ISSUE 9: Peak versus Average Demand Forecast in Pre-Dispatch

Summary of Action Item 50-1:

With respect to Issue #9, the IESO undertook to provide the following information and data:

- Hourly HOEP Impacts;
- Assessment of the impact of the government 'off-coal' program;
- Assessment of the conditions under which the IESO has historically purchased emergency energy and whether such conditions may be more likely if there was a change to using average demand forecast in pre-dispatch.

Hourly HOEP Impacts

Background

In its analysis of the price impacts resulting from the use of an average pre-dispatch demand forecast, the IESO reported an average annual increase in HOEP of $0.72/MWh[1]. Furthermore, it was reported that the hedge against price changes provided by the application of the global adjustment and the OPG rebate ultimately resulted in an average effective HOEP increase of $0.14/MWh[2].

In response to this, two consumers requested detailed average hourly HOEP impacts to assess overall cost and corresponding effective HOEP increases specific to representative consumption patterns. For example, it was expected that a load who consumes more in off-peak hours would be faced with a higher increase in overall energy costs than an on-peak consumer with the same total energy consumption. This expectation is based on the assumption that the average demand forecast would be used primarily in off-peak periods.

Additional Information, Analysis, and Results

Hourly average HOEP price deltas were provided to the requesting consumers. The data is presented below in Tables 1 and 2. Table 1 contains HOEP price deltas for all hours of day. Data in Table 2 is a subset of Table 1 and includes price deltas for all hours excluding 6-9 and 16-19.

[1] This estimate is based on the assumption that an average forecast is used in all hours except hours 6-9 and 16-19.

[2] Refer to IESO report, "Peak versus Average in Pre-Dispatch: Results of Analyses" (pages 9-11)

Table 1: HOEP Increase for Average Demand Forecast in All Hours

	Delta HOEP		
Hour	All Days	Mon-Fri	Sat-Sun
1	0.51	0.56	0.38
2	0.62	0.72	0.38
3	0.31	0.36	0.20
4	0.27	0.34	0.09
5	0.42	0.54	0.12
6	1.41	1.93	0.16
7	1.40	1.83	0.31
8	1.63	2.12	0.52
9	1.32	1.34	1.29
10	1.54	1.46	1.73
11	1.46	1.43	1.54
12	0.91	0.84	1.07
13	1.12	1.15	1.02
14	0.65	0.63	0.68
15	0.76	0.81	0.64
16	1.60	1.86	1.01
17	2.49	2.56	2.34
18	2.07	2.11	1.97
19	1.78	1.80	1.72
20	1.72	1.90	1.22
21	1.64	1.71	1.45
22	2.44	2.68	1.84
23	1.93	2.17	1.35
24	1.14	1.18	1.06
Avg	**1.30**	**1.42**	**1.00**

