in the RPP Manual.

Equation 1

$$C_{RPP} = M + \alpha\,[(A - B) + (C - D) + (E - F) + G] + H, \text{ where}$$

- C_{RPP} is the total RPP supply cost;
- M is the amount that the RPP supply would have cost under the Market Rules;
- α is the RPP proportion of the total Global Adjustment costs;[7]
- A is the amount paid to prescribed generators in respect of the output of their prescribed generation facilities;[8]
- B is the amount those generators would have received under the Market Rules;
- C is principally the amount paid to OEFC with respect to its payments under contracts with non-utility generators (NUGs);[9]

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[7] The elements in square brackets collectively represent the Global Adjustment. For RPP price setting purposes the elements of the Global Adjustment are described differently in this Price Report than they are in O. Reg. 429/04 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998.* "G" in the expression in square brackets integrates two separate components of the Global Adjustment formula (G and H). "E" and "F" in the expression in square brackets include certain generation contracts that are associated with "G" in O. Reg. 429/04. This is necessary to ensure that there is no double-counting and thus over-recovery of generation costs because all RPP supply is included in "M". As discussed below, forecast Global Adjustment costs are recovered through the RPP according to the allocation of the Global Adjustment between Class A and Class B consumers, and the RPP consumers' share of Class B consumption.

[8] The Board currently sets payment amounts for energy produced from Ontario Power Generation's nuclear and large baseload hydro-electric generating stations. The Board's most recent Decision setting these payment amounts (EB-2010-0008) was issued on March 10, 2011.

[9] In addition to the contracts with the NUGs, OEFC is also the counterparty to a contingency support agreement with OPG in relation to two of its generation facilities identified in O. Reg. 427/04 (Payments to the Financial Corporation re Section 78.2 of the Act) made under the *Act.* Payments made to OPG under this agreement are related to the cost recovery mechanism associated with the CO_2 limits that began to apply to OPG effective January 1, 2009.

- D is the amount that would have been received under the Market Rules for electricity and ancillary services supplied by those NUGs;
- E is the amount paid to the OPA with respect to its payments under certain contracts with renewable generators;
- F the amount that would have been received under the Market Rules for electricity and ancillary services supplied by those renewable generators;
- G is (a) the amount paid by the OPA for its other procurement contracts for generation or for demand response or CDM, and (b) the sum of any amounts approved by the Board for CDM programs approved by the Board that are payable by the IESO to distributors or to the OPA; and,
- H is the amount associated with the variance account held by the OPA. This includes any existing variance account balance needed to be recovered (or disbursed) in addition to any interest incurred (or earned).

The forecast per unit RPP supply cost will be the total RPP supply cost (C_{RPP}) divided by the total forecast RPP demand. RPP prices will be based on that forecast per unit cost.

2.2 Computation of the RPP Supply Cost

Broadly speaking, the steps involved in forecasting the RPP supply cost are:

1. Forecast wholesale market prices;
2. Forecast the load shape for RPP consumers;
3. Forecast the quantities in Equation 1; and
4. Forecast RPP Supply Cost = Total of Equation 1.

In addition to the four steps listed above, the calculation of the total RPP supply cost requires a forecast of the stochastic adjustment, which is not included in Equation 1. The stochastic adjustment is included in the RPP Manual as an additional cost factor calculated outside of Equation 1. Since the RPP prices are always announced by the Board in advance of the actual price adjustment being implemented, it is also necessary to forecast the net variance account balance at the end of the current RPP period (October 31, 2013).[10] This amount is included in Equation 1 (“H”).

The following sections will describe each term or group of terms in Equation 1, the data used for forecasting them, and the computational methodology to produce each component of the RPP supply cost.

2.2.1 Forecast Cost of Supply Under Market Rules

This section covers the first term of Equation 1:

$$C_{RPP} = \boldsymbol{M} + \alpha\ [(A - B) + (C - D) + (E - F) + G] + H.$$

[10] RPP prices are announced in advance by the Board to provide notification to consumers of the upcoming price change and to provide distributors with the necessary amount of time to incorporate the new RPP prices into their billing systems.

The forecast cost of supply to RPP consumers under the Market Rules depends on two forecasts:

- o The forecast of the simple average hourly Ontario electricity price (HOEP) in the IESO-administered market over all hours in each month of the year; and
- o The forecast of the ratio of the load-weighted average market price paid by RPP consumers in each month to the simple average HOEP in that month.

The forecast of HOEP is taken directly from the Market Price Forecast Report. That report also contains a detailed explanation of the assumptions that underpin the forecast such as generator fuel prices (e.g., coal and natural gas). Table 1 below shows forecast seasonal on-peak, off-peak, and average prices. The prices provided in Table 1 are simple averages over all of the hours in the specified period (i.e., they are not load-weighted). These on-peak and off-peak periods differ from and should not be confused with the TOU periods associated with the RPP TOU prices discussed later in this report.

