IMO Independent Electricity Market Operator

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CONNECTION ASSESSMENT & APPROVAL PROCESS

Preliminary Assessment Report For Thunder Bay Hydro

CAA ID 2001-042

Final Report

Long Term Forecasts & Assessments Department
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Preliminary Assessment Report

Thunder Bay Hydro – Bowater Saw Mill Load

Acknowledgement

The IMO wished to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimers

IMO

This report has been prepared solely for the purpose of assessing, on a preliminary basis, whether the connection applicant's proposed connection with the IMO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether a System Impact Assessment of the proposed connection should be conducted under Chapter 4, section 6 of the *Market Rules*. This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant, Hydro One and the IMO in accordance with Chapter 4, section 6 of the *Market Rules*. The IMO assumes no responsibility to any third party for any use which it makes of this report. Any liability which the IMO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the *Market Rules*. In the event that the IMO provides a draft of this report to the connection applicant, you must be aware that the IMO may revise drafts of this report at any time in its sole discretion without notice to you. Although the IMO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that it is using the most recent version of this report.

Hydro One

The results reported in this preliminary feasibility study are based on the information available to Hydro One Networks Inc., at the time of the study, suitable for a preliminary assessment of a new generation or load connection proposal.

The short circuit and thermal loading levels have been computed based on the information provided by the connection proponent at the time of the study. These levels may be higher or lower if the connection information changes as a result of, but not limited to, subsequent design modifications or when more accurate test measurement data is available.

This study does not assess the short circuit or thermal loading impact of the proposed connection on facilities owned by other load and generation (including OPGI) customers.

In this preliminary feasibility study, short circuit adequacy is assessed only for Hydro One Networks Inc. breakers and does not include other Hydro One Networks Inc. facilities. The short circuit results are only for the purpose of assessing the capabilities of existing Hydro One Networks Inc. breakers and identifying upgrades required to incorporate the proposed connection. These results should not be used in the design and engineering of new facilities for the proposed connection. The necessary data will be provided by Hydro One Networks Inc. and discussed with the connection proponent upon request.

The ampacity rating of Hydro One Networks Inc. facilities are established based on assumptions used in Hydro One Networks Inc. for power system planning studies. The actual ampacity ratings during operations may be determined in real-time and are based on actual system conditions, including ambient temperature, wind speed and facility loading, and may be higher or lower than those stated in this study.

The additional facilities or upgrades which are required to incorporate the proposed connection have been identified to the extent permitted by a preliminary assessment. Additional facility studies may be necessary to confirm constructability and the time required for construction. System impact or further studies at more advanced stages of the project development may identify additional facilities that need to be provided or that require upgrading.

Executive Summary

This assessment examined the effect of the proposed Thunder Bay Hydro load increase of 12 MW on the reliability of the IMO controlled grid. This project was subject to an expedited Connection Assessment process and it is not required to undergo a System Impact Assessment.

Proposed Project

Thunder Bay Hydro has started the work on a new service connection to their distribution system to supply a new Bowater sawmill operation. The new load is proposed to be supplied from Fort William TS, which is connected to Q4B and Q5B 115 kV circuits between Thunder Bay GS and Birch TS. The total new development would amount to an initial load increase of 4 MW and an ultimate load of approximately 12 MW by October 2002.

Conclusions and Recommendations

This Preliminary Assessment concluded the following:

1. The power transfer capability of Fort William TS is adequate to support the addition of the 12 MW Bowater sawmill load. The load connectivity arrangement must meet the requirements of the Distribution System Code.

2. No additional facilities are required to satisfy the obligations that are established by the *Market Rules* with respect to underfrequency load shedding requirements.

3. The additional Bowater sawmill load does not have an effect on the system short circuit levels at Fort William TS and other surrounding transformer stations.

4. The study results indicate that the addition of the new load at Fort William TS does not have a significant impact on the voltages in the Thunder Bay area.

5. The study results show that with all Thunder Bay GS units in service the peak load in the area can be supplied reliably.

6. The results also indicate that with one generating unit out of service the peak load in the area could be supplied reliably, provided that all the shunt capacitors in the area are switched on. However, some of the voltage sensitive loads may be tripped for the loss of the one Thunder Bay generating unit that is in service.

The study results indicated that the IMO controlled grid in the Thunder Bay area is approaching its limit of reliability, and it is possible that any future increase in area peak load could not be accommodated. In addition the opening of the electricity market in May 2002 can create situations when the local generation is not available jeopardizing the secure supply of the area load. <u>It is thus recommended that options for reinforcing the area transmission be pursued to satisfy the requirements for reliable supply of area load.</u>

The incorporation of the 12 MW load at Fort William does not require installation of additional network facilities. However, it is required that the new low voltage capacitor that Hydro One plans to install at Fort William TS be in service before the new load is connected.

It is recommended that approval be granted and Notification of Approval be issued.

Preliminary Assessment Report

1.0 Project Description

Thunder Bay Hydro has started the work on a new service connection to their distribution system to supply a new Bowater sawmill operation. The new load is proposed to be supplied from Fort William TS, which is connected to Q4B and Q5B 115 kV circuits. The total new development would amount to an initial load increase of 4 MW and an ultimate load of approximately 12 MW by October 2002.

A diagram of the Thunder Bay area and the location of the new load are shown in Figure 1.

This project was subject to an expedited CAA process, whereby an extended Preliminary Assessment was performed to address all the related concerns and an System Impact Assessment was not required.

