Q. Capacity Related Supply Costs: Regarding the added supply costs encountered by Hydro in the first quarter of 2014 as a result of a supply shortage, costs were incurred in January after the early January supply emergency and costs were also incurred in February and March. Please explain the nature and reasons for these post-emergency added costs.

A. Costs associated with the Corner Brook Pulp and Paper (CBPP) capacity assistance and the increased usage of Hydro's gas turbines, diesel plants, and Newfoundland Power generation continued to be incurred following the early January supply emergency as a result of additional capacity shortfalls that were experienced throughout this period. Hydro provided additional details regarding the nature and reasons for the costs incurred in January to March 2014 in its responses to requests for information in the *Newfoundland and Labrador Hydro Approval of the Deferral and Recovery of Expenses with Increased Capacity-Related Supply Costs on the Island Interconnected System in 2014* (which were previously filed on November 12, 2014) (the CDA Proceeding).

As explained in Hydro's response to NP-NLH-002 in that proceeding (attached, for ease of reference as PR-PUB-NLH-011 Attachment 1), "...the capacity constraints were caused by an accumulation of generation issues together with extended severe weather driving high load." See NP-NLH-002 Attachment 1, pages 7 and 8 (as noted, PR-PUB-NLH-011 Attachment 1) to that response for details with respect to the various generating unit forced outages that occurred in the months of January to March 2014 and which led to added costs to serve the customer load during these months. Information on the weather experienced over this period has also been filed as Exhibit 1 in Hydro's report to the Board Regarding Peak Forecast

Exceedances in the 2013/14 Winter Period dated March 2, 2015, attached as PR-PUB-NLH-011 Attachment 2.

Hydro provided its explanation of the reasonableness of the price it paid to CBPP for capacity assistance to help meet the capacity shortfalls during the January to March 2014 period in response to CA-NLH-004 in the CDA Proceeding (attached, for ease of reference as PR-PUB-NLH-011 Attachment 3).

In terms of the timing of when the CBPP capacity assistance was required, see PR-PUB-NLH-011 Attachment 3 (which provides the specific days and hours of the capacity assistance), NP-NLH-005 in the CDA Proceeding (which confirms Hydro did not have sufficient available capacity on the days when the capacity assistance was purchased) (attached as PR-PUB-NLH-011 Attachment 4), and NP-NLH-009 in the CDA Proceeding (which provides specific detail regarding the requirements for capacity assistance on February 4 and March 5, 2014) (attached as PR-PUB-NLH-011 Attachment 5).

Hydro provided details regarding the times and dates that each of the gas turbines and diesel plants were used during January to March 2014 in response to NP-NLH-006 in the CDA Proceeding (attached as PR-PUB-NLH-011 Attachment 6). Hydro also provided details regarding the additional fuel costs Hydro paid to Newfoundland Power for its thermal generation on specific dates during January to March 2014 in response to NP-NLH-007 in the CDA Proceeding (attached as PR-PUB-NLH-011 Attachment 7.

Q. **Reference: Evidence – Application for Deferral and Recovery of 2014 Capacity-Related Supply Costs, Page 1, Lines 2-4.**

Please describe the causes of the capacity constraints in January, February, and March of 2014 and indicate whether or not Hydro believes the capacity constraints could have been prevented.

A. The capacity constraints experienced were very unusual and not predictable. Most of the capacity shortfalls which occurred in and among themselves are not unusual problems to be experienced in the course of a year.

However, the combination of forced outages or forced deratings occurring on several generating units at one time is very unusual and led to the generation capacity shortfalls. The high peak load experienced over the Christmas period, together with the coincident generation issues, led to the requirement for Hydro to take action to obtain capacity assistance from Corner Brook Pulp and Paper and to incur an unusual amount of diesel fuel consumption through the operation of its diesel and gas turbine plants and Newfoundland Power's gas turbine and diesel plants.

Hydro undertook a review of the issues with all the generating facilities to determine action that could be taken in the future to reduce the likelihood of the recurrence of these events. At this point, in hindsight, it is possible to identify mitigation actions. However, based on past experience and the knowledge of the equipment entering into the winter of 2013/2014 Hydro could not have been reasonably expected to have all the mitigating measures in place to prevent the generation shortfalls.

With respect to the capacity constraints, as noted in the first paragraph of this response, the capacity constraints were caused by an accumulation of generation issues together with extended severe weather driving high load. Details with respect to generation unavailability are set out in NP-NLH-002 Attachment 1.[1]

[1] Filed as PUB-NLH-287 in the *Island Interconnected System Supply Issues and Power Outages* proceeding.

Q. Update the response to PUB-NLH-148 to include data for 2014 year to date (July 31). Include in the response an explanation for each forced outage in 2014.

A. Please refer to PUB-NLH-287 Attachment 1 which provides an update of PUB-NLH-148 with 2014 data year to date data (August 31, 2014). It is important to note that comparison of the 2014 year to date data to other years is not meaningful due to the impact of the operating pattern and annual maintenance outage schedules on a number of the performance measures. In particular, any measure which utilizes operating hours and planned outage hours in its calculation will be skewed because there is significant operating time on the generating units in the fall and some planned outage work has not yet been completed.

PUB-NLH-287 Attachment 2 provides the details for all forced outages to the generation contained in this update, up to August 31, 2014. This list includes all outages that resulted in a forced outage to the generating unit.

Please note that the Bay d'Espoir Generating Station figures are impacted by the removal of Unit 6 of the Bay d'Espoir Generating Station from service for an extended period (as shown in PUB-NLH-287 Attachment 2) due to failure and replacement of a rectifying transformer. Hydro has reported separately to the Board on this matter.

Holyrood Thermal Generating Station	2008	2009	2010	2011	2012	2013	2014 YTD
Unit 1							
Gross Unit Rating (MW)	170	170	170	170	170	170	170
Gross Capacity Factor (%)	19.6%	24.2%	22.9%	26.4%	26.0%	11.7%	34.3%
Gross Generation (MWh)	292,915	360,410	340,820	392,490	388,490	173,740	510,470
Gross Unit Efficiency (%)	34.4%	34.8%	34.3%	34.1%	34.4%	34.0%	34.4%
Gross Unit Heat Rate (BTUs/kWh)	9,919	9,805	9,948	10,006	9,919	10,026	9,910
Unit Operating Time (hours)	3,486	4,520	4,420	4,952	4,555	1,985	4,045
Unit Planned Outage Time (hours)	2,622	1,925	1,760	1,808	2,350	1,366	639
Unit Maintenance Outage Time (hours)	77	60	103	10	7	60	177
Unit Forced Outage Time (hours)	1,476	1,670	128	218	221	5,186	231
Number of Planned Outages	3	1	2	4	3	2	2
Number of Maintenance Outages	2	1	2	3	3	1	3
Number of Forced Outages	8	10	3	4	6	5	4
Failure Rate (Forced Outages/Oper. Hours x 8760)	17.64	15.30	-	3.54	7.71	13.24	5.85
Incapability factor (% of time)	49.38	44.23	23.47	23.52	29.85	78.35	22.80
DAFOR (% of time)	32.35	32.52	4.22	4.21	4.73	75.70	12.34
Utilization Forced Outage Probability (% of time)	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Unit 2							
Gross Unit Rating (MW)	170	170	170	170	170	170	170
Capacity factor (%)	36.7%	26.5%	20.6%	24.2%	22.9%	33.2%	30.6%
Gross Generation (MWh)	548,220	394,200	306,590	360,310	342,210	494,710	455,910
Gross Unit Efficiency (%)	35.0%	33.5%	33.6%	33.8%	33.4%	33.2%	33.9%
Gross Unit Heat Rate (BTUs/kWh)	9,749	10,185	10,155	10,095	10,216	10,280	10,080
Unit Operating Time (hours)	4,994	4,922	3,954	4,470	3,906	5,280	3,187
Unit Planned Outage Time (hours)	1,581	2,258	1,079	1,805	1,369	1,140	2,416
Unit Maintenance Outage Time (hours)	238	-	295	23	48	945	11
Unit Forced Outage Time (hours)	175	34	137	119	15	237	6
Number of Planned Outages	2	2	3	4	3	4	4
Number of Maintenance Outages	5	-	5	4	2	6	4
Number of Forced Outages	3	3	5	1	4	8	4
Failure Rate (Forced Outages/Oper. Hours x 8760)	1.76	3.56	11.08	-	9.00	8.34	1.86
Incapability factor (% of time)	23.10	29.04	18.15	24.85	17.03	27.84	41.46
DAFOR (% of time)	3.54	5.50	5.28	3.64	0.77	6.44	0.84
Utilization Forced Outage Probability (% of time)	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Note: 1. The outage information excludes impacts from outside sources that result in the generating unit being restricted or a unit outage. This includes outages caused by transmission equipment or any condition Outside of Plant Management Control.

