NAVIGANT CONSULTING

REGULATED PRICE PLAN – COST TRACKING

MONTHLY VARIANCE EXPLANATION (APR 05 – NOV 05)

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

All of the statistics presented in this report are taken or derived from publicly available information sources. Neither Navigant Consulting or the OEB has audited this information. Any revisions by the providers of the actual data will be included in future updates of this report.

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

Regulated Price Plan consumers pay a stable price for electricity that was set in advance by the Board. The initial RPP price went into effect on April 1, 2005. Under Ontario's current hybrid electricity market structure, there are essentially three sources of supply for the RPP:

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

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

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

Example:

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

- Similarly, regulations require that OPG generation facilities subject to a revenue cap must reimburse any difference between the average revenue earned on their generation output and their revenue cap (average of 4.7 cents per kWh) to consumers. This payment is called the "OPG Rebate" (often also referred to as the OPG Non-Prescribed Asset Rebate, or "ONPA rebate"). Under current Government regulations, this revenue cap (and rebate) is scheduled to expire on April 30, 2006. When the revenue cap expires, the OPG generation facilities currently subject to the revenue cap will transfer into the third category outlined above, and be paid the spot market price.

The primary effect of these regulations is that the cost of supplying electricity to RPP consumers from the first two sources – 1) generating facilities subject to regulated prices, or under contract to the OPA or OEFC that pay the Provincial Benefit; and 2) certain OPG generation facilities subject to a revenue cap that pay the OPG Rebate – is essentially fixed at a price that was expected to be, and has been, below the average spot price for electricity. This reduces the average cost of supply for all consumers and also reduces consumers' exposure to variability in spot market prices, since the cost of supply from the spot market is not fixed (i.e., changes every hour).

The initial RPP price which went into effect on April 1, 2005 was based on forecasts of many different factors, the most important of which were: 1) the relative amount of electricity coming from each of the three electricity supply sources; and 2) the price of electricity purchased from the spot market.

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

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

1. The first set of values are related to the spot market price of electricity.

2. The second set of values are related to generating facilities subject to regulated prices or under contract to the OPA or OEFC that pay the Provincial Benefit.

3. The third set of values are related to certain OPG facilities subject to a revenue cap that pay the OPG Rebate.

4. Lastly, the difference between the forecast and actual values for the cost of RPP supply and the revenues generated by the RPP are presented. This difference between the forecast and actual RPP supply cost, combined with the difference between the forecast and actual RPP revenue, is what is referred to as the "RPP Variance".

A subsequent forecast will be issued in advance of the Board setting the new RPP prices that go into effect on May 1, 2006. Following that, new forecasts will be issued every six months.[1]

1. Spot Market Prices and Key Drivers of Spot Prices

Simple Average Spot Market Price

This comparison shows the cost of electricity purchased from the spot market (<u>without</u> consideration of the Provincial Benefit and OPG Rebate) for a consumer that used the same amount of electricity in each hour. This price would apply to a relatively small subset of consumers.

Simple Average Cost of Electricity

RPP Year-To-Date (Apr 1, 2005 through Nov 30, 2005)	
Forecast	5.5 cents per kWh
Actual	7.2 cents per kWh
Percent Difference	29% higher

RPP-Load Weighted Average Spot Market Price

This comparison similarly shows the cost of electricity purchased from the spot market (<u>without</u> consideration of the Provincial Benefit and OPG Rebate). However, in this case, it is for a

[1] The RPP Manual also provides for a "trigger" after May 1, 2006. That is, if the actual RPP variance exceeds the forecast (or expected) RPP variance by over $160 million (positive or negative), it would trigger an automatic RPP price adjustment. However, a new forecast would not be issued until the next scheduled price adjustment.

consumer (e.g., residential) whose usage pattern is the same as the average RPP consumer (higher electricity consumption during the peak periods, such as winter evenings, when prices are higher).

RPP-Load Weighted Average Cost of Electricity

RPP Year-To-Date (Apr 1, 2005 through Nov 30, 2005)	
Forecast	6.0 cents per kWh
Actual	7.8 cents per kWh
Percent Difference	30% higher

Natural Gas Price

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

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

Natural Gas Prices ($USD)

RPP Year-To-Date (Apr 1, 2005 through Nov 30, 2005)	
Forecast	$6.85 /MMBtu
Actual	$9.04 /MMBtu
Percent Difference	32% higher

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

Weather, Cooling Degree Days (>24°C)

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

The number of such days far exceeded normal conditions. This was the primary reason the previous record for electricity consumption (25,414 MW set in August 2002) was exceeded on seven separate occasions this past summer. Only two other years – 2002 and 1988 – have been comparable in terms of heat and humidity since 1970.[2]

Cooling Degree Days (>24 °C)	
RPP Year-To-Date (Apr 1, 2005 through Nov 30, 2005)	
Normal	17
Actual	81
Percent Difference	363% higher

Weather, Heating Degree Days (<15°C)

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

This comparison shows the number of heating degree days below 15°C per month in the city of Toronto (Lester B. Pearson Int'l Airport). If the temperature is higher than or equal to 15°C, then the number will be zero.

