ONTARIO POWER GENERATION

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VIA COURIER AND RESS

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 26th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2007-0715 - Lennox Generating Station Reliability Must-Run Agreement – OPG's Responses to Board Interrogatories

Attached please find OPG's responses to the Board's interrogatories in the above referenced matter.

Pursuant to the Board's Procedural Order #1, provided are two (2) hardcopies of OPG's request and one electronic copy in searchable / unrestricted PDF format. Copies of the responses are also being provided to registered parties via email.

Please direct any comments or questions in this matter to the undersigned.

Yours truly,

[Original signed by]

Andrew Barrett

BOARD STAFF INTERROGATORY FOR OPG #1

Interrogatory

Re: Continued Operation of Lennox

This is the third consecutive one-year reliability must-run agreement between OPG and the Independent Electricity System Operator ("IESO") for which OPG has sought Board approval.

a. If the Board approves the 2007-08 RMR Agreement, does OPG expect to file with the IESO a Request to De-Register Lennox effective October 1, 2008?
b. If not, why not?
c. Does OPG have any reason to believe that, over the period from now to the end of 2010, revenues from the IESO-administered energy market would be sufficient to cover Lennox's fixed operating costs?

OPG Response

a. Yes. OPG will be filing a Request to De-Register Lennox effective October 1, 2008. This request will be made approximately 6 months prior to October 1, 2008; therefore, this will take place on or around April 1, 2008.

b. As per a) above, OPG will be filing the De-Registration Notice.

c. No. OPG expects Lennox to continue to operate as a "swing" or "peaking" plant going forward, and as such, revenues generated from the IESO-administered market are not expected to be sufficient to cover the costs associated with operating Lennox, hence the need to operate the facility under an RMR arrangement.

BOARD STAFF INTERROGATORY FOR OPG #2

Interrogatory

Re: Schedule D, Table 1 of the 2007-08 RMR Agreement

Please complete the following table, providing information in relation to each of the cost categories set out in Table 1 of Schedule D of the 2007-08 RMR Agreement.

OPG Response

See Table 1 below.

