Ontario

Regulated Price Plan

Price Report

May 1, 2017

to

April 30, 2018

Ontario Energy Board

April 20, 2017

Executive Summary

This report contains the electricity commodity prices under the Regulated Price Plan (RPP) for the period May 1, 2017 through April 30, 2018. The prices were developed using the methodology described in the Regulated Price Plan Manual (RPP Manual).

In accordance with the applicable regulation, the OEB must forecast the cost of supplying RPP consumers and ensure that RPP prices reflect this cost. The OEB's practice is to review RPP prices 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:

- 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;
- the costs of the supply contracts, and conservation and demand management (CDM) initiatives of the Independent Electricity System Operator[1] (IESO); and
- the net variance account balance (as of April 30, 2017) carried by the IESO.

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.

For this RPP price setting, the OEB has, consistent with its past practice of smoothing significant forecast price changes for customers, taken into account a portion of the estimated impact of the government's proposed Ontario Fair Hydro Plan announced on March 2, 2017. Legislation

[1] Contracts were formerly held by the Ontario Power Authority (OPA), which merged with the Independent Electricity System Operator effective January 1, 2015.

implementing the proposed Plan would, if passed, represent a significant step change in electricity bills for RPP consumers.

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 May 1, 2017 is $22.81/MWh (2.281 cents 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 $24.83/MWh (2.483 cents 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 at most times, the regulated prices for OPG's prescribed nuclear and hydroelectric generating facilities (the prescribed assets), which may be above or below market prices, and any remaining cost of supply contracts held by the Independent Electricity System Operator (IESO) which generators have not recovered through their market revenues. The cost associated with Conservation and Demand Management (CDM) initiatives implemented by the IESO is also included. The forecast net impact of the Global Adjustment is to increase the average RPP supply cost by $87.67/MWh (8.767 cents 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 included in the RPP price to "clear" the expected balance in the IESO variance account as of April 30, 2017. The current balance accumulated in part as a result of keeping May 2016 prices in place for a full year. In addition, the variance is a result of typical factors such as weather variation, fluctuations in natural gas prices, and differences in other cost inputs. The forecast adjustment factor, which would be expected to clear the existing variance balance, is a debit (increase in the RPP price) of $1.40/MWh (0.140cents per kWh).

The resulting average RPP supply cost (for the period starting May 1, 2017) is $114.90/MWh. The average RPP price (RPA) is 11.49 cents per kWh, or 0.35 cents per kWh higher than the forecast for 12 months beginning May 2016.[2] This is summarized in Table ES-1.

[2] In November 2016, the OEB determined that the time-of-use and tiered prices would not change relative to May 2016 prices. The OEB determined that the May 2016 prices would continue to be effective in recovering forecast costs.

Table ES-1: Average RPP Supply Cost Summary

RPP Supply Cost Summary for the period from May 1, 2017 through April 30, 2018		
Forecast Wholesale Electricity Price		$22.81
Load-Weighted Price for RPP Consumers ($ / MWh)		$24.83
Impact of the Global Adjustment ($ / MWh)	+	$87.67
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	$1.40
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$114.90**

Source: Navigant

Inevitably, there will be a difference between the actual and forecast cost of supplying electricity to all RPP consumers. Differences can arise as a result of changes in demand due to weather, variation in natural gas prices, changes in the supply mix, as well as other factors. The sum of these differences is referred to as the unexpected variance, which in accordance with usual practice is taken into account in the next RPP period.

RPP prices are designed such that consumers pay a stable and predictable price that reflects the cost of supplying their electricity over time. These prices are always based on a forecast of the costs for the year ahead. A consideration that the OEB employs in all aspects of its rate-setting is to smooth significant price changes in order to support more gradual transitions in electricity costs for customers over time. With this consideration in mind, the OEB has historically included a portion of significant price changes that may occur in the forecast period because of the smoothing benefits for customers.

In keeping with this practice, the OEB has considered it appropriate in this price setting to take into account a portion of the estimated impact of the government's proposed Fair Hydro Plan. The OEB has done this by way of a reduction in the forecast amount of the Global Adjustment of approximately $1B, which represents 50% of RPP consumers' estimated portion of the proposed refinancing of the Global Adjustment. This yields a total estimated RPP supply cost of $5.8B, or an overall average RPP cost of $97.62/MWh or 9.76 cents per kWh, which is roughly 1.7 cents lower than the RPP supply cost absent any consideration of the estimated impact of the proposed Fair Hydro Plan. This translates to a reduction of about 15% on the electricity line, and about 17% on the electricity bill (including the impact of the 8% rebate provided for under the *Ontario Rebate for Electricity Consumers Act, 2016* and the OEB's decision to remove the Ontario Electricity Support Program charge) for a typical residential customer relative to what prices would otherwise have been, once RPP prices come into effect on May 1, 2017. This is summarized in Table ES-2.

