System Impact Assessment Report

Final Report - Public

CAA ID: 2021-694 and 2021-695
Project: Algoma Steel – New Load Facility and Lake Superior Power CGS – Generation Reconfiguration
Connection Applicant: Algoma Steel Inc.

April 21, 2023

Connecting Today.
Powering Tomorrow.

Acknowledgement

The IESO wishes to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimers

IESO

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IESO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IESO should issue a notice of conditional approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Conditional approval of the project is based on information provided to the IESO by the connection applicant and Hydro One at the time the assessment was carried out. The IESO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by Hydro One at the request of the IESO. Furthermore, the conditional approval is subject to further consideration due to changes to this information, or to additional information that may become available after the conditional approval has been granted.

If the connection applicant has engaged a consultant to perform connection assessment studies, the connection applicant acknowledges that the IESO will be relying on such studies in conducting its assessment and that the IESO assumes no responsibility for the accuracy or completeness of such studies including, without limitation, any changes to IESO base case models made by the consultant. The IESO reserves the right to repeat any or all connection studies performed by the consultant if necessary to meet IESO requirements.

Conditional approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed project to the IESO-controlled grid. However, the conditional approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter(s) during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

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 and the IESO in accordance with Chapter 4, section 6 of the Market Rules. This report does not in any way constitute an endorsement of the proposed connection for the purposes of obtaining a contract with the IESO for the procurement of supply, generation, demand response, demand management or ancillary services.

The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO 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 IESO provides a draft of this report to the connection applicant, the connection applicant must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to the connection applicant. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used.

Hydro One

The results reported in this report are based on the information available to Hydro One, at the time of the study, suitable for a System Impact Assessment of this connection proposal.

The short circuit and thermal loading levels have been computed based on the information available 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 facilities on load and generation customers.

In this report, short circuit adequacy is assessed only for Hydro One circuit breakers. The short circuit results are only for the purpose of assessing the capabilities of existing Hydro One circuit breakers and identifying upgrades required to incorporate the proposed facilities. These results should not be used in the design and engineering of any new or existing facilities. The necessary data will be provided by Hydro One and discussed with any connection applicant upon request.

The ampacity ratings of Hydro One facilities are established based on assumptions used in Hydro One 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 facilities have been identified to the extent permitted by a System Impact Assessment under the current IESO Connection Assessment and Approval process. Additional facility studies may be necessary to confirm constructability and the time required for construction. Further studies at more advanced stages of the project development may identify additional facilities that need to be provided or that require upgrading.

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Project Description

Algoma Steel Inc. (the "connection applicant") is proposing to connect a new load facility for two new Electric Arc Furnaces (EAF), namely EAF CTS (CAA 2021-694), and re-connect the load displacement generators GTG-1 (42.5 MW of gas) and STG-1 (25 MW of steam) from Patrick St. TS (CAA 2021-695) back to their original configuration at the 115 kV Lake Superior Power (LSP) CGS bus. These two generator units along with the existing LSP CGS GTG-2 (42.5 MW) gas unit, which is not currently operating, will be in-service during EAF operation to offset the EAF's load and provide voltage support. All the above changes will be referred to as the "project" in this report.

EAF CTS will connect to LSP CGS via one new 0.6 km underground 115 kV cable. It will be supplied by two 115/34.5 kV 200 MVA step-down transformers with associated circuit breakers and disconnect switches, including switches intended for future connection to a 230 kV system supply. Figure 1, included in Appendix B: Project Data (Confidential), shows the single line diagram of the project and surrounding area.

The instantaneous peak load at EAF CTS can be as high as 140 MW and will ramp up and down between 0 and 140 MW between 30-60 times per day. Each ramping operation will occur within seconds. The power factor of the EAF load remains constant at 0.97 lagging at all times, including during ramping.

A new auxiliary load of 20 MW required for the EAFs operation will be added at the connection applicant's Patrick St. TS facility, while 8 MW of existing load at Patrick St. will be removed.