Table 1 - OPG Interrogatory #2

Cost Category (A)	RMR Agreement Oct. 1/05 to Sept. 30/06 ($k)		Difference between forecast and actual (Oct. 1/05 to Sept. 30/06)		RMR Agreement Oct. 1/06 to Sept. 30/07 ($k)		Difference between forecasts and actual for second RMR agreement	
	Forecasted amount per first RMR agreement (B)	Actual (C)	$k (D) = (B)-(C)	% (E) = (D)/(B)	Forecasted amount per second RMR agreement (F)	Actual (G)	$k (H) = (F) - (G)	% (I) = (H)/(F)
Cost Category								
Fuel								
Fixed and Variable Fuel Costs	29,625.00	52,148.98	(22,523.98)	-76%	43,183.82	78,600.32	(35,416.50)	-82%
OM&A								
Labour	24,106.00	24,647.59	(541.59)	-2%	26,450.07	26,474.89	(24.82)	0%
Energy Markets (fuel purchasing / trading)	215.00	215.00	-	0%	216.90	216.90	-	0%
Materials	5,210.00	4,107.84	1,102.16	21%	5,133.29	4,067.56	1,065.73	21%
Other	3,497.00	4,362.12	(865.12)	-25%	4,366.95	4,499.73	(132.78)	-3%
OEB Approval Process	-	39.21	(39.21)	N/A	12.00	20.70	(8.70)	-73%
Projects	14,555.00	11,271.65	3,283.35	23%	9,026.00	10,232.31	(1,206.31)	-13%
Corporate Functions at Facilities	1,344.00	1,381.80	(37.80)	-3%	1,404.48	1,376.88	27.60	2%
Insurance	1,782.00	1,683.02	98.98	6%	1,707.22	1,731.41	(24.19)	-1%
Property taxes	1,042.00	2,655.20	(1,613.20)	-155%	2,935.37	2,774.75	160.62	5%
Other								
Net Energy Market Settlement for Non-dispatchable Load - CC 101	-	4,684.11	(4,684.11)	N/A	-	3,974.64	(3,974.64)	N/A
Network Pool Service Charge– CC 650	-	689.09	(689.09)	N/A	780.35	677.28	103.08	13%
Debt Retirement Charge – CC 752	-	602.96	(602.96)	N/A	632.75	613.84	18.91	3%
Rural Rate Assistance Settlement Credit – CC 753	-	86.14	(86.14)	N/A	90.39	87.69	2.70	3%
OPA Administration Charge - CC 754	N/A	N/A	N/A	N/A	N/A	25.18		
IESO Energy Market Administration Charge – CC 9990	-	72.00	(72.00)	N/A	85.10	73.35	11.75	14%
Uplift	-	227.39	(227.39)	N/A	246.08	65.19	180.89	74%
Non-IESO Market Revenue Costs	-	-	-	N/A	-	-	-	N/A
Financing Cost on Working Capital	2,976.00	4,668.60	(1,692.60)	-57%	4,043.90	3,445.74	598.16	15%
TOTAL OPERATING COST AMOUNT (O)	84,352.00	113,542.69	(29,190.69)	-35%	100,314.68	138,958.38	(38,643.70)	-39%
MARGIN AMOUNT (M)	1,283.00	1,283.00	-	0%	1,403.57	1,403.57	-	0%
Revenue Category								
Energy								
Net Energy Market Settlement – CC 100	21,445.00	48,334.80	(26,889.80)	-125%	38,701.65	66,300.64	(27,598.99)	-71%
CMSC for Energy – CC 105	-	4,732.92	(4,732.92)	N/A	-	4,593.84	(4,593.84)	N/A
Generation Cost Guarantee Payment – CC 133	-	5,089.90	(5,089.90)	N/A	-	4,203.79	(4,203.79)	N/A
Ancillary								
10 Minute Spinning Reserve Market Settlement Credit– CC 200	3,351.00	420.17	2,930.83	87%	3,451.93	669.91	2,782.02	81%
10 Minute Non-spinning Reserve Market Settlement Credit – CC 202	-	-	-	N/A	-	-	-	N/A
30 Minute Operating Reserve Market Settlement Credit– CC 204	-	654.10	(654.10)	N/A	-	693.51	(693.51)	N/A
CMSC for 10 Minute Spinning Reserve – CC 106	-	218.26	(218.26)	N/A	-	489.79	(489.79)	N/A
CMSC for 10 Minute Non-spinning Reserve – CC 107	-	-	-	N/A	-	-	-	N/A
CMSC for 30 Minute Operating Reserve – CC 108	-	316.08	(316.08)	N/A	-	974.49	(974.49)	N/A
Salvage								
Gas Salvage Margin	-	(460.87)	460.87	N/A	-	171.71	(171.71)	N/A
Other								
Global Adjustment Settlement Amount – CC 146	-	89.61	(89.61)	N/A	-	(383.11)	383.11	N/A
OPG Non- Prescribed Assets Adjustment CC162	-	205.14	(205.14)	N/A	-	128.25	(128.25)	N/A
Other IESO Market Revenues	N/A	N/A	N/A	N/A	N/A	20.68		
Non-IESO Market Revenues	-	-	-	N/A	-	-	-	N/A
Total Gross Revenues	24,796.00	59,600.11	(34,804.11)	-140%	42,153.58	77,863.52	(35,709.94)	-85%

BOARD STAFF
INTERROGATORY FOR OPG #3

Interrogatory

Please complete the following table, providing information in relation to each of the cost categories set out in Table 1 of Schedule D of the 2007-08 RMR Agreement.

OPG Response

See Table 1 below.