The government has indicated that it intends to introduce legislation that would, if passed, implement the proposed Fair Hydro Plan starting this summer. The OEB will then further adjust RPP prices as needed so that RPP customers receive the full rate relief as legislated.

Table ES-2: Average RPP Supply Cost Summary with Consideration of the Proposed Fair Hydro Plan

RPP Supply Cost Summary for the period from May 1, 2017 through April 30, 2018		
Forecast Wholesale Electricity Price		$22.81
Load-Weighted Price for RPP Consumers ($ / MWh)		$24.83
Impact of the Global Adjustment ($ / MWh)	+	$70.39
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	$1.40
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$97.62**

Source: Navigant

Regulated Price Plan (TOU Pricing)

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 eligible time-of-use (or "smart") meters who pay time-of-use (TOU) prices, who make up the majority of RPP consumers, and one for consumers with conventional meters (Tiered 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. The prices for this plan are based on three time-of-use periods per weekday[3]. These periods are referred to as Off-Peak (with a price of $RPEM_{OFF}$), Mid-Peak ($RPEM_{MID}$) and On-Peak ($RPEM_{ON}$).

The resulting TOU prices for consumers with eligible time-of-use meters would be the following, absent any consideration of the estimated impact of the proposed Fair Hydro Plan:

- $RPEM_{OFF}$ = 9.1 cents per kWh;
- $RPEM_{MID}$ = 13.3 cents per kWh; and,
- $RPEM_{ON}$ = 18.5 cents per kWh.

The resulting TOU prices for consumers with eligible time-of-use meters are the following after taking into account the reduction in the forecast amount of the Global Adjustment of approximately $1B:

- $RPEM_{OFF}$ = 7.7 cents per kWh;
- $RPEM_{MID}$ = 11.3 cents per kWh; and,
- $RPEM_{ON}$ = 15.7 cents per kWh.

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

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These prices reflect the seasonal change in the TOU pricing periods which will take effect on May 1, 2017 and November 1, 2017. 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.
  - *Winter and summer weekends and holidays*:[4] 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 tiered prices for consumers with conventional meters would be the following, absent any consideration of the estimated impact of the proposed Fair Hydro Plan:

- $RPCM_{T1}$ = 10.7 cents per kWh, and
- $RPCM_{T2}$ = 12.5 cents per kWh.

The tiered prices for consumers with conventional meters are the following after taking into account the reduction in the forecast amount of the Global Adjustment of approximately $1B:

- $RPCM_{T1}$ = 9.1 cents per kWh, and
- $RPCM_{T2}$ = 10.6 cents per kWh.

Based on historical consumption, approximately 54% of RPP tiered consumption is forecast to be at the lower tier price ($RPCM_{T1}$) and 46% at the higher tier price ($RPCM_{T2}$). Given these

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[4] For the purpose of RPP TOU 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 TOU pricing purposes.

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). 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.

Major Factors Influencing RPP Prices

The forecast average supply cost for RPP consumers, absent any consideration of estimated impact of the proposed Fair Hydro Plan, increases by $3.49/MWh, or 3.1%, in the current forecast compared to the May 2016 forecast. A number of factors account for this change:

- Market prices are expected to be higher than in the previous price setting forecast period, primarily due to higher gas prices and despite slightly projected lower demand and higher availability of nuclear resources
- A decrease in the Ontario Electricity Financial Corporation contract and Ontario Power Generation payment amount components of the Global Adjustment are partially offset by increases in the IESO contract component of the Global Adjustment as a result of additional generation coming online

In summary, underlying cost factors- the load weighted market price for RPP consumers plus the Global Adjustment – increase the average supply cost by $3.05/MWh and the change in the variance account debit balance adds to the supply cost increase by $0.44/MWh. After taking into account the reduction in the forecast amount of the Global Adjustment of approximately $1B, the average supply cost drops by $13.79/MWh relative to May 2016 prices, or $17.28/MWh relative to what RPP consumers otherwise would have paid starting on May 1, 2017.

Regulated Price Plan – Prices Effective May 1, 2017

The RPP prices set by the OEB effective May 1, 2017 are set out in Table ES-3.

Table ES-3: May 1, 2017 RPP Prices

Time-of-Use RPP Prices	Off-Peak	Mid-Peak	On-Peak	Average Price
Price per kWh	7.7¢	11.3¢	15.7¢	9.8¢
% of TOU Consumption	65%	17%	18%	
Tiered RPP Prices	**Tier 1**		**Tier 2**	**Average Price**
Price per kWh	9.1¢		10.6¢	9.8¢
% of Tiered Consumption	53%		47%	

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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) 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 by the Ontario Government in O. Reg. 95/05 (Classes of Consumers and Determination of Rates) made under the *Act*. This report covers the period from May 1, 2017 to April 30, 2018.