2.0 Assessment Scope

The scope of this assessment was mainly to investigate the impact of the additional 12 MW imbedded load on the load meeting capability of the existing facilities. It should be noted that Thunder Bay Hydro has indicated, in their Connection Assessment application, that the new load requires a highly reliable service, hence careful consideration was given to the question of whether of not with the additional load the existing level of reliability of supply would be maintained.

Secondly, this assessment examined the capability of the generation and transmission facilities in the Thunder Bay area to securely supply the peak load.

3.0 Review of Station Capability and Connectivity Arrangement

The new Bowater proposed load in the Thunder Bay Hydro distribution system will be supplied via the existing 24.9 kV feeders 10M6 and 10M5, and the supply of the new load does not require any modifications to the configuration of Fort William TS.

Fort William TS is a DESN station connected to the double circuit 115 kV line Q4B and Q5B. The station is equipped with two 115/24.9 kV transformers each with a continuous rating of 83.3 MVA for continuous operation, and a 10 day Limited Time Rating of 103 MVA.

Historical records show that the maximum loading at Fort William TS was around 74 MW, hence the existing station capability of 103 MVA is sufficient to supply the existing and the additional Bowater load of 12 MW.

The sawmill connectivity arrangement to the Thunder Bay distribution system must meet the requirements of the Distribution System Code.

It can be concluded that:

The power transfer capability of Fort William TS is adequate to support the addition of the 12 MW Bowater sawmill load and the load connectivity arrangement must meet the requirements of the Distribution System Code.

4.0 Underfrequency Load Shedding Requirements

The *Market Rules* (Chapter 5 section 10.4) require that each distributor and connected wholesale customer, in conjunction with the relevant transmitter, make arrangements to enable the automatic disconnection of under-frequency demand of up to 35% of its peak demand. The underfrequency load shedding scheme is required to trip 12% of the station load at 59.3 Hz and an additional 23% at 58.8 Hz.

An automatic underfrequecy load shedding scheme which trips the station Q bus at 59.3 Hz is provided at Fort William TS. No additional relaying is required to meet the *Market Rules* requirements.

No additional facilities are required to satisfy the obligations that are established by the *Market Rules* with respect to underfrequency load shedding requirements.

5.0 Fault Level Assessment

The short circuit assessment was performed by Hydro One.

The LV breakers at Fort William TS have a symmetrical short circuit interrupting capability of 1500 MVA. Results of the short circuit studies indicated that the three phase fault and line-to-ground fault levels at Fort William TS are well under the interrupting capability of the station breakers.
The additional Bowater sawmill load does not have an effect on the system short circuit levels at Fort William TS and other surrounding transformer stations.

The additional Bowater sawmill load does not have an effect on the system short circuit levels at Fort William TS and other surrounding transformer stations.

Birch TS is equipped with HV circuit breakers that have short circuit symmetrical current ratings of 50 kA. The short circuit level at Birch TS, for a three phase fault at maximum system conditions, is 3909 MVA (computed based on short circuit current of 19.12 kA at a voltage of 118.05 kV), which is well under the rating of the breakers.

The proposed new load is composed of small motors and has minimal contribution to short circuit levels.

6.0 Impact on System Reliability

The studies carried out for this project focussed on two particular issues related to the Thunder Bay area.

Firstly, an investigation was performed to assess the impact of the additional 12 MW load on the reliability of the surrounding 115 kV system. The results of this investigation are described in the subsections below.

Secondly, an assessment was carried out of the adequacy of the 115 kV transmission system and local generation to provide reliable supply to the load in the area. The results of this assessment are included in section titled “Discussion”.

6.1 Description of Thunder Bay Area Transmission

The new Bowater sawmill plant will be connected to one of the feeders emanating from Fort William TS. Fort William TS is supplied from two of the 115 kV circuits connecting Thunder Bay GS to Birch TS, namely Q4B and Q5B.

The power supply to Thunder Bay area loads is shown in Figure 1 and is provided by the following facilities:

- Thunder Bay GS comprising of one synchronous condenser unit rated at 111 MVA (C1), two generating units rated at 192 MVA (G2, G3). The maximum power output of the generating units is about 165 MW,
- Four 115 kV circuits connecting Thunder Bay GS to Birch TS; Q4B from C1 to Birch TS, Q5B and Q8B from G2 to Birch TS and Q9B connecting G3 to Birch TS,
- Four 115 kV circuits connecting Lakehead 115 kV yard to Port Arthur TS#1 (L4P), Port Arthur TS#2 (L3P) and Birch TS (R1LB, R2LB),
- Two 115 kV circuits between Birch TS and Port Arthur TS#1 (P7B) and Port Arthur TS#2 (P3B).

The main connection of this 115 kV power system area to the 230 kV system is provided by the 115/230 kV Lakehead transformer station.

In addition to the facilities shown in Figure 1 a number of voltage support devices are connected to the transmission system in this area, and were modeled in the studies as follows:

- At Birch TS – two shunt capacitors each rated 15 Mvar connected to the 25 kV bus,
- At Fort William TS – two shunt capacitors connected to the 25 kV bus, rated 12.3 Mvar (SC1) and 15.9 Mvar (SC2) respectively.
- Lakehead TS – one 115 kV shunt capacitor rated at 85 Mvar, and two synchronous condensers connected to the 13.8 kV rated tertiary of the 115/230 kV transformers at Lakehead TS and rated 48 Mvar (C7) and 60 Mvar (C8), respectively.

Hydro One has informed the IMO that the existing shunt capacitor SC2 at Fort William TS which is connected to M9 feeder will be replaced with a larger unit rated 24.5 Mvar at 31 kV (which is the equivalent of 15.9 Mvar at 25 kV). The new capacitor will be connected to the station’s J bus.

