Ontario

Regulated Price Plan

Price Report

November 1, 2020

to

October 31, 2021

Ontario Energy Board

October 13, 2020

Executive Summary

This report contains the electricity commodity prices under the Regulated Price Plan (RPP) for the period November 1, 2020 through October 31, 2021. The prices were set in accordance with the methodology outlined in the Regulated Price Plan Manual (RPP Manual).

The Ontario Energy Board (OEB) is required by law to set RPP commodity prices for periods of not more than 12 months, and to set RPP prices to reflect the forecast cost of supplying RPP consumers. The OEB last set RPP prices on October 22, 2019, for the period November 1, 2019 to October 31, 2020.[1]

RPP prices are reviewed by the OEB 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 RPP supply cost for 12 months, and determining the true-up to recover an appropriate portion of the supply cost variance, and
2. Establishing prices to recover the above from RPP consumers over the 12-month period.

The calculation of the 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 Inc. (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 of the supply contracts, and conservation and demand management (CDM) initiatives of the Independent Electricity System Operator (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.

Average RPP Supply Cost

The hourly market price forecast was prepared for the OEB by Power Advisory LLC (Power Advisory). The forecast of the simple average market price for the 12 months from November 1, 2020 is $19.01/MWh (1.90 cents per kWh). After accounting for the consumption pattern of RPP

[1] *Regulated Price Plan Report*, October 22, 2019.

consumers, the average market price for electricity used by RPP consumers is forecast to be $20.87/MWh (2.09 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 IESO which generators have not recovered through their market revenues. The cost associated with 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 $109.47/MWh (10.95 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 supply costs during the forecast period. This "stochastic" adjustment was determined to be $1.00/MWh (or 0.100 cents per kWh).

An additional adjustment factor is included in the RPP price to recover the expected balance in the IESO variance account as of October 31, 2020 over an appropriate period of time. The current balance accumulated in part as a result of a combination of factors associated with the COVID-19 pandemic that have affected demand, supply costs and prices in the summer and fall of 2020. 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 RPP Manual states that while the adjustment for the balance in the IESO variance account would normally be set to recover that balance over the 12 months from the date of the price setting, in special circumstances the OEB may decide to set RPP prices with a view to recovering the balance over a longer period. The OEB has determined that, at this time, the impact on customers and ongoing uncertainty relating to COVID-19 is a special circumstance. The forecast adjustment factor has therefore been set on the basis of clearing the existing variance balance after 24 months, and is a debit (increase in the RPP price) of $2.24/MWh (or 0.22 cents per kWh). The OEB can re-evaluate this issue when the RPP prices for May 2021 are being considered.

As set out in Table ES-1, the resulting average RPP supply cost (for the period starting November 1, 2020) is $133.58/MWh. This average supply cost corresponds to an average RPP price, referred to as RPA, of 13.36 cents per kWh.

Table ES-1: Average RPP Supply Cost Summary (for the period from November 1, 2020 through October 31, 2021)

RPP Supply Cost Summary for the period from November 1, 2020 through October 31, 2021		$/MWh
Forecast Wholesale Electricity Price - Simple Average		$19.01
Load-Weighted Costs for RPP Consumers		
Wholesale Electricity Cost - RPP-Weighted		$20.87
Global Adjustment	+	$109.47
Adjustment to Reduce Existing Variances	+	$2.24
Adjustment to Address Bias Towards Unfavourable Variance	+	$1.00
Average Supply Cost for RPP Consumers	**=**	**$133.58**

Source: Power Advisory

Regulated Price Plan Prices

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: time-of-use (TOU) and tiered. RPP consumers with eligible TOU (or "smart") meters are charged on the basis of TOU prices, unless they elect instead to be charged on the basis of tiered prices by giving notice to their distributor in accordance with the OEB's Standard Supply Service Code. This customer choice option was introduced by the government for November 1, 2020. RPP consumers with conventional meters are charged on the basis of tiered prices.

Regulated Price Plan – TOU Pricing

The prices for this plan are based on three TOU 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 TOU prices for consumers with eligible TOU meters are:

- $RPEM_{OFF}$ = 10.5 cents per kWh;
- $RPEM_{MID}$ = 15.0 cents per kWh; and
- $RPEM_{ON}$ = 21.7 cents per kWh.

These prices reflect the seasonal change in the TOU pricing periods which will take effect on November 1, 2020 and May 1, 2021.[3] TOU pricing periods are:

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

[3] On April 14, 2020, in response to the COVID-19 emergency, the OEB announced that it would be leaving the winter TOU periods in place beyond May 1, 2020. As a result of government action related to COVID-19, consumers on TOU pricing have been paying a fixed price for all hours of the day since March 24, 2020.