The OEB has issued a Regulated Price Plan Manual (RPP Manual[5]) that explains how RPP prices are set. The OEB 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 OEB has used the RPP Manual's processes and methodologies to arrive at the RPP prices effective May 1, 2017.

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 May 1, 2017 through October 31, 2018* (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.

1.2 Process for RPP Price Determinations

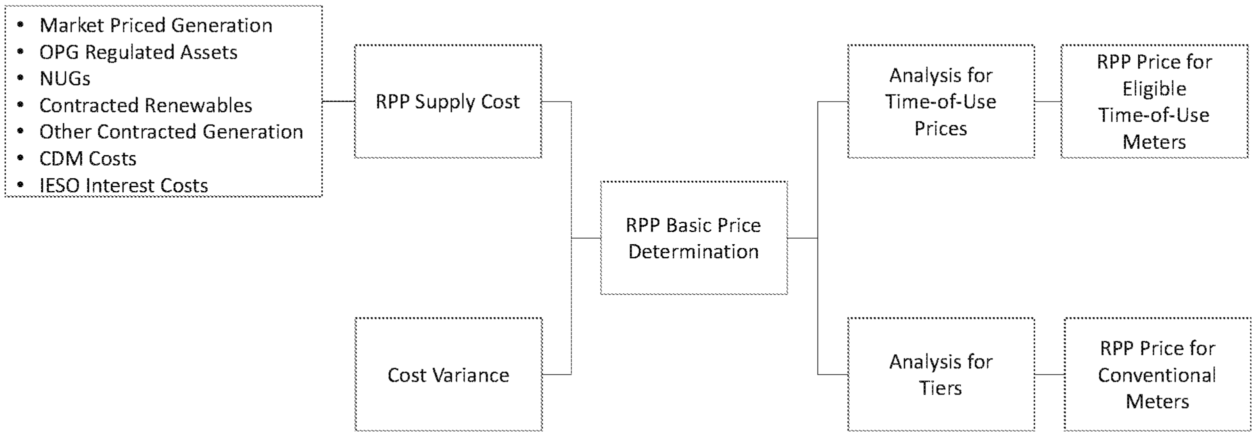
Figure 1 below illustrates the process for setting RPP prices. The RPP supply cost and the accumulated variance account balance (carried by the Independent Electricity System Operator, or the IESO) both contribute to the base RPP price, which is set to recover the electricity supply cost. The diagram below illustrates the processes to be followed to set the RPP price for both

[5] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2004-0205/RPP_Manual.pdf

[6] The Market Price Forecast Report is posted on the OEB web site, along with the RPP Price Report, on the RPP web page. http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2004-0205/Wholesale_Price_Forecast_Report_May2017.pdf

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 the amount paid to the Ontario Electricity Finance Corporation (OEFC) with respect to its payments under contracts with non-utility generators (NUGs);
- 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 IESO with respect to its payments under certain contracts with renewable generators;

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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 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] As set out in regulation O. Reg. 53/05 (Payments under Section 78.1 of the Act) made under the *Act*, the OEB sets payment amounts for energy produced from Ontario Power Generation's nuclear and certain hydro-electric generating stations (the prescribed assets). The OEB's most recent Order setting base payment amounts (EB-2013-0321) was issued on December 18, 2014.

- F is 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 IESO for its other procurement contracts for generation or for demand response or CDM, and (b) the sum of any OEB-approved amounts for CDM programs that are payable by the IESO to distributors; and,
- H is the amount associated with the variance account held by the IESO. 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 OEB 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 (April 30, 2017).[9] This amount is included in Equation 1 ("H").

In May 2016, the *Climate Change Mitigation and Low-carbon Economy Act, 2016* received Royal Assent and Ontario Regulation 144/16 was issued. Together, the legislation and regulation provide details about the Cap and Trade Program, which began on January 1, 2017. Under the legislation, large final emitters, natural gas distributors and electricity importers are required to verify and report their greenhouse gas emissions to the provincial government, and have to match their total emissions in each compliance period with an equivalent amount of "allowances."

Accordingly, this RPP forecast accounts for the cap and trade program over all twelve months of the RPP period. As more fully detailed in the Market Price Forecast Report, the forecast of wholesale market prices reflects the forecast of gas prices using a carbon price of $18.07 per metric ton, consistent with the results report of Ontario's first cap and trade auction (*March 2017 Ontario Auction #1)*, and an emissions factor of 0.054 metric tons per MMBtu.

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[9] RPP prices are announced in advance by the OEB 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 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:

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

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

- 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
- 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., 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	May 17 - Jul 17	$26.49	$11.55	$18.45	
	Q2	Aug 17 - Oct 17	$31.30	$16.57	$23.26	
	Q3	Nov 17 - Jan 18	$34.57	$20.47	$26.89	
	Q4	Feb 18 - Apr 18	$29.32	$16.95	$22.63	$22.81
Other	Q1	May 18 - Jul 18	$26.76	$13.01	$19.36	
	Q2	Aug 18 - Oct 18	$26.27	$13.05	$19.06	$19.21

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 RPP TOU pricing.