2. It is important to note that comparison of the 2014 year to date data to other years is not meaningful due to the impact of the operating pattern and annual maintenance outage schedules on a number of the performance measures. In particular, any measure which utilizes operating hours and planned outage hours in its calculation will be skewed because there is significant operating time on the generating units in the fall and some planned outage work has not yet been completed.

Holyrood Thermal Generating Station (cont'd)

Holyrood Thermal Generating Station (cont'd)	2008	2009	2010	2011	2012	2013	2014 YTD
Unit 3							
Gross Unit Rating (MW)	150	150	150	150	150	150	150
Capacity factor (%)	23.6%	19.1%	16.3%	14.9%	14.1%	27.1%	25.4%
Gross Generation (MWh)	310,380	251,130	214,450	196,100	186,180	355,930	333,380
Gross Unit Efficiency (%)	35.3%	34.3%	33.6%	33.6%	32.7%	33.5%	33.4%
Gross Unit Heat Rate (BTUs/kWh)	9,666	9,948	10,155	10,155	10,434	10,179	10,228
Unit Operating Time (hours)	3,082	2,946	2,811	2,443	2,221	3,664	3,484
Synchronous Condensor Time (hours)(1)	4,403	4,117	3,181	4,889	4,361	3	-
Unit Planned Outage Time (hours)	1,899	3,524	3,264	3,847	1,655	4,320	2,015
Unit Maintenance Outage Time (hours)	27	292	2	13	54	36	-
Unit Forced Outage Time (hours)	213	236	20	584	299	13	91
Number of Planned Outages	6	22	5	14	6	6	5
Number of Maintenance Outages	1	1	2	3	3	2	-
Number of Forced Outages	3	3	4	3	4	3	4
Failure Rate (Forced Outages/Oper. Hours x 8760)	5.70	5.95	9.35	7.17	7.91	7.17	3.40
Incapability factor (% of time)	25.61	46.35	39.31	51.60	24.87	55.68	42.66
DAFOR (% of time)	8.80	7.69	6.20	21.80	16.87	12.77	12.47
Utilization Forced Outage Probability (% of time)	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Overall Plant							
Gross Plant Rating (MW)	490	490	490	490	490	490	490
Gross Capacity Factor (%)	26.8%	23.4%	20.1%	22.1%	21.3%	23.9%	30.3%
Gross Generation (MWh)	1,151,515	1,005,740	861,860	948,900	916,880	1,024,380	1,299,760
Station Services (MWh)	71,287	65,875	58,790	63,586	61,054	66,938	82,587
Net Generation (MWh)	1,080,228	939,865	803,070	885,314	855,826	957,442	1,217,173
No. 6 fuel usage (bbls)	1,728,681	1,534,707	1,363,179	1,469,169	1,428,337	1,610,966	2,068,884
Plant Net Fuel Conversion Factor (kWh/bbl)	625	612	589	603	599	594	588
Failure Rate (Forced Outages/Oper. Hours x 8760)	7.60	8.11	6.27	2.95	8.22	8.84	3.87
Incapability factor (% of time)	32.70	39.88	26.98	33.32	26.92	53.96	35.64
Weighted DAFOR (% of time)	15.65	17.38	5.07	7.88	5.98	36.58	9.00
Utilization Forced Outage Probability (% of time)	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Note: 1. The outage information excludes impacts from outside sources that result in the generating unit being restricted or a unit outage. This includes outages caused by transmission equipment or any condition Outside of Plant Management Control.

2. It is important to note that comparison of the 2014 year to date data to other years is not meaningful due to the impact of the operating pattern and annual maintenance outage schedules on a number of the performance measures. In particular, any measure which utilizes operating hours and planned outage hours in its calculation will be skewed because there is significant operating time on the generating units in the fall and some planned outage work has not yet been completed.

3. In 2013 Unit 3 sync condense time was for testing only. The unit was not available for synchronous condensor operation during the late spring and summer due to planned capital work. Avalon voltage support was providedby the capacitor banks at Come by Chance.

Hardwoods Gas Turbine Plant

	2008	2009	2010	2011	2012	2013	2014 YTD
Overall Plant (Hardwoods Gas Turbine)							
Gross Unit Rating (MW)(1)	54	54	50	50	50	50	50
Gross Capacity Factor (%)	0.83%	0.50%	0.71%	0.14%	0.35%	0.39%	1.19%
Gross Generation (MWh)	3,938	2,369	3,089	634	1,534	1,699	5,227
Station Services (MWh)	939	964	1,198	823	873	714	776
Synchronous Condensor Use (MWh)	3,521	3,406	6,336	3,319	4,068	266	3,240
Net Generation (MWh)	(522)	(2,001)	(4,445)	(3,508)	(3,407)	719	1,211
No. 2 fuel usage (gal)(2)	397,039	223,967	289,309	73,044	151,158	140,958	504,593
Unit Gross Fuel Conversion Factor (kWh/gal)	9.9	10.6	10.7	8.7	10.1	12.1	10.4
Operating Time (hours)	206.40	104.13	150.00	38.38	103.30	80.98	301.00
Synchronous Condensor Time (hours)	3,398	3,458	5,943	3,187	3,790	75	4,124
Unit Planned Outage Time (hours)	-	-	953	594	51	-	22
Unit Maintenance Outage Time (hours)	41	211	163	19	-	1,831	6
Unit Forced Outage Time (hours)	8	40	221	28	474	300	264
Number of Planned Outages	5	-	5	4	5	-	2
Number of Maintenance Outages	4	10	8	2	-	3	2
Number of Forced Outages	14	12	7	5	13	4	11
Failure Rate (Forced Outages/Oper. Hours x 8760)	85.11	168.25	-	228.22	255.10	216.34	98.43
Incapability factor (% of time)	8.42	14.45	23.47	7.58	13.42	30.89	11.39
DAFOR (% of time)	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Utilization Forced Outage Probability (% of time)	13.23	16.84	19.34	10.20	35.14	15.94	14.97

Note: 1. The outage information excludes impacts from outside sources that result in the generating unit being restricted or a unit outage. This includes outages caused by transmission equipment or any condition Outside of Plant Management Control.

2. It is important to note that comparison of the 2014 year to date data to other years is not meaningful due to the impact of the operating pattern and annual maintenance outage schedules on a number of the performance measures. In particular, any measure which utilizes operating hours and planned outage hours in its calculation will be skewed because there is significant operating time on the generating units in the fall and some planned outage work has not yet been completed.

3. The gas turbine unit was derated to 50 MW as of January 1, 2010, however it remained as a 54 MW rated MCR unit in Hydro's Generation Equipment Status (GES) database until January 1, 2013.

4. There was fuel consumed at the Hardwoods GT in December 2013 that was not reported until January 2014.

Stephenville Gas Turbine Plant	2008	2009	2010	2011	2012	2013	2014 YTD
Overall Plant (Stephenville Gas Turbine)							
Gross Unit Rating (MW)(1)	54	54	50	50	50	50	50
Gross Capacity Factor (%)	0.05%	0.04%	0.09%	0.04%	0.00%	0.44%	1.37%
Gross Generation (MWh)	223	202	382	173	-	1,908	5,983
Station Services (MWh)	1,525	1,286	1,221	1,083	466	1,285	1,675
Synchronous Condensor Use (MWh)	6,077	4,550	5,105	5,803	-	2,858	4,723
Net Generation (MWh)	(7,379)	(5,634)	(5,944)	(6,713)	(466)	(2,235)	(415)
No. 2 fuel usage (gal)(2)	27,081	21,291	48,665	18,446	-	39,674	508,544
Unit Gross Fuel Conversion Factor (kWh/gal)	8.2	9.5	7.8	9.4	n/a	48.1	11.8
Operating Time (hours)(3)	22.97	9.57	51.45	13.03	-	65.63	327.00
Synchronous Condensor Time (hours)	7,929	6,421	6,433	8,096	-	4,169	5,003
Unit Planned Outage Time (hours)	53	37	262	65	-	295	5
Unit Maintenance Outage Time (hours)	209	163	71	37	-	283	256
Unit Forced Outage Time (hours)	11	220	28	189	8,784	3,663	114
Number of Planned Outages	9	5	8	6	-	1	1
Number of Maintenance Outages	8	7	7	7	-	6	2
Number of Forced Outages	6	6	4	7	-	5	13
Failure Rate (Forced Outages/Oper. Hours x 8760)	-	915.68	-	-	n/a	266.94	144.73
Incapability factor (% of time)	51.72	56.09	49.63	54.76	100.00	54.28	31.73
DAFOR (% of time)	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Utilization Forced Outage Probability (% of time)	9.77	12.70	5.83	16.41	n/a	50.00	11.70

Note: 1. The outage information excludes impacts from outside sources that result in the generating unit being restricted or a unit outage. This includes outages caused by transmission equipment or any condition Outside of Plant Management Control.