- *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*: 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, whether because they do not have an eligible TOU meter or because they have elected to pay tiered prices, will 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 1,000 kWh per month during the winter season (November 1 to April 30).[4] 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 are:

- $RPCM_{T1}$ = 12.6 cents per kWh, and
- $RPCM_{T2}$ = 14.6 cents per kWh.

Based on historical consumption patterns, approximately 55% of RPP tiered consumption would be forecast to be at the lower tier price ($RPCM_{T1}$) and 45% at the higher tier price ($RPCM_{T2}$). With the introduction of the customer choice option beginning November 1, 2020, it is expected that some consumers will elect to switch from TOU to tiered pricing and increase consumption at the lower tier price. The OEB has estimated that 25% of all TOU customers will switch from TOU to tiered prices, and as a result, approximately 61% of RPP tiered consumption over the RPP period is forecast to be at the lower tier price ($RPCM_{T1}$) and 39% at the higher tier price ($RPCM_{T2}$). If tiered prices were not adjusted accordingly, supply costs would not be fully recovered. Therefore, the OEB has adjusted the Tier 1 price to be closer to the RPA to ensure recovery of the forecast cost of supply. More information will be known about the impact of consumers switching to tiered prices when the RPP prices are set for May 2021, and the proportion of consumption for each tier will be re-assessed at that time.

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[4] On April 14, 2020, in response to the COVID-19 emergency, the OEB announced that it would be leaving the residential winter tier threshold in place beyond May 1, 2020. Therefore, as winter tier thresholds remained in effect until October 31, 2020, residential consumers will not experience a tier threshold change on November 1, 2020.

Regulated Price Plan – Prices Effective November 1, 2020

The RPP prices set by the OEB effective November 1, 2020 are set out in Table ES-2.

Table ES-2: November 1, 2020 RPP Prices

Time-of-Use RPP Prices	Off-peak	Mid-peak	On-peak	Average Price
Price per kWh	10.5¢	15.0¢	21.7¢	13.4¢
% of TOU Consumption	64%	18%	18%	
Tiered RPP Prices	**Tier 1**		**Tier 2**	**Average Price**
Price per kWh	12.6¢		14.6¢	13.4¢
% of Tiered Consumption	61%		39%	

The government rebate under the *Ontario Rebate for Electricity Consumers Act, 2016* provides bill relief for RPP consumers, among others, in the form of a reduction in the total pre-tax amount of the bill.

Major Factors Causing the Change in Average RPP Supply Cost

The forecast average supply cost for RPP consumers increases by 4.3% in the current forecast compared to the previous forecast (November 2019). The increase reflects two main factors:

- First, the COVID-19 pandemic has resulted in changes to demand. As a result of declining demand in certain sectors, there is less consumption over which to spread costs and RPP consumers' share of the Global Adjustment has increased.

- Second, also as a result of the decline in demand and the prevailing electricity prices in effect over the summer and fall of 2020, there has been an increasing shortfall that needs to be recovered. Given this special circumstance, the OEB has decided to spread collection of this shortfall over two years to ease the impact on consumers.

The supply cost estimate reflects increases to nuclear and hydroelectric generation rates and higher revenues for OPG's nuclear generation due to changes in the Darlington refurbishment schedule. However, these cost increases are offset by lower payments for Bruce Power's nuclear generation as a result of the Bruce Power unit 6 refurbishment, and lower CDM costs due to government policy changes.

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1. Introduction

Under amendments to the *Ontario Energy Board Act, 1998 (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 Ontario Regulation (O. Reg.) 95/05 (Classes of Consumers and Determination of Rates) made under the *Act*. This report covers the period from November 1, 2020 to October 31, 2021 (forecast period).

RPP prices are reviewed by the OEB every six months to determine if they need to be adjusted. In April 2020, the OEB announced that RPP prices would not be reset for May 1, 2020 given that the unprecedented uncertainties associated with COVID-19 cast significant doubt on the reliability of forecasting supply costs or consumer demand.[5] Since that time, the Independent Electricity System Operator (IESO) released its Reliability Outlook for October 2020 to March 2022.[6] The demand forecast set out in that Reliability Outlook has been updated by the IESO to reflect current COVID-19 conditions, with the caveat that the situation remains fluid. The OEB has used the demand forecast in the Reliability Outlook in developing the RPP supply cost forecast described below.