The connection applicant intends to operate EAF CTS, LSP CGS and Patrick St. TS facilities such that the net sum of the instantaneous peak load from all three facilities, as measured at their low voltage side of the 115 kV transformers at these three facilities, under normal operating conditions ("Algoma load") will not exceed 188 MW without the EAFs operating, and 218 MW during EAF operation.

When the EAF is not operating, the connection applicant plans to utilize the full capability of LSP to offset 110 – 120 MW of load at its Patrick St. TS facility by opening the 115kV connection to Clergue TS, and connecting to Patrick St. TS through a normally open low voltage tie circuit stemming from the EAF 34.5 kV bus.

The LSP CGS bus connects to Hydro One Inc.'s ("H1 transmitter") Clergue TS through COGEN#1 and COGEN #2 115 kV circuits, which are owned by the connection applicant.

In addition, as part of this project, all LSP CGS units will have their governors upgraded; GTG-1 and GTG-2 will have their rotors and stators rewound. Once these upgrades are complete, GTG-1 and STG-1 will initially be reconnected to their existing low-voltage bus at Patrick St. TS prior to being reconfigured to connect at the LSP 115 kV bus in Q4, 2023.

The in-service date of the EAF is expected to be Q1 2024.

Notification of Conditional Approval

This assessment concludes that the proposed connection of the project is expected to have no material adverse impact on the reliability of the integrated power system, provided that all requirements in this report are implemented. Therefore, the assessment supports the release of the Notification of Conditional Approval for connection of the project.

Assessment Findings

System impact studies were carried out to assess the impact of the project in accordance with Chapter 8 of Market Manual 1.4. The studied scenarios and main assumptions are available in Appendix D and detailed study results are available in Appendix E of this report. Based on the assessment results, we have identified the following findings:

1. The project load will reduce steady-state voltage performance in the Hydro One Sault Ste. Marie system during all elements in-service and outage conditions. This can be addressed by adding 75 MVar of reactive compensation. Installing two steps of 37.5 MVar each would satisfy the voltage change criteria of 4% for capacitor switching.
2. With any two transmission elements out of service, the addition of the project exacerbates or creates new post-contingency low-voltage violations and thermal overloading violations, which require up to 350 MW of total load interruption to address. Today, without the project, up to 310 MW of load interruption is required to address similar violations. The amounts of load that would need to be interrupted both today and with the project in-service are greater than the 150 MW allowed by the ORTAC (Ontario Resource and Transmission Assessment Criteria) load security requirement for two transmission elements out of service. For the current system, this has been grandfathered, given the system in this area was not originally designed meet all of today's ORTAC requirements. The IESO is currently in the process of addressing this issue through a Northeast bulk system planning study and an Integrated Resource Regional Plan (IRRP). In the interim, project's contribution to the thermal and voltage issues will be addressed through automatic load rejection by Remedial Action Schemes (RAS)s.
3. As a result of the amount of automatic load rejection required to resolve thermal and voltage issues for two elements out of service conditions, high voltages up to 263 kV could occur at Hanmer TS, Algoma TS, Wawa TS, Mississagi TS and Third Line TS. These voltages are acceptable for up to 30 minutes and there are control actions available within 30 minutes to reduce the voltages below the maximum continuous voltages.
4. At Mississagi Flow West (MISSW) flows above 700 MW, which may be needed to supply future loads connecting west of Mississagi, the system could inadvertently separate east of Mississagi TS following the loss of A23P and A24P under all-in-service conditions or the loss of S22A or X27A under outage conditions because of encroachment on protective relays on circuits X74P, S22A and X27A.

5. For certain recognized planning events involving transmission elements near the project, e.g. Breaker Fail (BF) of Third Line breaker 402, excessive area wide voltage decline occurs due to the addition of the project. This issue can be addressed by a voltage-based load rejection scheme located at the project.
6. In the SSM area, the system is operated within a tighter voltage range, 118-124 kV, than the rest of the system. The changes to voltages introduced by the ramping of the EAF will make operating within this range even more challenging.
7. The ramping of the EAF from 0 to 140 MW and vice versa results in material local voltage changes in the SSM area. Because of the frequency of voltage changes, both H1 transmitter and SSM PUC concluded that voltage changes in excess of 2% are not acceptable. This constraint is aligned with the Transmission System Code (TSC) Appendix 2 requirements.