2. It is important to note that comparison of the 2014 year to date data to other years is not meaningful due to the impact of the operating pattern and annual maintenance outage schedules on a number of the performance measures. In particular, any measure which utilizes operating hours and planned outage hours in its calculation will be skewed because there is significant operating time on the generating units in the fall and some planned outage work has not yet been completed.

3. The gas turbine unit was derated to 50 MW as of January 1, 2010, however it remained as a 54 MW rated MCR unit in Hydro's Generation Equipment Status (GES) database until January 1, 2013.

4. There was fuel consumed at the Stephenville GT in December 2013 that was not reported until January 2014.

5. The unit was on a forced outage in 2012.

Bay d'Espoir Generating Station

	2008	2009	2010	2011	2012	2013	2014 YTD
Overall Plant (Units 1-7)							
Gross Unit Rating (MW)	613.4	613.4	613.4	613.4	613.4	613.4	613.4
Gross Capacity Factor (%)	53.8%	45.5%	45.8%	52.3%	48.8%	53.5%	49.3%
Gross Generation (MWh)	2,897,002	2,445,773	2,462,069	2,811,437	2,627,702	2,876,419	2,651,040
Station Services (MWh)	6,477	5,171	5,178	5,776	5,203	5,482	5,255
Synchronous Condensor Use (MWh)	49	110	152	148	172	112	199
Net Generation (MWh)	2,890,476	2,440,492	2,456,739	2,805,513	2,622,327	2,870,825	2,645,586
Plant Net Hydraulic Conversion Factor (GWh/MCM)	0.433	0.434	0.436	0.434	0.434	0.432	0.431
Total Unit Operating Time (hours)	39,349	32,749	33,809	39,509	36,641	40,275	26,218
Synchronous Condensor Time (hours) (1)	130	290	399	391	444	296	467
Unit Planned Outage Time (hours)	2,689	2,363	5,042	3,450	4,148	5,741	3,739
Unit Maintenance Outage Time (hours)	59	1,234	797	520	2,064	283	94
Unit Forced Outage Time (hours)	285	72	5	12	379	332	4,383
Number of Planned Outages	15	14	15	8	12	13	4
Number of Maintenance Outages	13	21	22	10	20	11	3
Number of Forced Outages	7	4	2	3	14	9	11
Failure Rate (Forced Outages/Oper. Hours x 8760)	0.45	-	0.26	0.22	0.71	1.08	1.77
Incapability factor (% of time)	4.93	5.98	9.55	6.54	10.72	10.37	19.21
Weighted DAFOR (% of time)	0.60	0.18	0.05	0.08	0.83	0.68	12.44
Utilization Forced Outage Probability (% of time)	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Note: 1. The outage information excludes impacts from outside sources that result in the generating unit being restricted or a unit outage. This includes outages caused by transmission equipment or any condition Outside of Plant Management Control.

2. It is important to note that comparison of the 2014 year to date data to other years is not meaningful due to the impact of the operating pattern and annual maintenance outage schedules on a number of the performance measures. In particular, any measure which utilizes operating hours and planned outage hours in its calculation will be skewed because there is significant operating time on the generating units in the fall and some planned outage work has not yet been completed.

3. Synchronous condenser capability is for Unit 7 only.

Listing of Generating Units Forced Outages for 2014 (up to August 31, 2014)

Unit	Start Date	Finish Date	Comment
Hardwoods GT	2014/01/01 0:01	2014/01/07 19:39	Fuel System Problem
Stephenville GT	2014/01/03 21:32	2014/01/03 21:33	Fuel System Transfer Problem
Stephenville GT	2014/01/04 14:10	2014/01/04 14:28	Vibration Alarm
Stephenville GT	2014/01/04 15:33	2014/01/04 15:56	External Cause - Related to the Sunnyside Event
Bay d'Espoir Unit 5	2014/01/04 15:34	2014/01/04 16:48	External Cause - Related to the Sunnyside Event
Bay d'Espoir Unit 6	2014/01/04 15:34	2014/01/04 16:45	External Cause - Related to the Sunnyside Event
Holyrood Unit 1	2014/01/04 21:34	2014/01/05 21:30	Vibration issues
Holyrood Unit 2	2014/01/04 9:05	2014/01/04 21:34	External Cause - Related to the Sunnyside Event
Stephenville GT	2014/01/04 9:05	2014/01/04 9:57	External Cause - Related to the Sunnyside Event
Holyrood Unit 1	2014/01/04 9:05	2014/01/04 21:34	External Cause - Related to the Sunnyside Event
Holyrood Unit 3	2014/01/04 9:05	2014/01/05 1:40	External Cause - Related to the Sunnyside Event
Stephenville GT	2014/01/05 21:27	2014/01/05 22:31	External Cause - Related to the Sunnyside Event
Holyrood Unit 2	2014/01/05 21:30	2014/01/06 5:30	External Cause - Related to the Sunnyside Event
Holyrood Unit 1	2014/01/05 21:30	2014/01/08 15:38	External Cause - Unit tripped after B1T1 was closed
Holyrood Unit 3	2014/01/05 21:30	2014/01/06 7:15	External Cause - Unit tripped when Holyrood B1T1 was closed
Stephenville GT	2014/01/06 21:48	2014/01/06 22:06	Fuel System Problem
Stephenville GT	2014/01/06 22:10	2014/01/06 23:14	Fuel System Problem
Stephenville GT	2014/01/07 9:33	2014/01/07 11:29	Fuel System Problem
Stephenville GT	2014/01/08 8:25	2014/01/09 13:19	Unit Trip - Engine B failure
Holyrood Unit 2	2014/01/10 18:56	2014/01/11 1:22	No. 1 Compressor motor shorted to ground
Hardwoods GT	2014/01/11 20:59	2014/01/11 21:52	Unit Trip - Cause not recorded
Holyrood Unit 3	2014/01/12 17:35	2014/01/12 18:28	Main feed water isolator would not open trip low drum level
Hardwoods GT	2014/01/12 18:00	2014/01/12 18:58	Unit Trip - Cause not recorded
Holyrood Unit 1	2014/01/13 11:16	2014/01/14 1:03	Air Heater West bearing jacket failure
Holyrood Unit 2	2014/01/16 8:44	2014/01/16 15:50	External Cause - Tripped during testing on unit breaker in terminal station.
Hardwoods GT	2014/01/22 13:26	2014/01/22 13:57	Unit Trip during testing
Hardwoods GT	2014/01/22 14:12	2014/01/22 15:06	Unit Trip during testing
Hardwoods GT	2014/01/22 15:20	2014/01/22 15:52	Unit Trip during testing
Hardwoods GT	2014/01/22 16:02	2014/01/22 16:50	Unit Trip during testing
Holyrood Unit 1	2014/01/27 16:50	2014/01/27 18:49	Burner Management Issue
Bay d'Espoir Unit 6	2014/01/30 5:09	2014/02/01 22:56	Rectifying transformer failure
Holyrood Unit 1	2014/02/01 16:12	2014/02/04 15:21	Steam line to top valves flange gasket blown
Stephenville GT	2014/02/10 16:19	2014/02/10 17:04	High temperature alarm
Stephenville GT	2014/02/11 9:45	2014/02/11 11:53	Alternator belt failure
Bay d'Espoir Unit 6	2014/02/17 4:20	2014/08/05 13:26	Rectifying transformer failure (spare unit)
Stephenville GT	2014/03/06 15:45	2014/03/06 16:18	Fuel Forwarding Pump
Stephenville GT	2014/03/06 6:27	2014/03/06 6:54	Unit Trip - Cause not recorded
Stephenville GT	2014/03/06 9:17	2014/03/06 9:56	Fuel tanks didn't transfer
Stephenville GT	2014/03/10 5:54	2014/03/10 10:09	Unit Trip during testing
Bay d'Espoir Unit 3	2014/03/18 22:03	2014/03/19 1:48	External Cause - Breaker B2T4 failed close on opening. Bus lock out operated
Bay d'Espoir Unit 4	2014/03/18 22:04	2014/03/21 19:16	External Cause - Breaker B2T4 failed close on opening.
Hardwoods GT	2014/03/19 10:22	2014/03/19 10:43	Unit tripped during testing

Note: The External Cause events are not included in the calculation of statistics. They are presented here to show all unit forced outages only.