Heating Degree Days (<15 °C)	
RPP Year-To-Date (Apr 1, 2005 through Nov 30, 2005)	
Normal	1,094
Actual	763
Percent Difference	30% lower

2. Generating Facilities that Pay the Provincial Benefit

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

OPG Nuclear Output

This comparison shows the output (or production) of OPG's nuclear plants. Overall, the actual amount of electricity produced by these generation facilities is extremely close to their forecast output.

[2] 18°C is another common base temperature used to determine cooling degree days. Navigant Consulting and the OEB share the view that 24°C is more representative of when residential consumers use air conditioning.

OPG's Nuclear Output

RPP Year-To-Date (Apr 1, 2005 through Nov 30, 2005)	
Forecast	29.2 TWh
Actual	28.8 TWh
Percent Difference	2% lower

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

OPG Regulated (Baseload) Hydroelectric Output

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

OPG's Baseload Hydroelectric Output

RPP Year-To-Date (Apr 1, 2005 through Nov 30, 2005)	
Forecast	12.2 TWh
Actual	11.8 TWh
Percent Difference	4% lower

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

Provincial Benefit

This comparison shows the forecast versus actual Provincial Benefit (also referred to as the "Global Adjustment"). The actual Provincial Benefit is higher than forecast, which has helped to mitigate the impact of higher than forecast spot market prices. The forecast value of the Provincial Benefit is already included in the current RPP prices.

Provincial Benefit (Global Adjustment)

RPP Year-To-Date (Apr 1, 2005 through Nov 30, 2005)	
Forecast	0.3 cents per kWh
Actual	1.0 cents per kWh
Percent Difference	0.8 cents higher

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

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

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

OPG Coal-fired Output

This comparison shows the output of OPG's coal-fired generating plants. Overall, the actual output of these generators is less than their forecast output. This is due to a number of factors including unplanned outages and environmental constraints; e.g., air emission limits.

OPG's Coal Fired Output

RPP Year-To-Date (Apr 1, 2005 through Nov 30, 2005)	
Forecast	21.1 TWh
Actual	19.0 TWh
Percent Difference	10% lower

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

OPG Unregulated Hydro Electric Output

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

The actual output of these generators is much lower than their forecast output due to the limited amount of rainfall experienced this past summer. In terms of the overall electricity supply for RPP consumers, this lower than expected output forced more of the RPP supply to come from more expensive purchases on the spot market (e.g., natural gas-fired generators and electricity imports). The impact is further exacerbated because OPG's unregulated hydroelectric generating facilities contribute to the OPG Rebate.

OPG's Unregulated Hydroelectric Output

RPP Year-To-Date (Apr 1, 2005 through Nov 30, 2005)	
Forecast	12.6 TWh
Actual	8.5 TWh
Percent Difference	33% lower

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

OPG Rebate (estimated)

This comparison shows the OPG Rebate. The estimated OPG Rebate to date is higher than forecast, which has helped to mitigate the impact of higher than forecast spot market prices.

However, the degree to which it has mitigated price impacts is less than would be expected because the amount of supply that pays the OPG Rebate has been less than forecast, with lower output from both of OPG's unregulated hydroelectric and coal-fired generation (see above). The forecast value of the OPG Rebate is already included in current RPP prices.

OPG Rebate

RPP Year-To-Date (Apr 1, 2005 through Nov 30, 2005)	
Forecast	0.4 cents per kWh
Actual	0.6 cents per kWh
Percent Difference	0.2 cents higher

Under current Government regulations, this revenue cap (and rebate) is scheduled to expire on April 30, 2006.

4. RPP Supply Costs and Revenues

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

The RPP revenues represent the total revenues generated from the two tiered pricing structure of 5.0 cents per kWh (for consumption below the tier threshold) and 5.8 cents per kWh (for consumption above the tier threshold).

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

RPP Unit Supply Cost

The unit RPP supply cost is higher than forecast, largely due to: 1) higher than forecast spot market prices; and 2) lower than forecast OPG unregulated hydroelectric output (which had to be replaced by more expensive purchases from the spot market). Higher than expected natural gas prices have been a major contributor to the first factor which, in turn, exacerbated the impact of the second factor.