Table 1 - OPG Interrogatory #3							
Cost Category	RMR agreements - Forecasts per original applications ($k)			Differences between forecasts of second versus first RMR agreement		Differences between forecasts of 2007-08 versus second RMR agreement	
	First (Oct. 1/05 to Sep. 30/06) EB-2005-0490	Second (Oct. 1/06 to Sep. 30/07) EB-2006-0205	Third (Oct. 1/07 to Sep. 30/08) EB-2007-0715	k$	% change	k$	% change
(A)	(B)	(C)	(D)	(E)=(C)-(B)	(F)=(E)/(B)	(G)=(D)-(C)	(H)=(G)/(C)
Cost Category							
Fuel							
Fixed and Variable Fuel Costs	29,625.00	43,183.82	23,881.47	13,558.82	46%	(19,302.35)	-45%
OM&A							
Labour	24,106.00	26,450.07	28,203.83	2,344.07	10%	1,753.77	7%
Energy Markets (fuel purchasing / trading)	215.00	216.90	254.80	1.90	1%	37.90	17%
Materials	5,210.00	5,133.29	4,871.97	(76.71)	-1%	(261.32)	-5%
Other	3,497.00	4,366.95	4,518.12	869.95	25%	151.17	3%
OEB Approval Process	-	12.00	28.00	12.00	N/A	16.00	133%
Projects	14,555.00	9,026.00	16,641.00	(5,529.00)	-38%	7,615.00	84%
Corporate Functions at Facilities	1,344.00	1,404.48	1,400.00	60.48	5%	(4.48)	0%
Insurance	1,782.00	1,707.22	1,750.00	(74.78)	-4%	42.78	3%
Property taxes	1,042.00	2,935.37	3,000.00	1,893.37	182%	64.63	2%
Other							
Net Energy Market Settlement for Non-dispatchable Load - CC 101	-	-	-	-	N/A	-	N/A
Network Pool Service Charge– CC 650	-	780.35	682.86	780.35	N/A	(97.50)	-12%
Debt Retirement Charge – CC 752	-	632.75	631.15	632.75	N/A	(1.60)	0%
Rural Rate Assistance Settlement Credit – CC 753	-	90.39	90.16	90.39	N/A	(0.23)	0%
OPA Administration Charge - CC 754	N/A	N/A	18.66	N/A	N/A	N/A	N/A
IESO Energy Market Administration Charge – CC 9990	-	85.10	77.24	85.10	N/A	(7.85)	-9%
Uplift	-	246.08	221.65	246.08	N/A	(24.42)	-10%
Non-IESO Market Revenue Costs	-	-	-	-	N/A	-	N/A
Financing Cost on Working Capital	2,976.00	4,043.90	3,700.00	1,067.90	36%	(343.90)	-9%
TOTAL OPERATING COST AMOUNT	84,352.00	100,314.68	89,970.93	15,962.68	19%	(10,343.75)	-10%
MARGIN AMOUNT	1,283.00	1,403.57	1,492.93	120.57	9%	89.36	6%
Revenue Category							
Energy							
Net Energy Market Settlement – CC 100	21,445.00	38,701.65	12,806.90	17,256.65	80%	(25,894.75)	-67%
CMSC for Energy – CC 105	-	-	-	-	N/A	-	N/A
Generation Cost Guarantee Payment – CC 133	-	-	-	-	N/A	-	N/A
Ancillary							
10 Minute Spinning Reserve Market Settlement Credit– CC 200	3,351.00	3,451.93	1,551.97	100.93	3%	(1,899.96)	-55%
10 Minute Non-spinning Reserve Market Settlement Credit – CC 202	-	-	-	-	N/A	-	N/A
30 Minute Operating Reserve Market Settlement Credit– CC 204	-	-	-	-	N/A	-	N/A
CMSC for 10 Minute Spinning Reserve – CC 106	-	-	-	-	N/A	-	N/A
CMSC for 10 Minute Non-spinning Reserve – CC 107	-	-	-	-	N/A	-	N/A
CMSC for 30 Minute Operating Reserve – CC 108	-	-	-	-	N/A	-	N/A
Salvage							
Gas Salvage Margin	-	-	-	-	N/A	-	N/A
Other							
Global Adjustment Settlement Amount – CC 146	-	-	-	-	N/A	-	N/A
OPG Non- Prescribed Assets Adjustment CC162	-	-	-	-	N/A	-	N/A
Other IESO Market Revenues	N/A	-	-	N/A	N/A	-	N/A
Non-IESO Market Revenues	-	-	-	-	N/A	-	N/A
Total Gross Revenues	24,796.00	42,153.58	14,358.87	17,357.58	70%	(27,794.71)	-66%
TOTAL ESTIMATED PAYMENT	23,556.00	40,045.90	13,640.93	16,489.90	70%	(26,404.97)	-66%
MONTHLY PAYMENT	5,173.25	5,139.36	6,485.24	(33.89)	-1%	1,345.88	26%