Unit	Start Date	Finish Date	Comment
Bay d'Espoir Unit 2	2014/03/27 13:40	2014/03/28 12:53	Speed switch problem.
Holyrood Unit 1	2014/04/10 1:20	2014/04/10 3:34	Disconnect B1T1 did not close on all three phases
Bay d'Espoir Unit 2	2014/04/10 9:04	2014/04/10 10:30	External Cause - Shutdown to investigate air leak on B1T2
Bay d'Espoir Unit 4	2014/05/04 9:42	2014/05/04 11:42	T4 deluge system trouble (Deluge activated)
Hardwoods GT	2014/05/05 20:50	2014/05/05 21:52	Tripped on vibration
Bay d'Espoir Unit 7	2014/05/06 20:19	2014/05/10 19:06	Water in Bearing Oil Alarm. Faulty bearing coolers.
Hardwoods GT	2014/05/06 21:34	2014/05/06 23:14	Proximity/Speed switch problem.
Bay d'Espoir Unit 5	2014/05/11 11:33	2014/05/11 17:26	Shutdown to investigate possible Surface Air Cooler leak. Operators noted excessive water accumulation.
Bay d'Espoir Unit 7	2014/05/11 7:58	2014/05/11 11:01	Water in Bearing Oil Alarm/Vibration. Removed residual water from bearing.
Holyrood Unit 1	2014/05/12 2:15	2014/05/12 22:28	Disconnect B1T1 middle & west phases arcing
Stephenville GT	2014/05/16 10:53	2014/05/16 14:44	Glycol Leak
Bay d'Espoir Unit 2	2014/05/16 11:06	2014/05/16 11:45	Pit flood alarm
Bay d'Espoir Unit 5	2014/05/28 4:02	2014/05/28 9:30	Exciter Alarm. Card replaced in Exciter.
Stephenville GT	2014/06/06 14:00	2014/06/09 11:00	Loose Wire in controls, speed sensing error.
Hardwoods GT	2014/06/06 16:15	2014/06/10 13:18	GGA and GGB wouldn't start during test.
Bay d'Espoir Unit 4	2014/06/13 9:32	2014/06/14 15:47	Water in generator bearing oil due a leaking cooler.
Holyrood Unit 1	2014/06/25 17:40	2014/06/30 18:00	Air Heater East top bearing bolts sheared
Hardwoods GT	2014/07/04 18:59	2014/07/04 19:10	Fuel Supply Problems
Holyrood Unit 3	2014/07/08 20:00	2014/07/12 12:47	Fuel Oil Heater East end cover gasket failure, H2 leak
Holyrood Unit 3	2014/07/14 14:50	2014/07/14 16:35	Trip on high fan amps
Bay d'Espoir Unit 2	2014/07/16 7:03	2014/07/16 16:54	External Cause - Shutdown to investigate air leak on B1T2
Holyrood Unit 3	2014/07/28 7:28	2014/07/28 17:47	Switching on station service
Holyrood Unit 3	2014/07/29 9:43	2014/07/29 23:29	Switching in terminal station

Note: The External Cause events are not included in the calculation of statistics. They are presented here to show all unit forced outages only.

Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System

A Report to the Board of Commissioners of Public Utilities Regarding Peak Forecast Exceedances in the 2013/14 Winter Period

Newfoundland and Labrador Hydro

March 2, 2015

newfoundland labrador hydro
a nalcor energy company

TABLE OF CONTENTS

1.0 INTRODUCTION

In its Reply Submission presented to the Board of Commissioners of Public Utilities (the Board) on February 5, 2015 Newfoundland and Labrador Hydro (Hydro/NLH) indicated its agreement with the following recommendations made by Liberty Consulting (Liberty) in their Phase I Report (the Report) dated December 17, 2014:

2.5 By March 1, 2015 provide data relating the actual values of the weather variable on the 2013-14 winter days on which the annual peak forecast was exceeded.

2.6 By March 1, 2015: 1) clarify Hydro's proposed reconstruction of the winter 2013-14 peak; 2) provide a specific value for the reconstructed peak; and 3) report on the impact of the reconstructed peak on the analysis of 2013-14 forecast exceedances.

This is Hydro's submission in relation to these recommendations.

2.0 EXCEEDANCES OF THE ANNUAL PEAK WEATHER FORECAST

Hydro has reviewed its record of daily peak demands for the 2013-14 winter period (December 1, 2013 to March 31, 2014) for both the NLH and Island Interconnected systems. Forecast exceedances for the NLH system were determined on the basis of the winter peak demand forecast of 1,478 MW as reported in Hydro's response to PUB-NLH-011. Forecast exceedances for the Island Interconnected System (IIS) were determined on the basis of NLH's planning load forecast of 1,691 MW.

Table 2.1 below provides the list of winter days on which the peak forecasts were exceeded or would have been exceeded had any of the demand interruptions associated with the capacity assistance arrangements with Corner Brook Pulp and Paper not occurred. Hydro's review confirms there were a total of seven exceedances of the NLH System peak demand forecast and five exceedances of the NLH Island peak demand forecast. The weather conditions reported are consistent with Hydro's weather variable used in its long term planning model and reflect the range of wind chills measured between the hours of 7:30 AM and 8:30 PM on the day of the exceedance.

TABLE 2.1
Peak Demand Forecast Exceedances Winter 2013/14

Date of Exceedance	System	Weather (Cº)
December 14, 2013	NLH	-20.2 to -21.8
January 2, 2014	NLH and Island	-26.6 to -29.3
January 3, 2014	NLH and Island	-25.2 to -28.3
January 4, 2014	NLH and Island	-24.8 to -26.7
February 10, 2014	NLH and Island	-22.0 to -23.9
February 11, 2014	NLH	-22.1 to -23.8
March 5, 2014	NLH and Island	-26.5 to -30.0

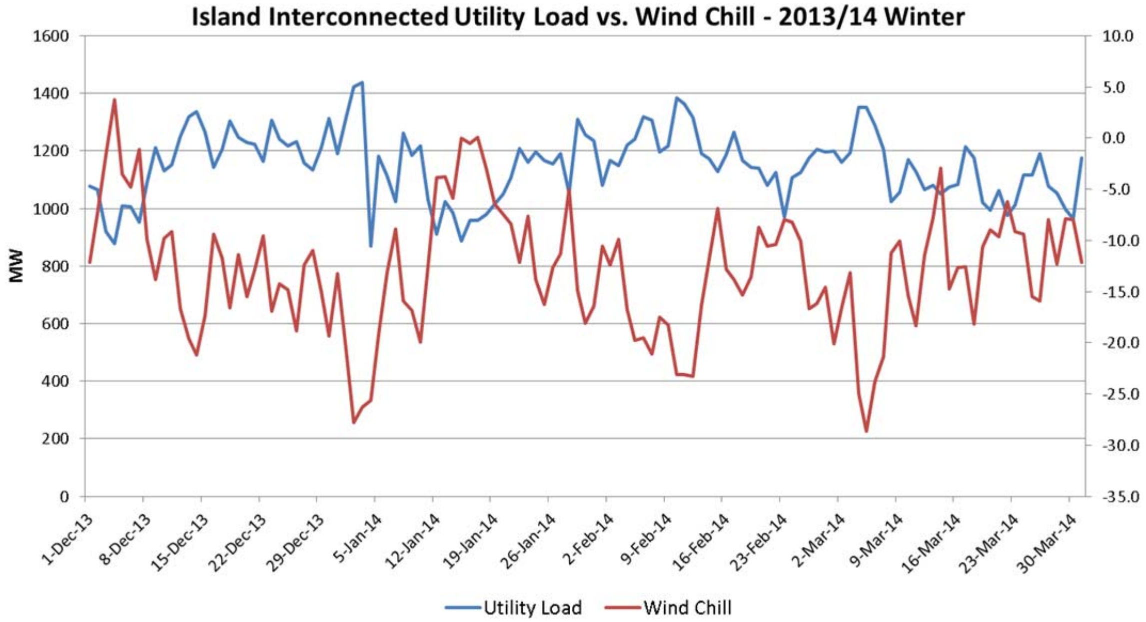
3.0 RECONSTRUCTION OF 2013-14 WINTER PEAK

3.1 Hydro's Reconstruction of the Winter Peak

An estimate of the 2013-14 peak demand on both the Island and NLH systems was provided in Hydro's Report to the Board on Load Forecasting Improvements dated October 31, 2014 (see Section 4.2, Tables 2 and 3). In completing its review at that time, Hydro considered January 2, 2014 for reconstruction based on the following factors:

1. Both the NLH and Island interconnected system winter peaks are a function of prevailing winter weather conditions given the significant penetration of electric heating in the residential and commercial end-use customer base. This is more relevant today than a decade ago as the Island system has much lower industrial load and a higher number of commercial and residential electric heat customers. Exhibit 1 below provides a graphical display of the correlation between Island utility demand requirements and weather conditions during the winter of 2013/14.