The OEB has issued a Regulated Price Plan Manual (RPP Manual[7]) that explains how RPP prices are set. The OEB relies on a forecast of wholesale electricity market prices, prepared by Power Advisory LLC (Power Advisory), 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 November 1, 2020.

This report consists of four chapters as follows:

- Chapter 1. Introduction
- Chapter 2. Calculating the RPP Supply Cost
- Chapter 3. Calculating RPP Price
- Chapter 4. Variance Accounts

1.1 Associated Documents

Two documents are closely associated with this report:

- The RPP Manual describes the methodology for setting RPP prices; and
- The *Ontario Wholesale Electricity Market Price Forecast For the Period November 1, 2020 through April 30, 2022* (Market Price Forecast Report),[8] prepared by Power Advisory,

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[5] See the OEB's April 14, 2020 letter.

[6] http://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook

[7] https://www.oeb.ca/sites/default/files/rpp-manual-20201013.pdf

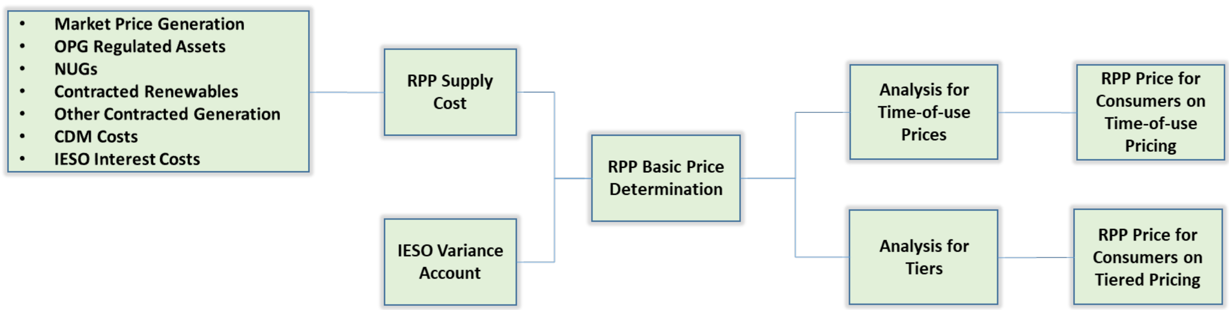
[8] https://www.oeb.ca/sites/default/files/rpp-wholesale-electricity-market-price-forecast-20201013.pdf

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 processes followed to calculate RPP prices. The RPP supply cost and the accumulated variance account balance (carried by the IESO) both contribute to the base RPP price, which is set to recover the average electricity supply cost. This report is organized according to this basic process.

Figure 1: Process Flow for Determining the RPP Price



Source: RPP Manual

There are two RPP price structures: time-of-use (TOU) and tiered. RPP consumers with eligible TOU (or "smart") meters are charged on the basis of TOU prices, unless they elect instead to be charged on the basis of tiered prices by giving notice to their distributor in accordance with the OEB's Standard Supply Service Code. This customer choice option was introduced by the government for November 1, 2020 and is being implemented through rules set out the Standard Supply Service Code.[9]

[9] See subsection 6(4) of O. Reg. 95/05 and section 3.5 of the Standard Supply Service Code.

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 for the forecast period requires forecast data for the variables 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 provided 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;[10]
- A is the amount paid to prescribed generators in respect of the output of their prescribed generation facilities;[11]
- 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;

[10] 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*. "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". The Global Adjustment formula in O. Reg. 429/04 also has a component ("H") for amounts approved by the OEB under section 78.5 of the *Act* that are payable to distributors. These were amounts related to OEB-approved conservation and demand management programs under Ministerial directive. The last such program ended in 2014. As discussed below, the Global Adjustment is 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.

[11] 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 OPG's nuclear and certain hydroelectric generating stations (the prescribed assets). The OEB's most recent Order setting hydroelectric payment amounts (EB-2019-0209) was issued on December 12, 2019. Nuclear payment amounts were approved as part of EB-2016-0152 effective January 1, 2017 and for each following year through to December 31, 2021. The Decision and Order in EB-2016-0152 was issued December 28, 2017 and the Payments Amount Order was issued March 29, 2018.

- E is the amount paid to the IESO with respect to its payments under certain contracts with renewable generators;
- 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 the amount paid by the IESO for its other procurement contracts for generation or for demand response or Conservation and Demand Management (CDM); and
- H is the amount associated with the variance account held by the IESO.

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 calculated 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 RPP supply cost calculation includes the stochastic adjustment, which is not represented in Equation 1. The stochastic adjustment is included to take into consideration the probability that the actual RPP supply cost will be higher than the forecast, as discussed in section 2.3.