It was assumed in the studies that the new capacitor would be in service before the proposed imbedded load is connected.

In most of the study scenarios, the maximum reactive support in the area was switched on in order to ensure adequate pre-contingency voltages.

6.2 Study Assumptions and Criteria

Loads

The study was performed for a system with all elements in service under summer peak load conditions. The MW, MVAR loads used in the study, and shown in Table 1, were calculated under the assumption that all the customers connected to the Thunder Bay area transmission meet the *Market Rules* requirement of operating at a power factor within the range 0.9 lagging to 0.9 leading. Likely, the overall peak load reactive power consumption in this area is less than that assumed in the study but this assumption corresponds to the maximum reactive power consumption allowed for loads under the *Market Rules*. It was selected because it maximizes the system VAR requirements, thus yielding stressed results.

Table 1. Station Loads

Load Name	Summer Peak Loads		Point of Connection
	MW	Mvar	
Abitibi Price	50	20	Q5B
Sterling Pulp Chemical	40	16	Q5B
Bowater Canada TMP (Q4B)	120	48	Q4B
Bowater Canada Kraft Mill & Bowater Canada (Q5B)	80	32	Q5B
Fort William TS	74	30	Q4/5B
Birch TS	88	35	-
Port Arthur DS	42	17	Port Arthur TS #1 and #2
Thunder Bay Packaging	15	6	Port Arthur TS#2
Provincial Papers	36.5	15	Port Arthur TS#2
Lac Des Iles	37	15	P5M

The total 115 kV Lakehead area load was assumed to be around 700 MW.

In the analysis, the loads in the Thunder Bay area were modeled as variable real and reactive power. The model assumed that half of the real power was proportional to the square of the voltage and the other half to the voltage. The reactive power load is proportional to the square of the voltage.

Generation

The generation dispatch that was selected in the studies is listed in Table 2 below.

Table 2. Generation Dispatch

Generating Station	Output MW
Alexander GS	59.5
Pine Portage GS	56.2,
Cameron Falls GS	58.2
TCPL-Nippigon	38
Kakabeka GS	24.2
Silver Falls GS	46.5

Because the Thunder Bay generation is the main power supplier in the area, the study concentrated on the impact that various Thunder Bay GS dispatch scenarios have on the system's ability to supply the peak load.

Study Criteria

The study criteria were based on the present system operating requirements, and principles used in system planning.

The operating instructions followed by the IMO and developed in order to securely supply the Thunder Bay area loads require that the Fort William TS, Birch TS and Port Arthur TS voltages, under normal conditions, be maintained between 120 to 125 kV. This voltage level is required because the paper mill loads connected to the QxB circuits require a minimum voltage of 118 kV for operation.

The IMO-controlled grid is planned and operated such that with all elements in service a single contingency shall not result in load loss except were the load is directly connected to the faulted element or as a result of operation of a load rejection scheme.

With one element out of service, a single contingency may result in load loss by configuration or operation of the load rejection scheme.

Study Scenarios

Five study scenarios were selected for this assessment as follows:

Scenario A: All Thunder Bay generation and synchronous condenser in service.
Scenario B: Thunder Bay G3 out of service.
Scenario C: Thunder Bay G2 out of service.
Scenario D: Thunder Bay G2 and G3 out of service.
Scenario E: Thunder Bay C1 and G2 out of service.

The assessment of the impact of the new connected load on the area voltages was performed assuming the most critical contingency for each scenario representation.

6.3 Study Results

The results of the load flow investigations performed for peak load conditions are summarized in tables 3A to 3E. The tables contains a description of the Thunder Bay GS dispatch, critical studied contingencies, the status of the reactive support devices in the area, and the voltages that were registered at the monitored buses.

Scenario A

For this scenario Thunder Bay units were assumed to be all in service with the following output: C1 at 60.5 Mvar, G2 at 165 MW, 80 Mvar, G3 at 156 MW, 47 Mvar. The post-contingency load flow analysis was performed for the loss of Thunder Bay G2.

Table 3A. Study Results for Scenario A:

Condition	**Thunder Bay Voltage (kV)**		**Birch TS**		**Fort William TS**			**Lakehead**		
No New Load	A Bus	D Bus	kV	MX	Q4B 115 kV	Q5B 115 kV	MX	115 kV	Cap MX	C7 C8
Pre-fault	121.2	120.9	121.2	14.1	120.4	120.4	14.2	123.9	106.5	-24 -30
Post loss of Thunder Bay G2	119.3	116.7	118.6	13.5	118	117.2	13.5	123.8	104.1	-7 -8
					LT Voltage = 26.1 kV					
% kV	**1.6%**	**3.5%**	**2.2%**	**-**	**2%**	**2.7%**	**-**	**0%**	**-**	**-**
With New Load	A Bus	D Bus	kV	MX	Q4B 115 kV	Q5B 115 kV	MX	115 kV	Cap MX	C7 C8
Pre-fault	120.7	120.4	120.7	14.	119.6	119.6	13.7	123.5	105.7	-24 -30
Post loss of Thunder Bay G2	118.8	116.0	118.	13.4	117.2	116.4	13.1	122.1	103.3	-6 -12
					LT Voltage = 25.7 kV					
% kV	**1.6%**	**3.6%**	**2.2%**	**-**	**2%**	**2.7%**	**-**	**1.1%**	**-**	**-**

The results of the load flow studies indicate that with all elements in service and Thunder Bay units in service, **without the new embedded load**, the pre-contingency voltages are above 120 kV.