BOARD STAFF INTERROGATORY FOR OPG #4

Interrogatory

Re: Schedule D, Table 1 of the 2007-08 RMR Agreement

In the 2007-08 RMR Agreement, Fixed and Variable Fuel Costs are estimated to be $23,881,471. In contrast, the corresponding Fixed and Variable Fuel Costs for the second RMR agreement were forecasted at $43,183,823. The change $19,302,352, which is a decrease of 44.70% over last year's estimate. In section 5 of the Application, OPG states that actual net costs under the second RMR agreement for the period October 1, 2006 to June 30, 2007 were higher than estimated ($93.49M versus $75.24M) with the variance being accounted in large part due to increased fuel costs ($47.16M versus $32.39M for the period).

a. Please provide an explanation for the estimated reduction in the forecasted Fixed and Variable Fuel costs for the 2007-08 RMR Agreement, particularly in light of the fact that actual fuel costs for the period October 1, 2006 to June 30, 2007 exceeded the forecast amounts set out in the second RMR agreement.
b. Please break down and provide explanations for the forecasted reduction in Fixed and Variable Fuel costs for the 2007-08 RMR Agreement as between the following: i) increases in the prices of oil and natural gas; ii) changes in the expected quantity of fuel due to the changed forecasts for operation of Lennox under must-run conditions; and iii) other.

OPG Response

a. The 2007-08 RMR Agreement was negotiated based on a number of forecasts including, estimated run time of Lennox, fuel and labour costs, revenues and project costs. These forecasts were based on OPG's Business Planning Assumptions at the time this RMR was negotiated. The Fixed and Variable Fuel costs in the 2007-08 RMR are significantly less than the previous RMR due to the fact that OPG's planning assumptions indicate significantly less production from Lennox for the 2007-08 RMR timeframe (152 GWh versus 368 GWh forecasted for the October 1, 2006 to September 30, 2007 RMR). This is due to a variety of factors, including increased generation coming on line during this period. The Fixed and Variable Fuel costs were higher than forecast for the October 1, 2006 to June 30, 2007 timeframe because Lennox operated significantly more (380 GWh) than originally forecasted (178 GWh) due to other expected generation not being available.

b. OPG's response in 4(a) above explains the rationale for the forecast energy difference. The Fixed and Variable Fuel cost difference between forecasts is summarized as follows:
   i. Increases in oil and natural gas prices resulted in an increase in costs of $4.3 Million.
   ii. Changes in the expected quantity of fuel due to the changed forecasts resulted in a reduction of $23.4 Million.
   iii. Other cost changes resulted in a cost reduction of $0.2 Million.

   The cumulative impact of the above changes amounts to a fuel cost reduction of $19.3 Million.

BOARD STAFF INTERROGATORY FOR OPG #5

Interrogatory

Re: Schedule D, Table 1 of the 2007-08 RMR Agreement

a. Please provide details of the estimated costs of $16,641,000 described as "Projects".

b. Footnote 7 to Schedule D states that one of the projects will be a "permanent unloading shed". Please explain why a permanent facility is required for a facility that OPG has, for the past few years, intended to de-register.

OPG Response

a. See table 1 below. Additional explanations are provided for large projects.

Table 1 – Project Details	
Project Description	**$**
250VDC Protection	523,000
250VDC Annunciation	200,000
Water Treatment Plant Controls Replace the existing obsolete water treatment plant control system which is over 30 years old. Existing automated control equipment fails on a regular basis requiring manual intervention. Spare parts are no longer available for this equipment. Station reliability is the main risk driver for this project.	1,795,000
4kv Motor Relays	150,000
Tank Inspections	800,000
Generator Rotor Inspection/Repairs Complete generator rotor inspection and repairs on Lennox Unit 4. Project work includes rotor removal, inspection and repair of all damaged/worn rotor components. Inspection findings resulted in the need for a complete rotor rewind as well as the replacement of retaining rings.	4,450,000
Air Ejector PCVs	80,000
LP Boiler Fill System	200,000
Daytank Cladding	175,000
HVAC Systems	300,000
Ignition Piping	150,000
Battery Room Showers	300,000
Back End Ducting	238,000
Permanent Unloading Shed Design and construct a permanent oil train unloading system for residual oil. The original unloading pit system which was used prior to 2006 was removed from service due to containment integrity issues. An inspection of the pit in 2006 revealed irreparable damage. As a result, a new permanent residual unloading system is required.	5,930,000
Roofs	150,000
Power House Elevator	850,000
Ventilation Louver	250,000
Mechanical Maintenance Office	100,000
Total	**16,641,000**

b. Prior to 2006, a 50,000 barrel unloading pit (underground oil storage tank) was used as an oil transfer point when receiving residual oil by rail. In 2006 it was discovered that the integrity of the pit was irreparably damaged. The tank was immediately removed from service and Lennox GS was no longer able to unload residual fuel. As a stop-gap measure, a temporary oil unloading system was constructed. This temporary system is operationally constrained and has an unacceptable environmental spill risk. The permanent solution is to restore the unloading capability to original system design flow rates, reduce the environmental spill risk and meet current industry tank train unloading design standards.