Table 1: Ontario Electricity Market Price Forecast ($ per MWh)

Term	Quarter	Calendar Period	On-Peak	Off-Peak	Average	Term Average
RPP Year	Q1	Nov 13 - Jan 14	$30.08	$21.46	$25.38	
	Q2	Feb 14 - Apr 14	$23.30	$16.06	$19.39	
	Q3	May 14 - Jul 14	$21.96	$12.72	$16.99	
	Q4	Aug 14 - Oct 14	$21.60	$13.03	$16.92	$19.67
Other	Q1	Nov 14 - Jan 15	$28.78	$19.79	$23.88	
	Q2	Feb 15 - Apr 15	$25.04	$17.37	$20.90	$22.42

Source: Navigant, *Wholesale Electricity Market Price Forecast Report*

Note: On-peak hours include the hours ending at 8 a.m. through 11 p.m. Eastern Standard Time (EST) on working weekdays and off-peak hours include all other hours. The definition of "on-peak" and "off-peak" hours for this purpose bears no relation to the "on-peak", "mid-peak" and "off-peak" periods used for time-of-use pricing.

The forecasts of the monthly ratios of load-weighted vs. simple average HOEP are based on actual prices between April 2005 and August 2013. The on-peak:off-peak ratio is also based on data through August 2013.

As shown in Table 1, the forecast simple average HOEP for the period November 1, 2013 to October 31, 2014, is $19.67/ MWh (1.967cents per kWh). The forecast of the load weighted average price for RPP consumers ("M" in Equation 1) is $21.56/ MWh (2.156cents per kWh), or $1.3 billion in total, the result of RPP consumers having load patterns that are more peak oriented than the overall system.

2.2.2 RPP Share of the Global Adjustment

Alpha ("α") in Equation 1 represents the share of the Global Adjustment paid by (or credited to) RPP consumers. Effective January 1, 2011, O. Reg. 429/04 (Adjustments under Section 25.33 of the *Act*) made under the *Electricity Act, 1998* was amended to revise how Global Adjustment costs are allocated to two sets of consumers, Class A and Class B (includes RPP consumers)[11] .

The first step to determine alpha is to estimate Class A's share of the Global Adjustment. Based on the formula in O. Reg. 429/04 the Class A share has been increased to 10.4% for the July 2013 to June 2014 period; and it is assumed to remain at that level for the July 2014 to June 2015 period.[12] Class B's share of the Global Adjustment is therefore 89.6%.

The next step is to estimate RPP consumers' share of Class B consumption. One factor to consider is the migration of customers to competitive retail supply or the spot market. This is a potential risk factor in determining the RPP supply cost. The expected impact of this migration away from the RPP (or attrition) has been reflected in the forecast volume of RPP consumers. However, attrition is not expected to have a significant impact on the load shape of RPP consumers for this period.

Based on historical data on RPP consumption as a share of total Ontario consumption it is forecast that RPP consumption will represent about 59 TWh or 49.2% of total Class B consumption.[13] The RPP share varies from month to month, ranging between 47.0% and 51.3%. The value of α therefore ranges between 0.421 and 0.458. Over the entire RPP period, RPP consumers are forecast to be responsible for 44.0% of the Global Adjustment.

2.2.3 Cost Adjustment Term for Prescribed Generators

This section covers the second term of Equation 1:

$$C_{RPP} = M + \alpha\ [\boldsymbol{(A - B)} + (C - D) + (E - F) + G] + H$$

The prescribed generators are comprised of the nuclear and baseload hydroelectric facilities of Ontario Power Generation (OPG). The amounts paid to OPG's prescribed generation since March 2011 have been $55.85 / MWh for nuclear generation and $34.13 / MWh for hydraulic generation. The nuclear payment amount includes a base rate of $51.51 / MWh, plus a rider of $4.33 / MWh. The hydraulic base rate is $35.78, minus a rider of $1.65. As set out in the EB-2012-0002 Settlement Agreement dated March 14, 2013 and subsequently approved by the OEB on March 25, 2013, the riders for 2013 and 2014 have been adjusted to $6.27 and $4.18 respectively for nuclear, and to $4.04 and $2.02 respectively for hydro. Quantity A was therefore forecast by multiplying these fixed payment amounts per MWh, for the prescribed generation facilities, times their total forecast output per month in MWh.

Quantity B was forecast by estimating the market values of each MWh of nuclear and prescribed hydraulic generation, and multiplying those market values by the volume of nuclear

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[11] O. Reg. 429/04 defines two classes of consumers; Class A, comprised of consumers whose maximum hourly demand for electricity in a month is 5 MW or more; and Class B consumers, comprised of all other consumers, including RPP consumers.

[12] The percentage of Class A Global Adjustment costs was based on Class A load during peak demand hours in the May 1, 2012 to April 30, 2013 period. Most likely, a revised Class A peak demand factor will be effective for the July 1, 2014 to June 30, 2015 period, based on peak load percentages in the May 1, 2013 to April 30, 2014 period.