The immediate post contingency voltage decline at Fort William meets the 10% voltage decline criteria, but the actual voltage at the 115 kV Q5B tap is under 118 kV. If some of the other loads connected to Q4B and Q5B require, for continuous operation, a firm minimum voltage of 118 kV then, for this load level, more shunt capacitors may be required to be switched on in the pre fault.

It should be noted, that the studies results show that the post contingency voltage on the LV side of the Fort William 115/24.9 kV transformers is 26.1 kV which is considered to be adequate for continued operation of the connected equipment.

The Thunder Bay synchronous condenser generated 75 Mvar immediately following the loss of G3.

With the new 12 MW load incorporated at Fort William TS, the pre-contingency voltages in the area are lower by about .5 kV and under 120 kV. Consequently, the second LV capacitor at Fort William TS would have to be switched on in pre contingency.

The post contingency voltage decline is within the adopted criteria of 10% voltage decline, and the actual post contingency voltages at the Fort William TS tap points onto the 115 kV circuits Q4B and Q5B, are under 118 kV. It should be noted, that the studies results show that, with the new 12 MW load incorporated, the post contingency voltage on the LV side of the Fort William 115/24.9 kV transformers is 25.7 kV which is considered to be adequate.

The results of the study indicate that the addition of the new load at Fort William TS does not have a significant impact on the voltages in the Thunder Bay area.
With all Thunder Bay GS units in service the peak load in the area can be supplied reliably.

Scenario B

For this scenario the assumed status of the Thunder Bay GS units was: C1 at 59.5 Mvar, G2 at 165 MW, 80 Mvar, G3 out of service. The post-contingency load flow analysis was performed for the loss of Thunder Bay G2.

In this case all the low voltage shunt capacitors at Birch TS and Fort William TS are switched on to provide increased reactive support, hence higher pre contingency voltages.

Table 3B. Study Results for Scenario B:

Condition	**Thunder Bay Voltage (kV)**		**Birch TS**		**Fort William TS**			**Lakehead**		
No New Load	A Bus	D Bus	kV	MX	Q4B 115 kV	Q5B 115 kV	MX	115 kV	Cap MX	C7 C8
Pre-fault	121.3	121	121.2	29.1	120.5	120.5	32.1	124.6	107.6	4, 4
Post loss of Thunder Bay G2	118.3	115.4	117.2	28	116.9	116	29.9	121.4	103	35, 35
					LT Voltage =25.7 kV					
% kV	**2.5%**	**4.6%**	**3.3%**	**-**	**3%**	**3.7%**	**-**	**2.6%**	**-**	**-**
With New Load	A Bus	D Bus	kV	MX	Q4B 115 kV	Q5B 115 kV	MX	115 kV	Cap MX	C7 C8
Pre-fault	121.1	120.9	121.1	28.9	120.4	120.3	31.4	124.8	107.9	14 14
Post loss of Thunder Bay G2	118.1	115.2	117.1	27	116.6	115.8	29.2	122.2	103.5	48 48
					LT Voltage =25.4 kV					
% kV	**2.5%**	**4.7%**	**3.3%**		**3.2%**	**3.7%**		**2.1%**		

The results of the load flow studies indicate that with Thunder Bay G3 out of service, **without the new embedded load**, the pre-contingency voltages are above 120 kV.

The immediate post contingency voltage decline at Fort William meets the 10% voltage decline criteria, but the actual voltages at the Fort William TS tap points onto 115 kV circuits Q4B and

Q5B are under 118 kV. There is a possibility that if some of the other loads connected to Q4B and Q5B require, for continuous operation, a firm minimum voltage of 118 kV, then in the event of the loss of Thunder Bay G2, some of the equipment could become disconnected.

It should be noted, that the studies results show that the post contingency voltage on the LV side of the Fort William 115/24.9 kV transformers is 25.7 kV which could be adequate for continued operation of the connected equipment.

The Thunder Bay synchronous condenser generated 80 Mvar immediately following the loss of G3.

With the new 12 MW load incorporated at Fort William TS the pre-contingency voltages in the area are lower by about 0.1 kV. The post contingency voltage decline is within the adopted criteria of 10% voltage decline, and the actual post contingency voltages at Fort William TS tap points onto the 115 kV circuits Q4B and Q5B, are under 118 kV. It should be noted, that the studies results show that, with the new 12 MW load incorporated, the post contingency voltage on the LV side of the Fort William 115/24.9 kV transformers is 25.4 kV.

The results of the study indicate that the addition of the new load at Fort William TS does not have a significant impact on the voltages in the Thunder Bay area.
With Thunder Bay G3 out of service,

- the pre-contingency voltages in the 115 kV system in the Thunder Bay area are above 120 kV,
- under peak load conditions, a contingency involving Thunder Bay G2 may result in some of the more sensitive loads being shaken off due to low post contingency voltages.

Scenario C

For this scenario the status of the Thunder Bay GS units was assumed to be the following: C1 at 61 Mvar, G2 out of service, G3 at 165 MW, 80 Mvar. The post-contingency load flow analysis was performed for the loss of Thunder Bay G3.

For this particular scenario all the low voltage shunt capacitors at Birch TS and Fort William TS are switched on to provide increased reactive support, hence higher pre contingency voltages.