   Maintaining Lennox's ability to operate as a dual-fuel facility during winter months is consistent with the RMR contract and performance standards. Without a guaranteed supply of residual oil in the winter months, a contract for the supply of uninterrupted gas in winter months would be required. A firm gas supply contract is estimated to cost approximately $30M per year. This is significantly more costly than the $5.93M cost to construct the permanent unloading shed.

BOARD STAFF INTERROGATORY FOR OPG #6

Interrogatory

Re: Schedule D, Table 1 of the 2007-08 RMR Agreement

In the 2007-08 RMR Agreement, Project costs are estimated at $16,641,000. The corresponding Project costs in the second RMR agreement in effect from October 1, 2006 to September 30, 2007 were $9,026,000. The change in project costs is an increase of $7,615,000 or 84.37%. Please explain the increase in Project costs.

OPG Response

Project costs vary from year to year based on assessed needs and priority ranking of required work. Programs are established to address legal and regulatory requirements, health and safety issues, environmental issues and obsolescence.

The major change in the project budget from the 2006/2007 contract to the 2007/2008 contract is the addition of two significant projects; the Permanent Unloading Shed as discussed in Interrogatory #5, and the Water Treatment Plant Controls.

The project changes between the 2006/2007 contract period and the 2007/2008 contract period, supporting the $7,615K increase, are shown in Table 1 below.

Table 1 – Project Cost Details			
Project Description	**2006/2007 ($K)**	**2007/2008 ($K)**	**Difference ($K)**
250VDC Protection	750	523	(227)
250VDC Annunciation	-	200	200
4 kV Motor Relays	-	150	150
CTU Controls & Cooler Upgrades	150	-	(150)
PCB Transformer/Exciter	330	-	(330)
Water Treatment Plant Controls	100	1,795	1,695
Tank Inspections	800	800	0
Permanent Unloading Shed	-	5,930	5,930
Fire System Upgrades	250	-	(250)
Generator Rotor Inspection	4,350	4,450	100
Roof Repairs	175	150	(25)
Air Ejector PCVs	550	80	(470)
LP Boiler Fill System	-	200	200
WTP Upgrades	60	-	(60)
Stack Inspection	150	-	(150)
Lime Unloading	50	-	(50)
Mechanical Maintenance/NDE Upgrades	100	100	0
Make Up Air Ducts	150	-	150
Ventilation Louver	100	250	150
Powerhouse Elevators	300	850	550
CCW Pump Impeller Replacement	300	-	(300)
Traveling Screens	261	-	(261)
Primary Thermal Oil	100	-	(100)
Daytank Cladding	**-**	175	175
HVAC Systems	-	300	300
Ignition Piping	-	150	150
Battery Room Showers	-	300	300
Back End Ducting	-	238	238
Total	**9,026**	**16,641**	**7,615**

BOARD STAFF INTERROGATORY FOR OPG #7

Interrogatory

Re: Application, Section 5, Performance under the 2006-07 Lennox RMR Contract

In section 5 of its application, OPG indicates that, for the period October 1, 2006 to June 30, 2007, actual total costs under the second RMR agreement were $93.49 M versus an estimate of $75.24 M while actual total revenues were $40.81 M versus an estimate of $31.62 M. OPG identifies certain factors explaining some of the variance between actual results and estimates. However, it is not clear to what extent some of the variance is due to the operation of Lennox as a must-run facility more frequently than was forecasted.

a. Please document OPG's operation of Lennox for the period October 1, 2006 to September 30, 2007, inclusive, in comparison to the estimated operation reflected in the second RMR agreement.
   Please document the operation in terms of:
   i. Total hours of operation; and
   ii. Number of times when OPG was requested by the IESO to run Lennox as a "must-run" facility.

b. With respect to the performance and reward mechanism under the second RMR agreement, please provide the actual, if and to the extent available, or the estimated amount of any performance reward payable under the second RMR agreement for the entire term of the agreement, as the Application currently provides this information only for the shoulder period October 1, 2006 to November 30, 2006 and April 1, 2007 to May 31, 2007.

