AMPCO

**VIA RESS AND COURIER**

March 11, 2009

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, ON  M4P 1E4

Dear Ms. Walli:

**Re: Hydro One Networks Inc. Changes to Transmission Rates**
**Submission of AMPCO Undertakings**
**Board File No. EB-2008-0272**

Attached please find AMPCO's responses to undertakings J6.1, J6.2, J6.3, J6.4, J6.5, J6.6 and J6.7.

Please contact me if you have any questions or require any further information.

Sincerely yours,

Adam White

Copies to: Glen MacDonald, Hydro One Networks Inc.
Intervenors (email)

**Association of Major Power Consumers in Ontario**
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# ***UNDERTAKING***

## ***Undertaking***

TO REVIEW AND COMMENT UPON VECC'S CALCULATION OF THE CURRENT TRANSMISSION SHADOW PRICE FOR CUSTOMERS BILLED AT 85 PERCENT OF NONCOINCIDENT PEAK.

## ***Response***

The calculation shown below is based on the number of working weekdays in 2007. The transmission shadow price is calculated according to the current transmission network charge determinant where the charge is assessed based on a customer's demand during working weekdays between 0700 and 1900 in each month.

**Calculating the transmission shadow price in each month of 1 MW of demand reduction under the current network charge determinant for a customer currently billed at 85% of its non-coincident peak between 0700 and 1900 on working weekdays**

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| a | Network Charge Determinant per kW-month | | | | | $2.57 | | | | | | | |
| b | Transmission cost savings per MW average demand response per month | | | | | $2,570 | | | | | | | |
| c | Non-coincident ratchet | | | | | 85% | | | | | | | |
| | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
| d | Number of peak demand hours avoided to achieve 1 MW savings each month | 264 | 240 | 264 | 240 | 264 | 252 | 264 | 264 | 228 | 264 | 264 | 228 |
| e | The value of transmission cost savings per MW of demand response per MWh | $8.27 | $9.10 | $8.27 | $9.10 | $8.27 | $8.67 | $8.27 | $8.27 | $9.58 | $8.27 | $8.27 | $9.58 |

The transmission shadow price for each month is calculated by the formula:

$$e = \frac{b \times c}{d}$$

Where: b is the network charge determinant on a $/kW-month basis
C is the 85 percent non-coincident peak ratchet
d is the number of hours in a month on working weekdays between 7:00 a.m. and 7:00 p.m.

# ***UNDERTAKING***

***Undertaking***

TO PROVIDE THE ANSWER TO WHY THE PRICE OF $57.02 IN COLUMN 3 OF THE TABLE AT THE BOTTOM OF PAGE 8 OF 9, EXHIBIT I, TAB 17, SCHEDULE 14, IS DIFFERENT THAN $55.40 IN EXHIBIT I, TAB 17, SCHEDULE 14, PAGE 4 OF 9 UNDER THE "MEAN OF HOEP" COLUMN IN THE DATA SUMMARY.

***Response***

Both values are incorrect because (1) the value of $57.02 is the arithmetic mean of HOEP between the hours 7:00 a.m. to 8:00 p.m. during the summer months of 2007; and (2) the value of $55.40 is the arithmetic mean of HOEP during the hours 6:00 a.m. to 7:00 p.m. during the summer months of 2007.

The correct value is $57.50, the arithmetic mean of HOEP during the hours 7:00 a.m. to 7:00 p.m. during the summer months of 2007. The revised results of the regression analysis (from Exhibit I, Tab 17, Schedule 14, Pages 4 and 5 of 9) are shown below.

The statistical results are slightly stronger than those previously calculated, both in terms of the estimated coefficients and the associated t-statistics.

A. Peak Hours (8 am - 6:59 pm)

The SURVEYREG Procedure

Regression Analysis for Dependent Variable price

Data Summary

| | |
|---|---|
| Number of Observations | 1476 |
| Mean of price | 57.49991 |
| Sum of price | 84869.9 |

| | |
|---|---|
| R-square | 0.5057 |

Estimated Regression Coefficients

| Parameter | Estimate | Standard Error | t Value | Pr > \|t\| |
|---|---|---|---|---|
| Intercept | 51.2352159 | 24.6521175 | 2.08 | 0.0619 |
| odem | 0.0159704 | 0.0062200 | 2.57 | 0.0262 |
| imp | -0.0088862 | 0.0074577 | -1.19 | 0.2585 |
| exp | 0.0167312 | 0.0060332 | 2.77 | 0.0181 |
| coal | -0.0104992 | 0.0062777 | -1.67 | 0.1226 |
| gas | -0.0067930 | 0.0070470 | -0.96 | 0.3558 |
| CERIgp | -5.8898629 | 1.9594914 | -3.01 | 0.0120 |
| nuclear | -0.0166563 | 0.0066812 | -2.49 | 0.0299 |
| hydro | -0.0060805 | 0.0061855 | -0.98 | 0.3467 |
| HHI1 | -0.0098745 | 0.0030713 | -3.22 | 0.0082 |
| day | 0.1142513 | 0.0436348 | 2.62 | 0.0239 |
| m5 | 12.4180926 | 2.8900283 | 4.30 | 0.0013 |
| m6 | 5.2932215 | 1.3794597 | 3.84 | 0.0028 |
| h8 | -0.8671432 | 1.0379846 | -0.84 | 0.4213 |
| h9 | 0.8259198 | 0.5389933 | 1.53 | 0.1537 |
| h10 | 6.7190488 | 0.1263713 | 53.17 | <.0001 |
| h11 | 6.3177964 | 0.3260975 | 19.37 | <.0001 |
| h12 | 11.0888485 | 0.5108943 | 21.70 | <.0001 |
| h13 | 11.1952184 | 0.6753793 | 16.58 | <.0001 |
| h14 | 8.5257180 | 0.6708382 | 12.71 | <.0001 |
| h15 | 6.9028988 | 0.5416215 | 12.74 | <.0001 |
| h16 | 5.5757208 | 0.5085211 | 10.96 | <.0001 |
| h17 | 6.6707858 | 0.5091761 | 13.10 | <.0001 |
| h18 | 3.3228123 | 0.2849786 | 11.66 | <.0001 |