The forecasts of the monthly ratios of load-weighted vs. simple average HOEP are based on actual prices between April 2005 and March 2017. The on-peak to off-peak ratio is also based on data through March 2017.

As shown in Table 1, the forecast simple average HOEP for the period May 1, 2017 to April 30, 2018 is $22.81/MWh (2.281 cents per kWh). The forecast of the load weighted average price for RPP consumers ("M" in Equation 1) is $24.83/MWh (2.483 cents per kWh), or $1.5 billion in total, the result of RPP consumers having load patterns that are more peak oriented than the overall system.

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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)[10].

The first step to determine alpha is to estimate Class A's share of the Global Adjustment. Based on the formula and periods defined in O. Reg. 429/04, the Class A share has been decreased to 11.7% for the July 2016 to June 2017 period; and it is assumed for the purposes of this forecast to remain at that level for the July 2017 to June 2018 period.[11] Class B's share of the Global Adjustment is therefore 88.3%.

The next step is to estimate RPP consumers' share of Class B consumption. Based on historical data on RPP consumption as a share of total Ontario consumption, it is forecast that RPP consumption will represent about 60 TWh or 53.1% of total Class B consumption.[12] The RPP share varies from month to month, ranging between 51.3% and 55.8%. The value of α therefore ranges between 0.453 and 0.493. Over the entire RPP period, RPP consumers are forecast to be responsible for 47.1% of the Global Adjustment.

The government has recently expanded the Industrial Conservation Initiative to include, on an opt-in basis, all electricity loads with an average monthly peak demand over 1MW and certain electricity loads with an average monthly peak demand over 500 kW. This RPP price setting does not reflect any adjustments to account for the impact of these changes owing to the fact that uptake for the program by these newly-eligible consumers is not currently known, and the OEB does not have the information necessary to forecast that uptake.

2.2.3 Cost Adjustment Term for Prescribed Generators

This section covers the second term of Equation 1:

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

The prescribed generators are comprised of the rate-regulated nuclear and hydroelectric facilities of Ontario Power Generation (OPG). The amounts paid for the prescribed generation as set out in the EB-2013-0321 Payment Amounts Order dated December 18, 2014 is \$59.29/MWh for nuclear generation, \$40.20/MWh for prescribed hydroelectric generation and \$41.93/MWh for prescribed hydroelectric generation.

On May 27, 2016, OPG filed an application (EB-2016-0152) seeking approval for payment amounts for its prescribed generation facilities commencing January 1, 2017 through to the end

[10] O. Reg. 429/04 defines two classes of consumers; Class A, comprised of consumers whose maximum hourly demand for electricity exceeds a specified threshold; and Class B consumers, comprised of all other consumers, including RPP consumers. The demand threshold for Class A eligibility has been reduced over time, most recently by amendments to O. Reg. 429/04 made in 2016 (O. Reg. 366/16) and 2017 (O. Reg. 107/17).

[11] The percentage of Class A Global Adjustment costs was based on Class A load during peak demand hours in the May 1, 2015 to April 30, 2016 period. The Class A peak demand factor effective for the July 1, 2016 to June 30, 2017 period will be based on peak load percentages in the May 1, 2015 to April 30, 2016 period.

[12] 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 March 2017 period.

of 2021. On March 8, 2017, OPG submitted an amended rate smoothing proposal with updated payment amounts. At the time this report was prepared, a final decision and order with respect to OPG payment amounts was not available.

Consistent with past practice, the OEB believes that it is appropriate to take into account some effect of the application in this RPP forecast. This approach is consistent with one of the objectives of the RPP, which is to smooth changes in prices over time. Therefore, 50% of the impact of OPG's requested payment amounts, as smoothed by OPG's updated smoothing proposal, has been used for the purpose of calculating the RPP prices. The inclusion of an amount in the RPP should in no way be taken as predictive of the outcome of the OEB's proceeding.

Quantity A was therefore forecast by multiplying payment amounts per MWh consistent with the assumption described above, by the prescribed assets' 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 and prescribed hydraulic generation. The value of A is $4.2 billion, and the value of B is $1.6 billion.

2.2.4 Cost Adjustment Term for Non-Utility Generators and Other Generation under Contract with the 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 IESO 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.

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 the NUGs) is estimated to be $0.4 billion, and the value of "D" (i.e., the market value of the NUG output) is estimated to be $0.1 billion.

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

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 IESO 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 and redeveloped hydro facilities; 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 IESO. 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).[13]

The size and generation type of the successful renewable energy projects to date have been announced by the Government and the IESO. 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 $4.7 billion, and the value of "F" (i.e., the market value of renewable generation) is estimated to be $0.5 billion.