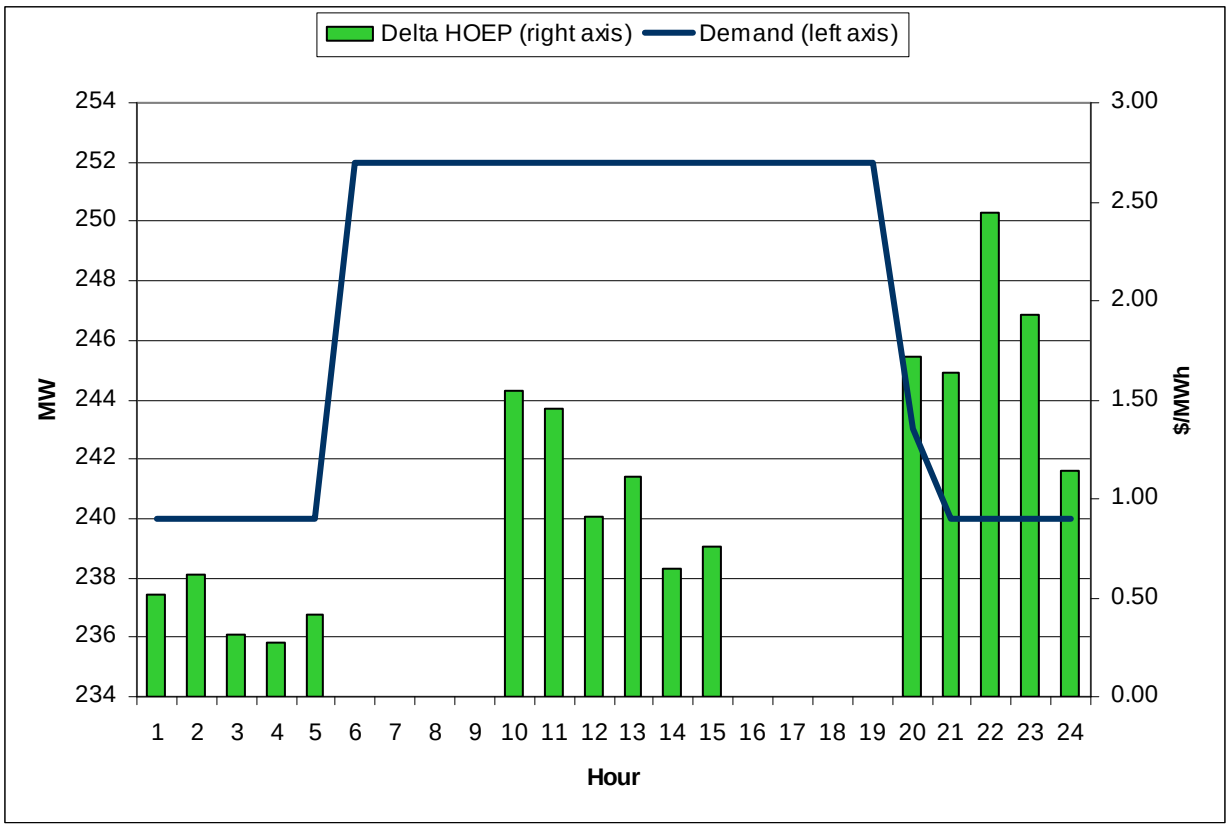
Table 2: HOEP increase for Average Demand Forecast in All Hours except 6-9 and 16-19

	Delta HOEP		
Hour	All Days	Mon-Fri	Sat-Sun
1	0.51	0.56	0.38
2	0.62	0.72	0.38
3	0.31	0.36	0.20
4	0.27	0.34	0.09
5	0.42	0.54	0.12
6	0	0	0
7	0	0	0
8	0	0	0
9	0	0	0
10	1.54	1.46	1.73
11	1.46	1.43	1.54
12	0.91	0.84	1.07
13	1.12	1.15	1.02
14	0.65	0.63	0.68
15	0.76	0.81	0.64
16	0	0	0
17	0	0	0
18	0	0	0
19	0	0	0
20	1.72	1.90	1.22
21	1.64	1.71	1.45
22	2.44	2.68	1.84
23	1.93	2.17	1.35
24	1.14	1.18	1.06
Avg	**0.73**	**0.77**	**0.62**

The requesting consumers used the hourly price data in Table 2 to calculate expected overall increase in annual cost and effective HOEP increases specific to their respective consumption patterns. These values were then evaluated against the expected overall annual costs and effective HOEP increases for a hypothetical flat-load consumption profile. Using the consumer developed method as a template; the IESO has applied three stylised load shapes to the same hourly price data (in Table 2) to determine overall cost and average effective HOEP increases for different consumption patterns. The stylised load shapes are presented in Figures 1, 2 and 3. Each of the stylised load shapes was generated to have the same average hourly consumption of ~250 MWh to make overall energy costs between load shapes comparable. The resulting cost and effective HOEP effects of applying the load shapes to hourly price increases are presented in Table 3.