Exhibit 1
Island Interconnected Utility Load vs. Wind Chill - 2013/14 Winter



The weighted island wind chill was more severe on January 2, 2014 than at any other time over the January 2-8, 2014 outage period. It would be expected that the maximum system peak occurred on this day assuming industrial load was constant and ignoring abnormal system impacts associated with system transmission losses; cold load pick-up linked to the rotating outages; and customer behavior responses. While weather conditions measured by wind chill for March 5, 2014 were equally as cold, loads on January 2 would have been positively influenced by Christmas season loads pushing load higher than was experienced on March 5, 2014.

2. The Newfoundland Power component of the IIS represents the largest share of system peak load requirements. In estimating this component of the reconstructed system peaks, Hydro used its peak demand forecasting equation for the Newfoundland Power native load. This peak demand model has been reviewed by external consultants[1] and its weather adjustment component has been accepted by the Public Utilities Board for weather adjusting Newfoundland Power's native load for billing purposes. See Appendix A for a description of Hydro's current peak demand model used for input to the weather adjustment procedures for Newfoundland Power's native load.[2]

3. A revised and validated version of the hourly peak demand forecasting model (Nostradamus) was not available in October for the purpose of recreating the hourly loads during the outage period. Hydro therefore relied on other methods for reconstructing the winter peaks.

The reconstructed winter peaks provided by Hydro in October, 2014 reflected estimates of transmission loss that were somewhat lower than those more recently determined by system transmission planning analysis[3]. Based on a review of customer loads and system peaks during the high demand periods during the winter 2013/14 period, and validated by Hydro's recently completed analysis of system losses and transmission line contingencies,

[1] See the reviews completed by Ventyx as part of Hydro's internal review of the January, 2014 power outages and by Manitoba Hydro International as part of the Muskrat Falls review by the Public Utilities Board.
[2] Note that Hydro's peak demand model for Newfoundland Power native load was not used to predict the Newfoundland Power component of the system winter peak demand of 1478 MW provided in PUB-NLH-011.
[3] See Hydro's report "Transmission Losses for Abnormal Generation\Transmission" dated January 2015.

the combined transmission losses and station service loads have been recalculated to be between 88 to 90 MW.

Table 3.1 below provides the reconstructed winter peak for the Island and NLH systems for the winter of 2013/2014 that would have occurred on January 2, 2014. Had no loss of load been experienced on January 2, 2014 Hydro would have experienced an Island peak demand of 1,763 MW.[4]

TABLE 3.1
Customer/System Peak Demand Estimates for January 2, 2014 (Revised)

	Island Interconnected	NLH System
Newfoundland Power	1,411	1,321
Hydro Rural	100	100
Industrial	162	48
Transmission Losses	66	66
Station Service	24	24
System Total	**1,763**	**1,559**

Note: Customer demand estimates are for actual weather conditions during the peak period of 5:00 to 6:00 p.m. on January 2, 2014.

3.2 Assessment of Forecast Exceedances

Appendix B presents a variance analysis of the winter 2013/14 forecast exceedances relative to the NLH system peak demand forecast. The table shown there includes the reconstructed load for the January 2, 2014 peak and the actual loads for the daily system peaks for those days in which utility loads were not artificially impacted by rolling outages. The customer loads and system peaks associated with January 3 and 4, 2014 have not been reconstructed and are therefore not included.

Based on these variances the following observation can be made:

[4] The Island and NLH system peaks previously indicated by Hydro on October 31, 2014 for January 2, 2014 were 1,748 MW and 1,544 MW respectively.

a) Industrial loads at all peak exceedances were lower than had been forecast. The lower loads were associated with lower demand requirements for the nickel refining operations in Long Harbour and lower demand requirements for Corner Brook Pulp and Paper;
b) Hydro's supply to Newfoundland Power at all peak exceedances was higher than had been forecast. The December supply variance was influenced by the lower than assumed Newfoundland Power generation level. The January supply variance was influenced by colder than average weather conditions coinciding with Christmas season loads. The March supply variance was influenced by colder than average weather conditions. The February supply variances were partially influenced by Newfoundland Power generation levels;
c) Total Newfoundland Power load (NLH to Newfoundland Power + Newfoundland Power generation) was modestly higher than forecast on both February 10 and February 11 with weather conditions milder than average historical peak weather conditions;
d) Hydro's rural customer loads were higher than forecast for the peak exceedances occurring in the pre-Christmas and Christmas period and lower than forecast for the February and March system peak exceedances; and
e) Losses and station service requirements at all of the peak exceedances were higher than had been forecast but are in line with Hydro's current system transmission loss analysis and varying station service requirement configurations. The losses and station service requirements on March 5 were lower as a result of high Newfoundland Power generation levels on the Avalon Peninsula.

Based on the preceding analysis Hydro concludes that weather, system losses and customer generation were all contributing factors in explaining the peak exceedances that occurred in the winter of 2013/14. Hydro continues to view the weather as having played a significant contributory role in many of these exceedances.

The weather conditions that drove the Newfoundland Power and Hydro Rural loads during the first week of January were colder than, or close to, average peak weather conditions, but the weather conditions occurred earlier than normally experienced for that time of the year (as indicated in Appendices B and D of the October 2014 Load Forecasting report). The weather condition that existed on March 5 was colder than average and would have driven the Newfoundland Power peak higher than had been forecast. Newfoundland Power's December peak deviation is explained by customer generation, but the weather condition was consistent with historical annual peaks occurring in December, and therefore weather can be viewed as a contributing factor.

The Newfoundland Power loads during the February 10 and 11 peaks were higher than had been forecast despite weather conditions being somewhat milder than average historical peak weather conditions, and therefore weather does not explain these exceedances.

APPENDIX A

NLH Model for Newfoundland Power Winter Peak Demand

Dependent Variable: NPWPEAK
Method: Least Squares
Sample: 1968 2013
Included observations: 46

Variable	Coefficient	Std. Error	t-Statistic	Prob.
NPRDCUST	0.001504	0.0004	3.72	0.001
NPAEDCUST	0.006721	0.0010	6.41	0.000
WIND CHILL ^{2}	0.165798	0.0148	11.17	0.000
AAEHTMPAT(-1)	-18.74086	3.4395	-5.45	0.000
NPTOTGSWA(-1)	0.229576	0.0595	3.86	0.000
TECHCGE90	-7.600414	1.5862	-4.79	0.000
DECPEAK	32.42917	6.9831	4.64	0.000
NST	-10.10592	8.7877	-1.15	0.257

R-squared	0.998	Mean dependent var	873.5
Adjusted R-squared	0.997	S.D. dependent var	329.6
S.E. of regression	17.8	Durbin-Watson stat	1.96
Sum squared resid	12066.3		

Variable Description

NPWPEAK	- Newfoundland Power native winter peak (MW)
NPRDCUST	- Newfoundland Power year end regular domestic customers
NPAEDCUST	- Newfoundland Power year end electric heat domestic customers
WIND CHILL ^{2}	- Weighted Island wind chill (^{o}C Equivalent)
AAEHTMPAT(-1)	- Lagged residential electrcicty price ($/kWh)
NPTOTGSWA(-1)	- Lagged weather normal Newfoundland Power general service sales (GWh))
TECHCGE90	- Technical change trend variable beginning in 1990
DECPEAK	- indicator variable for winter peaks occuring in December
NST	- indicator variable for winter peaks occuring outside supper time period.

