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August 31, 2009

Mr. Naren Pattani
Manager, Transmission Planning
Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
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Dear Mr. Pattani:

Kenora TS Power/Angle Relay
Notification of Conditional Approval of De-registration Request
CAA ID Number: 2009- EX448

The IESO has performed an assessment on the impact to the reliability of the IESO-controlled grid for the Kenora TS Power/Angle relay de-registration request. This assessment concluded that the relay decommissioning will have no material adverse impact on the IESO-controlled grid under the existing and near-term (next couple of years) system conditions. Thus, the IESO is granting approval for the Kenora Power/Angle de-registration, subject to the following:

- Should a decision to protect Ontario system from extreme contingencies be made in the future, Hydro One will need to install a protection on the Ontario-Manitoba tie circuits.
- The L/R feature of the SPS will remain fully functional, as described in the FDD 1027 (R0), after the Power/Angle relay is decommissioned.

Please acknowledge the receipt of this notice and direct any comments or questions to the undersigned.

Yours truly,

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Expedited System Impact Assessment
Hydro One Networks Inc.

1.0 EXECUTIVE SUMMARY

Kenora TS has a Power/Angle relay which is armed to trip loads in the Northwest system following large power swings on circuits K21W/K22W. The relay consist of two measuring elements, one which responds to changes in the tie line power (ΔP) and the second element which responds to changes in the phase (ΔΘ) of the line voltage. The purpose of the ΔΘ element is to supervise the trip circuits of the positive and negative functions of the Kenora ΔP relay, in such a way as to inhibit tripping for power swings as a result of contingencies in Ontario, but still enable the Kenora ΔP circuits to trip for power swings as a result of contingencies west of the Ontario-Manitoba border.

Hydro One has submitted a request for de-registration of the Power/Angle relay at Kenora TS in February 2009. The IESO has performed an assessment of the impact that removal of this SPS would have on the reliability of the IESO controlled grid. The assessment was conducted in two stages:

1. Assessing the need for the Power/Angle relay
2. Assessing whether the L/R function of the relay will be needed to supply the NW load

The assessment concluded the following:

- The Kenora Power/Angle relay is not expected to operate for conditions as required in Manitoba-IESO Operating Instruction MH-IESO-C06-R0. The operation of the relay might occur for some extreme contingencies. The historical records indicated that the relay operated only once in the last five years as a result of the widespread cascading event that took place in Manitoba, Minnesota, and surrounding areas. Thus, it could be concluded that the relay decommissioning will not result in violation of the NW design criteria nor will have material adverse impact on the operation of the NW system. Nevertheless, should a decision to protect Ontario system against extreme contingencies be made in the future, Hydro One will need to install a modern protection that can perform an equivalent function for the Ontario-Manitoba ties.

- Ability to supply load in the NW without a need for an L/R scheme is dependent on the future of coal generation. Based on the load forecast data and the current inflow limits, and assuming that Atikokan GS and Thunder Bay GS will retire by year 2014, about 221 MW of power will be needed to supply load by year 2015. If Atikokan GS and Thunder Bay G2 are converted into biomass units and assuming that there are no reductions to the current inflow limits, present generation and transmission capacities in the NW will be sufficient to supply future loads in the NW without the need for an L/R scheme. It should be noted that this is a transmission total capacity assessment that assessed the capability of the NW transmission system to supply forecasted normal and extreme loads in the NW. Before a decision about the future of the L/R scheme can be made, a complete assessment including a Resource Adequacy Assessment would be required. Also, more clarity about the future of the coal generation in the NW will be needed (i.e. retirement or conversion/replacement).

Note: Hydro One is required to update the related FDD 1027 (R0) following decommissioning of the Kenora Power/Angle relay, to reflect the remaining functional details of the L/R scheme.

Should Hydro One decide to make any changes to the functionality of the L/R scheme including the de-commissioning of the scheme, it would be assessed in a separate SIA. Hydro One will be required to submit an application for such an assessment.

2.0 KENORA TS POWER/ANGLE RELAY ASSESSMENT

2.1 Assessment Criteria

The IESO, as a member of Northeast Power Coordinating Council (NPCC), plans its system in accordance with the NPCC criteria A-2, "Basic Criteria for Design and Operation of the Interconnected Systems". Furthermore, NPCC criteria are applicable to the bulk power system only. The Northwest (NW) part of the IESO system is defined as a local area and thus NPCC criteria are not applicable in this region where only local area contingencies are respected.