   Our studies identified that 105 MVar of fast-response dynamic Vars would maintain the local voltage changes within 2% for a 140 MW load fluctuation. This amount of dynamic reactive power could be sourced from the LSP generators and other devices. Please note this amount of reactive power is not in addition to, and would satisfy, the reactive power compensation mentioned in Finding #1 above.
8. The ramping of the EAF results in material voltage changes at transmission stations in the bulk system as far east as Hanmer TS. Because of the frequency of voltage changes, H1 transmitter has confirmed that, in order to maintain acceptable voltage performance for the existing customers and avoid excessive wear and tear on their equipment, voltage changes in excess of 2% are not acceptable.

   Studies indicate that excessive voltage changes occur under heavy flows on the MISSW interface. While the IESO will deploy available resources to minimize grid voltage changes, there may be times when those resources are insufficient. At those times, EAF operation will be restricted. Based on historical flows and system conditions, EAF operation would be restricted for about 2% of the time annually. More information regarding system conditions under which EAF will be restricted and the degree of EAF restriction will be determined during the Market Registration stage, and will be subject to updates during operations planning and real-time operation as system conditions change.
9. The ramping of the EAF load will cause significant swings in active power (MW) flow through critical interfaces in Northeastern and Northwestern Ontario. Maintaining power flows within the operating security limits will require careful coordination of EAF operation with IESO's operations planning and real-time operations teams.
10. The full ramping of the EAF load could result in a change of 12.7 MW on the Minnesota interconnection and a total of 20 MW on the Manitoba interconnection. Minnesota phase shifters will automatically change tap positions should the difference between the actual and scheduled flows exceed 10 MW. Manitoba phase shifters will automatically change tap positions should the difference between the actual and scheduled flows exceed 25.6 MW. Minnesota Power and Manitoba Hydro have been informed of the results of this study and have agreed to

monitor the additional duty on the phase shifters once the project goes in-service to determine whether further investigation is needed.

11. For an outage to the main protection of T6 at Patrick St. TS, which has no fast redundant protection, a three phase fault or line-ground fault close to the Patrick St. TS bus, will cause the LSP CGS units to go unstable as the fault will remain on the bus until cleared by back-up protection after 1.3 seconds. If backup protection timing can be improved to clear a fault within 120 ms, units at LSP CGS will remain stable.

IESO Requirements for Connection

Specific Requirements:

The following specific requirements are applicable for the incorporation of the project and its connection facilities. Specific requirements pertain to the level of reactive power compensation needed, operation restrictions, remedial action scheme, upgrading of equipment and any project specific items not covered in the general requirements.

Requirements for the Connection Applicant

1. Ensure that the instantaneous peak Algoma load does not exceed 188 MW without EAF operation, or 218 MW during EAF operation with LSP generation in-service. The connection applicant must have measures in place to reduce its load within 5 minutes in the event the 188 MW, or 218 MW limit, are inadvertently exceeded; exceedance of these limits during normal operations is not allowed.
2. To support the levels of Algoma load described in requirement #1 above, LSP units must operate in voltage control mode and the connection applicant must install the equivalent of 75 MVar additional reactive support at its facilities. Two 37.6 MVar shunt capacitors rated at 34.5 kV would be acceptable.
3. Operate at voltages between 118 kV and 124 kV at its connection point. However, if current local voltage restrictions are relaxed or lifted in the future, the connection applicant shall be able to operate within normal voltage ranges, i.e., 113 kV to 127 kV.
4. Ensure that the operation of the EAF does not result in a local voltage change that exceeds H1 transmitter's and SSM PUC's 2% voltage change threshold. This could be achieved by installing locally placed fast-acting reactive compensation device(s) (i.e. SVC, Statcom, etc.) or, if feasible, by coordinating its own local reactive devices in a manner that is acceptable to the IESO, H1 transmitter and SSM PUC. The solution to satisfy the local voltage change needs shall be presented to the IESO and H1 transmitter for evaluation at least twelve months before the in-service date of the project.