A. Non Peak Hours (7 pm - 12 am)
The SURVEYREG Procedure

Regression Analysis for Dependent Variable price

Data Summary

| | |
|---|---|
| Number of Observations | 1476 |
| Mean of price | 32.71623 |
| Sum of price | 48289.2 |

| | |
|---|---|
| R-square | 0.7141 |

| Parameter | Estimate | Error | t Value | Pr > \|t\| |
|---|---|---|---|---|
| Intercept | -38.820361 | 11.7200303 | -3.31 | 0.0069 |

| | | | | |
|---|---|---|---|---|
| odem | 0.005709 | 0.0028288 | 2.02 | 0.0686 |
| imp | 0.000948 | 0.0028566 | 0.33 | 0.7461 |
| exp | 0.004846 | 0.0028901 | 1.68 | 0.1217 |
| coal | -0.001439 | 0.0027999 | -0.51 | 0.6174 |
| gas | 0.006002 | 0.0040495 | 1.48 | 0.1664 |
| CERIgp | -1.336357 | 1.6876091 | -0.79 | 0.4452 |
| nuclear | -0.005835 | 0.0027181 | -2.15 | 0.0550 |
| hydro | -0.004554 | 0.0027673 | -1.65 | 0.1281 |
| HHI1 | 0.009086 | 0.0014149 | 6.42 | <.0001 |
| day | 0.140885 | 0.0297250 | 4.74 | 0.0006 |
| m5 | 2.475128 | 3.1010104 | 0.80 | 0.4417 |
| m6 | -2.171433 | 1.1397651 | -1.91 | 0.0832 |
| h1 | 0.145213 | 1.2683744 | 0.11 | 0.9109 |
| h2 | -0.652653 | 1.3123390 | -0.50 | 0.6288 |
| h3 | -0.556896 | 1.3764820 | -0.40 | 0.6935 |
| h4 | -0.160127 | 1.3632336 | -0.12 | 0.9086 |
| h5 | -0.264388 | 1.2661780 | -0.21 | 0.8384 |
| h20 | 6.816701 | 2.7156966 | 2.51 | 0.0290 |
| h21 | 10.818919 | 2.6772194 | 4.04 | 0.0019 |
| h22 | 1.905429 | 2.1172029 | 0.90 | 0.3874 |

# ***UNDERTAKING***

## ***Undertaking***

TO PROVIDE AN EXPLANATION OF HOW THE FIGURES IN EXHIBIT I, TAB 17, SCHEDULE 14, PAGE 8 OF 9, OF 18.68, -5.77, AND -4.70 ARE CALCULATED.

## ***Response***

Mean demand by industry sector during on-peak and off-peak hours is shown in the following table. On-peak hours are those between the hours ending 0800 and 1900. Off-peak hours are those between the hours ending 2000 and 2400. The figures below are revised from those originally filed as Exhibit I, Tab 17, Schedule 14, page 8 of 9, in response to VECC IR#14(g).

**Mean Industry Demand Summer 2007**

| Hour ending | 0800 to 1900 | 2000 to 2400 |
|---|---|---|
| Pulp | 408.05 | 479.74 |
| Metal | 508.78 | 532.85 |
| Iron | 465.43 | 486.77 |
| Motor | 157.75 | 148.77 |
| Petrol | 219.49 | 220.20 |

The effect of changes in Ontario demand on the Hourly Ontario Electricity Price is estimated as shown in the following table.

**Estimated Coefficients of Price with Respect to Demand**

| | | |
|---|---|---|
| a | Effect of Demand on HOEP during peak periods | 0.0159704 |
| b | Effect of Demand on HOEP during non-peak periods | 0.0057090 |

The average HOEP during on-peak hours (for the summer of 2007) is $57.50 (as shown at Exhibit J6.3, page 2, line 11).

The average HOEP during off-peak periods is $32.72 (as shown at Exhibit J6.3, page 2, line 57).

The transmission shadow price expressed as an average value during the 12 hour on-peak period is estimated as shown in the table below.

| **Calculating a Shadow Price for Transmission Network Services** | | | |
|---|---|---|---|
| a | Network Charge Determinant | $2.57 | per kW-month |
| b | Transmission cost savings per MW average demand response | $2,570 | per MW-month |
| c | Transmission cost savings per MW average demand response | $30,840 | per MW-year |
| d | Number of peak demand periods avoided to achieve 1 MW savings | 5 | per year |
| e | Number of demand reductions to avoid each peak demand period | 5 | per period |
| f | Number of demand reductions to avoid all peak demand periods | 25 | per year |
| g | Duration of average demand reduction to achieve 1 MW savings | 12 | hours |
| h | Demand reduction-hours to achieve 1 MW savings | 300 | hours |
| **i** | **The value of transmission cost savings per MW of demand response** | **$102.80** | **per MWh** |

Where:

$$i = (a \times 1000 \times 12)/(d \times e \times g)$$
$$i = c/(f \times g)$$
$$i = c/h$$