As a member of Mid-continent Area Power Pool (MAPP), Manitoba Hydro designs its system in accordance with NERC design criteria. Prior to the establishment of the NERC standards, Ontario and Manitoba agreed to a list of design criteria contingencies applicable to the NW. These contingencies were listed in *Manitoba Hydro – IESO Operating Instruction MH-IESO-C06-R0* and they were considered in this assessment. The list of respected contingencies in the NW is provided below:

(a) Loss of a single element due to a normally cleared permanent LLG or LG fault
(b) Loss of a 230 kV double circuit line (simultaneous phase to ground faults on the same or different phases of each of the double circuit) under High Risk Operating State
(c) Loss of an element without a fault, including a generator, HVDC pole, synchronous condenser, etc
(d) Loss of fully loaded bipolar HVDC line
(e) Single line to ground fault on a dc pole with successful clearing by primary protection and correct operation of applicable supplementary controls
(f) Misoperation of a Special Protection System, including
  - operates when not intended to
  - fails to operate when initiated, unless fully duplicated

Comparing the current design and operating criteria for the NW (MH-IESO-C06-R0) to the NPCC and NERC TPL standards, it can be concluded that although the NW criteria is comparable to the NERC SOL and IROL criteria (FAC-010 and FAC-011), it is less stringent than the NPCC A-2 and TPL-002 to TPL-004 design criteria.

2.2 Kenora Delta Power/Angle Relay Scheme General Description

The Kenora Power/Angle relay was designed to protect Ontario against the Manitoba – USA tie contingencies. In 1974 when the scheme was introduced, there were only 2 ties linking the two systems and Minnesota and Ontario were not interconnected. At present, there are 4 tie lines enabling power transfers between Manitoba and USA. Also, a tie between Ontario and Minnesota was built.

To inhibit the Kenora Power/Angle relay operation following the loss of Manitoba-USA tie circuit(s), a DC reduction scheme is available in Manitoba. Based on discussion with Manitoba Hydro, the DC reduction scheme is fully redundant. The loss of both schemes (A and B) could occur under some extreme conditions only.

Furthermore, if the DC reduction scheme is declared unavailable, Manitoba Hydro has developed operational limits to prevent the operation of the Kenora Power/Angle relay.

The simulations performed for the new Minnesota-Wisconsin 345 kV tie line that was placed in-service in 2008, indicated that some extreme contingencies might cause power swings into Manitoba and Ontario.

The Interconnection Reliability Limits (IROL) were established to prevent operation of the Kenora Power/Angle relay.

Manitoba Hydro also indicated that based on their studies Kenora Power/Angle relay is not expected to operate for the NW design criteria contingencies.

2.3 Historical Information

Historical information regarding Kenora Power/Angle relay operation provided by Hydro One for the 2004-2009 period indicates the following:

1. The relay has tripped at least three times since 2004
2. Two relay operations (January and February 2007) were linked with Whiteshell phase shifters off load tap changer adjustments
3. One relay operation (September 17, 2007) was caused by cascading outages in Manitoba, Minnesota and surrounding areas.

The Kenora Power/Angle relay operations during the off load tap changer adjustments at Whiteshell was not a result of contingency related power swing.

In the last five years, the relay operated only once for the power swings caused by the widespread cascading event that caused multiple outages in Manitoba, Minnesota, and surrounding areas.

November 2004 record indicates Kenora TS L/R scheme was armed as well.

The detailed description of the relay operation events is given in Table 1 of Appendix A.

2.4 Conclusion

As indicated in the current *SCO: NW-Northwest* and based on the discussion with Manitoba Hydro, the Kenora Power/Angle relay is not expected to operate for NW design criteria contingencies (as required in Manitoba-IESO Operating Instruction MH-IESO-C06-R0). The operation of the relay might occur for some extreme contingencies. The historical records indicated that the relay operated only once in the last five years as a result of the widespread cascading event that took place in Manitoba, Minnesota, and surrounding areas. Thus, it could be concluded that the relay decommissioning will not result in violation of the NW design criteria nor will have material adverse impact on the operation of the NW system. Nevertheless, should a decision to protect Ontario system against extreme contingencies be made in the future, Hydro One will need to install a modern protection that can perform an equivalent function for the Ontario-Manitoba ties.