2.2.6 Cost Adjustment Term for Other Contracts with the IESO

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

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

[13] For information related to the FIT Price Schedule, see the IESO's dedicated web page at: http://www.ieso.ca/sector-participants/feed-in-tariff-program/overview

The costs for three types of resources under contract with the IESO 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 and B nuclear facilities.

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

- Clean Energy Supply (CES) and other contracts, which include conventional generation contracts as well as one demand response contract awarded to Loblaws;[14]
- The "early mover" contracts; and
- Contracts awarded for projects classified as Combined Heat and Power (CHP) projects[15].

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 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,[16]as well as an NRR of $17,000 per megawatt-month 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 IESO of any additional CDM initiatives is also captured in term G of Equation 1. Starting on January 1, 2015, and continuing until December 31, 2020, electricity distributors are expected to continue to offer CDM programs to customers in their service area, consistent with the Minister of Energy's Directive issued to the OEB and the Direction to the OPA, both dated March 31, 2014. Costs for these programs will be recovered and settled with the IESO, by way of contracts with the LDCs, for the period 2015 to 2020.

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[14] Ten facilities holding CES and other contracts are operational during this RPP period: the GTAA Cogeneration Facility, the Loblaws Demand Response Program, eight large gas-fired plants (Portlands, Goreway, Greenfield, St. Clair, York Energy Centre, Halton Hills, Green Electron Power, and Napanee), and two biomass projects (Atikokan and Thunder Bay). The IESO entered into contracts with these facilities pursuant to directives from the Minister of Energy.

[15] 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. Other facilities from other procurement processes are included as well.

[16] The NRR for the "early movers" was assumed to be the same.

In December 2015, the IESO negotiated an amended agreement with Bruce Power in relation to the refurbishment and continued operation of the Bruce Power nuclear units[17]. The amended contract stipulates that an initial price of $65.73/MWh would be paid for the output of Bruce A and B. The amended contract also stipulates that the initial price will be indexed to inflation every April 1, as well as adjusted periodically for asset management, waste fees, and refurbishments. For the upcoming RPP period, these revised contract terms have been applied for the output of Bruce A and B.

The IESO has 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 $4.1 billion.

2.2.7 Estimate of the Global Adjustment

The total Global Adjustment is estimated to be a cost of $11.1 billion. The RPP share of this (i.e., α times the total cost) is estimated to be a cost of $5.2 billion, or $87.67/MWh (8.767 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 May 1, 2017 to April 30, 2018.

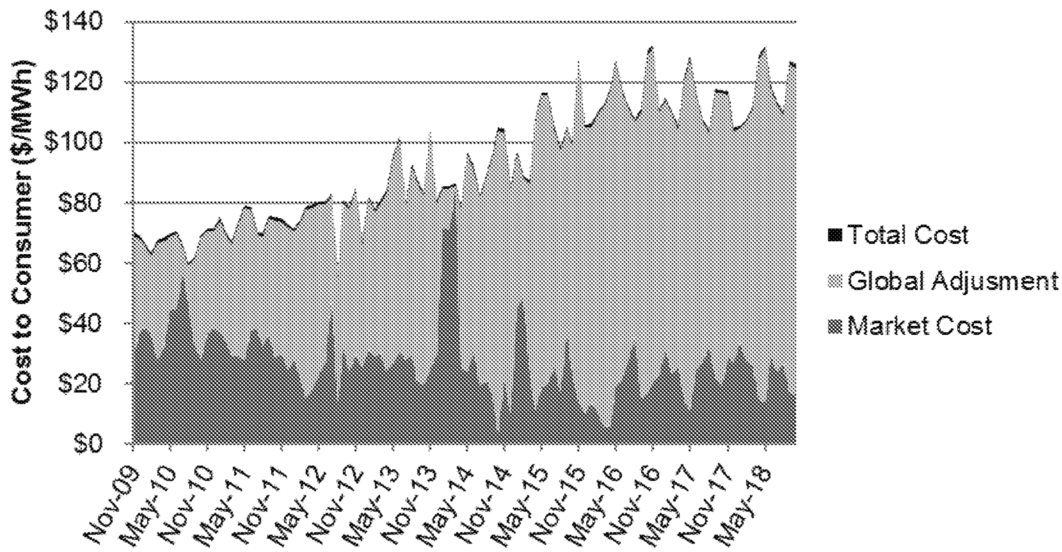
The Global Adjustment represents the difference between the total contract cost of the various contracts it covers (for the prescribed generating assets, Bruce nuclear, gas plants, renewable generation, CDM, etc.) and the market value of contracted generation. The Global Adjustment therefore changes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

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

This is illustrated in Figure 2, which shows how the Global Adjustment is expected to change over the next 18 months. All Ontario consumers have been paying 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 slightly increase over the next 12 months.