5. Provide single points of contact to the IESO, reachable 24/7, and have those contacts participate in operations planning and real-time operations processes to allow for:
   a. the IESO be aware of the intended next-day and real-time operations of the facility, and
   b. the connection applicant to be aware when EAF operation needs to be restricted to accommodate system conditions, including outages, as communicated by the IESO market forecasts and integration team (MFI) or the IESO control room.
6. Have a demand management procedure acceptable to the IESO and H1 transmitter that ensures that the EAF operation can be curtailed within 5 minutes. The need for load curtailment could occur when H1 transmitter's 2% voltage change criterion is at risk of being violated, during outages to LSP CGS units, or during any other operating situations where the IESO cannot manage the power or voltage fluctuations triggered by the EAF's operation.

   The demand management procedure must be subject to the following conditions:

   a. Reduce up to the entire project load, upon direction by the IESO, within 5 minutes; failure to follow the direction could result in immediate disconnection of the project from the transmission grid;

   b. Set up a dedicated direct line for the IESO and H1 transmitter to reach the facility control room, which will be staffed at all times when the EAF is in-service; and,

   c. Prepare a detailed procedure outlining how the EAF load reduction and/or EAF shutdown will be implemented. The procedure is to be approved by IESO and H1 transmitter.
7. The connection applicant shall install RAS facilities to participate in the following Remedial Action Schemes (RAS) that will automatically disconnect the EAF load for system events: Third Line Instantaneous Load Rejection Scheme and Northwest RAS. EAF loads must be rejected within 66 ms upon receipt of the signal from the applicable schemes.

   The connection applicant shall ensure that the RAS facilities comply with NPCC Reliability Reference Directory #7 as per the RAS type classification which will be finalized during the Market Registration process. To avoid any delay to the project, it is strongly recommended the RAS facilities be designed to meet NPCC Reliability Reference Directory #7 for NPCC Type I RAS before the RAS type classification is finalized. If deemed or expected to be a Type II or Limited Impact RAS, the connection applicant shall ensure the RAS facilities have provisions to comply with NPCC Reliability Reference Directory #7 for Type I RAS in case the RAS is re-classified as NPCC Type I RAS in the future as the system evolves.

   Telemetry, including but not limited to, MW, MVar and breaker status for the feeders/equipment tripped by the RAS, as specified by the IESO at the time of registration, shall be provided.
8. To prevent area wide voltage decline, install a voltage-based tripping scheme that will automatically disconnect one or all of its EAF(s) for voltages below 108 kV at the EAF 115 kV

bus within 1 second. All capacitors and LSP generator units shall remain in-service. Any other proposed settings will need to be approved by the IESO.

9. Ensure the LSP generators, exciters and power system stabilizers of GTG-1, GTG-2 and STG-1 meet, at a minimum, the original performance requirements applicable to them when the units were once connected directly to the 115 kV LSP CGS bus, in the event they are not able to meet the prevailing performance requirements as per Market Rules Appendix 4.2.
10. Be prepared to re-incorporate LSP units GTG-1 and STG-1 into the Mississagi Generation Scheme in the future if there is a need, upon request from the IESO.
11. To address Finding 11, the backup protection timing for Patrick St. T6 needs to be improved to clear a fault within 120 ms; otherwise T6 must be removed from service should the main protection be out-of-service. The connection applicant must work with H1 transmitter and SSM PUC to confirm what other equipment at the Patrick St. 115 kV bus may also be required to be taken out of service should equipment have similar protections to T6 in place, if improvements to back-up timing allowing the LSP CGS units to remain stable, cannot be made.

    This requirement must be fulfilled prior to LSP CGS being reconfigured in Q4, 2023.
12. The connection applicant shall provide the missing governor model for STG-1 during the Market Registration process.