Effective January 1, 2019, gas-fired generation in Ontario (as well as in some other provinces) has been subject to Part II of the federal government's *Greenhouse Gas Pollution Pricing Act*, and the associated Output-Based Pricing System Regulations[12]. That legislative regime introduced an output-based pricing system (OBPS), including compliance benchmarks, and prices on emissions above those benchmarks.

On September 21, 2020, the government of Ontario announced that the federal government has accepted the province's Emissions Performance Standards (EPS) program as an alternative to the OBPS system.[13] This means that gas-fired generators in Ontario will transition from the OBPS system to the EPS program; however, the date of this transition is not yet known. The EPS program is quite similar to the OBPS system, including identical charges for excess emissions. One difference is in the benchmark above which excess emission charges would need to be paid: 370 tonnes/GWh in the federal OBPS, 420 tonnes/GWh in Ontario's EPS program.

As more fully detailed in the Market Price Forecast Report, the forecast of wholesale market prices reflects the forecast of natural gas prices plus the excess emissions charges under the EPS ($30.00/tonne of carbon dioxide equivalent (CO_2e) in 2020, $40.00/tonne of CO_2e in 2021, and $50.00/tonne of CO_2e in 2022).

[12] https://laws-lois.justice.gc.ca/eng/regulations/SOR-2019-266/index.html

[13] https://news.ontario.ca/en/statement/58455/statement-from-minister-yurek-on-federal-acceptance-of-ontario-emissions-performance-standards

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 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)

Quarter	Calendar Period	On-Peak	Off-Peak	Average
Q1	Nov 2020 - Jan 2021	$28.91	$16.43	$22.11
Q2	Feb 2021 - Apr 2021	$22.56	$15.30	$18.60
Q3	May 2021 - Jul 2021	$22.23	$10.90	$16.11
Q4	Aug 2021 - Oct 2021	$24.86	$14.43	$19.20
Average	**Nov 2020 - Oct 2021**	**$24.66**	**$14.26**	**$19.01**

Source: Power Advisory, 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 September 2020. The On-peak to Off-peak ratio is also based on data through September 2020.

As shown in Table 1, the forecast simple average HOEP for the period November 1, 2020 to October 31, 2021 is $19.01/MWh (1.90 cents per kWh). The forecast of the load weighted average price for RPP consumers ("M" in Equation 1) is $20.87/MWh (2.09 cents 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 RPP consumers' share of the Global Adjustment. 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 the Global Adjustment is allocated to two sets of consumers, Class A and Class B (includes RPP consumers).[14]

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 decreased from 17.7% for the July 2019 to June 2020 period, to 16.7% for the July 2020 to June 2021 period[15]. This decrease was due to a decrease in the average load factor (the ratio of coincident peak demand to annual energy consumption) across all Class A customers. The Class A share of Global Adjustment charges is expected to remain at 16.7% for the July 2020 to June 2021 period, because the government has announced a "peak hiatus" for the 2020-2021 Base Period.[16]

Class B's share of the Global Adjustment is forecast to be 83.3% over the forecast period.

On June 14, 2019, the government of Ontario concluded its online consultation on the design and effectiveness of current industrial electricity pricing and programs.[17] Changes resulting from this and other consultation activities on industrial electricity pricing could impact RPP supply costs in the future, and they will be reflected as appropriate in future RPP supply cost forecasts when such changes, if any, are known.

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 amount to approximately 60 TWh, or 62% of total Class B consumption. The RPP share varies with the seasons, ranging between 59% and 66%. RPP consumers' share of monthly Global Adjustment charges ranges between 49% and 55%. Over the entire forecast period, the RPP consumers' share of the Global Adjustment is forecast to be 51.8%. The value of α is therefore 0.518.

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 rate-regulated nuclear and hydroelectric facilities of Ontario Power Generation Inc. (OPG) for which the OEB sets payment amounts. The payment amounts for OPG's prescribed generation are $94.96/MWh in 2020 and $95.83/MWh in 2021 for

[14] 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).

[15] "Class A customers are assessed their portion of GA costs based on the percentage that their consumption contributes to the top five system coincident peaks during a predetermined base period (May 1-April 30) and will be charged their percentage of total GA costs through the next adjustment, or billing period (July 1-June 30)." (http://www.ieso.ca/en/Sector-Participants/Settlements/Global-Adjustment-and-Peak-Demand-Factor)

[16] See section 19.2 of O. Reg. 429/04 (Adjustments Under Section 25.33 of the Act), which came into effect on June 30, 2020, and which provides that existing Class A consumers will be assessed Global Adjustment in the 2021-2022 adjustment period based on their electricity consumption in the 2019-2020 base period rather than the 2020-2021 base period.