[17] In 2005, Bruce Power entered into an initial Bruce Power Refurbishment Implementation Agreement in relation to the operation of Bruce Units 1 and 2. In December 2015, the IESO and Bruce Power entered into an Amended and Restated Bruce Power Refurbishment Implementation Agreement.

Figure 2: Components of the RPP Supply Cost



Source: Navigant

Overall, supply costs have increased by 3.1% between this RPP period and the supply costs which were applicable to the May 2016 price setting and then maintained for the November 2016 price setting. For the first time in several forecasts, temporary payments to recover costs of prescribed generation assets, which expired at the end of 2016, no longer feature in the 12 month forecast. Underlying costs are lower as a result. However, that decrease is largely offset by an increase in costs related primarily to new renewable sources of generation. Similarly, higher wholesale market prices result in only a slight increase in supply cost because they are largely offset by a decrease in the Global Adjustment.

2.2.8 Cost Adjustment Term for IESO 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 IESO 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 (May 2017 – April 2018). 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 IESO to carry consumer debit variances in some months are generally offset by interest income the IESO receives from carrying consumer credit balances in other months. In addition, the interest rate paid by the IESO 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 April 30, 2017 the net variance account balance is forecast to be a negative balance (i.e. a deficit) of approximately $84 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 April 30, 2017. This variance clearance factor has increased from a debit of 0.097 cents per kWh in the May 2016 RPP report to a debit of 0.140 cents per kWh, based on costs and market activity from April 2016 through to April 2017. This increase in the variance account balance is due in part to May 2016 prices being continued in November 2016. Despite slightly higher forecast supply costs in November 2016 relative to May 2016, it was determined that the May 2016 RPP prices would continue to be effective in recovering the forecast costs attributable to customers on the Regulated Price Plan and no adjustments to prices were made in November 2016. In addition, the variance is a result of typical factors such as weather variation, fluctuations in natural gas prices, and differences in other cost inputs. As a result, the debit that had accumulated in the variance account was further increased. The variance clearance factor increases the average RPP supply cost by the amount of the debit: $1.40/MWh (0.140 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 supply less energy than forecast (due to unscheduled outages) than to supply more than forecast (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 OEB 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 Cost

	% of Total Supply	% of Total GA	Total Unit Cost (Cents/kWh)
Nuclear	60%	40%	6.9
Hydro	24%	12%	5.8
Gas	6%	15%	20.5
Wind	8%	18%	17.3
Solar	2%	14%	48.0
Bio Energy	0%	0%	13.1

Source: Navigant

NB: Hydro excludes NUGs and OPG non-prescribed generation. Gas includes Lennox, NUGs and OPG bioenergy facilities. Percentage (%) of Total GA excludes CDM costs.

The total RPP supply cost is estimated to be $6.9 billion.[18]

The following table itemizes the various steps discussed above to arrive at an average RPP supply cost of $114.90/MWh. This average supply cost corresponds to an average RPP price, which is referred to as RPA, of 11.49 cents per kWh.

Table 3: Average RPP Supply Cost Summary

RPP Supply Cost Summary for the period from May 1, 2017 through April 30, 2018		
Forecast Wholesale Electricity Price		$22.81
Load-Weighted Price for RPP Consumers ($ / MWh)		$24.83
Impact of the Global Adjustment ($ / MWh)	+	$87.67
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	$1.40
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$114.90**

Source: Navigant

RPP prices are designed such that consumers pay a stable and predictable price that reflects the cost of supplying their electricity over time. These prices are always based on a forecast of the costs for the year ahead. A consideration that the OEB employs in all aspects of its rate-setting is to smooth significant price changes in order to support more gradual transitions in electricity costs for customers over time. With this consideration in mind, the OEB has historically included a portion of significant price changes that may occur in the forecast period because of the smoothing benefits for customers. The OEB has done this with respect to payments for OPG's generation output when an application is before the OEB but has not yet been adjudicated to a final decision. As noted above, the OEB is doing the same in this price-setting.

In keeping with this practice, the OEB has considered it appropriate in this price setting to take into account a portion of the estimated impact of the government's proposed Fair Hydro Plan. The government has stated that it proposes to take steps to lower electricity bills starting this summer, and that it intends to introduce legislation to implement the proposed Plan. Legislation implementing the proposed Fair Hydro Plan would, if passed, represent a

[18] The total cost figure is net of the forecast variance account balance as of April 30, 2017.

significant step change in electricity bills for RPP consumers during the forecast period associated with this RPP price setting.