[13] The Class A/Class B split did not exist before January 2011. Data on RPP consumption as a share of total Class B consumption is available only for the January 2011 to August 2013 period.

and prescribed hydraulic generation.[14] The value of A is $3.6 billion, and the value of B is $1.4 billion.

2.2.4 Cost Adjustment Term for Non-Utility Generators (NUGs) and Other Generation under Contract with OEFC

This section describes the calculation of the third term of Equation 1:

$$C_{RPP} = M + \alpha\ [(A - B) + \boldsymbol{(C - D)} + (E - F) + G] + H$$

Although the details of these payments (amounts by recipient, volumes, etc.) are not public, published information from the OPA about aggregate monthly payments to non-utility generators (NUGs) has been used as the basis for forecasting payments in future months. This data has been supplemented by information provided by the OEFC. This forecast was used to compute an estimate of the total payments to the NUGs under their contracts, or amount C in Equation 1.

Since the beginning of 2009, the component of the Global Adjustment referred to as quantity "C", as published by the IESO, has included an additional component: contingency support payments (CSPs) made in relation to certain OPG coal-fired generation facilities. These payments are explained as follows by OPG in its *2009 Second Quarter Results* report: *"a contingency support agreement [was] established with the Ontario Electricity Financial Corporation ("OEFC") to provide for the continued reliability and availability of OPG's Lambton and Nanticoke generating stations. The agreement was put in place in accordance with the Shareholder Resolution that an appropriate recovery mechanism be established to enable OPG to recover the costs of its coal-fired generating stations following implementation of OPG's carbon dioxide ("CO_2") emissions reduction strategy."*[15] Based on the agreement,[16] OPG receives payments through OEFC which make up the difference between OPG's actual costs and its gross revenues for these two plants. The plants' market revenues continue to be very low because of a combination of low market demand and low market prices. As a result, according to OPG's financial reports, these payments were $322 million in the twelve months ending June 30, 2013[17]. For the purpose of setting the RPP prices for this period, these payments have been forecast based on the following:

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[14] The forecast of the dollar amount that the prescribed generators would receive under the Market Rules (quantity B in Equation 1) was calculated as their forecast monthly generation multiplied by their forecast average market revenue in each month. Forecasts of both of these variables were taken from Navigant's statistical model. For details of the statistical model and the wholesale market price forecast, see the Market Price Forecast Report.

[15] See page 8 of OPG's *2009 Second Quarter Results* report at the following: www.opg.com/investor/pdf/2009_Q2_FullRpt.pdf.

[16] The body of the agreement (excluding the schedules) is available at: www.opg.com/pdf/OEFC%20Agreement%202009.pdf. According to the agreement, Gross Revenues and Actual Costs are comprised of: (1) *Actual costs* include OM&A, fuel costs (including emission credit/allowances), depreciation, insurance, capital/property taxes, direct corporate support costs, interest on inventory (including fuel), IESO market charges (i.e., uplifts), and biomass costs; (2) *Gross revenues* include all net market revenues (all energy related market revenues, CMSC credits, ancillary service revenues), revenues from emission credits, generation cost guarantee payments, and other non-electricity revenues (i.e., by-products and dock rentals).

[17] Ontario Power Generation Quarterly Financial Results, http://www.opg.com/investor/fin_reports/index.asp

- Monthly forecasts of coal generation, based on the historical relationship between market prices and the volume of coal generation (i.e., when market prices are low, coal plants generate less);
- Monthly forecasts of the average hourly market price received by coal generation, based on historical relationships; and,
- Estimates of the monthly revenue requirement and unit variable costs, based on historical data on hourly coal generation and hourly market prices, and the actual payments received by OPG in 2009, 2010, 2011, 2012 and 2013.

The monthly forecast of coal generation includes the recent decision to shut down the remaining coal units by the end of 2013, one year earlier than originally scheduled.

The amount that the NUGs would receive under the Market Rules, quantity D in Equation 1, is their hourly production times the hourly Ontario energy price. These quantities were forecast on a monthly basis, as an aggregate for the NUGs as a whole.

The value of "C" in Equation 1 (i.e., the contract cost of both the NUGs and the coal plants) is estimated to be $1.2 billion, and the value of "D" (i.e., the market value of the NUG and coal output) is estimated to be $0.2 billion.

2.2.5 Cost Adjustment Term for Certain Renewable Generation Under Contract with the OPA

This section describes the calculation of the fourth term of Equation 1:

$$C_{RPP} = M + \alpha\ [(A - B) + (C - D) + \boldsymbol{(E - F)} + G] + H$$

Quantities E and F in the above formula refer to certain renewable generators paid by the OPA under contracts related to output. Generators in this category are renewable generators under the following contracts:

- Renewable Energy Supply (RES) Request for Proposals (RFP) Phases I, II and III;
- the Renewable Energy Standard Offer Program (RESOP);
- the Feed-In Tariff (FIT) Program;
- the Hydroelectric Energy Supply Agreements (HESA) directive, covering new hydro; and,
- the Hydro Contract Initiative (HCI), covering existing hydro plants.