RPP Unit Supply Cost

RPP Year-To-Date (Apr 1, 2005 through Nov 30, 2005)	
Forecast	5.3 cents per kWh
Actual	6.2 cents per kWh
Percent Difference	15% higher

RPP Total Supply Cost

For the same reasons as given above, the RPP total supply cost is higher than forecast.

RPP Total Supply Cost

RPP Year-To-Date (Apr 1, 2005 through Nov 30, 2005)	
Forecast	$2,618 million
Actual	$2,980 million
Percent Difference	14% higher

RPP Unit and Total Revenues

The actual RPP revenue is essentially the same as forecast. A more detailed discussion of the RPP unit and total revenues is available in the Appendix section of this report.

RPP Variance[3]

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

Although the forecast RPP variance at the end of the RPP Year (March 30, 2006[4]) was expected to be zero, forecast monthly variations in RPP consumption, spot market prices and the relative mix of generation supply from the three sources led to relatively small positive or negative variances at different times throughout the year in the forecast.

The following comparison shows the forecast and actual RPP variance as of November 30, 2005.

RPP Variance

RPP Year-To-Date (Apr 1, 2005 through Nov 30, 2005)	
Forecast	-$22 million
Actual	-$372 million

The negative $372 million RPP variance corresponds to the "Net Variance Account Balance" identified on the OEB's Final RPP Variance Settlement Amount web page.[5] This value is taken to be the amount outstanding after the estimated accrued OPG Rebate (attributable to RPP

[3] The RPP variance includes interest incurred by the OPA for balances held in the variance account, as required by the Board's RPP Manual. The new price set by the Board on May 1, 2006 will take into account any accumulated interest on the balance carried from the previous year.

[4] As per the Board Notice issued on November 2, 2005, the RPP year-end was extended by one month to April 30, 2006, so that the changes to the RPP prices are synchronized with the Board approved distribution rate adjustments as well as the seasonal changes to the residential tier thresholds.

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

consumers) is taken into account. A portion of the variance balance will be paid by consumers leaving the Regulated Price Plan during the year (e.g., customers who switch to retail supply contracts or the spot market price, or move outside Ontario) through what is referred to as the RPP Settlement.[6] The remaining balance will be incorporated into the RPP price when it is reset on May 1, 2006.

It is important to note that the RPP prices set by the Board that will go into effect on May 1, 2006 will take into account a new price forecast, as well as the variance account balance at that time.

Finally, it is important to place the current variance balance in context. While the price forecast is based on "normal" weather conditions, the summer of 2005 was, on average, the hottest and most humid summer for Ontario in recent history as explained above.

[6] The web page referred to in footnote 5 also shows the monthly RPP Settlement Factor that distributors use to calculate the RPP Settlement. It also shows what a typical residential RPP consumer (e.g., 1000 kWh per month) would pay upon leaving the RPP. This web page is updated on a monthly basis.

Appendix A – Key Variance Drivers, Monthly Values

Presented in this appendix are the monthly values for the factors discussed in the body of this document. As well, two additional summary tables are provided for the output from Lennox Generating Station and RPP total demand which are not addressed previously.

1. Spot Market Prices and Key Drivers of Spot Prices

Simple Average Spot Market Price

cents per kWh	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Y to D
Forecast	5.4	4.9	5.7	6.1	6.1	5.5	5.7	5.0	5.5
Actual	6.2	5.3	6.6	7.6	8.8	9.4	7.6	5.8	7.2
Difference	15%	7%	15%	25%	46%	72%	34%	18%	29%

RPP Load Weighted Average Spot Market Price[7]

cents per kWh	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Y to D
Forecast	5.8	5.3	6.3	6.7	6.6	5.9	6.1	5.3	6.0
Actual	6.6	5.6	7.3	8.3	10.0	10.3	7.7	6.2	7.8
% Difference	15%	4%	16%	25%	50%	73%	26%	17%	30%

RPP Demand

RPP Demand (TWh)	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Y to D
Forecast	5.8	5.9	6.6	6.6	5.6	5.8	6.0	6.8	49.1
Actual	5.5	5.4	6.3	6.9	6.4	5.7	6.2	6.0	48.4
% Difference	-6%	-8%	-4%	5%	14%	-1%	4%	-12%	-1.4%

Lennox Generating Station (GS) Output

Lennox GS is one of the facilities that receives the spot market price for the electricity it produces. Given the relatively high position Lennox GS holds within the supply stack, the higher than forecast output is indicative of the increased reliance within the market on higher priced resources.

[7] Actual values are calculated based on LDC reported monthly RPP revenues and costs for RPP supply which was provided by the IESO. The forecast values were developed based on an estimate of the consumption pattern for RPP consumers.