The price-elasticities of demand by sector were estimated by Dr. Sen, as follows:

| | *Pulp* | *Metal* | *Iron* | *Motor* | **Petrol** |
|---|---|---|---|---|---|
| **A. 2007** | | | | | |
| Current HOEP | -0.234 | -0.043 | -0.0469 | 0.353 | 0.0137 |
| | (0.0215)a | (0.0127)a | (0.0167)a | (0.044)a | 0.008879) |
| Average HOEP for past 12 hours | 0.103 | 0.056 | 0.026 | 0.155 | 0.016 |
| | (0.021)a | (0.010)a | (0.0188) | (0.042)a | (0.009)b |
| Month Fixed Effects | Yes | Yes | Yes | Yes | Yes |
| Observations | 244 | 244 | 244 | 244 | 244 |
| R Square | 0.2994 | 0.4798 | 0.4308 | 0.3617 | 0.9364 |
| **B. 2006** | | | | | |
| Current HOEP | -0.263 (0.02)a | -0.022 | -0.0358 | 0.367 | -0.006 |
| | | (0.0259) | (0.0176)b | (0.053)a | (0.019) |
| Average HOEP for past 12 hours | 0.136 | 0.096 | 0.093 | 0.165 | 0.0012 |
| | (0.020)a | (0.025)a | (0.018)a | (0.057)a | (0.014) |
| Month Fixed Effects | Yes | Yes | Yes | Yes | Yes |
| Observations | 244 | 244 | 244 | 244 | 244 |
| **R Square** | 0.3735 | 0.4877 | 0.3009 | 0.3343 | 0.7512 |

The above table contains Ordinary Least Squares estimates of the effects of current and 12 hour lagged average electricity prices on electricity demand; 'a' denotes whether the coefficient estimate of an explanatory variable is statistically significant at the 1% level; 'b' indicates that a covariate is statistically significant at the 5% level. Elasticity is expressed as the relative change in quantity with respect to a change in price, multiplied by the ratio of average price to average quantity.

$$\varepsilon = \frac{\partial q}{\partial p} \times \frac{\bar{P}}{\bar{Q}}$$

Since we have estimated price elasticities of demand for each industry sector, and we have calculated the average price during on-peak and off-peak periods, as well as the average demand during on-peak and off-peak periods for each sector, we are able to solve for the change in demand with respect to a change in price as follows:

$$\frac{\partial q}{\partial p} = \varepsilon \times \frac{\bar{Q}}{\bar{P}}$$

The resulting values for each sector are as shown in the following tables. The first table shows the effect of changing transmission rates on demand in real time.

**The Effect of Transmission Rates on Demand in Real-Time**

| a | b | c | d | e | f | g | h |
|---|---|---|---|---|---|---|---|
| | **Industrial demand Summer 2007 Peak Periods** | **Average HOEP Summer 2007 Peak Periods** | **Transmission Shadow Price** | **% change in price on-peak** | **Elasticity of Demand with respect to HOEP in Real-Time** | **Change in demand in response to change in price** | **Average Hourly Change in Demand** |
| | Qnp | Pnp | T$ | (t$+P)/P | e=(dq/dp)*(P/Q) | dq/dp | MW |
| Pulp | 408.05 | | | | -0.2344403 | -1.664% | -18.93 |
| Metal | 508.78 | | | | -0.0433269 | -0.383% | -5.44 |
| Iron | 465.43 | $57.50 | $102.80 | 279% | -0.0468795 | -0.379% | -4.92 |
| Motor | 157.75 | | | | | | |
| Petrol | 219.49 | | | | | | |
| Note: statistically insignificant results are excluded | | | | | | | -29 |

Where:

$$h = \frac{f \times (b \div c)}{100} \times \frac{(d + c)}{c} \times b$$

$$h = g \times e \times b$$

The change in demand in response to the change in price for the pulp and paper sector, for example, is calculated by multiplying the estimated elasticity of demand with respect to price for the pulp and paper sector (-0.2344403), by the ratio of the average hourly demand for the pulp and paper relative change in price (408.05/57.50).

The average hourly change in demand, again using the example of the pulp and paper sector, is calculated by multiplying the calculated percentage change in demand in response to the percentage change in price (-1.664%) by the percentage change in price (279%). For the pulp and paper sector, the result of the change in transmission rate is an average 18.93 MW reduction in demand during the on-peak hours 0800 to 1900. The sum of these estimates for each sector is an average on-peak period demand reduction of 29 MW.

The second table shows the effect of changing transmission rates on demand during off-peak hours within the same day, i.e., the hours ending 2000 to 2400 following the 12-hour on-peak period.

**The Effect of Transmission Rates on Peak Shifting**

| a | b | c | d | e | f | g | h |
|---|---|---|---|---|---|---|---|
| | **Industrial demand Summer 2007 Non-Peak Periods** | **Average HOEP Summer 2007 Peak Periods** | **Transmission Shadow Price** | **% change in price on-peak** | **Elasticity of Demand: Average HOEP for past 12 hours** | **Change in demand in response to change in price** | **Average Change in Demand** |
| | Qnp | Pnp | T$ | (t$+P)/P | e=(dq/dp)*(P/Q) | dq/dp | MW |
| Pulp | 479.74 | | | | 0.1033274 | 0.862% | 11.53 |
| Metal | 532.85 | | | | 0.0554928 | 0.514% | 7.64 |
| Iron | 486.77 | $57.50 | $102.80 | 279% | 0.0262302 | 0.222% | 3.01 |
| Motor | 148.77 | | | | 0.1550334 | 0.401% | 1.66 |
| Petrol | 220.20 | | | | 0.01582819 | 0.061% | 0.37 |
| Note: statistically insignificant results are excluded | | | | | | | 24 |