Quantity E in Equation 1 is the forecast quantity of electricity supplied by these renewable generators times the fixed price they are paid under their contract with the OPA. The statistical model includes estimates of the fixed prices. In some cases, this is simply the announced contract price (e.g., $420 / MWh for solar generation under RESOP). In others, the contract price needs to be adjusted in each year either partially or fully in proportion to inflation. In still others, detailed information on contract prices is not available, and they have been estimated based on publicly-available information (for example, the Ontario Government announced that the weighted average price for Renewable RFP I projects was $79.97 / MWh, but did not announce prices for individual contracts).[18]

The size and generation type of the successful renewable energy projects to date have been announced by the Government and the OPA. The statistical model produced forecasts of additional renewable capacity coming into service during the RPP period, and the monthly output of both existing and new plants, using either historical values of actual outputs (where available), or estimates based on the plants' capacities and estimated capacity factors. The statistical model also forecasts average market revenues for each plant or type of plant. Quantity F in Equation 1 is therefore the forecast output of the renewable generation multiplied by the forecast average market revenue (based on market prices in the Wholesale Market Price Forecast Report) at the time that output is generated.

The value of "E" in Equation 1 (i.e., the contract cost of renewable generation) is estimated to be $2.7 billion, and the value of "F" (i.e., the market value of renewable generation) is estimated to be $0.4 billion.

2.2.6 Cost Adjustment Term for Other Contracts with the OPA and for Board-approved CDM Programs

This section describes the calculation of the fifth term of Equation 1:

$$C_{RPP} = M + \alpha\ [(A - B) + (C - D) + (E - F) + \boldsymbol{G}] + H$$

The costs for three types of resources under contract with the OPA are included in G:

1. conventional generation (e.g., natural gas) whose payment relates to the generator's capacity costs;
2. demand side management or demand response contracts; and
3. Bruce Power, which has an output-based contract for generation from its Bruce A nuclear facility, and a price guarantee contract (i.e., floor price) for its Bruce B facility.

The contribution of conventional generation under contract to the OPA to quantity G relates to several contracts:

- The Clean Energy Supply (CES) RFP, which includes conventional generation contracts as well as a 10-MW demand response contract awarded to Loblaws;[19]
- The "early mover" contracts;[20]

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[18] For information related to the FIT Price Schedule, see the OPA's dedicated web page at: fit.powerauthority.on.ca/ Page.asp?PageID=924&ContentID=10543

[19] Seven facilities holding CES contracts are expected to be operational during this RPP period: the GTAA Cogeneration Facility, the Loblaws Demand Response Program, the Greenfield Energy Centre, the Portlands Energy Centre, the Goreway Station Project, the St. Clair Energy Centre and Halton Hills Generating Station. The OPA entered into contracts with these facilities pursuant the Ministry of Energy's directive of March 24, 2005.

[20] On December 14, 2005, the Minister of Energy directed the OPA to negotiate contracts with plants that had entered service since 1998 without a contract. Five facilities signed early mover contracts with the OPA: the Brighton Beach facility, TransAlta's Sarnia facility, and three Toromont facilities. On December 24, 2008, the OPA was directed to negotiate new contracts which are to expire no later than December 26, 2026. For forecasting purposes, it is assumed

- Seven contracts awarded through the Combined Heat and Power (CHP) Phase I RFP[21]; and,
- Six large gas-fired plants (Portlands, Goreway, Greenfield, St. Clair, York Energy Centre and Halton Hills). The first of these, the Portlands Energy Centre, began operation as a simple-cycle plant in June 2008 and has been converted into a combined-cycle plant. Greenfield began commercial operation in October 2008, St. Clair in March 2009, and Goreway in June 2009. The Halton Hills Generating Station began operation in 2010, and the York Energy Centre (393 MW), began supplying energy to the grid in 2012.

The costs of these contracts, for the purpose of calculating the RPP supply cost, are based on an estimate of the contingent support payments to be paid under the contract guidelines. The contingent support payment is the difference between the net revenue requirement (NRR) stipulated in the contracts and the "deemed" energy market revenues. The deemed energy market revenues were estimated based on the deemed dispatch logic as stipulated in the contract and the Wholesale Market Price Forecast Report that underpins this RPP price setting activity. The NRRs and other contract parameters for each contract have been estimated based on publicly available information. Examples include the average NRR for the CES contracts which was announced by the Government to be $7,900 per megawatt-month,[22] as well as an NRR of $17,000 for the cancelled Oakville Generating station which has been used as a guideline for some of the more recent gas plant additions.

The cost to the OPA of any additional conservation and demand management (CDM) initiatives is also captured in term G of Equation 1. The OPA is currently offering or planning to offer several CDM initiatives over the next 12 months. These programs generally fall into three categories: Mass Market programs, Commercial / Institutional Market programs and Industrial Market programs, and are based on various Ministerial directives to the OPA and the Board between June 2005 and July 2010.