Results presented in Table 3 confirm that the overall increase in energy costs and corresponding effective HOEP are impacted by different consumption patterns. Specifically, the results indicate that an off-peak consumer faces a higher increase energy costs (and effective HOEP), while an on-peak consumer faces a lower increase energy costs (and effective HOEP) when both are compared to a hypothetical flat-load consumer. These results are also based on the assumption of an average demand forecast being used in non-ramp up hours[3]. Furthermore, the magnitude of overall cost and price impacts is dependent upon the respective magnitudes of off-peak and on-peak consumption (e.g. a load that consumes exclusively off-peak is expected to face a higher increase in costs than the stylised off-peak consumer).

Figure 1: Stylised On-Peak Consumption Profile



[3] Ramp-up period assumed to be hours 6-9 and 6-19, consistent with the assumption used in the IESO report , "Peak versus Average in Pre-Dispatch: Results of Analyses" (page 6)

Figure 2: Stylised Flat-load Consumption Profile

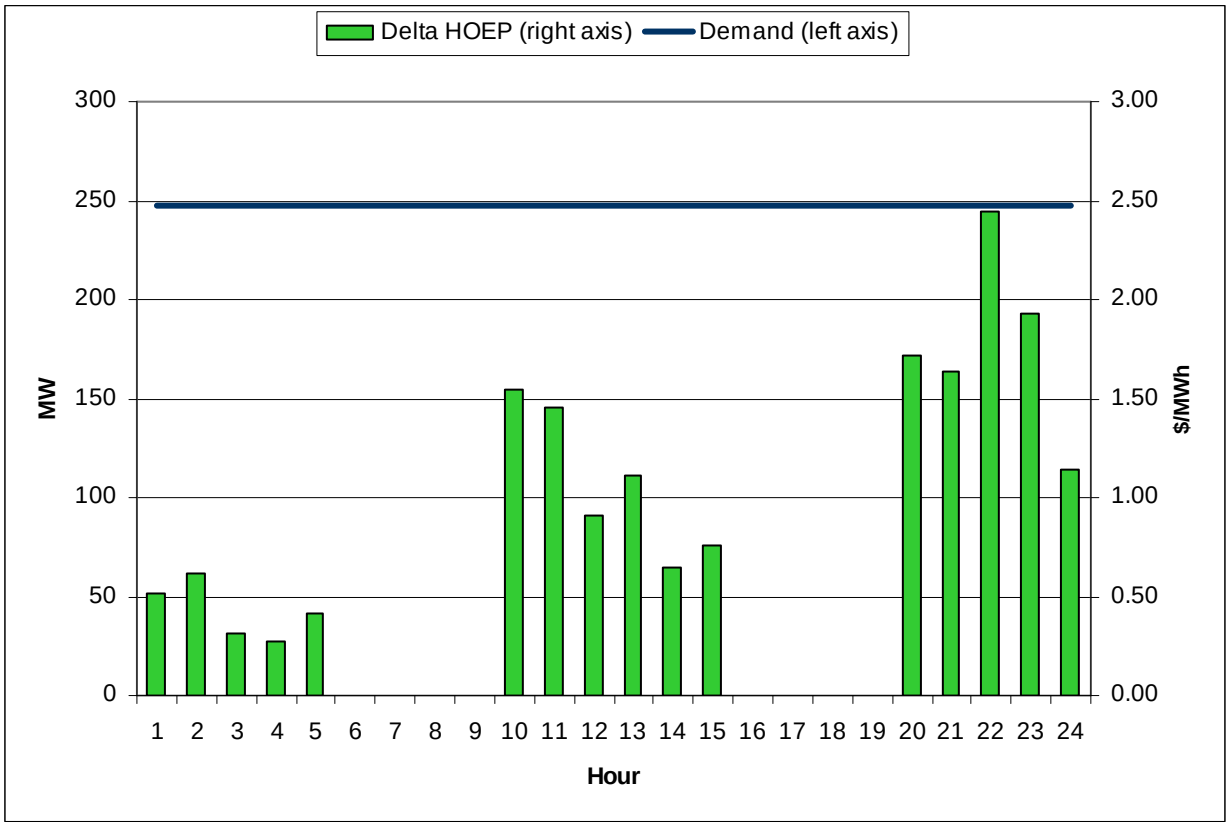


Figure 3: Stylised Off-peak Consumption Profile

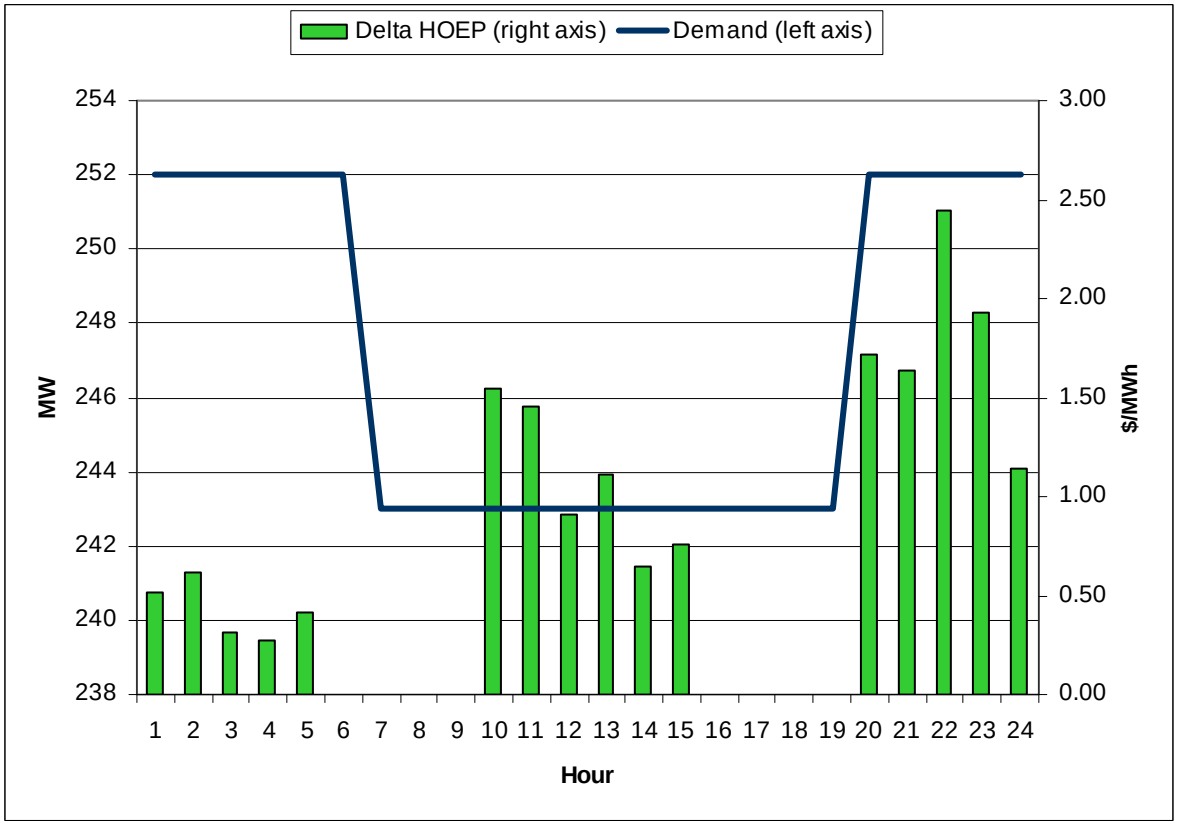


Table 3: Stylised Consumption Profiles Impact on Overall Energy Cost and Effective HOEP

	Stylised Load Shapes (see Figures 1 to 3)		
	On-Peak Profile	**Flat Load Profile**	**Off-Peak Profile**
Overall Increase in Annual Costs ($)	$1,556,238	$1,571,503	$1,581,380
Effective HOEP increase ($/MWh)	$0.1438	$0.1452	$0.1461