Where:

$$h = \frac{f \times (b \div c)}{100} \times \frac{(d + c)}{c} \times b$$

$$h = g \times e \times b$$

The calculation is identical to that described above. The relative change in price is computed for the 12 hour on-peak period. The elasticity of lagged demand, i.e., demand in the same-day off-peak hours between 2000 and 2400 was estimated by Dr. Sen. The average change in demand for each sector is calculated by multiplying the relative change in demand in response to a change in price by the relative change in price during the on-peak period immediately preceding the off-peak period, by the average demand for each industry sector during the same off-peak periods. The sum of these estimates for each sector is an average increase in demand of 24 MW during off-peak periods in response to a change in transmission rates.

The effect of industrial demand reduction during peak periods, and increases in demand during subsequent off-peak periods caused by peak-shifting, are shown in the following table.

**The Impact of Transmission Rate Changes on Other Customers**

| | | | |
|---|---|---|---|
| a | Average industrial demand reduction during peak periods | -29 | MW |
| b | Effect of Demand on HOEP during peak periods | 0.0159704 | |
| c | Effect of industrial demand reduction on HOEP during peak periods | -$0.47 | $/MWh |
| d | Total demand during peak periods in summer months | 27,219,556 | MWh |
| e | Total savings from industrial demand reduction during peak summer periods | -$12,731,225 | $/year |
| f | Average industrial demand increase during off-peak periods | 24 | MW |
| g | Effect of Demand on HOEP during non-peak periods | 0.0057090 | |
| h | Effect of industrial demand increase on HOEP during off-peak periods | $0.14 | $/MWh |
| i | Total demand during off-peak periods in summer months | 10,295,654 | MWh |
| j | Total increase from industrial peak-shifting during peak summer periods | $1,423,476 | $/year |
| k | Net savings from industrial demand reduction and peak shifting during summer months | -$11,307,749 | $/year |
| l | Annual transmission savings per MW | $30,840 | $/MW |
| m | Total annual industrial transmission savings | -$903,208 | $/year |
| n | Total annual demand by other customers | 132,334,189 | MWh |
| o | Transmission cost increase to other customers (applies to all MW in the year) | $0.0068 | $/MWh |
| p | Transmission cost increase to other customers (applies to all MW in the year) | $903,208 | $/year |
| **q** | **Net effect on other customers** | **-$10,404,541** | **$/year** |

Where:

$$e = (a \times b) \times d$$
$$e = c \times d$$
$$j = (f \times g) \times i$$
$$j = f \times d$$
$$k = e + j$$
$$m = a \times l$$
$$o = -m \div n$$
$$p = -m$$
$$q = k + p$$

# ***UNDERTAKING***

## ***Undertaking***

TO CONFIRM THAT THE REDUCTION IN PRICE IS OVER THE SAME PERIOD AS THE AVERAGE DEMAND REDUCTION BEING REPORTED; AND TO CLARIFY HOW THE .222 MEGAWATT HOURS' OVERALL IMPACT WAS DETERMINED AND TO WHICH PERIOD IT IS APPLICABLE.

## ***Response***

The $0.222/MWh figure shown in AMPCO's interrogatory response (at Exhibit I, Tab 17, Schedule 14, Page 8 of 9) was calculated as a weighted average of the effect of demand reduction by each sector on HOEP. However, the sum of the demand reductions should have been used instead of the weighted average. The correct value is not $0.222/MWh but $0.47/MWh. This correct value is used at row c of the table on page 5 of J6.3. The period to which it applies is the summer peak hours shown at row d of the table on page 5 of J6.3.

# ***UNDERTAKING***

## ***Undertaking***

TO PROVIDE AN EXPLANATION OF WHY THE EQUATION IN THE TABLE AT EXHIBIT I, TAB 17, SCHEDULE 14 USES THE HOEP PRICE IN THE OFF-PEAK PERIOD; AND TO PROVIDE AN EXPLANATION OF HOW THE FIGURE $.068 WAS DETERMINED AND TO WHICH PERIOD IT IS APPLICABLE .

## ***Response***

The use of the average off-peak HOEP is incorrect because the econometric analysis estimated the relationship between off-peak demand to average HOEP during the previous on-peak period. Therefore, the correct value to use is the average HOEP during peak periods, i.e., $57.50/MWh.

The $0.068 figure shown in Exhibit I, Tab 17, Schedule 14, page 9 of 9 was based on the weighted average of the effect of industrial demand increases by sector. However, the sum of the demand increases should have been used instead of the weighted average. The correct value is shown at row f of the table at page 5 of exhibit J6.3.

# ***UNDERTAKING***

***Undertaking***

TO PROVIDE JCP&L TARIFF AND ERCOT.

***Response***

AMPCO member Gerdau AmeriSteel has facilities in New Jersey and Texas that operate within the PJM and ERCOT systems respectively, where the transmission rate designs are similar to the design proposed by AMPCO.

1. PJM

Gerdau AmeriSteel has two facilities located within the PJM system. One plant, located in Sayreville, New Jersey is serviced by the Local Distribution Company (LDC) JCP&L and the other plant, located in Perth Amboy, New Jersey is serviced by the LDC, PSE&G.