Further to a directive issued to the Board under section 27.2 of the *Act*, electricity distributors are required by their conditions of licence to achieve certain conservation and demand reductions through the delivery of CDM programs. Amounts approved by the Board (including performance incentives) for CDM programs approved by the Board[23] pursuant to that directive will be settled through the IESO and recovered through the Global Adjustment. These Board-approved CDM amounts will be included in quantity "G" based on the timing of payments by the IESO as determined by the Board under section 78.5 of the *Act*.

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that the contribution to the Global Adjustment of these contracts will be similar to what it would have been under the old contracts.

[21] Seven facilities holding CHP Phase I contracts are expected to be operational during this RPP period: the Great Northern Tri-gen Facility, the Durham College District Energy Project, the Countryside London Cogeneration Facility, the Warden Energy Centre, the Algoma Energy Cogeneration Facility, the East Windsor Cogeneration Centre, and the Thorold Cogeneration Project.

[22] Given the ministerial directive to the OPA, the NRR for the "early movers" was assumed to be the same.

[23] Distributors may meet their CDM targets through the delivery of CDM programs that are made available by the OPA and/or the delivery of CDM programs that have been approved by the Board.

The Bruce Power contract initially stipulated that output from the Bruce A facility would be paid a base price of $57.37 / MWh, indexed to inflation, plus fuel costs. As of April 1, 2008, the base price was increased by $2.11 / MWh, to $59.48 / MWh.[24] At today's fuel prices and including inflation adjustments since the contract went into effect, the average price during the upcoming RPP period is estimated to be approximately $75 / MWh. Under the agreement, Bruce Power will be paid a monthly contingent support payment if its actual revenues are less than contract revenues or it will make a revenue sharing payment to the OPA if actual revenues are greater than contract revenues.

The Bruce Power contract also stipulates that output from the Bruce B facility be guaranteed a floor price of $45 / MWh, indexed to inflation, over a calendar year. Adjustments for inflation are made on an annual basis. For the upcoming RPP period, the average floor price is forecast to be approximately $53 / MWh.

The OPA has signed a contract with OPG for the on-going operation of OPG's Lennox Generating Station, a 2,140-MW peaking plant. The cost of this contract is included in the "G" variable.

The value of "G" in Equation 1 (i.e., net cost of Bruce nuclear, gas and Lennox generation plus CDM programs) is estimated to be $3.5 billion.

2.2.7 Estimate of the Global Adjustment

The total Global Adjustment is estimated to be a cost of $9.1 billion. The RPP share of this (i.e., α times the total cost) is estimated to be a cost of $4.0 billion, or $67.93/MWh (6.793 cents per kWh). This is the forecast of the average Global Adjustment cost per unit that will accrue to RPP consumers over the period from November 1, 2013 to October 31, 2014

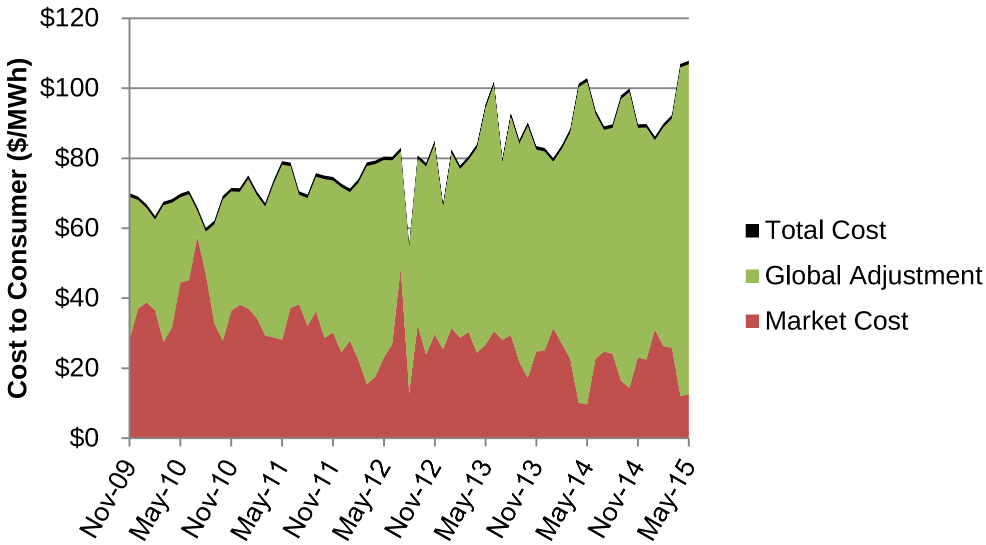
The Global Adjustment represents the difference between the total contract cost of the various contracts it covers (for OPG nuclear and prescribed hydro, Bruce nuclear, gas plants, renewable generation, OPG coal, CDM, etc.) and the market value of certain of the contracted generation. The Global Adjustment therefore changes for two reasons:

- changes (usually increases) in the number and aggregate capacity of contracts it covers, or
- fluctuations in the market value of the contracted generation.