In a letter to the OEB dated April 10, 2017, a copy of which is attached to this Report, the Minister of Energy provided additional detail regarding elements of the proposed Fair Hydro Plan for consideration as inputs into this RPP price setting as the OEB considers appropriate. Taking into consideration that additional detail as well as information made available to the public by the government when it announced the proposed Fair Hydro Plan on March 2, 2017, the OEB has reflected a portion of the estimated impact of the proposed Fair Hydro Plan by way of a reduction in the forecast amount of the Global Adjustment of approximately $1B or about $17.28/MWh. Based on an estimate of consumption provided to the OEB by letter from Ministry staff, a copy of which is attached to this Report, this reduction in the forecast Global Adjustment represents 50% of RPP consumers' estimated portion of the proposed refinancing of the Global Adjustment.[19] No provision has been made for changes in consumption patterns that may result from the proposed Fair Hydro Plan.

This yields a total estimated RPP supply cost of $5.8B, or an overall average RPP cost of $97.62/MWh or 9.76 cents per kWh, which is roughly 1.7 cents lower than the RPP supply cost absent any consideration of the estimated impact of the proposed Fair Hydro Plan. This translates to a reduction of about 15% on the electricity line, and about 17% on the total electricity bill (including the impact of the 8% rebate provided for under the *Ontario Rebate for Electricity Consumers Act, 2016* and the OEB's decision to remove the Ontario Electricity Support Program charge) for a typical residential customer relative to what prices would otherwise have been, once RPP prices come into effect on May 1, 2017. This is summarized in Table 4.

Table 4: Average RPP Supply Cost Summary with Consideration of the Proposed Fair Hydro Plan

RPP Supply Cost Summary for the period from May 1, 2017 through April 30, 2018		
Forecast Wholesale Electricity Price		$22.81
Load-Weighted Price for RPP Consumers ($ / MWh)		$24.83
Impact of the Global Adjustment ($ / MWh)	+	$70.39
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	$1.40
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$97.62**

Source: Navigant

Taking the estimated impact of the proposed Fair Hydro Plan into account in setting May 1, 2017 RPP prices protects the interests of consumers. Reflecting only a portion of that estimated impact in prices at this time and under present circumstances is in keeping with the OEB's

[19] As indicated in the Minister's letter, the government's proposal to take steps to lower electricity bills relative to what they would otherwise have been without the Fair Hydro Plan is expected to benefit consumers beyond those that are on the RPP. The Ministry provided the OEB with an estimate of consumption for all RPP-eligible consumers, whether they are actually on the RPP or have opted out of it (about 72 TWh annually). As noted in section 2.2.2, the OEB estimates that RPP consumers will consume roughly 60 TWh over the coming 12 months.

normal RPP forecasting activities. The government has indicated that it intends to introduce legislation that would, if passed, implement the proposed Fair Hydro Plan starting this summer. The OEB will then further adjust RPP prices as needed so that RPP customers receive the full rate relief as legislated. As set out in section 3 of the RPP Manual (Price True-Ups for Extraordinary Circumstances), a mechanism also already exists to accommodate and remedy material and unexpected departures from the forecast that impair the effectiveness of RPP prices.

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, three separate prices 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 three prices are calculated to recover the supply cost, given the load shape of TOU customers. The RPP Manual does not prescribe the order in which prices are determined.

The first step in deriving the TOU prices for this forecast period was 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, $RPEM_{MID}$, was similarly set. After these two prices were 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, most 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. Payments to natural gas generators have been allocated into the Mid-Peak and On-Peak periods. Though the gas generators operate in all three periods, costs for generation in Off-Peak times have been allocated to the On-Peak period, reflecting the system purpose for which many of the facilities were initially contracted: ensuring reliability of supply and being a dispatchable source of power at times of higher demand. 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 overall effect of this allocation is to set the differential between the On-Peak and Off-Peak prices to 2.0:1. This ratio strengthens the incentive for electricity consumers to shift their consumption away from On-Peak periods, when their electricity prices are highest. Not only is the On-Peak price higher under this scenario, but the Off-Peak price is also lower than it would have been absent this increase to the ratio. A customer with a consumption pattern that mirrors the total TOU consumption would experience no overall bill impact from this change to the ratio, since each of the TOU prices are set so that they collectively recover the same average cost.

The OEB has a number of objectives in setting the RPP. These include setting prices to recover the cost of RPP supply on a forecast basis, as well as ensuring that prices are fair, stable and predictable.

The resulting TOU prices would be the following, absent any consideration of the estimated impact of the proposed Fair Hydro Plan:

- $RPEM_{OFF}$ = 9.1 cents per kWh
- $RPEM_{MID}$ = 13.3 cents per kWh, and
- $RPEM_{ON}$ = 18.5 cents per kWh.

The resulting TOU prices are the following after taking into account the reduction in the forecast amount of the Global Adjustment of approximately $1B:

- $RPEM_{OFF}$ = 7.7 cents per kWh
- $RPEM_{MID}$ = 11.3 cents per kWh, and
- $RPEM_{ON}$ = 15.7 cents per kWh.