The PJM Transmission Tariff references each LDC as shown in Attachment 1 (pages 486, 468A and 468B, 489, and 490). The document (over 1700 pages) can be found at: http://www.pjm.com/markets-and-operations/transmission-service.aspx. Implementation details of the tariff are found in separate documents prepared by each LDC (JCP&L and PSE&G) as follows:

JCP&L:
http://www.firstenergycorp.com/supplierservices/files/Supplier_Registration/2009_PJM_Capacity_Website_Document_09-09-08.pdf

PSE&G:
http://www.pseg.com/customer/energy/pdf/capacity_obligation.pdf

2. ERCOT

Gerdau Ameristeel has facilities located in Midlothian, Texas. The Midlothian facility is serviced by the Local Distribution company (LDC) Oncor. The Oncor transmission tariff and the reference to the 4 Coincident Peak (CP) can be found on page 74 of the PDF. The document can be found at:

http://www.puc.state.tx.us/electric/rates/Trans/Oncor.pdf

**INTRODUCTION**

This document is intended to define the process Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), and Jersey Central Power & Light Company ("JCP&L") d/b/a FirstEnergy ("Company") and Third Party Suppliers (New Jersey) and Electric Generation Suppliers (Pennsylvania) ("Suppliers") will apply to calculate and coordinate the information transfer for retail open access associated with Supplier unforced capacity and transmission service obligations in the Company Zone(s) of the PJM Interconnection. A complete description of the procedures, together with examples and details on customer load profiles and customer classes, is maintained at FirstEnergy's web site (http://wwwfirstenergycorp.supplierservices).

**Supplier Unforced Capacity Obligations and Supplier Network Integrated Transmission Service (NITS) Obligations**

In accordance with the PJM Reliability Assurance Agreement ("RAA"), the PJM Open Access Transmission Tariff ("OATT"), and assorted PJM Manuals, Procedures and Business Rules:

RULE 1: The Company is responsible for administering the LDC functions of the JCP&L Zone, the Met-Ed Zone and the Penelec Zone.

RULE 2: On an annual basis PJM assigns to each LDC Zone the LDC's Zonal capacity obligation Peak Load Share of the PJM Pool capacity requirement and the LDC's Zonal NITS obligation (Zonal Transmission Peak).

RULE 3: On an annual basis each LDC is responsible for allocating their assigned Zonal Peak Load Share to customers in the LDC's Zone (a.k.a., the capacity peak load tickets and the NITS tickets, jointly referred to as "peak load tickets").

RULE 4: The Company will determine each Suppliers capacity and NITS allocation based the Supplier's portfolio of customers for a given day (the Supplier allocations will be based on the sum of their portfolio of customers peak load tickets).

RULE 5: The Company will report each Supplier capacity and NITS allocation to PJM on a timetable defined by PJM using PJM designated systems.

RULE 6: Each Supplier is responsible for scheduling its capacity resources and/or Transmission reservations with PJM following PJM requirements.

**Calculation of the Customer Capacity and NITS Peak Load Tickets**

RULE 7: The LDC Zonal capacity allocation determined by PJM is based on the various zonal loads at the time of the five PJM Pool peak hours. The method used by PJM includes, but is not

Limited to weather normalization, unrestricted loads (i.e., add-backs, such as curtailed loads), historical smoothing (regression analysis), seasonal smoothing (i.e. 5 CP's) and zonal loads at the system (or Interchange) level (i.e., includes losses). Furthermore, PJM Business Rules include requirements related to customer peak load tickets, such as those promulgated under Demand Response and Behind the Meter. In calculating customer peak load tickets, the Company shall include load components reflective of the zonal allocation method and business rules currently in effect by PJM.

RULE 8: The basic framework for performing the annual customer peak load allocation (tickets) requires using available customer data. Such customer data varies by meter type, consequently different algorithms are required to calculate the customer peak load tickets for the various meter types. The Company will use the usage data, which in the Company's judgment most closely reflects the customer actual usage at the time of the peak hours.

RULE 9: Actual metered loads for (hourly) interval-metered customers are adjusted to include any load curtailed as a result of Active Load Management (ALM) events. The adjusted loads are referred to as "unrestricted loads".

RULE 10: Not all customers have hourly usage metering, therefore the customer allocation process will necessarily require using load profiles.

RULE 11: The Company will ensure that the sum of the peak load tickets corresponding to the customers active on each of the five peak days used in the calculation will average to equal the LDC's zonal allocation.

RULE 12: The Company will adjust each customers loads for losses consistent with the most recent state commission filing of loss factors by voltage classes.

RULE 13: Within the Zone there can and do exist "load zones" (i.e., municipalities, cooperatives, etc.) which may or may not be directly PJM Suppliers. These load-zones will have their aggregate customer peak load tickets determined consistent with the methodology used for all customers, unless a) an alternate methodology is agreed to by the Company, the Supplier and PJM, or b) PJM directs the Company to follow a different methodology as a matter of PJM requirements.

Coordination, Reconciliation and Settlement

RULE 14: The Supplier capacity and/or THE Supplier NITS allocations submitted by the Company to PJM for a given day shall be considered final so long as the actual meter read date of switching customers for that day occurs within +/-5 days of the scheduled meter read date.

RULE 15: In the event a switching customers meter read date is more than 5 days from the scheduled meter read date or there are errors in customer usage which result in adjustment to

Supplier billing to customers, reasonable efforts will be made to adjust the Supplier Peak Load allocation accordingly. The Supplier and the Company shall agree upon such adjustments. Adjustments will be calculated based upon the weighted average of the published PJM capacity credit market-clearing price for the applicable time frame. PJM monthly bills to the Company and Supplier (or their Scheduling Coordinator) shall be subject to the adjustment agreed upon by the Company and the Supplier (or their Scheduling Coordinator). Disputes shall be resolved through the PJM Dispute Resolution process.