[17] https://www.ontario.ca/page/consultation-industrial-electricity-prices

nuclear generation, and \$45.65/MWh in 2020 and \$45.93/MWh[18] in 2021 for hydroelectric generation. These payment amounts, which reflect both base payment amounts and rate riders, were set out in the following two OEB decisions: EB-2016-0152 and EB-2019-0209.

Quantity A was therefore forecast by multiplying payment amounts per MWh 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 hydroelectric generation, and multiplying those market values by the volume of nuclear and prescribed hydroelectric generation. The value of A is \$5.37 billion, and the value of B is \$1.44 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 NUGs has been used as the basis for forecasting payments in future months. 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 \$0.11 billion, and the value of "D" (i.e., the market value of the NUG output) is estimated to be \$0.02 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 Standard Offer Program (HESOP);

[18] The 2021 hydroelectric payment amount is comprised of riders approved in EB-2016-0152 and EB-2018-0243, and an estimated base payment amount. The 2021 hydroelectric base payment amount was estimated by escalating the approved 2020 base payment amount by 1.7%. The escalation factor applied for hydroelectric generation in 2021 is an assumption based on best available information and is not meant to be predictive of the OEB's Decision on OPG's 2021 hydroelectric payment.

- the Hydroelectric Energy Supply Agreements (HESA) directive, covering new and redeveloped hydro facilities;
- the Hydro Contract Initiative (HCI), covering existing hydro plants;
- the Energy from Waste program; and
- NUGs who are under contract with the IESO rather than OEFC.

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).[19]

The size and generation type of the successful renewable energy projects to-date have been announced by the government of Ontario and the IESO. The forecast includes additional renewable capacity coming into service during the forecast 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 forecast also considers 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 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 $4.91 billion, and the value of "F" (i.e., the market value of renewable generation) is estimated to be $0.45 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:

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

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. Conservation and demand management costs, and storage 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:

[19] 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

- Clean Energy Supply (CES) and other contracts, which include conventional gas generation contracts as well as one demand response contract;
- The "early mover", "Accelerated CES" and "Northern York Region" contracts; and
- Contracts awarded for gas-fired projects classified as Combined Heat and Power (CHP) projects.

The costs of these generation 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 report. 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 of Ontario to be $7,900 per megawatt-month,[20] 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 of CDM initiatives delivered under contract with the IESO is also captured in term G of Equation 1. On March 21, 2019, the Conservation First Framework was discontinued by Ministerial directive, and replaced with a new Interim Framework effective April 1, 2019.[21] Under the Interim Framework, which runs from April 1, 2019 to December 31, 2020, the IESO will centrally deliver a reduced portfolio of CDM programs. On September 30, 2020, the Minister of Energy, Northern Development and Mines directed the IESO to establish and deliver a new 2021-2024 CDM Framework under which the IESO will centrally deliver CDM programs using procurement contracts as required.[22] The forecast of CDM initiative costs for the forecast period reflects an estimate of the cost reduction implications of both the new and existing CDM Frameworks.

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. 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 this forecast 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 gas-fired peaking plant. The cost of this contract is included in the "G" variable.

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

[21] For information on the IESO's CDM activities under the Interim Framework, see the IESO's dedicated web page at: http://www.ieso.ca/Sector-Participants/Conservation-Delivery-and-Tools/Interim-Framework

[22] http://www.ieso.ca/-/media/Files/IESO/Document-Library/ministerial-directives/2020/Directive-CDM-Framework.pdf?la=en

The value of "G" in Equation 1 (i.e., net cost of Bruce Power nuclear, gas, CDM costs and storage contracts) is estimated to be $4.24 billion.