3.0 KENORA TS L/R SCHEME ASSESSMENT

The adequacy of the NW System transmission and generation facilities to supply the NW system load was assessed under summer (April to October) and winter (November to March) conditions. This is a transmission total capacity assessment that assessed the capability of the NW transmission system to supply forecasted normal and extreme loads in the NW. Before a decision about the future of the L/R scheme can be made, a complete assessment including a Resource Adequacy Assessment would be required. Also, more clarity about the future of the coal generation in the NW will be needed (i.e. retirement or conversion/replacement).

3.1 L/R Scheme General Description

Load rejection facilities are available to increase the NW system operating limits for recognized contingencies. Load rejection may be initiated by the Kenora Power/Angle relay or K21W/K22W line protections for the contingencies west of Kenora TS (loss of the Ontario-Manitoba ties, Manitoba DC contingencies, and Manitoba-USA tie contingencies). Loads in the Kenora area, loads west of and including Lakehead TS and the Wawa tertiary reactors can be armed for these contingencies.

3.2 Study Assumptions

The assessment was based on the following assumptions:

- NW System normal and extreme loads were set as per IESO forecast data. Data were available up to year 2014. Year 2015 loading levels were assumed to be the same as for year 2014.
- 2010-2015 generation capacity data were based on the existing and committed facilities.
- Gas and coal generation power output were assumed at 0.9 of installed capacity.
- Since no decision was made about the future of the coal generation in NW (total capacity of 541 MW) at the time this report was written, it was assumed that Atikokan GS will be taken out-of-service in June 2011, Thunder Bay G2 in June 2012 and Thunder Bay G3 will retire by the end of 2014.
- Hydro generation - summer case:
  Drought conditions with hydro generation output assumed to be at 2 percentile bottom (corresponding to about 32% of installed capacity).
  Hydro generation - winter case:
  Hydro generation output assumed to be at 45% of installed capacity based on PI hourly interpolated data for year 2002-2008 period.
  Hydro generation data excludes hydro connected to the distribution system since this is already accounted for in the demand forecast.
- Inflow limits depend on the power transfers over Ontario-Manitoba ties, Ontario-Minnesota tie and East-West ties. The maximum inflow limits were assumed.

3.1 Study Results

Study results for all elements in service and outage conditions under summer and winter conditions are summarized in Table 4 to Table 7 of Appendix B.

The following can be concluded from the study results:

- With all transmission elements in-service, there will be sufficient capacity (local generation + inflow) to supply forecasted load levels under both summer and winter conditions.

- Under outage conditions, with K21W + K22W out-of-service, maximum inflow limit is 300 MW. If Atikokan GS and Thunder Buy G2 generation capacity is not replaced with similar dispatchable generation capacity, the NW will become power deficient under extreme load conditions as of winter 2011.

- About 221 MW of additional generation will be needed to supply extreme winter peak load in NW by year 2015.

3.2 Impact of the Kenora TS L/R Scheme on the SCO: NW-Northwest

Arming of the L/R scheme can be used to expand the E-W-TR-W, O-M-TR-E and MPFN limits. The operating limits are provided for arming up to 200 MW of load rejection at any one time.

3.3 Historical Information

The L/R scheme was armed once in November 2004.

3.4 Conclusion

Ability to supply load in the NW without a need for an L/R scheme is dependent on the future of coal generation. Based on the load forecast data and the current inflow limits, and assuming that Atikokan GS and Thunder Bay GS will retire by year 2014, about 221 MW of power will be needed to supply load by year 2015. If Atikokan GS and Thunder Bay G2 are converted into biomass units and assuming that there are no reductions to current inflow limits, present generation and transmission capacities in the NW will be sufficient to supply future loads in the NW without the need for an L/R scheme.
It should be noted that this is a transmission total capacity assessment that assessed the capability of the NW transmission system to supply forecasted normal and extreme loads in the NW. Before a decision about the future of the L/R scheme could be made, a complete assessment including a Resource Adequacy Assessment would be required. Also, more clarity about the future of the coal generation in the NW will be needed (i.e. retirement or conversion/replacement).