RULE 16: The Supplier, any third party acting on behalf of the Supplier, or any authorized entity in possession of any relevant data, will cooperate with reasonable audit requests by the Company or professional auditing firms acting on the Company's behalf. Such audits are intended to provide the Company with a reasonable confidence in the validity and accuracy of any information that the Company obtains from the Supplier or third party. The Company shall bear the cost of the audit. The scope of the audit and the terms of payment are to be agreed upon by the Company and the Supplier or the third party prior to commencement of the audit.

RULE 17: The Supplier, any third party acting on behalf of the Supplier, or any authorized entity in possession of any relevant data for the determination of customer peak load ticket as described herein, will cooperate to provide the full and complete data required to the Company within reasonable timetables.

RULE 18: The Company will cooperate with reasonable audit requests by Suppliers. Audits are intended to provide the Supplier with reasonable confidence that the Company is calculating the Supplier's capacity and NITS allocations. The Supplier shall bear the cost of the audit. The scope of the audit and the terms of payment are to be agreed upon by the Company and the Supplier prior to commencement of the audit. Specific customer information (unless released by the customer) and proprietary information shall not be provided by the Company. The Company will address audit requests on a first come, first served basis.

## PROCEDURES FOR LOAD DETERMINATION

The procedures by which PSE&G will determine the peak and hourly loads reported to the Transmission Provider are set forth in the following provisions.

### A. CUSTOMER CAPACITY AND TRANSMISSION OBLIGATIONS

Both the capacity (generation) and transmission obligations for retail and wholesale customers have been developed so that the sum of the individual customer obligations within a zone will total the PJM zonal (LDC's) obligation. This zonal obligation may vary as provided for under the PJM Reliability Agreement due to the effects of net new customer load. PJM uses a "top down" method in allocating the PJM system peak load to each LDC, while the transmission loads are LDC (zone) specific. Each LDC uses a "bottom up" approach to calculate individual peak loads based upon the zonal loads. These preliminary customer peak loads are then scaled up or down to match (1) the normalized peak load calculated by PJM for each LDC for capacity purposes and (2) the actual zonal load for transmission purposes. Capacity peak loads, aggregated by Supplier, are adjusted for reserves and diversity by PJM. Transmission peak loads, aggregated by Supplier, transmitted to PJM need no further adjustment.

Since retail customers within a PJM zone (LDC service area) will be free to change suppliers, an obligation "tag" is needed to be assigned to each customer for both capacity and transmission obligations. These tags will be recalculated periodically to incorporate new customers, changing customer usage and to ensure consistency with the PJM and LDC peak loads and obligation calculations.

Discussed below is an explanation of how each individual customer's capacity and transmission peak load will be determined.

#### 1. Customer Capacity Peak Load Determination

To calculate a retail and wholesale customer's capacity peak load share, the total normalized peak demand is first determined for each zone by PJM. In the case of the PSE&G zone, the normalized peak load in the Summer of 1998 was approximately 9200 MW. This normalized peak load was based upon allocating PJM's normalized peak load to PSE&G using the ratio between PSE&G's actual load and PJM's actual load during the five highest PJM peak hours.

In determining the peak load contribution for each of its customers, PSE&G will use the actual hourly meter readings for hourly (interval) metered customers at the time of the five highest peak hours for PJM. For non-hourly metered customers, summer kWh usage and billing demand information for each customer, along with load research (profile) data for customers in the same rate class will be used. There are several steps involved in the peak load calculation.

The first step requires the calculation of a preliminary peak load estimate for each customer based on the available information. For customers without demand meters, such as Rate Schedule RS, this preliminary peak will be based on the individual customer summer energy use and the summer seasonal load factor (weather adjusted) calculated from the appropriate profile data. For customers with non time-of-day demand meters, such as Rate Schedule GLP, a similar calculation will be performed using appropriate weather adjusted profiled summer load factors, with the exception that the resulting customer peak load estimate will then be compared with the customer's maximum summer measured demand. The lower of the two values will be used for the preliminary peak load estimate. For customers with time-of-day demand meters, such as secondary customers on Rate Schedule LPL, a similar calculation is used utilizing appropriate profiled summer on-peak load factors. The lower of the resulting customer peak load estimate or the summer on-peak measured demand will then be used. For hourly customers such as Rate Schedule HTS, the average of five coincident hourly peaks will be used. The five hours will be based on the same five PJM peak hours as discussed above. If any of these hourly customers were interrupted during the five hours due to Active Load Management (ALM) events, their loads will be adjusted accordingly, or an alternate day peak load will be substituted, so that their subsequent peak is on an "unrestricted" basis. These adjustments are necessary to be consistent with the PJM and LDC loads, which are also on an "unrestricted" basis. The impact of these ALM events will be treated and tracked separately.

The second step calls for the total of these individual loads (with appropriate LDC losses added) to be compared to the PSE&G normalized summer peak load calculated by PJM (approximately 9200 MW as discussed above). A final scaling up or down is performed on each customer's peak load so that the total of the customer peaks equals the 9200 MW.

An estimated peak load will also be assigned to each new customer added since the Summer peak period is based on available information and system average values.

This information, aggregated by Supplier (including PSE&G Basic Generation Service), will be transmitted to PJM. PJM applies a reserve factor and a diversity factor to each Supplier's capacity peak load received from the LDC to determine the Supplier's capacity obligation within the PSE&G zone.