Requirements for H1 Transmitter

1. H1 transmitter shall include the project in the Third Line Instantaneous Load Rejection Scheme, and NW RAS (formerly Northwest SPS2) as per Appendix F of this report. During the IESO Market Registration process, a revised Facility Description Document (FDD) for both the Third Line Instantaneous Load Rejection Scheme and NW RAS (formerly Northwest SPS2), must be provided and finalized at least twelve months prior to in-service. The FDD must contain the finalized RAS matrix as well as expected operating times. The actual operating times must be measured during commissioning and documented as a Performance Validation Record.

    If the FDD or performance testing as per the Performance Validation Record indicates a change in design or slower than expected operating times, as compared to what was assumed in this assessment, then further analysis of the project will need to be done by the IESO. This may delay the grant of IESO final approval to place the project in-service.

    The H1 transmitter shall ensure that the RAS facilities comply with NPCC Reliability Reference Directory #7 as per the RAS type classification which will be finalized during the Market Registration process. To avoid any delay to the project, it is strongly recommended the RAS facilities be designed to meet NPCC Reliability Reference Directory #7 for NPCC Type I RAS before the RAS type classification is finalized. If deemed or expected to be a Type II or Limited Impact RAS, the transmitter shall ensure the RAS facilities have provisions to comply with NPCC Reliability Reference Directory #7 for Type I RAS in case the RAS is re-classified as NPCC Type I RAS in the future as the system evolves.

Telemetry, as specified by the IESO at the time of registration, shall be provided.

This requirement must be fulfilled prior to the EAF coming into service in Q1 2024.

2. Patrick St. T6 must be removed from service should the main protection be out-of-service, unless backup protection timing can be improved to clear a fault within 120 ms. H1 transmitter must work with the connection applicant and SSM PUC to confirm what other equipment at the Patrick St. 115 kV bus may also be required to be taken out of service or require protection timing improvement should equipment have similar protections to T6 in place.

   This requirement must be fulfilled prior to LSP CGS being reconfigured in Q4, 2023.

General Requirements:

The connection applicant shall satisfy all applicable requirements specified in the Market Rules, the Transmission System Code (TSC) and reliability standards. Some of the general requirements that are applicable to this project are presented in detail in Appendix A: General Requirements of this report.

Recommendation

1. To relieve the number of times static reactive devices may need to be switched, it is recommended that H1 transmitter and SSM PUC examine possible solutions to addressing the operating voltage limitations at Third Line TS. Today, the acceptable continuous voltage range at the station is 118 kV to 124 kV whereas the ORTAC requirement should be between 113 kV to 127 kV.

2. The transmitter is recommended to modify the relay characteristics of circuits X74P, X27A and S22A and/or decrease the timing of the Third Line RAS L/R function. This will enable higher MISSW transfers without the risk of post-contingency system separation mentioned in finding 4.

Appendix A: General Requirements

The connection applicant shall satisfy all applicable requirements specified in the Market Rules, the Transmission System Code and reliability standards. This section highlights some of the general requirements that are applicable to the project.

The following requirements, i.e. (1) – (9), apply to both Algoma Steel – New Load Facility (CAA 2021-694) and Lake Superior Power CGS – Generation Reconfiguration (2021-695) portions of the project:

1. The connection applicant must notify the IESO at connection.assessments@ieso.ca as soon as they become aware of any changes to the project scope or data used in this assessment. The IESO will determine whether these changes require a re-assessment.

2. The connection applicant shall ensure that the BPS elements are in compliance with the applicable NPCC criteria and the BES elements in compliance with the applicable NERC reliability standards. To determine the standard requirements that are applicable, the IESO provides mapping tools titled "NPCC Criteria Mapping Spreadsheet" for BPS elements and "NERC Reliability Standard Mapping Tool/Spreadsheet" for BES elements at the IESO's website of Applicability Criteria for Compliance with Reliability Requirements.

   Note, the connection applicant may request an exception to the application of the BES definition. The procedure for submitting an application for exemption can be found in Market Manual 11.4: "Ontario Bulk Electric System (BES) Exception" at the IESO's website.

   The IESO's criteria for determining applicability of NERC reliability standards and NPCC Criteria can be found in the Market Manual 11.1: "Applicability Criteria for Compliance with NERC Reliability Standards and NPCC Criteria" at the IESO's website.