Note: Hydro One is required to update the related FDD 1027 (R0) following decommissioning of the Kenora Power/Angle relay, to reflect the remaining functional details of the L/R scheme.

Should Hydro One decide to make any changes to the functionality of the L/R scheme including the de-commissioning of the scheme, it would be assessed in a separate SIA. Hydro One will be required to submit an application for such an assessment.

Appendix A: Kenora Power/Angle Operation Historical Records

January, 27 2007	Kenora K22W Terminal (230 KV) was automatically removed from service from power angle relay protection during a Manitoba Hydro/IESO tap change at Whiteshell on Circuit K21W. Circuit K22W was out of service for a planned outage. **IESO Report:** None
February, 25 2007	Circuit K22W tripped from power angle relay operation after the circuit was off loaded at Whiteshell to allow off load tap changer operation. The flow on circuit K22W was slightly over 100MW into Ontario at the time and the power relays setting was set to 100MW. **IESO Report:** None
September 17, 2007	**IESO Report:** K21W 230 kV and F3M 115 kV circuits were automatically removed from service from Kenora Delta Power cross trip relaying on the Manitoba tie and out of step relaying on the Minnesota tie. With K22W already out of service planned these trips constituted a separation from the MISO area. According to PI data, flow into Ontario from Manitoba went from 30 N to 120 N over a five minute period before the trip and F3M went from zero to 100 N over the same time period. MISO reported that two electrical islands had formed in their system. The larger island consisted of the Manitoba, Minnesota, North Dakota and part of South Dakota areas. Saskatchewan was in its own island. The generation loss was reported to be 800 MW in Saskatchewan. Saskatchewan also reported a 50% load loss. The islands formed as a result of the sequential loss of three 345 kV circuits (reported to be approximately one minute apart) due to electrical storm activity, combined with ongoing planned outages to 4 transmission circuits, which resulted in the cascading trip of one additional 345 kV circuit and two 230 kV circuits.

Appendix B: Study Results

Table 2: Installed Generation Capacity in NW

	ABKENORA	AGUASABON	ALEXANDER	CAMERONFALLS	PINEPORTAGE	CARIBOUFALLS	EARFALLS	MANITOUFALLS	KAKABEKA	SILVERFALLS	CALMLAKE	STURGEONFALL	VALRIEFALLS	UMBATA	WAWATAY	WHITEDOG	LAC SEUL	FORTFRANCSWC	TCNIPIGON	ATIKOKAN	THUNDERBAY
CAPACITY (MW)	15	47	69	79	132	86	16	67	24	48	6	9	10	24	13.5	69	13	114	38	211	330
TOTAL HYDRO (MW)																	727				
TOTAL GAS (MW)																			152		
TOTAL COAL (MW)																					541
TOTAL (MW)																					1420

Table 3: Inflow Limits

	ELEMENT(S) O/S	OMTE	EWTW	MPFN	INFLOW
Tab 1	ALL I/S	195	350	25	570
Tab 2	K21W or K22W	195	350	25	570
Tab 3	K21W + K22W	***0***	***300***	***0***	***300***
Tab 4	K7K and/or Kenora T1/Kenora P Bus	195	350	25	570
Tab 5	K24F/Fort Frances K Bus	195	350	25	570
Tab 5a	K23D	195	350	25	570
Tab 6	D26A/Mackenzie H Bus or Mackenzie Breaker HL 93	300	215	25	540
Tab 6a	F25A/ Fort Frances A Bus or Mackenzie Breaker PL 25	300	215	25	540
Tab 7	A3M and/or Mackenzie T3/Mackenzie P Bus	195	350	25	570
Tab 8	M2D, K3D or K6F	195	350	25	570
Tab 9	M23L/Marathon A Bus or M24L	195	350	25	570
Tab 10	A21L or A22L	215	300	25	540
Tab 11	F3M/Minnesota 126L	*70*	*350*	*0*	*420*
Tab 12	W21M/Marathon H Bus or W22M/Wawa A Bus	185	250	25	460
Tab 13	A23P/Mississagi L23Bus or A24P/Mississagi L24 Bus	195	350	25	570
Tab 14	Mississagi Breaker L26L74 or KL74	195	350	25	570
Tab 15	X74P	195	350	25	570
Tab 16	X27A/Algoma K Bus or S22A	195	350	25	570
Tab 17	D602F, Y51L, L20D, DRxPR, R49R, G82R, R50M, M50L, 907 or 96L	195	350	25	570
Tab 18	Dorsey Relay	195	350	25	570
Tab 19	P25W or P26W/Wawa H Bus or P26W + Mississagi L26L74	185	250	25	460
Tab 20	W23K/Wawa L23 Bus	195	350	25	570
Tab 21	K24G	195	350	25	570
Tab 22	Wawa Breaker L21L25 or L23L25 or AL23 or AH	195	350	25	570