2.2.7 Estimate of the Global Adjustment

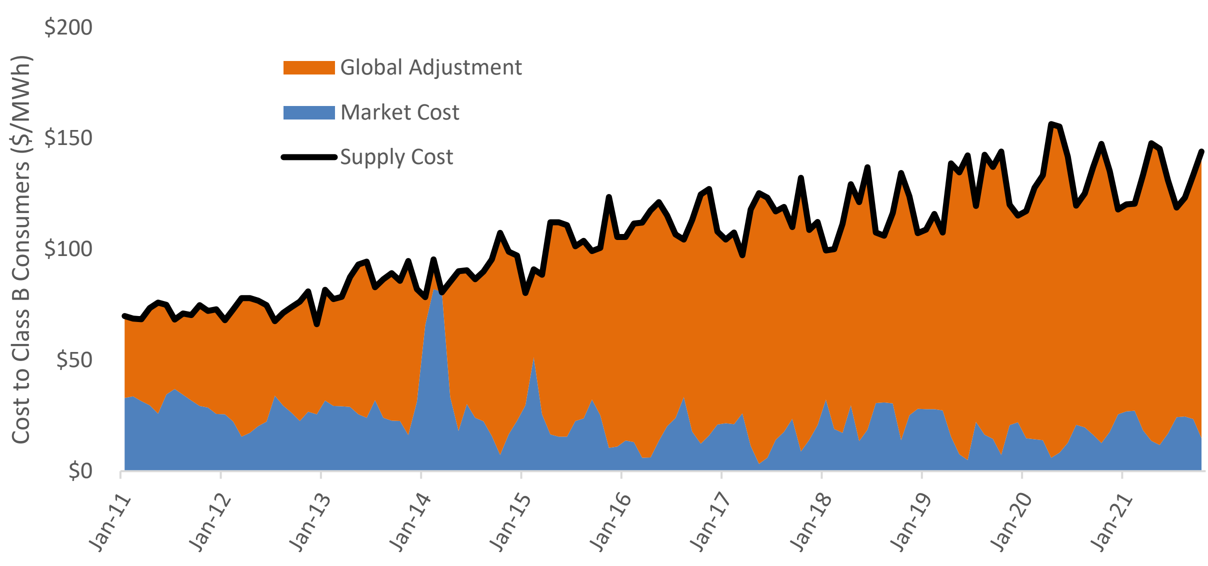
The total Global Adjustment cost is estimated to be $12.7 billion. The RPP share of this (i.e., α times the total cost) is estimated to be $6.6 billion, or $109.47/MWh (10.95 cents per kWh). This is the forecast of the average Global Adjustment cost per unit for RPP consumers over the period from November 1, 2020 to October 31, 2021. The RPP share of the total Global Adjustment is affected by changes in the share of the Global Adjustment costs paid by Class A and Class B consumers, as well as changes in the volume of Class B consumption.

The Global Adjustment represents the difference between the total contract cost of the various contracts it covers (for Bruce Power nuclear, gas plants, renewable generation, CDM, etc.) and the market value of contracted generation, as well as the difference between the payment amounts set for OPG's prescribed generating assets and the market value of that generation. Total Global Adjustment costs can therefore change for three reasons:

- changes (mostly increases) in the number and aggregate capacity of contracts or rate-regulated assets it covers;
- changes in regulated rates or inflation-based adjustments in contract rates; and
- 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 12 months.

Figure 2: Components of the RPP Supply Cost



Source: Power Advisory

Overall, per-MWh RPP supply costs have increased by 4.3% between this forecast period and the supply costs which were forecast for the November 2019 to October 2020 period, as set out in the OEB's October 22, 2019 *Regulated Price Plan Price Report*. The increase reflects two main factors:

- First, the COVID-19 pandemic has resulted in changes to demand. As a result of declining demand in certain sectors, there is less consumption over which to spread costs and RPP consumers' share of the Global Adjustment has increased.

- Second, also as a result of the decline in demand and the prevailing electricity prices in effect over the summer and fall of 2020, there has been an increasing shortfall that needs to be recovered. Given this special circumstance, the OEB has decided to spread collection of this shortfall over two years to ease the impact on consumers.

The supply cost estimate reflects increases to nuclear and hydroelectric generation rates and higher revenues for OPG's nuclear generation due to changes in the Darlington refurbishment schedule. However, these cost increases are offset by lower payments for Bruce Power's nuclear generation as a result of the Bruce Power unit 6 refurbishment, and lower CDM costs due to government policy changes.

2.2.8 Cost Adjustment Term for and Recovery Related to IESO Variance Account

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

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

For the purposes of setting RPP prices, two aspects of the IESO's variance account are considered. The first is the forecast interest costs associated with carrying any RPP-related variances incurred during the upcoming RPP period (May 2020 – April 2021). The second represents the price adjustment required to clear (i.e., recover or disburse) an appropriate portion of the RPP variance and accumulated interest.

The first aspect 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 forecast interest costs for this price setting period are approximately $1 million. For this price setting period, interest income does not offset interest expenses as the IESO variance account is not being cleared through RPP process over a 12-month period, as noted below.