   Compliance with these reliability standards will be monitored and assessed as part of the IESO's Ontario Reliability Compliance Program. For more details about compliance with applicable reliability standards reliability standards, the connection applicant is encouraged to contact orcp@ieso.ca and also visit the Ontario Reliability Compliance Program webpage.

   However, like any other system element in Ontario, the BPS and BES classifications of the project will be periodically re-evaluated as the electrical system evolves. Newly identified BPS and BES facilities associated with this project are listed in Appendix C.

3. The connection applicant shall ensure that the project's equipment meet the voltage requirements specified in section 4.2 and section 4.3 of the Ontario Resource and Transmission Assessment Criteria (ORTAC).

4. According to Section 6.1.2 of the TSC, the connection applicant must ensure the project's transmission connection equipment is designed to withstand the fault levels in the area. According to Section 6.4.4 of the TSC, if any future system changes result in an increased fault level higher than the project's equipment capability, the connection applicant is required to

replace that equipment with higher rated equipment capable of withstanding the increased fault level, up to the maximum fault level specified in Appendix 2 of the TSC.

It is the connection applicant's responsibility to verify that all equipment and circuit breakers within the project are appropriately sized for the local fault levels.

The connection applicant shall ensure that the circuit breakers/switchers installed at the project have rated interrupting time that satisfies Appendix 2 of the TSC. Fault interrupting devices installed at the project must be able to interrupt fault currents at the applicable maximum continuous voltage as specified in Section 4.2 and Section 4.3 of ORTAC.

5. The connection applicant shall ensure that the protection systems are designed to satisfy all the requirements of the TSC. New protection systems must be coordinated with existing protection systems. Protection systems within the project shall only trip the appropriate equipment isolating the fault.

   Associated overvoltage protective relaying must be set to ensure that the project's equipment does not automatically trip for voltages up to 5% above the equipment's corresponding maximum continuous voltage as specified in section 4.2 of the ORTAC.

   BPS elements are deemed by the IESO to be essential to system reliability and security and must be protected by redundant protection systems in accordance with Section 8.2 of the TSC. These redundant protection systems must satisfy all requirements of the TSC, and in particular, they must be physically separated and not use common components, common battery banks, or common instrument transformer secondary windings.

   The protection systems for transmission voltage BES elements (whose rated voltage is higher than 100 kV) must be redundant. Redundancy must be present in protective relaying for normal fault clearing and control circuitry associated with protective functions including trip coils of the circuit breakers or other interrupting devices. These redundant protection systems must not use common instrument transformer secondary windings. A single communication system, if used, must be monitored and reported and a single DC supply, if used, must be monitored and reported for both low voltage and open circuit.

   As the electrical system evolves, transmission voltage non-BPS or non-BES elements (whose rated voltage is higher than 100 kV) within the project, may be re-classified as BPS elements or BES elements. The connection applicant is recommended to design the protection systems for these elements according to the protection requirements for BPS elements or have adequate provisions for future upgrade to meet those requirements.

   The connection applicant shall ensure that the project's automatic reconnection capability, if available, be disabled. Upon its disconnection following a contingency, the connection applicant must obtain the IESO's approval before reconnecting the project to the IESO-controlled grid.

6. The connection applicant shall ensure that the connection equipment is designed to be fully operational in all reasonably foreseeable ambient conditions. Failures of the connection

equipment must be contained within the project and have no adverse impact on the IESO-controlled grid.

7. The connection applicant must initiate the IESO's Market Registration process at least eight months prior to the commencement of any project related outages.

   The connection applicant is required to provide "as-built" equipment data for the project during the IESO Market Registration process. If the submitted equipment data differ materially from the ones used in this assessment, then further analysis of the project may need to be done by the IESO before final approval to connect is granted.

   Models and data, including any controls that would be operational, must be provided to the IESO. This includes both PSS/E and DSA software standard library models representing the new equipment for further IESO, NPCC and NERC analytical studies. The models and data may be shared with other reliability entities in North America as needed to fulfill the IESO's obligations under the Market Rules, NPCC and NERC rules. The connection applicant may need to contact the software manufacturers directly, in order to have the models included in their packages. This information should be submitted at least eight months before energization to the IESO-controlled grid, to allow the IESO to incorporate this project into IESO work systems and to perform any additional reliability studies.