This is illustrated in Figure 2, which shows how the Global Adjustment is expected to change over the next 18 months. Consumers pay the full cost of the contracts covered by the Global Adjustment, either through market costs or through the Global Adjustment itself. The Global Adjustment fluctuates as market prices rise and fall, but the total supply cost (market cost plus Global Adjustment) is expected to increase over the next 12 months.

[24] http://www.powerauthority.on.ca/sites/default/files/page/5142_First_Amendment_BPRIA_20070829.pdf The "base" (or "reference") price was increased due to the agreement involving the expansion of the Bruce A refurbishment project.

Figure 2: Components of the RPP Supply Cost



The primary factor contributing to the increase in the supply cost between this RPP period and the previous one is an increase in renewable generation.

Wholesale market prices do not materially contribute to an increase or decrease in supply cost because changes in market prices are almost exactly offset by changes in the opposite direction in the Global Adjustment.

2.2.8 Cost Adjustment Term for OPA Variance Account

This section describes the calculation of the sixth term of Equation 1:

$$C_{RPP} = M + \alpha\,[(A - B) + (C - D) + (E - F) + G] + \boldsymbol{H}$$

The cost adjustment term for the OPA variance account consists of two factors. The first is the forecast interest costs associated with carrying any RPP-related variances incurred during the upcoming RPP period (November 2013 – October 2014). The second represents the price adjustment required to clear (i.e., recover or disburse) the existing RPP variance and interest accumulated over the previous RPP period.

The first term discussed above is small, as any interest expenses incurred by the OPA to carry consumer debit variances in some months are generally offset by interest income the OPA receives from carrying consumer credit balances in other months. In addition, the interest rate paid by the OPA on the variance account is relatively low.

The second term is significant. It represents the price adjustment necessary to clear the total net variance accumulated since the RPP was introduced on April 1, 2005 through to the beginning of this RPP Period. As of October 31, 2013 the net variance account balance is forecast to be a favourable, or positive, balance of approximately $88 million including interest. This is quantity "H" in Equation 1.

A variance clearance factor has been calculated that is estimated to bring the variance account to approximately a zero balance over the twelve month period, after taking into account both the changes in total RPP consumption and the Final RPP Variance Settlement Amount payments expected as of October 31, 2013. This variance clearance factor has decreased from a credit of 0.421 cents per kWh in the previous RPP report to a credit of 0.150 cents per kWh. This change is primarily the result of lower-than-forecast Global Adjustment costs relative to the level of HOEP, which increased the variance account surplus balance. The variance clearance factor decreases the average RPP supply cost by the amount of the credit: $1.50/ MWh (0.150 cents per kWh).

2.3 Correcting for the Bias Towards Unfavorable Variances

The supply costs discussed in section 2.2 are based on a forecast of the HOEP. However, actual prices and actual demand cannot be predicted with absolute certainty. Calculating the total RPP supply cost therefore needs to take into account the fact that volatility exists amongst the forecast parameters, and that there is a slightly greater likelihood of negative or unfavourable variances than favourable variances. For example, because nuclear generation plants tend to operate at capacity factors between 80% and 90%, these facilities are more likely to "under-generate" (due to unscheduled outages) than to "over-generate" (i.e., there is 10-20% upside versus 80-90% downside on the generator output). Similarly, during unexpectedly cold or hot weather, prices tend to be higher than expected as does RPP consumers' demand for electricity. The net result is that the RPP would be "expected" to end the year with a small unfavourable variance in the absence of a minor adjustment to reflect the greater likelihood of unfavourable variances.

The Board regularly reviews the differences between the estimated and actual RPP supply cost. Based on this experience, the Adjustment to Address Bias Towards Unfavourable Variance is set at $1.00 / MWh (0.100 cents per kWh). This amount is included in the price paid by RPP consumers to ensure that the "expected" variance at the end of the RPP year is zero.

2.4 Total RPP Supply Cost

Table 2 shows the percentage of Ontario's total electricity supply attributable to various generation sources, the percentage of forecasted Global Adjustment costs for each type of generation and the total unit costs. Total unit costs are based on contracted costs for each generation type, including global adjustment payments and market price payments, where applicable.

Table 2: Total Electricity Supply and Cost

	% of Total Supply	% of Total GA	Total Unit Cost (cents/kWh)
Nuclear	66	47	6.0
Hydro*	15	8	4.8
Gas**	10	21	13.5
Wind	6	11	12.0
Solar	1	11	48.9
Bioenergy	1	2	12.6

*Excludes NUGs and OPG non-prescribed generation. **Includes Lennox and NUGs.

The total RPP supply cost is estimated to be $5.3 billion.[25]

The following table itemizes the various steps discussed above to arrive at the average RPP supply cost of $89.00/ MWh. This average supply cost corresponds to an average RPP price, which is referred to as RPA, of 8.900 cents per kWh.