Assessment of the impact of the Ontario government's 'off-coal' program

Background

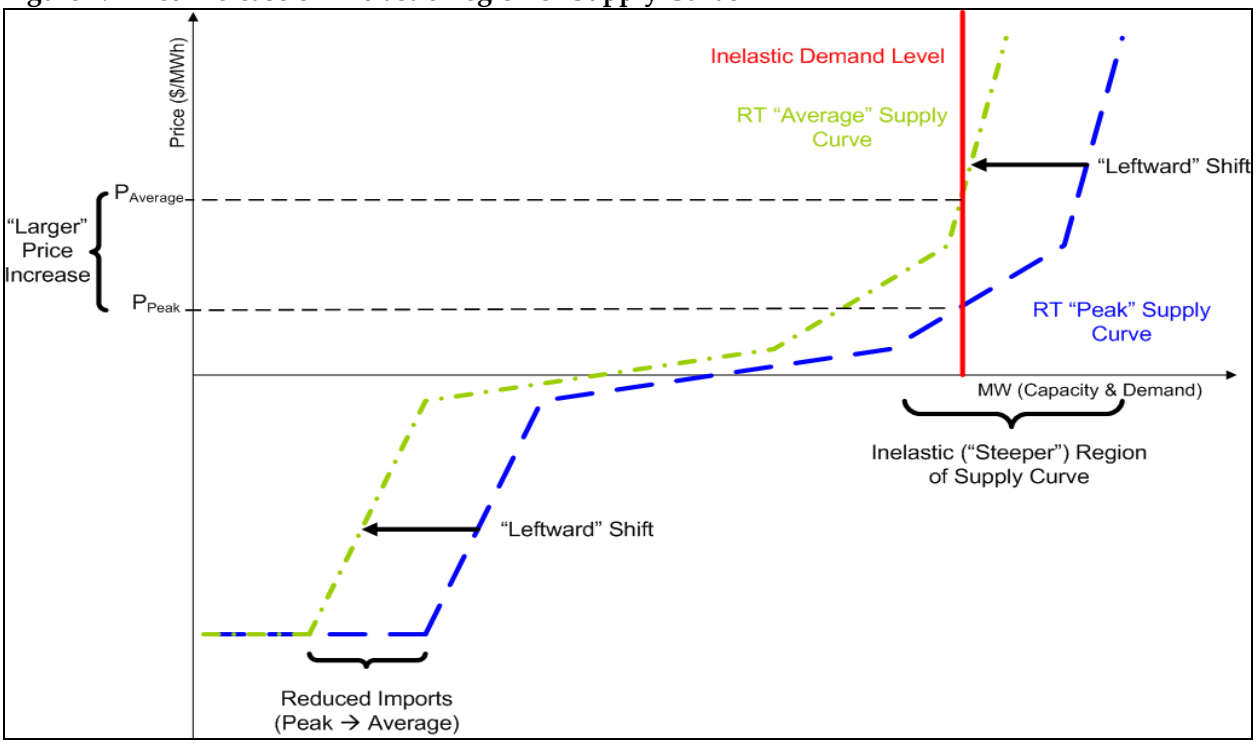
In response to the analysis on the Price Impacts in the IESO report, "Peak versus Average in Pre-Dispatch: Results of Analyses", consumers suggested that the government 'off-coal' program could change the future supply mix so dramatically, that the existing analysis based on the existing supply mix was not relevant. The IESO undertook to provide an assessment of the 'off-coal' program's impact on the estimated price changes that were reported.

The IESO is applying the following framework to assess the 'off-coal' impact on the estimated price change of using an average demand forecast.