APPENDIX B

Variance Analysis of Peak Demand Forecast Exceedances for
Winter 2013/14 – NLH System

Variance Report of Peak Demand Forecast Exceedances for Winter 2013/14 - NLH System

Date of Exceedance		December 14, 2013		January 2, 2014		February 10, 2014		February 11, 2014		March 5, 2014	
Weather Condition [1]		-20.2 °C to -21.8 °C		-26.6 °C to -29.3 °C		-22.0 °C to -23.9 °C		-22.1 °C to -23.8 °C		-26.5 °C to -30.0 °C	
Demand (MW)	Forecast [2]	Actual	Variance	Reconstruction	Variance	Actual	Variance	Actual	Variance	Actual	Variance
NLH Industrial [3]	66	44	(22)	48	(18)	46	(20)	32	(34)	40	(26)
NLH Newfoundland Power	1,255	1,272	17	1,321	66	1,293	38	1,283	27	1,290	34
NLH Rural Customers	89	94	6	100	11	82	(6)	79	(10)	76	(12)
Total Customer Demand	1,410	1,410	0	1,469	59	1,421	11	1,393	(17)	1,406	(4)
Losses and Station Service	68	91	23	90	22	92	24	92	24	80	12
NLH System Peak Demand	1,478	1,501	23	1,559	81	1,513	35	1,486	8	1,486	8
Newfoundland Power Generation at NLH System Peak	85	61	(23)	90	6	69	(15)	79	(5)	109	24

Notes:
1. Weather condition is the range of wind chill between the hours of 7:30 AM to 8:30 PM and expressed in °C equivalent.
2. Forecast is NLH System winter peak forecast reported in PUB-NLH-011.
3. Actual industrial demand for March 5, 2014 was reduced by Corner Brook Pulp and Paper capacity assistance request.

Q. (Re: October 2014 Evidence submitted as part of Application) On page 3 lines 11 to 20, it appears that the cost/kW of CBPP interruptible power for the past winter was about $102/kW. If this calculation is incorrect, please provide the correct calculation, and in either case, provide a comparison of the cost/kW of CBPP interruptible power over the past winter to 1) the annualized cost in $/kW of a combustion turbine, and 2) the cost in $/kW of Newfoundland Power's Curtailable Service.

A. The capacity assistance arrangement with CBPP during the 2013/14 winter season provided a lower fixed payment and a higher variable payment. The variable payment increased with the amount of capacity required based upon the increased impact upon CBPP ability to operate its facility.[1]

Hydro understands that the calculation of the $102/kW was derived by taking the total costs of $6,126,000 and dividing this by 60,000 kW. CBPP was requested to provide up to 60 MW of capacity through load curtailment at the CBPP mill to support the Island Interconnected System for 148 hours during the period January to March, 2014.[2] The ability to obtain capacity from CBPP was critical to system integrity and materially reduced the requirement for customer outages to deal with capacity constraints.

To permit the Board to assess the reasonableness of the price paid to CBPP, Hydro believes it is appropriate to compare the cost incurred to minimize customer

[1] Variable Payment of each four-hour block: 20 MW = $40,000 ($0.50/kWh); 40 MW = $100,000 ($0.625/kWh); and 60 MW = $180,000 ($0.75/kWh).
[2] Hydro also called upon CBPP for capacity assistance for eight hours in December 2013.

outages to the estimated marginal cost forecast for 2014. In response to request CA-NLH-033 filed in Hydro's 2013 GRA, Hydro was requested to provide updated marginal costs based on the methodology outlined in NERA's May 2006 marginal cost study documented in the report entitled *Newfoundland and Labrador Hydro Marginal Costs of Generation and Transmission* and the July 2006 report entitled *Implications of Marginal Cost Results for Class Revenue Allocation and Rate Design.*

Based upon the NERA methodology, the marginal capacity cost on the Island Interconnected System for 2014 was $176 per kW.[3] The $102 average cost per kW incurred by Hydro to minimize customer outages is materially lower than the estimated system marginal capacity cost for 2014.[4]

With respect to the cost of a combustion turbine, the marginal cost estimate for 2014 of $176 per kW is based upon the cost of a combustion turbine giving consideration to forecast system LOLEs for 2014. The cost of $102 per kW incurred by Hydro compares favorably from a least cost perspective to the marginal cost of a combustion turbine.

NP's curtailable load requires customers be provided one hour notice, with limited hours of availability per day and the number of requested hours per winter cannot exceed 100 hours. The CBPP capacity assistance agreement provided for notice of 15 minutes and no limitations on the hours of availability per day or a cap on the hours requested. As a result the cost of the NP curtailable service option is not a valid comparison to the cost of the CBPP capacity assistance agreement.

[3] See Table 2 of response to CA-NLH-033, 2013 Hydro General Rate Application.
[4] The high marginal capacity cost from 2014 to 2017 is directly linked to high LOLEs for the period which was used to demonstrate the requirement for the new combustion turbine at Holyrood.

The cost incurred to obtain 60 MW of capacity from CBPP compared to the system marginal costs combined with the customer benefits obtained through reduced customer outages demonstrates that the negotiation of the agreement with CBPP was consistent with the provision of least cost reliable service.

Q. **Evidence – Application for Deferral and Recovery of 2014 Capacity-Related Supply Costs, Page 2, Table 1.**
Please provide a table that shows which of Hydro's plants were available but not in operation for each time that CBPP was providing capacity assistance.

A. There was one instance when Hydro's plants were available but not in operation when CBPP was providing capacity assistance.

On January 6, 2014, for the capacity assistance request made at 20:00 hours, the St. Anthony Diesel plant (9.7 MW Capacity) and Hawke's Bay Diesel plant (5.0 MW Capacity) were available but not in operation.

Hydro notes that the capacity assistance requested during this period was for 40 MW, i.e., substantially greater than the combined capacity of the St. Anthony and the Hawke's Bay plants. As such, if these plants were operated, the capacity assistance would still have to be requested.

Q. **Evidence – Application for Deferral and Recovery of 2014 Capacity-Related Supply Costs, page 3, Lines 17-19.**

Please describe the specific capacity constraints that led to Hydro having to require capacity assistance from CBPP on February 4 and March 5 of 2014.

A. On February 4, 2014, Hydro had 1,450 MW of available capacity. The following table indicates the capacity that was unavailable.

Unit	Capacity	Status	Deficit
Holyrood Unit #1	170 MW	Unavailable	170 MW
Holyrood Unit #3	150 MW	Derated to 143 MW	7 MW
Stephenville	50 MW	Derated to 25 MW	25 MW
Total			202 MW

The load forecast for the morning of February 4, 2014 was 1,350 MW. At 8:00, the actual system load was at 1,388 MW. This meant the reserves were at 62 MW without the capacity assistance. Based on the limited reserves, it was determined that a request for capacity assistance was required.

On March 5, 2014, Hydro had 1500 MW of available capacity. The following table indicates the capacity that was unavailable.

Unit	Capacity	Status	Deficit
Holyrood Unit #1	170 MW	Derated to 140 MW	30 MW
Bay d'Espoir Unit #6	75 MW	Unavailable	75 MW
Hardwoods	50 MW	Derated to 25MW	25 MW
Stephenville	50 MW	Derated to 25 MW	25 MW
Total			155 MW

The load forecast for the morning of March 5, 2014 was 1,350 MW. However, at 6:00, the actual system load was at 1,404 MW. This meant the reserves were at 96 MW without the capacity assistance. Based on the limited reserves and the anticipated increase in load, it was determined that a request for capacity assistance was required.

For the second request on March 5, 2014 at 9:30, the system load was 1,458 MW at 9:00. The available capacity remained at 1,500 MW. This meant the reserves were at 42 MW without the capacity assistance. Based on the limited reserves, it was determined that a further need for capacity assistance was required.

Q. **Evidence – Application for Deferral and Recovery of 2014 Capacity-Related Supply Costs, Page 2, Table 1.**

Please provide a table that shows the Gas Turbine and Diesels costs for January, February, and March of 2014 including the following details: (i) the plants that were operated, (ii) the costs associated with each plant, and (iii) the times and dates that each plant was in service.