OPG Response

a.
   i. OPG's aggregate operation of Lennox Generating Station as a generator for the period October 1, 2006 to September 30, 2007 was 2,446 hours. The second RMR agreement for the period October 1, 2006 to September 30, 2007 used an estimate of 2,310 hours of operation.

   ii. OPG was requested by the IESO to run Lennox Generating Station units a total of 318 times during the period October 1, 2006 to September 30, 2007. The estimated number of starts reflected in the second RMR agreement for the period October 1, 2006 to September 30, 2007 was 302 times.

b. For the peak period (defined as December 1, 2006 to March 31, 2007 and June 1, 2007 to September 30, 2007), the EFOR-OP was 1.99%. The peak period EFOR-OP Target is between 4% and 6% with performance measured by the application of performance points that represent a percentage number by which the actual EFOR-OP was below or above the EFOR-OP Target. For the purposes of calculating a penalty or reward, each performance point is valued at $250,000 for the peak period. The reward to OPG is calculated at $250,000 x (4%-1.99%) x 100 = $502,500.

   For the shoulder period (defined as October 1, 2006 to November 30, 2006 and April 1, 2007 to May 31, 2007), the EFOR-OP was 0.51%. The shoulder period EFOR-OP Target is between 6% and 8%. For the purposes of calculating a penalty or reward, each performance point is valued at $125,000 for the shoulder period. The reward to OPG is calculated as $125,000 x (6%-0.51%) x 100 = $686,250.

   Therefore, the total reward paid to OPG for the second RMR agreement in effect from October 1, 2006 to September 30, 2007 was $502,500 + $686,250 = $1,188,750.

BOARD STAFF INTERROGATORY FOR OPG #8

Interrogatory

Re: Application, Section 5, Performance under the 2005-06 and 2006-07 Lennox RMR Agreements

Please provide energy production information for Lennox since September 30, 2005, organized as follows:

a. Monthly production expressed in MWh and as a capacity factor;
b. Peak hourly production each month; and
c. The number of hours in each month when energy production exceeded each of the following: 500 MWh; 1,000 MWh; and 1,500 MWh.

OPG Response

See Table 1 below. Data is provided to the end of the second RMR Agreement (September 30, 2007).

Table 1 - OPG Interrogatory #8						
	a. Production		b. Peak Hourly	c. Number of Hours when Energy Production Exceeded		
Month	MWh	Capacity Factor	Production MW	500 MWh	1,000 MWh	1,500 MWh
Oct 2005	41,994	2.5%	1,438	22	3	0
Nov 2005	23,611	1.4%	996	8	0	0
Dec 2005	48,063	2.8%	1,352	24	4	0
Jan 2006	16,827	1.0%	829	8	0	0
Feb 2006	6,927	0.4%	477	0	0	0
Mar 2006	-	0.0%	-	0	0	0
Apr 2006	5,088	0.3%	512	4	0	0
May 2006	35,375	2.2%	1,552	27	13	10
Jun 2006	62,571	4.0%	1,252	52	4	0
Jul 2006	133,345	8.2%	2,036	88	45	28
Aug 2006	67,160	4.2%	2,041	42	26	15
Sep 2006	-	0.0%	-	0	0	0
Oct 2006	2,271	0.1%	226	0	0	0
Nov 2006	54,468	3.4%	1,281	24	1	0
Dec 2006	13,636	0.8%	826	4	0	0
Jan 2007	45,736	2.7%	1,589	28	8	1
Feb 2007	100,609	6.8%	1,826	74	38	13
Mar 2007	40,077	2.4%	1,547	27	12	1
Apr 2007	2,020	0.1%	294	0	0	0
May 2007	10,904	0.7%	721	6	0	0
Jun 2007	110,196	7.0%	1,982	85	51	10
Jul 2007	61,673	3.8%	2,033	44	29	12
Aug 2007	239,913	14.9%	2,050	163	96	61
Sep 2007	80,925	5.2%	1,542	67	29	5