Table 3C. Study Results for Scenario C:

Condition	Thunder Bay Voltage (kV)		Birch TS		Fort William TS			Lakehead		
No New Load	A Bus	D Bus	kV	MX	Q4B 115 kV	Q5B 115 kV	MX	115 kV	Cap MX	C7 C8
Pre-fault	121.1	119.1	121	29.8	120.3	119.7	31.8	124.6	107.6	9.6 9.6
Post loss of Thunder Bay G3	118.3	115.4	117.3	28	116.9	116	30	122.2	103.5	40 40.3
					LT Voltage =25.7 kV					
% kV	**2.3%**	**3.1%**	**3.1%**	**-**	**2.8%**	**3.1%**		**2%**	**-**	**-**
With New Load	A Bus	D Bus	kV	MX	Q4B 115 kV	Q5B 115 kV	MX	115 kV	Cap MX	C7 C8
Pre-fault	121	119.1	121	29.8	120.2	119.6	32	124.8	108	20.2 20.2
Post loss of Thunder Bay G3	118.1	115.2	117.1	27.9	116.6	115.8	30	122.3	103.6	48 53
					LT Voltage =25.7 kV					
% kV	**2.4%**	**2.7%**	**3.2%**	**-**	**3%**	**3.2%**		**2%**	**-**	**-**

The results of the load flow studies indicate that, **without the new embedded load**, with Thunder Bay G2 out of service the pre-contingency voltages at the Birch TS and Fort William TS are around 120 kV. The 119.7 kV voltage at Fort William TS tap point to the 115 kV circuit Q5B is marginally acceptable, and if higher voltage is required then, there is available reactive capacity at Thunder Bay C1 which could be activated.

The immediate post contingency voltage decline at Fort William meets the 10% voltage decline criteria, but the actual voltages at the 115 kV Q4B and Q5B Fort William TS tap points are well under 118 kV.

If some of the other loads connected to Q4B and Q5B require, for continuous operation, a firm minimum voltage of 118 kV, these could become disconnected in the event of the loss of Thunder Bay G2. It should be noted, that the studies results show that the post contingency voltage on the LV side of the Fort William 115/24.9 kV transformers is 25.7 kV. This LV voltage could be adequate for continued operation of the equipment that is connected at this station.

The Thunder Bay synchronous condenser generated 80 Mvar immediately following the loss of G3.

With the new 12 MW load incorporated at Fort William TS the pre-contingency voltages in the area are lower by about 0.1 kV, and the post contingency voltage decline is within the adopted criteria of 10% voltage decline. However, the actual post contingency voltages at the 115 kV Q4B and Q5B Fort William TS taps are under 118 kV. It should be noted, that the studies results show that, with the new 12 MW load incorporated, the post contingency voltage on the LV side of the Fort William 115/24.9 kV transformers is 25.7 kV, which is unchanged from the case without the additional load.

The results of the study indicate that the addition of the new load at Fort William TS does not have a significant impact on the voltages in the Thunder Bay area.

With Thunder Bay G2 out of service,

- the pre-contingency voltages in the 115 kV system in the Thunder Bay area are as low as 119.7 kV,
- under peak load conditions, a contingency involving Thunder Bay G3 may result in some of the more sensitive loads being shaken off due to low post contingency voltages.

Scenario D

Under scenario D, Thunder Bay generating units G2 and G3 were both assumed to be out of service. The synchronous condenser C1 produced 80 Mvar. The post-contingency load flow analysis was performed for the loss of Thunder Bay synchronous condenser.

For this particular scenario all the low voltage shunt capacitors at Birch TS and Fort William TS are switched on to provide increased reactive support, hence higher pre contingency voltages.

Table 3D. Study Results for Scenario D:

Condition	**Thunder Bay Voltage (kV)**		**Birch TS**		**Fort William TS**			**Lakehead**		
No New Load	A Bus	D Bus	kV	MX	Q4B 115 kV	Q5B 115 kV	MX	115 kV	Cap MX	C7 C8
Pre-fault	120.4	117.6	119.5	29.5	119.1	118.2	31.8	124.9	108.1	48 60
Post loss of Thunder Bay C1	113.3	114.1	115.9	27.8	114.4	114.7	29.7	122.3	103.7	48 60
					LT Voltage =25.6 kV					
% kV	**5.9%**	**3%**	**3%**	**-**	**3.9%**	**3%**	**-**	**2.1%**	**-**	**-**
With New Load	A Bus	D Bus	kV	MX	Q4B 115 kV	Q5B 115 kV	MX	115 kV	Cap MX	C7 C8
Pre-fault	119.4	116.6	118.6	30	118.	117.2	31.5	124.2	107	48 60
Post loss of Thunder Bay C1	112.3	113.1	115	28.2	113.4	113.7	29.3	121.7	102.7	48 60
					LT Voltage =25.2 kV					
% kV	**6%**	**3%**	**3%**	**-**	**3.9%**	**3%**	**-**	**2%**	**-**	**-**

The results of the load flow studies indicate that with Thunder Bay G2 and G3 out of service, **and with or without the new embedded load**, the pre-contingency voltages are as low as 118.2 kV at Fort William TS. The pre contingency voltages in the area are below the level of 120 kV required to ensure the reliable supply of the area load.

With Thunder Bay G2 and G3 out of service,

- the pre-contingency voltages in the 115 kV system in the Thunder Bay area are as low as 118.2 kV,
- the reliable supply of the peak load in the area cannot be sustained

The results of the study indicate that, for peak load conditions, the addition of the new load at Fort William TS lowers the area voltages by about 1 kV.

Scenario E

Under scenario E, Thunder Bay generating units G2 and C1 were both assumed to be out of service. The post-contingency load flow analysis was performed for the loss of Thunder Bay G3.

For this particular scenario all the low voltage shunt capacitors at Birch TS and Fort William TS were switched on to provide increased reactive support, hence higher pre contingency voltages.