Peak vs. Average: Real-Time Price Increase using Average

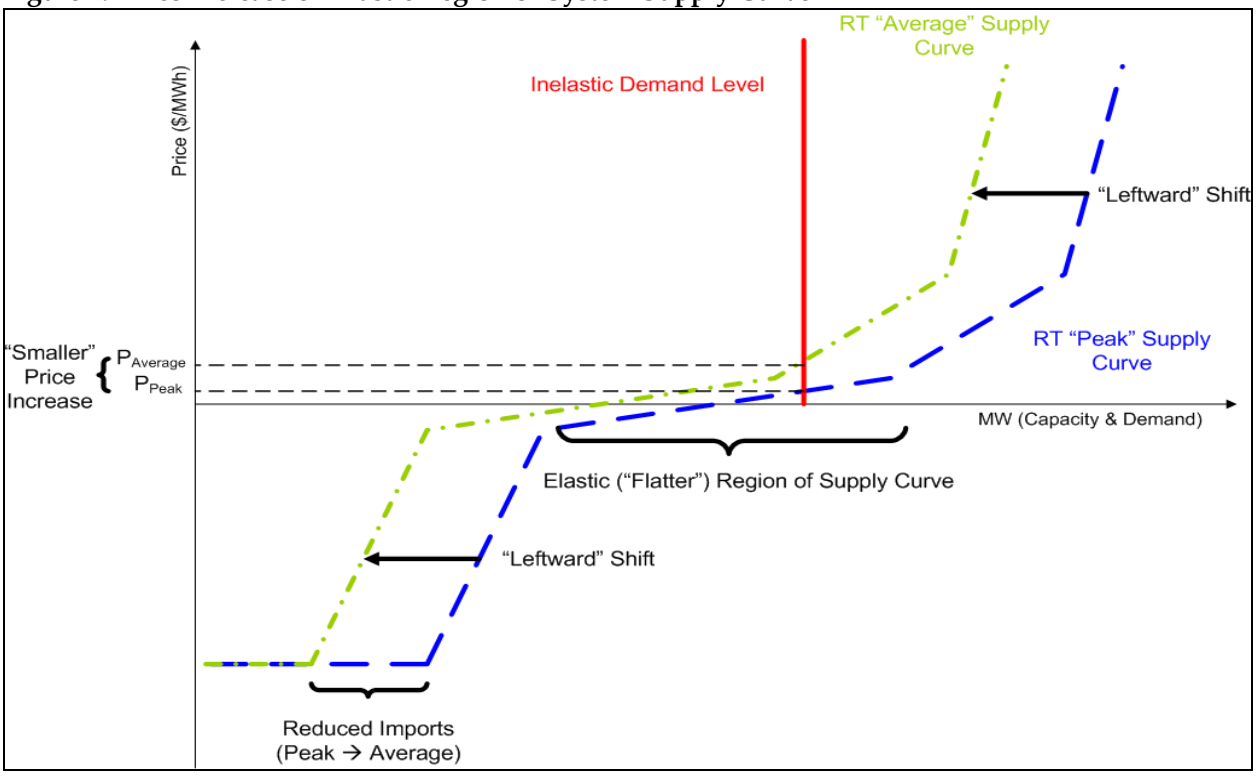
The estimated real-time price increases associated with the use of an average demand forecast are the result of a leftwards shift in the real-time system supply curve. This shift occurs because under an average demand forecast, fewer net imports are scheduled in pre-dispatch. As a result, fewer net imports populate the far left (bottom) of the supply curve in real-time, in comparison to a supply curve associated with a peak demand forecast. For a given level of inelastic demand, the leftwards shift in the real-time supply curve generally results in an upwards pressure on price. Larger price increases correspond to inelastic demand levels at or near inelastic regions on the supply curve (i.e. regions on the supply curve with a steep slope). Figure 1 illustrates this result.

Figure 1: Price Increase on Inelastic Region of Supply Curve



Smaller price increases (including potentially a zero price change) are the result of inelastic demand levels intersecting elastic regions on the supply curve (i.e. flatter regions on the supply curve). Figure 2 illustrates this result.