The second aspect represents the price adjustment to reduce the variance accumulated through to the beginning of this RPP period. As of August 31, 2020, the net variance account balance was a deficit of $130 million, but it is expected to reach a deficit of $267 million by October 31, 2020, due to differences between current rates and forecast supply costs in September and October.

The RPP Manual states that while the adjustment for the balance in the IESO variance account would normally be set to recover that balance over the 12 months from the date of the price setting, in special circumstances the OEB may decide to set RPP prices with a view to recovering the balance over a longer period. The OEB has determined that, at this time, the impact to customers and ongoing uncertainty relating to COVID-19 is a special circumstance. The forecast adjustment factor has therefore been set on the basis of clearing the existing variance balance after 24 months and is a debit (increase in the RPP price) of $2.24/MWh (or 0.22 cents per kWh). The OEB can re-evaluate this issue when the RPP prices for May 2021 are being considered.

2.3 Correcting for the Bias Towards Unfavourable Variances (Stochastic Adjustment)

The supply costs discussed in section 2.2 are based on "most likely" forecasts of demand, HOEP, gas prices, generator operations, and other factors. However, none of these factors can 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 it is more likely that RPP supply costs will exceed the forecast than fall below it, unless there is a minor adjustment to reflect the greater likelihood of unfavourable variances.

The Adjustment to Address Bias Towards Unfavourable Variance (stochastic adjustment) is set at $1.00/MWh (0.100 cents per kWh). This amount is included in the RPP supply cost.

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 or regulated payment amounts 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 Global Adjustment	Total Unit Cost (cents/kWh)
Nuclear	53%	45%	8.9¢
Hydro	26%	12%	6.0¢
Gas	9%	12%	14.3¢
Wind	9%	15%	14.8¢
Solar	2%	14%	49.7¢
Bioenergy	1%	2%	25.1¢

Source: Power Advisory

NB: Percentage (%) of Total Global Adjustment excludes CDM costs.

The total RPP supply cost is estimated to be $8.0 billion.

The following table itemizes the various steps discussed above to arrive at an average RPP supply cost of $133.58/MWh. This average supply cost corresponds to an average RPP price, which is referred to as RPA, of 13.36 cents per kWh.

Table 3: Average RPP Supply Cost Summary

RPP Supply Cost Summary for the period from November 1, 2020 through October 31, 2021		$/MWh
Forecast Wholesale Electricity Price - Simple Average		$19.01
Load-Weighted Costs for RPP Consumers		
Wholesale Electricity Cost - RPP-Weighted		$20.87
Global Adjustment	+	$109.47
Adjustment to Reduce Existing Variances	+	$2.24
Adjustment to Address Bias Towards Unfavourable Variance	+	$1.00
Average Supply Cost for RPP Consumers	**=**	**$133.58**

Source: Power Advisory

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 RPA. This chapter explains how prices are determined for consumers 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 TOU Prices

For those consumers with eligible TOU (or "smart") meters and that have not elected tiered pricing, prices are calculated for three separate price periods: On-peak ($RPEM_{ON}$), Mid-peak ($RPEM_{MID}$), and Off-peak ($RPEM_{OFF}$). The times when each of these periods applies are set out in the RPP Manual and also noted below. 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 RPA, given the load shape of TOU customers. The RPP Manual does not prescribe the order in which prices are calculated. Generally, when setting prices, consideration is given to both the current ratios between $RPEM_{ON}$, PEM_{MID} and $RPEM_{OFF}$, and how the various components of Global Adjustment costs are allocated to TOU consumption periods based on the type of cost.

The various components of Global Adjustment costs are first allocated to TOU consumption periods based on the type of cost. The costs associated with OPG's rate-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 Global Adjustment 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 adjustment to clear the IESO variance account is allocated equally to all consumption periods. The overall effect of this allocation is that the differential between the On-peak and Off-peak prices is 2:1.

The ratios developed for the November 1, 2020 price setting are consistent with the ratios generated through the cost allocation exercise and the current ratio between On-, Off-, and Mid-peak prices, and maintains the strong incentive for electricity consumers to shift their consumption away from On-peak periods, when their electricity prices are highest.

The resulting TOU prices are:

- $RPEM_{OFF}$ = 10.5 cents per kWh
- $RPEM_{MID}$ = 15.0 cents per kWh, and
- $RPEM_{ON}$ = 21.7 cents per kWh.

These prices reflect the seasonal change in the TOU pricing periods which will take effect on November 1, 2020[23] and May 1, 2021. 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*[24]: 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 load profile assumed for TOU consumers was calculated based on TOU consumers' actual Off-, Mid-, and On-peak consumption observed over the previous four years. The load profile for non-TOU RPP (tiered) consumers was determined using the methodology described in section 3.2.