Table 3E. Study Results for Scenario E

Condition	**Thunder Bay Voltage (kV)**		**Birch TS**		**Fort William TS**			**Lakehead**		
No New Load	A Bus	D Bus	kV	MX	Q4B 115 kV	Q5B 115 kV	MX	115 kV	Cap MX	C7 C8
Pre-fault	117.1	118.	120	29.4	118.3	118.6	31.8	124.8	108.1	48 60
Post loss of Thunder Bay G3	111.1	112	113.9	27.8	112.3	112.6	29.7	120.1	103.7	48 60
					LT Voltage =25 kV					
With New Load	A Bus	D Bus	kV	MX	Q4B 115 kV	Q5B 115 kV	MX	115 kV	Cap MX	C7 C8
Pre-fault	117	118	119.9	30	118.2	118.5	31.5	124.2	107	48 60
Post loss of Thunder Bay G3	110	110.9	112.8	28.2	111.1	111.4	29.3	119.2	102.7	48 60
					LT Voltage =24.9 kV					

The results of the load flow studies indicate that with Thunder Bay G2 and C1 out of service, **and with or without the new embedded load**, the pre-contingency voltages at Fort William TS are as low as 118.3 kV. The pre contingency voltages in the area are below the level of 120 kV required to ensure the reliable supply of the area load.

With Thunder Bay G2 and C1 out of service,

- the pre-contingency voltages in the 115 kV system in the Thunder Bay area are as low as 118.3 kV,
- the reliable supply of the peak load in the area cannot be sustained

The results of the study indicate that, for peak load conditions, the addition of the new load at Fort William TS lowers the post contingency voltages by about 0.1 kV.

7.0 Discussion

Scenarios A, B and C that were described in section 4.3, constitute system conditions that are normally included in the criteria for connection assessments; namely stressed system load conditions with all power system elements in service, and one critical elements out of service. The conclusions of this assessment, as summarized in section 8.0, are based on the findings of these three scenarios. These conclusions together with other issues described below raise concerns with respect to the secure supply of the customer loads in the area.

Firstly, it should be noted that the study results obtained for scenarios A,B and C indicated that the IMO controlled grid in the Thunder Bay area may be approaching its limit of reliability, and it is possible that any future increase in area peak load could not be accommodated. In these study scenarios the peak loads were assumed to have a lagging power factor of 0.9. In reality, the loads in the area may operate at a higher power factor, hence the reactive power demand could be less than it was assumed in the studies.

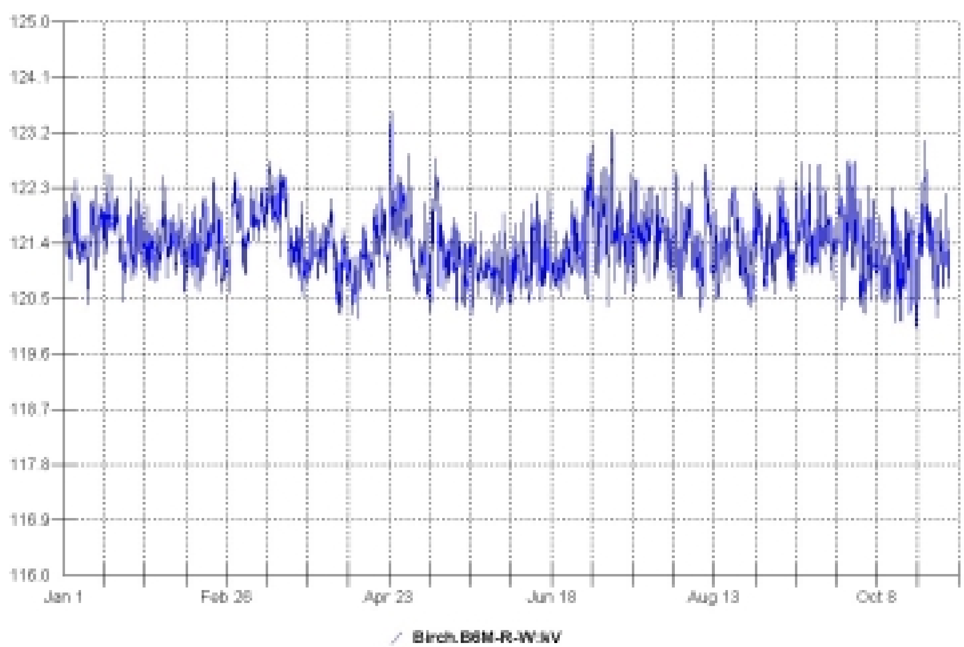


Figure 2. Year 2001 Birch TS Voltage

Secondly, past operating practices require that the minimum voltages in the Thunder Bay area be maintained at about 118 kV in order to ensure secure supply of some of the paper mill loads connected to the QxB circuits. Historical records indicate that during 2001 the voltage at Birch TS was maintained above 120 kV, as shown in Figure 2, even during periods when only one

Thunder Bay generator was in service. A further analysis of records indicates that at all times during 2001 at least one Thunder Bay generating unit was in service. Figure 3 and 4 below show that G2 was out of during the summer months, and G3 was removed from service during the fall.