Table 4: Supply versus Demand Analysis - Summer Conditions

All Elements In-service							
Year		2010	2011	2012	2013	2014	2015
Hydro Generation Output (MW)		228	230	230	231	243	252
Gas Generation Output (MW)		137	137	137	137	137	137
Coal Generation Output (MW)		487	297	149	149	149	0
Inflow Limit (MW)		570	570	570	570	570	570
Total Power Available (MW)		1422	1234	1085	1086	1098	959
Peak Load (MW)	Normal	654	924	878	880	836	836
	Extreme	690	947	900	902	857	857
Power Surplus (MW)	Normal	768	310	207	207	262	123
	Extreme	731	287	185	184	241	102
Comments: Unavailable Units			Atikokan	Atikokan, TB G2	Atikokan, TB G2	Atikokan, TB G2	Atikokan, TB G2&G3

Table 5: Supply versus Demand Analysis - Summer Conditions

Outage Conditions							
Year		2010	2011	2012	2013	2014	2015
Hydro Generation Output (MW)		228	230	230	231	243	252
Gas Generation Output (MW)		137	137	137	137	137	137
Coal Generation Output (MW)		487	297	149	149	149	0
Inflow Limit (MW)*		300	300	300	300	300	300
Total Power Available (MW)		1152	964	815	816	828	689
Peak Load (MW)	Normal	654	924	878	880	836	836
	Extreme	690	947	900	902	857	857
Power Surplus (MW)	Normal	498	40	**-63**	**-63**	**-8**	**-147**
	Extreme	461	17	**-85**	**-86**	**-29**	**-168**
Unavailable Units			Atikokan	Atikokan , TB G2	Atikokan, TB G2	Atikokan, TB G2	Atikokan, TB G2&G3

** Tab 3: K21W + K22W O/S*

Table 6: Supply versus Demand Analysis - Winter Conditions

All Elements In-service							
Year		2010	2011	2012	2013	2014	2015
Hydro Generation Output (MW)		338	338	338	338	338	338
Gas Generation Output (MW)		137	137	137	137	137	137
Coal Generation Output (MW)		487	297	149	149	149	0
Inflow Limit (MW)		570	570	570	570	570	570
Total Power Available (MW)		1532	1342	1193	1193	1193	1045
Peak Load (MW)	Normal	766	1014	982	956	933	933
	Extreme	818	1083	1049	1021	996	996
Power Surplus (MW)	Normal	766	328	211	237	261	112
	Extreme	714	258	144	172	197	49
Unavailable Units			Atikokan	Atikokan , TB G2	Atikokan, TB G2	Atikokan, TB G2	Atikokan, TB G2&G3

Table 7: Supply versus Demand Analysis - Winter Conditions

Outage Conditions							
Year		2010	2011	2012	2013	2014	2015
Hydro Generation Output (MW)		338	338	338	338	338	338
Gas Generation Output (MW)		137	137	137	137	137	137
Coal Generation Output (MW)		487	297	149	149	149	0
Inflow Limit (MW)*		300	300	300	300	300	300
Total Power Available (MW)		1262	1072	923	923	923	775
Peak Load (MW)	Normal	766	1014	982	956	933	933
	Extreme	818	1083	1049	1021	996	996
Power Surplus (MW)	Normal	496	58	**-59**	**-33**	**-9**	**-158**
	Extreme	444	**-12**	**-126**	**-98**	**-73**	**-221**
Unavailable Units			Atikokan	Atikokan , TB G2	Atikokan, TB G2	Atikokan, TB G2	Atikokan, TB G2&G3

** Tab 3: K21W + K22W O/S*