A. The plants that were operated during the period of January to March 2014 are as follows:

Plants that were Operated	
1)	Hardwoods Gas Turbine (HWD GT)
2)	Stephenville Gas Turbine (SVL GT)
3)	Hawke's Bay Diesel Plant (HBY)
4)	St. Anthony Diesel Plant (SDP)
5)	Holyrood - Newfoundland Power Gas Turbine / Diesel[1] (HRD GT)
6)	Newfoundland Power Thermal Generation[2] (NP Standby)

1 Hydro requested Newfoundland Power to install portable generation at Holyrood for Hydro Operations.

2 Newfoundland Power standby generation units, operated at the request of Hydro.

The following table shows the Gas Turbine and Diesel variance costs for each of the months of January, February and March of 2014. The table reflects the NP costs of $549,000 as noted in the response to CA-NHL-007.

Table 1
Gas Turbine and Diesel Variance Costs
January – March (2014)

Generation - Gas Turbines and Diesels (Variance)[1][2][3] ($000s)				
Plant	**January**	**February**	**March**	**Total**
HRD GT[4]	297	31	66	394
HWD GT	271	880	610	1,761
SVL GT	1,199	442	436	2,077
NP Standby	330	81	138	549
SDP	292	105	62	459
HBY	175	71	50	296
Total	2,564	1,610	1,362	5,536

Notes:

1. Includes variance costs of generation from Holyrood, Hardwoods, and Stephenville GTs, St. Anthony and Hawkes Bay diesels, and NP Standby generation at Hydro's request.
2. Variance is against the 2014 Test Year Budget for Gas Turbines and Diesels.
3. Savings due to deferred Holyrood production are not netted out.
4. During the winter of 2014 the NP mobile unit (NP-MGT) was relocated to Holyrood.

The times and dates that each plant was in service is outlined in NP-NLH-006, Attachment 1[1].

[1] For NP Standby at Hydro's request, the dates of the requests are included.

Hardwoods			**Duration**
(yyyy:mm:dd)	**(hh:mm)**	**(hh:mm)**	**(dd:hh:mm)**
2014-01-09	14:51	24:00	00:09:09
2014-01-10	0:00	24:00	01:00:00
2014-01-11	0:00	9:04	00:09:04
2014-01-11	13:17	19:04	00:05:47
2014-01-11	19:35	20:59	00:01:24
2014-01-12	13:47	18:00	00:04:13
2014-01-18	13:48	15:10	00:01:22
2014-01-21	14:20	16:21	00:02:01
2014-01-21	17:14	18:33	00:01:19
2014-01-21	21:21	22:31	00:01:10
2014-01-22	13:57	14:03	00:00:06
2014-01-22	15:06	15:12	00:00:06
2014-01-22	15:52	15:57	00:00:05
2014-01-25	11:47	13:11	00:01:24
2014-01-27	17:40	18:56	00:01:16
2014-01-28	18:04	18:51	00:00:47
Total (Jan):			**02:15:13**
2014-02-01	10:46	11:54	00:01:08
2014-02-04	7:08	10:21	00:03:13
2014-02-05	13:25	14:59	00:01:34
2014-02-06	17:08	21:48	00:04:40
2014-02-07	9:17	10:36	00:01:19
2014-02-07	14:29	15:46	00:01:17
2014-02-08	12:40	13:07	00:00:27
2014-02-08	14:52	14:58	00:00:06
2014-02-08	15:26	15:27	00:00:01
2014-02-08	16:18	16:23	00:00:05
2014-02-08	16:31	16:50	00:00:19
2014-02-09	12:11	14:02	00:01:51
2014-02-10	4:06	24:00	00:19:54
2014-02-11	0:00	24:00	01:00:00
2014-02-12	0:00	24:00	01:00:00
2014-02-13	0:00	24:00	01:00:00
2014-02-14	0:00	8:37	00:08:37
2014-02-15	19:00	20:35	00:01:35
2014-02-16	13:27	16:38	00:03:11
2014-02-17	13:20	13:55	00:00:35
2014-02-17	14:46	16:58	00:02:12
2014-02-18	2:35	13:18	00:10:43
2014-02-28	13:55	14:35	00:00:40
2014-02-28	17:53	18:13	00:00:20
Total (Feb):			**05:15:47**
2014-03-01	9:39	10:44	00:01:05
2014-03-01	11:50	12:47	00:00:57
2014-03-01	13:03	13:07	00:00:04
2014-03-01	16:32	16:42	00:00:10
2014-03-02	12:16	12:22	00:00:06
2014-03-02	14:10	14:36	00:00:26
2014-03-04	5:21	10:44	00:05:23
2014-03-04	11:33	12:10	00:00:37
2014-03-04	15:36	24:00	00:08:24
2014-03-05	0:00	9:02	00:09:02
2014-03-05	9:13	12:01	00:02:48
2014-03-05	13:00	24:00	00:11:00
2014-03-06	0:00	10:35	00:10:35
2014-03-06	15:27	24:00	00:08:33
2014-03-07	0:00	10:39	00:10:39
2014-03-07	15:26	15:31	00:00:05
2014-03-10	4:39	9:53	00:05:14
2014-03-11	6:38	10:14	00:03:36
2014-03-18	6:27	9:24	00:02:57
2014-03-18	16:07	16:19	00:00:12
2014-03-19	5:35	9:06	00:03:31
2014-03-19	10:19	10:33	00:00:14
2014-03-19	10:44	10:48	00:00:04
2014-03-25	13:18	15:51	00:02:33
2014-03-30	14:32	15:21	00:00:49
Total (Mar):			**03:17:04**
Total (3-Month):			**12:00:04**

Stephenville			**Duration**
(yyyy:mm:dd)	**(hh:mm)**	**(hh:mm)**	**(dd:hh:mm)**
2014-01-01	0:00	24:00	01:00:00
2014-01-02	0:00	23:46	00:23:46
2014-01-03	2:32	21:32	00:19:00
2014-01-03	22:03	23:09	00:01:06
2014-01-04	2:14	9:05	00:06:51
2014-01-04	12:46	14:10	00:01:24
2014-01-04	14:53	15:33	00:00:40
2014-01-04	17:40	24:00	00:06:20
2014-01-05	0:00	22:32	00:22:32
2014-01-06	22:08	22:10	00:00:02
2014-01-06	23:15	23:44	00:00:29
2014-01-07	9:26	9:33	00:00:07
2014-01-07	11:29	12:36	00:01:07
2014-01-08	7:35	8:25	00:00:50
2014-01-09	13:19	24:00	00:10:41
2014-01-10	0:00	10:09	00:10:09
2014-01-10	15:46	24:00	00:08:14
2014-01-11	0:00	8:54	00:08:54
2014-01-15	14:18	14:57	00:00:39
2014-01-18	11:27	12:05	00:00:38
2014-01-21	13:54	15:49	00:01:55
2014-01-25	12:26	15:23	00:02:57
2014-01-27	18:16	19:15	00:00:59
2014-01-28	18:24	18:27	00:00:03
2014-01-28	19:12	21:04	00:01:52
2014-01-29	14:08	16:18	00:02:10
Total (Jan):			**06:13:25**
2014-02-01	10:42	13:38	00:02:56
2014-02-04	8:47	11:00	00:02:13
2014-02-05	11:00	11:57	00:00:57
2014-02-06	17:12	22:01	00:04:49
2014-02-07	6:01	10:04	00:04:03
2014-02-09	12:22	13:25	00:01:03
2014-02-10	4:15	16:19	00:12:04
2014-02-10	17:04	21:37	00:04:33
2014-02-11	6:39	9:45	00:03:06
2014-02-11	11:53	24:00	00:12:07
2014-02-12	0:00	24:00	01:00:00
2014-02-13	0:00	9:47	00:09:47
2014-02-15	20:04	21:06	00:01:02
2014-02-18	6:05	9:26	00:03:21
2014-02-24	10:33	12:59	00:02:26
2014-02-24	13:28	15:39	00:02:11
2014-02-24	16:15	16:55	00:00:40
2014-02-24	17:51	18:57	00:01:06
2014-02-25	10:20	11:46	00:01:26
2014-02-28	15:55	17:06	00:01:11
Total (Feb):			**03:23:01**
2014-03-01	10:00	15:38	00:05:38
2014-03-02	15:01	16:16	00:01:15
2014-03-03	15:06	17:09	00:02:03
2014-03-04	6:00	9:27	00:03:27
2014-03-04	11:57	12:39	00:00:42
2014-03-04	15:28	22:59	00:07:31
2014-03-05	5:32	22:45	00:17:13
2014-03-06	6:45	9:17	00:02:32
2014-03-06	9:56	10:24	00:00:28
2014-03-06	15:32	15:45	00:00:13
2014-03-06	16:18	21:43	00:05:25
2014-03-07	5:43	9:04	00:03:21
2014-03-07	16:02	16:05	00:00:03
2014-03-08	15:54	16:58	00:01:04
2014-03-10	10:09	11:18	00:01:09
2014-03-10	15:13	15:14	00:00:01
2014-03-11	7:10	10:09	00:02:59
2014-03-19	5:37	9:03	00:03:26
2014-03-25	9:24	10:41	00:01:17
2014-03-25	15:06	16:24	00:01:18
2014-03-30	16:26	17:56	00:01:30
2014-03-30	20:56	21:06	00:00:10
2014-03-30	21:18	21:19	00:00:01
Total (Mar):			**02:14:46**
Total (3-Month):			**13:03:12**