Figure 3. Year 2001 Thunder Bay G2

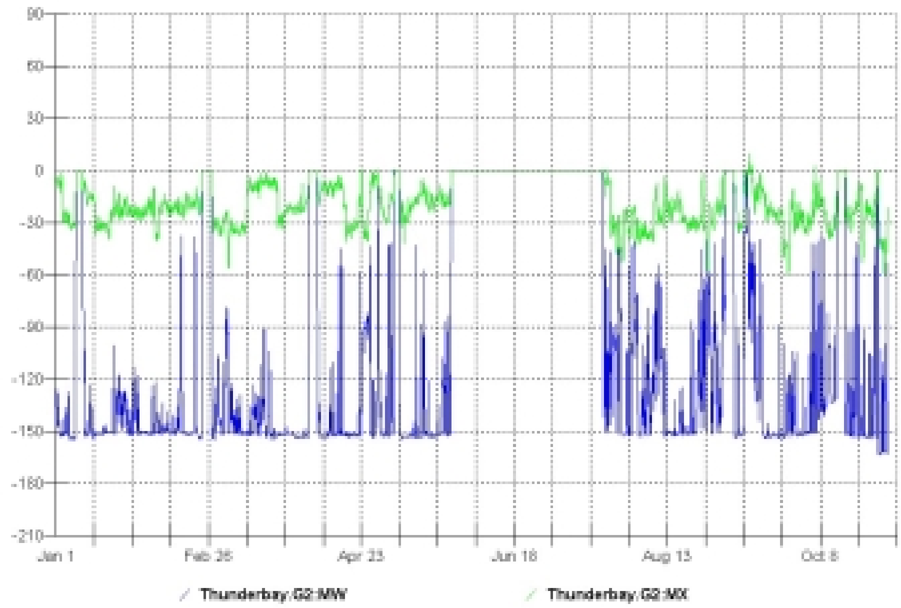
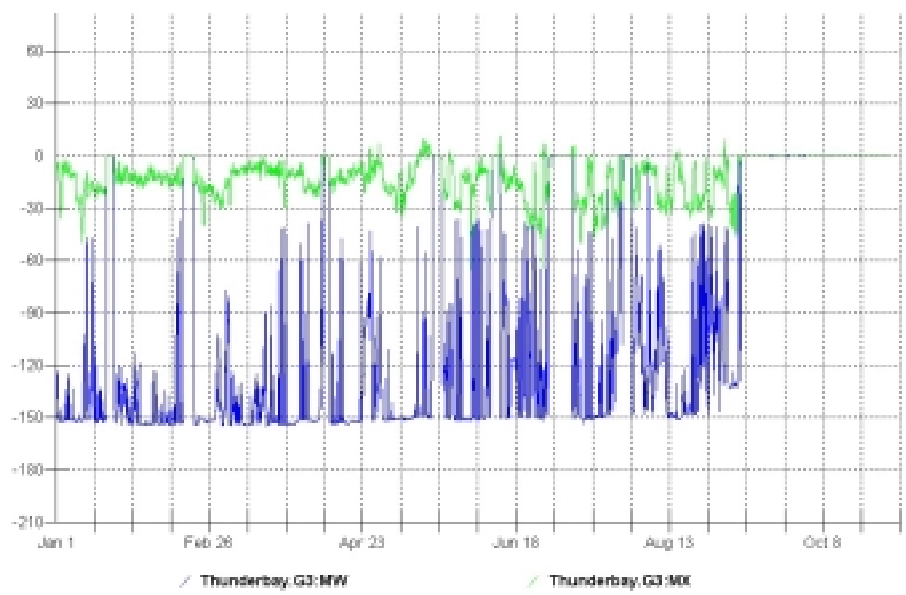


Figure 4. Year 2001 Thunder Bay G3



Thirdly, there are concerns related to the ability of continuing these operating practices and the availability of Thunder Bay generation under the open market environment. If under conditions of peak load Thunder Bay GS would not offer energy into the market, then the supply of the load in the area may be in jeopardy.

Based on historical records, the results of our studies, and the concerns related to the secure supply of the area peak load, it is recommended that options for reinforcing the area transmission be considered to maintain the reliability of power supply for future load growth. The IMO has performed a brief investigation of three options for minor transmission modification that could improve the supply reliability in the Thunder Bay area. The results are presented in the next paragraphs.

The first option looked at installing additional facilities which would allow the solid operation of bus A and bus D at Thunder Bay GS. The study was performed for one Thunder Bay GS unit out of service in pre-contingency. The study results show that the voltage performance of the 115 kV area transmission system would not improve.

The second option assessed the addition of shunt capacitors at Birch TS. The intent was to identify how much reactive support is required at Birch TS to ensure that a voltage of 118 kV is maintained in post contingency when one Thunder Bay unit is out of service and the second one is lost due to contingency. It was concluded that shunt capacitors totaling about 100 Mvar would be needed to obtain the desired result.

The third option evaluated the possibility of moving the connection point for Sterling Pulp Chemical and Abitibi Price loads to Q8B. The study results showed that this reconnection of the loads would not result in an improvement to the area voltages.

Scenarios D and E represent situations where two generating units at Thunder Bay GS are out of service. These conditions were studied to give an indication of the load supply adequacy in the area if the local generation is unavailable. It can be concluded from the results, that with two generating units out of service at Thunder Bay GS during peak load conditions, the system voltages are below the levels required for secure operation of the system.

8.0 Conclusions and Recommendations

This Preliminary Assessment has examined the impact of connecting 12 MW of new imbedded load at Fort William TS in the Thunder Bay area. The assessment concluded the following:

1. The power transfer capability of Fort William TS is adequate to support the addition of the 12 MW Bowater sawmill load. The load connectivity arrangement must meet the requirements of the Distribution System Code.

2. No additional facilities are required to satisfy the obligations that are established by the *Market Rules* with respect to underfrequency load shedding requirements.

3. The additional Bowater sawmill load does not have an effect on the system short circuit levels at Fort William TS and other surrounding transformer stations.

4. The study results indicate that the addition of the new load at Fort William TS does not have a significant impact on the voltages in the Thunder Bay area.