Figure 2: Price Increase on Elastic Region of System Supply Curve



Impact of Off-Coal Program on Price Increase using an Average Demand Forecast

At the root of the problem is not the level change in HOEP expected to occur as a result of the implementation of the government's 'off coal' program – this change will be taken "as given" in the analysis. Rather, the issue is whether or not the effect on the existing supply mix resulting from 'off-coal' will result in material differences in the expected changes in price resulting from the use of an average demand forecast instead of a peak demand forecast. As described in the previous section (and depicted in Figures 1 and 2), price increases for a given level of inelastic demand will be larger on steeper regions of the supply curve, and smaller (with possibly no price increase at all) on the flatter regions. With this in mind, an assessment of the 'off-coal' impacts on price increases associated with an average demand forecast can be reduced to determining the expected elasticity of the new system supply curve(s) as the 'off-coal' program is implemented.

Three general scenarios resulting from the 'off-coal' implementation can be envisioned:

- Slope of the system supply curve remains relatively unchanged → Current 'price increase' analysis holds

- Slope of the system supply curve becomes relatively steeper (less elastic) → Current 'price increase' analysis potentially under-forecasts the price impact of moving to an Average Demand Forecast
- Slope of the system supply curve becomes relatively flatter (more elastic) → Current 'price increase' analysis potentially over-forecasts the price impact of moving to an Average Demand Forecast

Proposed Next Steps

1. Determine the impact of 'off-coal' program on the supply curve.
   In doing so, we must remain cognisant of the various stages of implementation in the 'off-coal' plan, and its implications to the supply curve. Over the 2009-2014 period, it is expected that a combination of emissions restrictions and generator retirements will limit the output of coal-fired generation, but that at least some of coal-fired capacity will remain in the supply curve. Past 2014, all coal-fired generation will be effectively removed from the supply curve. These two scenarios require different assumptions to be made regarding the impact of the various stages of implementation of the government 'off-coal' plan.

2. Conduct further 'price impact' analysis or simulations.
   Once the impact(s) of the 'off-coal' plan on the system supply curve have been established, further analysis on the price impact of moving to an average forecast can be conducted.

Assessment of Emergency Energy Purchases

An assessment of the conditions under which the IESO has purchased emergency energy in the past, in addition to an evaluation of whether such conditions would be more likely if using an average demand forecast was conducted as part of the Reliability Assessment contained in the IESO report, "Peak versus Average in Pre-Dispatch: Results of Analyses" (pages 5-6).

It this assessment, the increased probability of the use of control actions was used as a proxy for the increased reliability risk of moving from peak to average. Emergency energy purchases were explicitly included as one of the control actions considered in the assessment. Furthermore, the assessment identified certain hours where the use of an average demand forecast would result in unacceptable risk of adverse reliability impacts. From this, the IESO determined that it would retain the use of a peak demand forecast in the following hours:

- "Ramp-up periods" to be defined and published by the IESO in advance of implementing any proposed change
- Hours where the supply cushion is below 5% in the day-ahead commitment run
- Any hours where the IESO identifies any reliability concern with using average for that hour

In all remaining hours, it was determined that the risk of adverse reliability impacts of using an average demand forecast was deemed to be manageable as the probability of increased control actions, including the purchase of emergency energy, would be insignificant.

Additional historical analysis was conducted for the 40 hours where emergency purchases were made dating back to January 2003 (excluding the August 2003 blackout). This analysis reveals that about half (19 out of 40) of these hours occurred within the "roughly" identified ramp-up hours of 6-9 and 16-19[4]. Furthermore, the real-time supply cushion for the majority (35 of 40) of these hours was well below 5%, often falling into the negative supply cushion range[5]. This historical analysis, in addition to the previously conducted reliability assessment, leads the IESO to conclude that the likelihood of emergency energy purchase events should not increase as a result of the proposed implementation of an average demand forecast in the specified hours.

[4] Refer to page 6 of IESO report, "Peak versus Average in Pre-Dispatch: Results of Analyses"

[5] The remaining 5 hours in which emergency purchases were made (where the supply cushion was not below the 5% threshold) occurred during a single event in Northwest zone as a result of local area supply shortfalls resulting from a combination of transmission and generator forced outages. The IESO believes that the use of an average demand forecast instead of peak would not have exacerbated this local area event.