Table 3: Average RPP Supply Cost Summary

RPP Supply Cost Summary for the period from November 1, 2013 through October 31, 2014		
		Current
Forecast Wholesale Electricity Price		$19.67
Load-Weighted Price for RPP Consumers ($ / MWh)		$21.56
Impact of the Global Adjustment ($ / MWh)	+	$67.93
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	($1.50)
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$89.00**

Source: Navigant

[25] The total cost figure is net of the forecast variance account balance as of October 31, 2012.

3. Calculating the RPP Price

The previous chapter calculated a forecast of the total RPP supply cost. Given the forecast of total RPP demand, it also produced a computation of the average RPP supply cost and the average RPP supply price, RPA. This chapter explains how prices are determined for consumers with eligible time-of-use meters that are being charged the TOU prices, $RPEM_{ON}$, $RPEM_{MID}$, and $RPEM_{OFF}$, and for the tiers, $RPCM_{T1}$ and $RPCM_{T2}$.

3.1 Setting the TOU Prices for Consumers with Eligible Time-of-Use Meters

For those consumers with eligible time-of-use meters whose distributors have implemented time-of-use (TOU) prices, three separate prices will apply. The times when these prices apply varies by time of day and season, as set out in the RPP Manual. There are three price levels: On-peak ($RPEM_{ON}$), Mid-peak ($RPEM_{MID}$), and Off-peak ($RPEM_{OFF}$). The load-weighted average price must be equal to the RPA.

As described in the RPP Manual, the first step is to set the Off-peak price, or $RPEM_{OFF}$. This price reflects the forecast market price during that period, including the Global Adjustment and the variance clearance factor. The Mid-peak price, $RPEM_{MID}$, is similarly set. After these two prices are set, and given the forecast levels of consumption during each of the three periods, the On-peak price, $RPEM_{ON}$, is determined by the requirement for the load-weighted average of TOU prices to equal the RPA.

The various components of Global Adjustment costs are allocated to TOU consumption periods based on the type of cost. The costs associated with OPG's regulated facilities, Bruce Power's nuclear plants, renewable generation and CDM costs related to conservation programs are allocated uniformly across all consumption. The remaining portion of the CDM cost is allocated only to On-peak consumption, because the purpose of the demand management portion of CDM is to ensure uninterrupted supply during peak times. Payments to Lennox are also allocated to the on-peak period, for the same reason. Contingent support payments to the coal and gas plants are allocated to the three periods based on the amount of generation in each period over the past twelve months (October 2012 – September 2013), taking into account the change in the TOU schedule. The NUG component of the GA is allocated to both Mid-peak and On-peak consumption because these generators serve non-Off-peak consumption. As well, approximately one-quarter of the stochastic adjustment was allocated to the Mid-peak price and three-quarters was allocated to the On-peak price because the majority of risks covered by the adjustment are borne during these time periods.

The resulting **time-of-use prices** are:

- $RPEM_{OFF}$ = 7.2 cents per kWh
- $RPEM_{MID}$ = 10.9 cents per kWh, and
- $RPEM_{ON}$ = 12.9 cents per kWh.

As defined in the RPP Manual, the time periods for time-of-use (TOU) price application are defined as follows:

- *Off-peak* period (priced at $RPEM_{OFF}$):
  - *Winter and summer weekdays*: 7 p.m. to midnight and midnight to 7 a.m.

        - *Winter and summer weekends and holidays*:[26] 24 hours (all day)
    - *Mid-peak* period (priced at $RPEM_{MID}$)
        - *Winter weekdays (November 1 to April 30)*: 11 a.m. to 5 p.m.
        - *Summer weekdays (May 1 to October 31)*: 7 a.m. to 11 a.m. and 5 p.m. to 7 p.m.
    - *On-peak* period (priced at $RPEM_{ON}$)
        - *Winter weekdays*: 7 a.m. to 11 a.m. and 5 p.m. to 7p.m.
        - *Summer weekdays*: 11 a.m. to 5 p.m.

The above times are given in local time (i.e., the times given reflect daylight savings time in the summer).

The average price for a consumer on time-of-use prices depends on the consumer's load profile (i.e., how much electricity is used at what time). The load profile assumed for TOU consumers is different from the load profile for non-TOU RPP consumers. RPP prices are set so that a TOU consumer with an average TOU load profile will pay the same average price as an RPP consumer that pays the tiered prices with a typical (non-TOU) load profile. This average price is equal to the RPA, 8.9¢ / kWh.

3.2 Setting the Tiered Prices

The final step in setting the price for RPP consumers with conventional meters is to determine the tiered prices. For these consumers, there is a two-tiered pricing structure: $RPCM_{T1}$ (the price for consumption at or below the tier threshold) and $RPCM_{T2}$ (the price for consumption above the tier threshold). The tier threshold is an amount of consumption per month.