5. The study results show that with all Thunder Bay GS units in service the peak load in the area can be supplied reliably.

6. The results also indicate that with one generating unit out of service the peak load in the area could be supplied reliably, provided that all the shunt capacitors in the area are switched on. However, some of the voltage sensitive loads may be tripped for the loss of the one Thunde Bay unit which is in service.

7. The study results indicated that the IMO controlled grid in the Thunder Bay area may be approaching its limit of reliability, and it is possible that any future increase in area peak load could not be accommodated.

8. It is recommended that Hydro One pursue options of reinforcing the Thunder Bay area transmission.

The IMO identified that it is required to have the new low voltage shunt capacitor that Hydro One plans to install at Fort William TS in service, before the new load becomes connected.

9.0 IMO Requirements

The IMO requires that the new low voltage capacitor that Hydro One plans to install at Fort William TS, to replace an existing damaged unit, is in service before the new load is connected.

There are no required system modifications for which Thunder Bay Hydro is the sole beneficiary.

10.0 Identification of "Sole Beneficiary"

Section 9.2.5 of the Transmission System Code states that "modifications and upgrades on specific network facilities or installation of new network facilities that are triggered by a load customer and are for its sole benefit of shall be borne by the customer."

The incorporation of the 12 MW load at Fort William does not require installation of new network facilities. However it is required that the new low voltage capacitor that Hydro One plans to install at Fort William TS is in service before the new load is connected.

11.0 Notification of Approval

Section 9.0 of the Preliminary Assessment Report lists the requirements identified by the IMO for the incorporation of the proposed 12 MW new load at Fort William TS. Notification of Approval is issued conditional upon implementation of these requirements.

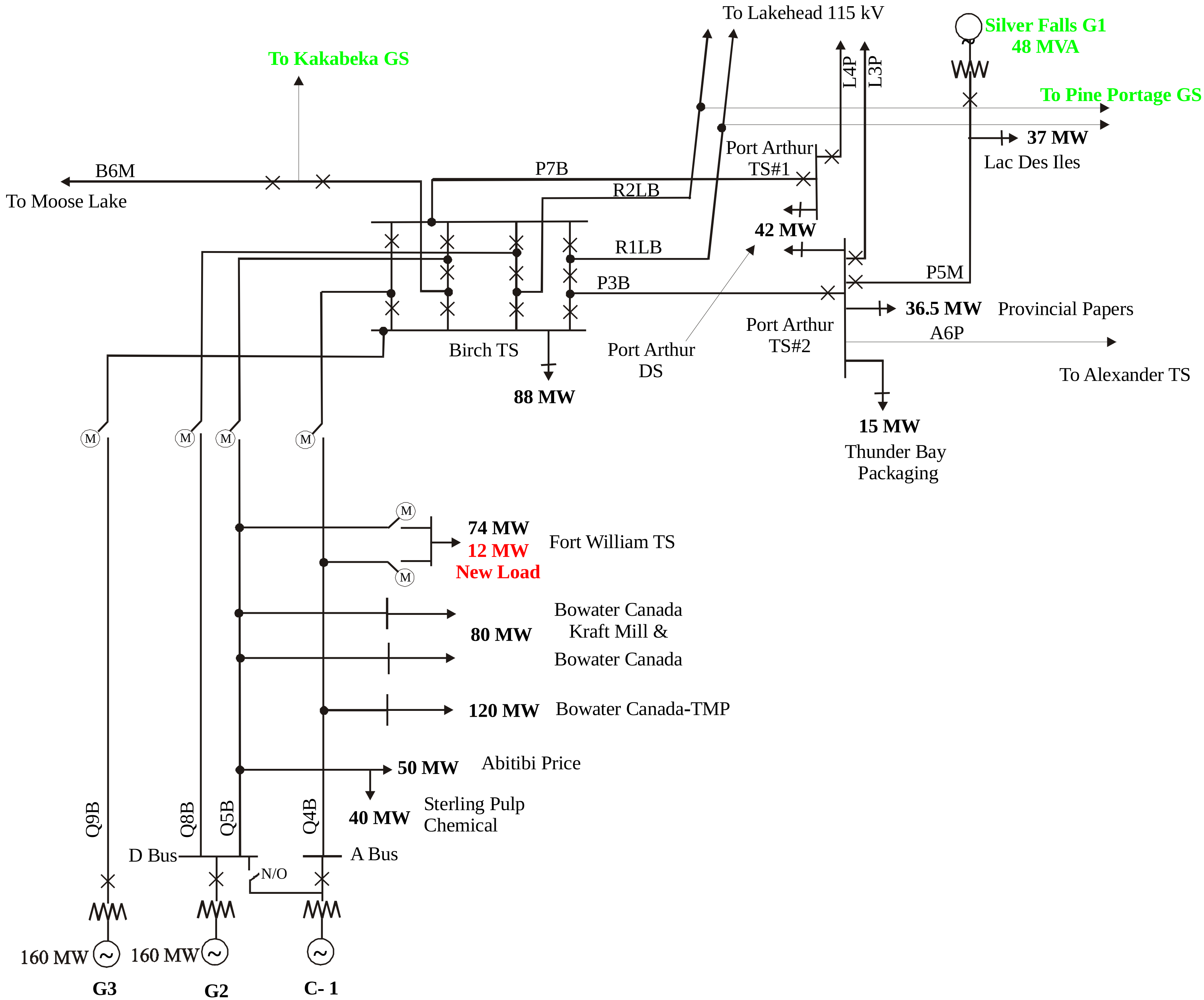


Figure 1. Thunder Bay Area Transmission Configuration - Existing and New Summer Peak Loads