Hawkes Bay			Duration
(yyyy:mm:dd)	(hh:mm)	(hh:mm)	(dd:hh:mm)
2014-01-01	10:59	13:48	00:02:49
2014-01-01	15:52	22:14	00:06:22
2014-01-02	6:35	24:00	00:17:25
2014-01-03	0:00	23:03	00:23:03
2014-01-04	7:03	9:05	00:02:02
2014-01-04	10:37	15:33	00:04:56
2014-01-04	16:13	23:03	00:06:50
2014-01-05	7:24	21:27	00:14:03
2014-01-06	7:52	13:43	00:05:51
2014-01-06	16:30	18:32	00:02:02
2014-01-08	6:27	14:24	00:07:57
2014-01-08	15:19	20:35	00:05:16
2014-01-10	4:35	9:54	00:05:19
2014-01-10	16:38	22:37	00:05:59
2014-01-18	11:27	11:38	00:00:11
2014-01-21	14:49	15:19	00:00:30
2014-01-23	0:16	1:22	00:01:06
2014-01-23	7:14	20:13	00:12:59
2014-01-25	15:56	16:27	00:00:31
2014-01-28	18:10	18:20	00:00:10
Total (Jan):			**05:05:21**
2014-02-01	10:33	10:48	00:00:15
2014-02-04	7:12	10:10	00:02:58
2014-02-05	11:28	11:39	00:00:11
2014-02-06	16:48	21:00	00:04:12
2014-02-07	6:53	10:21	00:03:28
2014-02-09	13:33	14:06	00:00:33
2014-02-10	3:52	13:28	00:09:36
2014-02-10	16:33	21:41	00:05:08
2014-02-11	5:41	9:24	00:03:43
2014-02-12	4:44	9:36	00:04:52
2014-02-15	19:33	19:57	00:00:24
2014-02-18	6:38	9:50	00:03:12
2014-02-22	6:36	10:05	00:03:29
2014-02-26	12:15	12:26	00:00:11
2014-02-28	13:25	13:44	00:00:19
Total (Feb):			**01:18:31**
2014-03-04	6:04	6:47	00:00:43
2014-03-04	6:50	6:52	00:00:02
2014-03-04	6:54	8:52	00:01:58
2014-03-04	15:29	22:27	00:06:58
2014-03-05	5:21	12:14	00:06:53
2014-03-05	16:15	21:33	00:05:18
2014-03-06	5:33	8:59	00:03:26
2014-03-06	16:42	20:33	00:03:51
2014-03-07	5:46	8:46	00:03:00
2014-03-11	6:56	9:40	00:02:44
2014-03-20	17:26	17:28	00:00:02
2014-03-25	17:39	18:12	00:00:33
2014-03-30	14:31	14:47	00:00:16
Total (Mar):			**01:11:44**
Total (3-Month):			**08:11:36**

St. Anthony			Duration
(yyyy:mm:dd)	(hh:mm)	(hh:mm)	(dd:hh:mm)
2014-01-01	10:45	13:57	00:03:12
2014-01-01	16:03	22:18	00:06:15
2014-01-02	6:18	24:00	00:17:42
2014-01-03	0:00	24:00	01:00:00
2014-01-04	0:00	0:35	00:00:35
2014-01-04	8:01	9:05	00:01:04
2014-01-04	10:49	24:00	00:13:11
2014-01-05	0:00	23:44	00:23:44
2014-01-06	7:44	13:58	00:06:14
2014-01-06	16:26	18:31	00:02:05
2014-01-08	6:37	21:03	00:14:26
2014-01-10	5:03	9:51	00:04:48
2014-01-10	16:38	22:05	00:05:27
2014-01-18	11:12	12:29	00:01:17
2014-01-21	14:03	14:11	00:00:08
2014-01-21	15:16	16:25	00:01:09
2014-01-23	0:25	20:12	00:19:47
2014-01-25	12:12	15:06	00:02:54
2014-01-28	19:11	20:33	00:01:22
Total (Jan):			**06:05:20**
2014-02-01	10:36	11:37	00:01:01
2014-02-04	7:55	10:22	00:02:27
2014-02-05	10:56	11:59	00:01:03
2014-02-06	16:48	21:19	00:04:31
2014-02-07	6:23	10:19	00:03:56
2014-02-07	11:02	11:42	00:00:40
2014-02-07	13:11	13:57	00:00:46
2014-02-07	14:50	15:52	00:01:02
2014-02-07	17:13	17:37	00:00:24
2014-02-09	11:40	13:23	00:01:43
2014-02-10	4:05	14:23	00:10:18
2014-02-10	16:23	22:01	00:05:38
2014-02-11	5:52	9:59	00:04:07
2014-02-12	4:47	9:36	00:04:49
2014-02-15	19:51	21:10	00:01:19
2014-02-18	6:32	9:40	00:03:08
2014-02-22	6:33	10:29	00:03:56
2014-02-26	11:07	11:20	00:00:13
2014-02-28	13:08	14:02	00:00:54
Total (Feb):			**02:03:55**
2014-03-04	5:57	8:57	00:03:00
2014-03-04	15:34	22:32	00:06:58
2014-03-05	5:16	12:13	00:06:57
2014-03-05	15:49	22:06	00:06:17
2014-03-06	5:50	9:14	00:03:24
2014-03-06	16:38	20:35	00:03:57
2014-03-07	4:35	9:02	00:04:27
2014-03-11	6:58	9:37	00:02:39
2014-03-19	5:47	9:06	00:03:19
2014-03-25	10:59	12:35	00:01:36
2014-03-26	14:15	14:40	00:00:25
2014-03-30	14:35	15:29	00:00:54
Total (Mar):			**01:19:53**
Total (3-Month):			**10:05:08**

NP Thermal at Hydro Request
(yyyy:mm:dd)
2014-01-01
2014-01-02
2014-01-03
2014-01-04
2014-01-05
2014-01-06
2014-01-08
2014-01-10
2014-01-19
Total Days Requested (Jan): 9
2014-02-04
2014-02-06
2014-02-10
2014-02-11
2014-02-12
Total Days Requested (Feb): 5
2014-03-04
2014-03-05
2014-03-06
2014-03-07
2014-03-11
2014-03-19
Total Days Requested (Mar): 6
Total (3-Month): 20

Q. **Evidence – Application for Deferral and Recovery of 2014 Capacity-Related Supply Costs, Page 2, Table 1.**

Please complete the following table.

Generation – Gas Turbines and Diesels ($000s)				
Year	**January**	**February**	**March**	**Total**
2014	2,235	2,074	1,224	5,533
2013				
2012				
2011				
2010				
2009				

A. The following table shows the Gas Turbine and Diesel variance costs for each of the months January to March for the years 2009 to 2014. The total variance cost below reflects the NP costs of $549,000 as noted in Hydro's response to CA-NLH-007.

Table 1
Gas Turbine and Diesel Variance Costs
January–March (2009-2014)

Generation - Gas Turbines and Diesels (Cost Variances)[(1)(2)(3)(4)] ($000s)				
Year	**January**	**February**	**March**	**Total**
2014	2,564	1,610	1,362	5,536
2013	593	382	(41)	934
2012	41	6	(22)	25
2011	(5)	(32)	(18)	(55)
2010	11	(25)	189	175
2009	57	(10)	(50)	(3)

Notes:

1. Includes variance costs of generation from Holyrood, Hardwoods, and Stephenville GTs, St. Anthony and Hawkes Bay diesels, and NP Standby generation at Hydro's request.
2. Variances for 2009-2013 are against the 2007 Test Year Budget for Gas Turbines and Diesels.
3. Variances for 2014 are against the 2014 Test Year Budget for Gas Turbines and Diesels.
4. Savings due to deferred Holyrood production are not netted out.