The tiered prices are calculated so that the average per unit revenue generated is equal to the RPA. This is achieved by maintaining the ratio between the original upper and lower tier prices (i.e., the ratio between 4.7 and 5.5 cents per kWh) and forecasting consumption above and below the threshold in each month of the RPP.

RPP tiered prices are set such that the weighted average price will come as close as possible to the RPA, based on the forecast ratio of Tier 1 to Tier 2 consumption, and maintaining a 15-17% difference between Tier 1 and Tier 2 prices.

The resulting **tiered prices** are:

- $RPCM_{T1}$ = 8.3 cents per kWh; and,
- $RPCM_{T2}$ = 9.7 cents per kWh.

[26] For the purpose of RPP time-of-use pricing, a "holiday" means the following days: New Year's Day, Family Day, Good Friday, Christmas Day, Boxing Day, Victoria Day, Canada Day, Labour Day, Thanksgiving Day, and the Civic Holiday. When any holiday falls on a weekend (Saturday or Sunday), the next weekday following (that is not also a holiday) is to be treated as the holiday for RPP time-of-use pricing purposes.

Table 4: Price Paid by Average RPP Consumer under Tiered and TOU RPP prices

Tiered RPP Prices	Tier 1		Tier 2	Average Price
Price	8.3¢		9.7¢	8.9¢
% of Tiered Consumption	57%		43%	
Time-of-Use RPP Prices	**Off-Peak**	**Mid-Peak**	**On-Peak**	**Average Price**
Price	7.2¢	10.9¢	12.9¢	8.9¢
% of TOU Consumption	64%	18%	18%	

4. Expected Variance

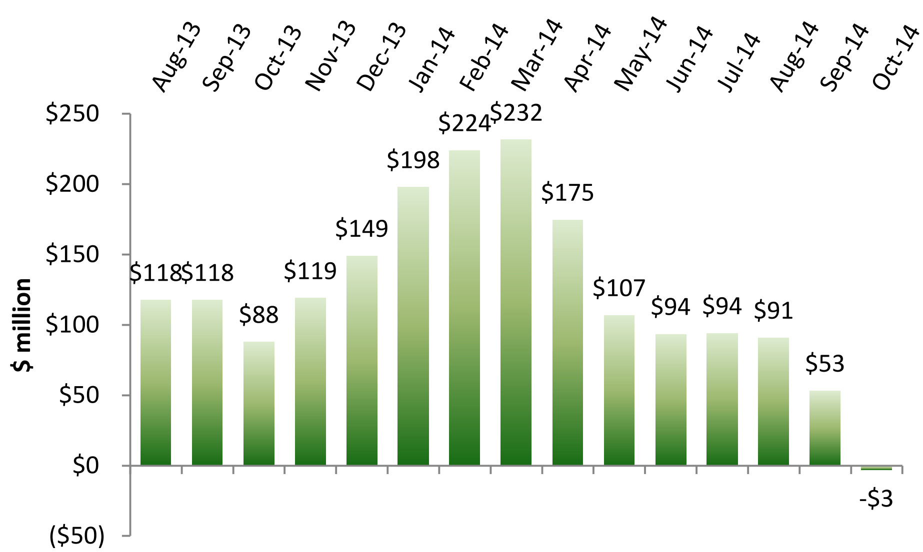
After RPP prices are set, the monthly expected variance can be calculated directly. The variance clearance factor is set so that the expected variance balance at the end of the RPP period will be as close as possible to zero. However, the variance balance is not expected to decline smoothly; the amount of the variance balance cleared is expected to vary significantly from month to month for several reasons:

- Variance clearance will tend to be higher in months when RPP volumes are higher (i.e., summer and winter) and lower when volumes are lower (i.e., spring and fall).
- While there is only technically a single average RPP price (or RPA) in this report, the residential tier thresholds are higher in winter (1000 kWh) than in summer (600 kWh). This means that the average price that RPP consumers on tier prices pay will be lower in winter than in summer, because they will have less consumption at the higher tiered price in the winter. Thus, variance clearance will vary from summer to winter.
- The HOEP is projected to be higher in some months (especially summer) and lower in others (especially the shoulder seasons), but RPP prices remain constant. This will be partially offset by changes in the Global Adjustment. Thus, variance clearance will vary by month, depending on market prices.

The combined effect of these factors is shown in Figure 6. The values in each month of Figure 6 represent the total expected balance in the OPA variance account at the end of each month.

Because the RPP prices are rounded to the nearest tenth of a cent, the amount of revenue to be collected cannot be adjusted to exactly clear the variance account. In this case, the new RPP prices given above are expected to collect slightly less than the RPP supply cost, leaving an "expected" balance of -$3 million in the variance account at the end of the RPP period. However, any decrease in the RPP prices would lead to an even larger under-collection. The RPP prices are therefore set to bring the variance balance as close as possible to zero.

Figure 3: Expected Monthly Variance Account Balance ($ million)



Source: Navigant