Lennox Output (TWh)	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Oct-05	Y to D
Forecast	0.00	0.00	0.10	0.23	0.16	0.00	0.00	0.00	0.50
Actual	0.03	0.00	0.25	0.32	0.35	0.14	0.04	0.02	1.17
Difference	N/A	0%	143%	40%	117%	N/A	N/A	N/A	136%

Natural Gas Price

(USD$/MMBtu)	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Y to D
Forecast	$6.78	$6.75	$6.78	$6.83	$6.85	$6.82	$6.85	$7.15	$6.85
Actual	$7.45	$6.69	$7.23	$7.53	$9.24	$11.57	$13.12	$9.45	$9.04
% Difference	10%	-1%	7%	10%	35%	70%	92%	32%	32%

Weather, Cooling Degree Days (> 24 °C)

> 24 °C	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Y to D
Normal	0	0	2	10	5	1	0	0	17
Actual	0	0	26	39	14	1	0	0	81
% Difference	0%	0%	1098%	315%	215%	-35%	0%	0%	363%

Weather, Heating Degree Days (< 15 °C)

< 15 °C	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Y to D
Normal	282	86	13	1	4	62	227	421	1094
Actual	213	102	0	0	0	5	145	298	763
% Difference	-25%	18%	-100%	-100%	-100%	-92%	-36%	-29%	-30%

2. Generators that Pay the Provincial Benefit

OPG Nuclear Output

Nuclear (TWh)	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Y to D
Forecast	3.2	3.7	3.1	3.6	3.6	3.7	4.0	4.3	29.2
Actual	2.6	3.2	3.6	4.1	4.1	3.8	3.4	3.9	28.8
% Difference	-17%	-14%	16%	13%	14%	3%	-14%	-9%	-2%

OPG Regulated Hydroelectric Output

Regulated Hydro (TWh)	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Y to D
Forecast	1.5	1.6	1.5	1.6	1.6	1.5	1.5	1.5	12.2
Actual	1.6	1.7	1.4	1.5	1.5	1.4	1.3	1.5	11.8
% Difference	7%	6%	-8%	-7%	-7%	-7%	-11%	-3%	-4%

Provincial Benefit (or "Global Adjustment")

cent per kWh	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Y to D
Forecast	0.2	-0.1	0.4	0.5	0.6	0.3	0.2	0.1	0.3
Actual	0.5	0.2	0.7	1.2	1.8	2.1	1.2	0.4	1.0
% Difference	0.3	0.2	0.3	0.7	1.2	1.8	0.9	0.3	0.8

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

OPG Coal-fired Output

Coal Output (TWh)	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Y to D
Forecast	2.3	2.2	2.5	2.8	3.2	2.7	2.7	2.7	21.1
Actual	2.0	1.8	2.7	2.7	2.9	2.4	2.2	2.1	19.0
% Difference	-12%	-17%	10%	-1%	-11%	-10%	-17%	-23%	-10%

OPG Non-prescribed Hydroelectric Output

Unreg. Hyrdo (TWh)	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Y to D
Forecast	2.0	2.1	1.8	1.4	1.2	1.2	1.3	1.5	12.6
Actual	1.7	1.5	1.0	0.8	0.6	0.5	1.1	1.3	8.5
% Difference	-15%	-31%	-43%	-46%	-48%	-56%	-22%	-10%	-33%

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

OPG Rebate

cents per kWh	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Y to D
Forecast	0.6	0.3	0.4	0.4	0.6	0.5	0.5	0.3	0.4
Actual	0.4	0.2	0.6	0.7	1.0	1.0	0.7	0.3	0.6
Difference	(0.2)	(0.1)	0.2	0.3	0.4	0.5	0.2	0.0	0.2

4. RPP Unit and Total Revenues

The RPP unit revenue is calculated as the weighted average price of electricity consumed by RPP consumers at the two tiered prices (5.0 and 5.8 cents per kWh). The actual unit revenue is essentially the same as forecast.

cents per kWh	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Y to D
Forecast	5.4	5.4	5.4	5.3	5.4	5.4	5.4	5.2	5.4
Actual	5.4	5.4	5.4	5.4	5.4	5.4	5.3	5.4	5.4
% Difference	0%	0%	0%	2%	0%	-1%	-2%	4%	0%

The differential between *forecast* and *actual* RPP demand results in a slight difference between the *forecast* and *actual* total RPP revenue.

million $	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Y to D
Forecast	314	321	355	353	306	313	326	352	2,640
Actual	295	292	341	376	348	309	332	319	2,613
% Difference	-6%	-9%	-4%	6%	13%	-1%	2%	-9%	-1.0%

Since there is only a slight difference between the *forecast* and *actual* RPP total revenues, this indicates that the negative variance balance is primarily due to the difference between the *forecast* and *actual* RPP supply cost.