**2. Customer Transmission Peak Load Determination**

Each customer's transmission load/obligation is calculated using a similar method as described above for capacity. The method above is adjusted as follows: (1) the value assigned by PJM to each zone is based upon the actual load for each zone at the single highest hour of the zone load (not the weather normalized value) and (2) allocation of the transmission peak load to individual customers will be based on the five highest zonal peak loads (not the five highest PJM peak loads).

This information, supplied by the Company and aggregated by Supplier, is transmitted to PJM. No further adjustment is required by PJM.

**B. CUSTOMER ENERGY - INTERCHANGE OBLIGATIONS**

The PSE&G zonal hourly load of an electric generation supplier ("EGS") supplying load within PSE&G's service territory shall be the sum of the EGS's individual wholesale and retail customer hourly loads. PSE&G shall report to PJM each day the estimated hourly loads for EGSs. On a monthly basis, PSE&G shall reconcile actual individual customer meter readings and applicable load profile data with the estimated data previously provided on a daily basis for all EGSs and report all hourly differences to PJM by EGS. Individual wholesale and retail customer ("customer") hourly loads for the PSE&G zone shall be determined as follows:

1. Customer usage will be adjusted for losses based on the customer's voltage level. Loss factors will be based on losses contained in PSE&G's then-current Tariff for Electric Service or successor tariff.
2. For hourly (interval) metered customers, the customer's telemetered hourly meter readings will be used in the determination of the customer's estimated hourly load shares. On a monthly basis, PSE&G shall reconcile actual customer meter readings and data previously used in the daily report to PJM for use in reporting any EGS hourly differences to PJM.
3. Each non-hourly metered customer will be assigned a load profile based on the customer's rate schedule for electric service.
4. For non-hourly metered customers, the customer's estimated hourly load shares will be based on the average kWh use of the assigned load profile determined daily from the readings of load research sample meters. On a monthly basis, PSE&G shall reconcile actual individual customer meter readings and applicable load profile data with the estimated hourly data reported daily to PJM. On a monthly basis, PSE&G shall report hourly differences to PJM by EGS.
5. For unmetered rate schedules, the customer's hourly load shares reported will be based on static load research profiles determined for each rate schedule. Load research profiles used for unmetered rate schedules are flat and vary seasonally by on-peak and off-peak time periods.

Information regarding loads, load share calculations, obligations, and load profiles for the PSE&G zone is available on PSE&G's web site.

# UNDERTAKING

## Undertaking

TO PROVIDE AN ESTIMATE ON HOW THE $6.8 MILLION WOULD BE SPLIT BETWEEN LDCS ON THE ONE HAND AND ALL OTHER CUSTOMERS ON THE OTHER, INCLUDING ANY ASSUMPTIONS USED TO ARRIVE AT THE ESTIMATE AND THE CALCULATION USED TO ARRIVE AT THE $6.8 MILLION.

## Response

The estimates are shown in the table below, based on the analysis in Undertakings J6.3, J6.4 and J6.5. The share of savings from demand reduction, and of price increases from peak-shifting, are allocated on the basis of industry and LDC shares of total demand during the on-peak and off-peak periods for the summer months of 2007.

Because industry consumes a lower proportion of total demand during on-peak hours, compared to LDCs, the net combined effect of lower prices during on-peak periods and higher prices during off-peak periods is slightly higher for LDCs than for industry. In other words, LDCs stand to gain slightly more from AMPCO's proposal to change rates than do industrial customers overall.

| | On-peak demand | | On-peak savings | Off-peak demand | | Off-peak increase | Net effect | |
|---|---|---|---|---|---|---|---|---|
| Industry | 3,637,605 | 13.4% | -$1,701,393 | 1,601,444 | 15.6% | $221,415 | -$1,479,978 | 13.1% |
| LDC | 23,581,951 | 86.6% | -$11,029,832 | 8,694,210 | 84.4% | $1,202,060 | -$9,827,771 | 86.9% |
| TOTAL | 27,219,556 | | -$12,731,225 | 10,295,654 | | $1,423,476 | -$11,307,749 | |

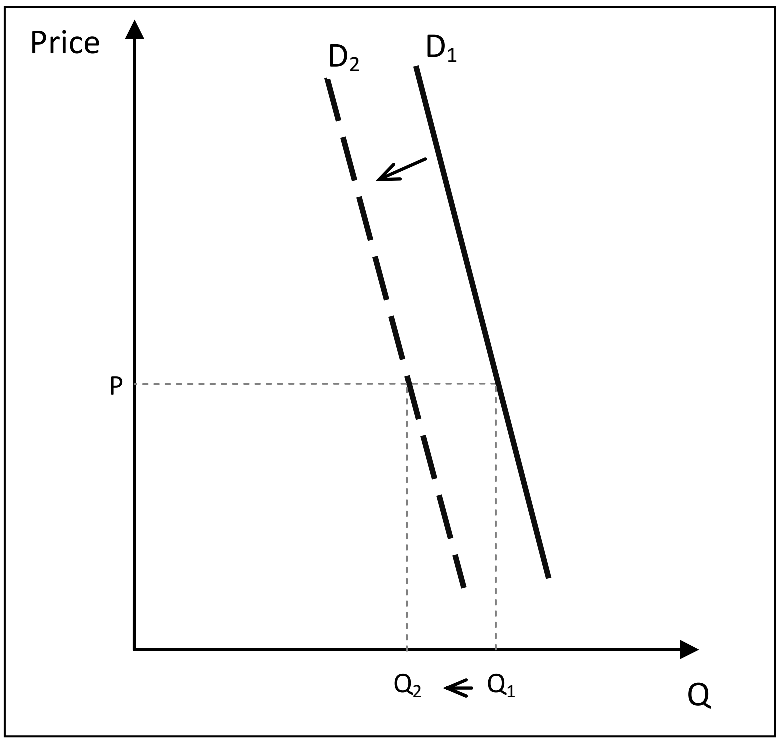
# ***UNDERTAKING***

## ***Undertaking***

TO PROVIDE THE GRAPHS DRAWN BY DR. ANINDYA SEN ON MARCH 3, 3008.