These prices reflect the seasonal change in the TOU pricing periods which will take effect on May 1, 2017 and November 1, 2017. As defined in the RPP Manual, the time periods for TOU price application are 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*:[20] 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 TOU 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

[20] For the purpose of RPP TOU 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 TOU pricing purposes.

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.

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 would be the following, absent any consideration of the estimated impact of the proposed Fair Hydro Plan:

- $RPCM_{T1}$ = 10.7 cents per kWh; and,
- $RPCM_{T2}$ = 12.5 cents per kWh.

The resulting tiered prices are the following after taking into account the reduction in the forecast amount of the Global Adjustment of approximately $1B:

- $RPCM_{T1}$ = 9.1 cents per kWh; and,
- $RPCM_{T2}$ = 10.6 cents per kWh.

Table 5 below summarizes what TOU and tiered prices would have been absent any consideration of the proposed Fair Hydro Plan. Table 6 below summarizes the RPP prices that have been set by the OEB effective May 1, 2017, which reflect consideration of an appropriate portion of the estimated impact of that proposed Plan.

Table 5: Price Otherwise Payable by Average RPP Consumer under TOU and Tiered Prices (Absent any Consideration of the Proposed Fair Hydro Plan)

Time-of-Use RPP Prices	Off-Peak	Mid-Peak	On-Peak	Average Price
Price per kWh	9.1¢	13.3¢	18.5¢	11.5¢
% of TOU Consumption	65%	17%	18%	
Tiered RPP Prices	**Tier 1**		**Tier 2**	**Average Price**
Price per kWh	10.7¢		12.5¢	11.5¢
% of Tiered Consumption	53%		47%	

Table 6: May 1, 2017 RPP Prices

Time-of-Use RPP Prices	Off-Peak	Mid-Peak	On-Peak	Average Price
Price per kWh	7.7¢	11.3¢	15.7¢	9.8¢
% of TOU Consumption	65%	17%	18%	
Tiered RPP Prices	**Tier 1**		**Tier 2**	**Average Price**
Price per kWh	9.1¢		10.6¢	9.8¢
% of Tiered Consumption	53%		47%	

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4. Expected Variance

After RPP prices are set, the monthly expected variance can be calculated directly. The variance clearance factor has been set so that the expected variance balance at the end of the RPP period will be as close as possible to zero. This variance clearance factor has been set based on the OEB's usual practice and without consideration of any potential variances related to the changes to the Global Adjustment that are proposed to be a component of the proposed Fair Hydro Plan. The government has indicated that it intends to introduce legislation that would, if passed, enable the refinancing of the Global Adjustment over a longer period of time.

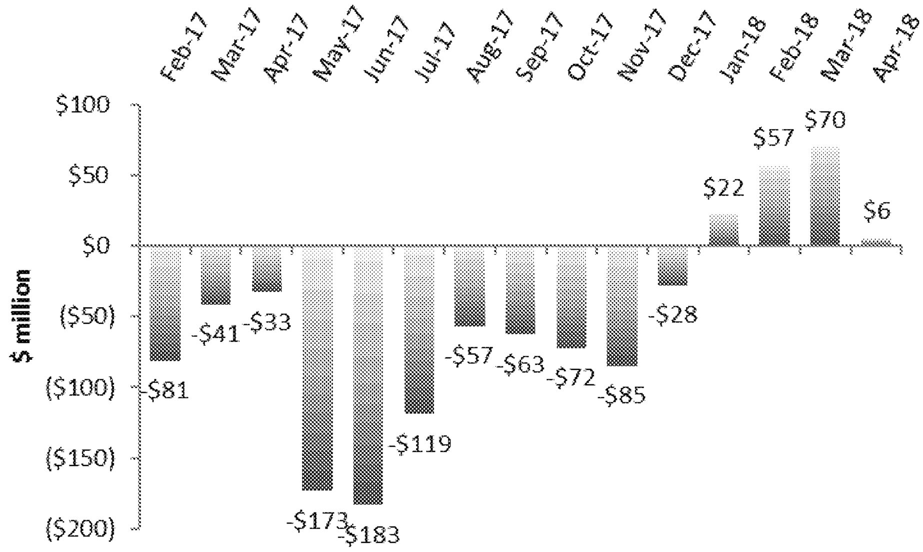
The variance balance is not expected to decline smoothly; the amount of the variance balance cleared is expected to vary significantly from month to month for several reasons:

- 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.

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 RPP prices resulting from the forecast RPA in this report would be expected to collect slightly more than the RPP supply cost, leaving an "expected" credit of $6 million in the variance account at the end of the RPP period, i.e. on April 30, 2018.

The combined effect of these factors is shown in Figure 3. The values in each month of Figure 3 represent the total expected balance in the variance account at the end of each month.

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



Source: Navigant