RPP prices are calculated so that a TOU consumer with an average TOU load profile would 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. Note that RPP consumers generally (i.e., both tier and TOU RPP consumers) have load profiles that are more peak oriented than the overall system.

3.2 Tiered Prices

The final step is to calculate tiered prices, which apply to RPP consumers with conventional meters and to RPP consumers with eligible TOU (or "smart") meter that have elected to pay tiered pricing. 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.

RPP consumers with eligible TOU (or "smart") meters may now elect instead to be charged on the basis of tiered prices by giving notice to their distributor in accordance with the OEB's Standard Supply Service Code. This customer choice option was introduced by the government

[23] On April 14, 2020, in response to the COVID-19 emergency, the OEB announced that it would be leaving the winter TOU periods in place beyond May 1, 2020. However, as a result of government action related to COVID-19, consumers on TOU pricing have been paying a fixed price for all hours of the day since March 24, 2020.

[24] 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.

for November 1, 2020, and is being implemented through rules set out the Standard Supply Service Code.[25]

Based on historical consumption patterns, approximately 55% of RPP tiered consumption would be forecast to be at the lower tier price ($RPCM_{T1}$) and 45% at the higher tier price ($RPCM_{T2}$). With the introduction of the customer choice option beginning November 1, 2020, it is expected that some consumers will elect to switch from TOU to tiered pricing and increase consumption at the lower tier price. The OEB has estimated that 25% of all TOU customers will switch from TOU to tiered prices, and as a result, approximately 61% of RPP tiered consumption over the RPP period is forecast to be at the lower tier price ($RPCM_{T1}$) and 39% at the higher tier price ($RPCM_{T2}$). If tiered prices were not adjusted accordingly, supply costs would not be fully recovered. Therefore, the OEB has adjusted the Tier 1 price to be closer to the RPA to ensure recovery of the forecast cost of supply. More information will be known about the impact of consumers switching to tiered prices when the RPP prices are set for May 2021, and the proportion of consumption for each tier will be re-assessed at that time.

The tiered prices are calculated so that the average per unit revenue would be 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, equal to a ratio of 0.85) and forecasting consumption above and below the threshold in each month of the forecast period.

RPP tiered prices are calculated 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 0.85 ratio between Tier 1 and Tier 2 prices.

The resulting tiered prices are:

- $RPCM_{T1}$ = 12.6 cents per kWh; and
- $RPCM_{T2}$ = 14.6 cents per kWh.

Table 4 below summarizes the RPP TOU and tiered prices effective November 1, 2020.

Table 4: November 1, 2020 RPP Prices

Time-of-Use RPP Prices	Off-peak	Mid-peak	On-peak	Average Price
Price per kWh	10.5¢	15.0¢	21.7¢	13.4¢
% of TOU Consumption	64%	18%	18%	
Tiered RPP Prices	**Tier 1**		**Tier 2**	**Average Price**
Price per kWh	12.6¢		14.6¢	13.4¢
% of Tiered Consumption	61%		39%	

[25] See subsection 6(4) of O. Reg. 95/05 and section 3.5 of the Standard Supply Service Code.

4. Variance Accounts

There are two sources of variances: cumulative under- or over-collection due to discrepancies in forecast versus actual supply costs (referred to as the "unexpected variance" in the RPP Manual) and those created by predictable seasonal variances (referred to as the "expected variance" in the RPP Manual). The cumulative discrepancy represents the price adjustment necessary to clear the total balance in the IESO variance account accumulated through to the beginning of this RPP period. As of August 31, 2020, the cumulative discrepancy was a deficit of $130 million, but it is expected to reach a deficit of $267 million by October 31, 2020, due to differences between current rates and forecast supply costs in September and October.

The variance caused by seasonal variation represents the amount of money customers are expected to over- or underpay for the electricity they consume in a given month. The balance in the variance account varies 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 RPA in this report, the residential tier thresholds are normally higher in winter (1,000 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.

RPP prices are being set with a view to achieving a balance of zero for the variance balance associated with seasonal variation at the end of the RPP period.

As noted above, for this price-setting the OEB has determined that the IESO variance account will be recovered over 24 months instead of 12 months. Accordingly, RPP prices resulting from the forecast RPA in this report would be expected to reduce the cumulative discrepancies related deficit to approximately $133 million at the end of the RPP period (i.e., on October 31, 2021). The OEB can re-evaluate this issue when the RPP prices for May 2021 are being considered.

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 IESO variance account at the end of each month.

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