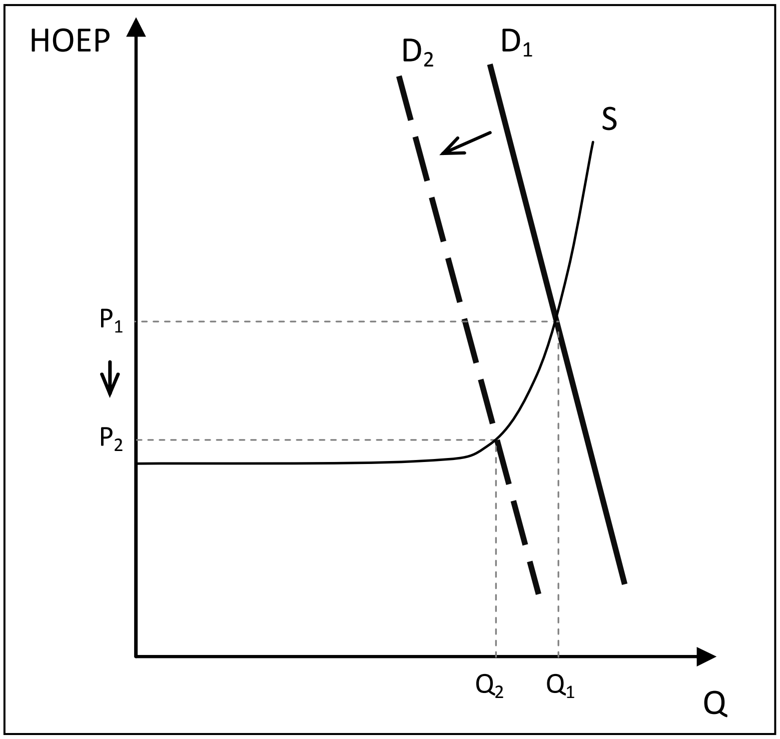
## ***Response***

Figure 1 shows a typical demand curve for a firm, $D_1$. $P_1$ represents the HOEP determined by the intersection of total demand and corresponding supply of electricity (from Figure 2).



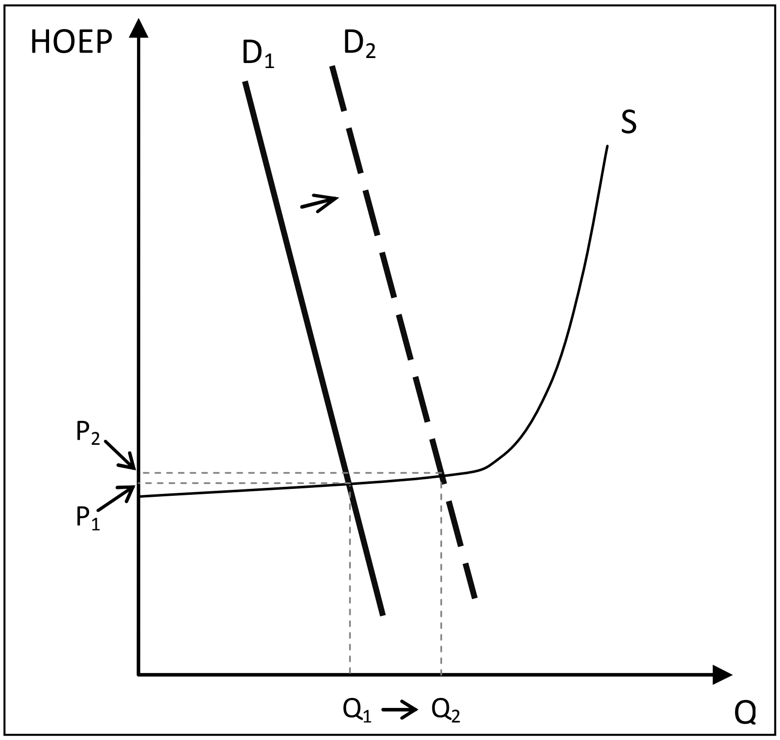

The introduction of an additional incentive to reduce demand will shift demand down from $D_1$ to $D_2$ even though prices remain unchanged at $P_1$.

Figure 2 depicts the effect of a shift in market demand (the aggregate of all firm demands) on price during peak periods. The supply curve is given by S and is J-shaped as accepted in the literature, and as observed in Ontario.




The introduction of an incentive to reduce demand during peak periods and/or to shift demand from peak periods to off-peak periods is depicted in the figure as a shift in the market demand curve from $D_1$ to $D_2$ causing a reduction in quantity consumed from $Q_1$ to $Q_1$. Because the shift in market demand takes place during peak periods, i.e., during times when the demand curve meets the supply curve along the steep portion of the supply curve, the market price is reduced from $P_1$ to $P_2$.

Figure 3 depicts the effect of peak-shifting, or an increase in off-peak demand caused by incentives or increased prices during peak periods.




In this scenario, demand shifts upward from $D_1$ in the figure to $D_2$. However, because this increase in market demand takes place during off-peak periods, i.e., during times when the demand curve meets the supply curve along the relatively flat portion of the supply curve, the increase in market price is relatively small.