   As part of the IESO Market Registration process, the connection applicant must also provide evidence to the IESO confirming that the project's equipment installed meets the Market Rules requirements and matches or exceeds the performance predicted in this assessment. This evidence shall be either type tests done in a controlled environment or commissioning tests done on-site. In either case, the testing must be done not only in accordance with widely recognized standards, but also to the satisfaction of the IESO. Until this evidence is provided and found acceptable to the IESO, the Market Registration process will not be considered complete and the connection applicant must accept any restrictions the IESO may impose upon this project's participation in the IESO-administered markets or connection to the IESO-controlled grid. The evidence must be supplied to the IESO within 30 days after completion of commissioning tests. Failure to provide evidence may result in disconnection from the IESO-controlled grid.

   If the submitted models and data differ materially from the ones used in this assessment, then further analysis of the project may need to be done by the IESO before final approval to connect is granted.

   At the sole discretion of the IESO, performance tests may be required at generation and transmission facilities. The objectives of these tests are to demonstrate that equipment performance meets the IESO requirements, and to confirm models and data are suitable for IESO purposes. The H1 transmitter may also have its own testing requirements. The IESO and the H1 transmitter will coordinate their tests, share measurements and cooperate on analysis to the extent possible.

   Once the IESO's Market Registration process has been successfully completed, the IESO will provide the connection applicant with a Registration Approval Notification (RAN) document, confirming that the project is fully authorized to connect to the IESO-controlled grid. For more details about this process, the connection applicant is encouraged to contact IESO's Market Registration at market.registration@ieso.ca.

8. The connection applicant shall ensure that wholesale revenue metering installations comply with Chapter 6 of the Market Rules. This includes any intermediate project stages such as installation of temporary equipment or the use of mobile transformers. For more details, the connection applicant is encouraged to seek advice from their Metering Service Provider (MSP) or from the IESO metering group in early stages of project design.

9. As per Market Manual 1.4: Connection Assessment and Approval (formerly Market Manual 2.10), the connection applicant will be required to provide a status report of its proposed project with respect to its progress upon request of the IESO using the project status report form on the IESO website. Failure to comply with project status requirements listed in Market Manual 1.4: Connection Assessment and Approval (formerly Market Manual 2.10) will result in the project being withdrawn.

   The connection applicant will be required to also provide updates and notifications in order for the IESO to determine if the project is "committed" as per Section 3.3 of Market Manual 1.4: Connection Assessment and Approval (formerly Market Manual 2.10).

The following requirements, i.e. (10) – (13), apply to only Algoma Steel – New Load Facility (CAA 2021-694):

10. In accordance with Appendix 4.3 of the Market Rules, the connection applicant shall ensure the project have the capability to maintain the power factor within the range of 0.9 lagging and 0.9 leading as measured at the defined meter point of the project by adjusting its reactive compensation at any time, upon the IESO's or the transmitter's request. However, it is recognized that the project with its reactive compensation required by the IESO in-service may normally operate outside this range.

11. The connection applicant has a total peak load at all its owned facilities, including the project, which is greater than 25 MW. According to Section 10.4.6 of Chapter 5 of the Market Rules and Section 11.3 of the Market Manual 7.1, the connection applicant is required to participate in the automatic Under-Frequency Load Shedding (UFLS) program and must select 35% of total peak load among its owned facilities for under-frequency tripping, based on a date and time specified by the IESO that approximates system peak, according to Section 10.4 of Chapter 5 of the Market Rules.

    The UFLS relay connected loads shall be set to achieve the amounts to be shed as stated in Section 11.3 of Market Manual 7.1. Table 1 summarizes UFLS relay settings as a function of the total peak load of all facilities, including the project, owned by the connection applicant.

Table 1: UFLS relay settings

Aggregate Summer Peak Load	UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)	Load Shed at stage as % of Connection Applicant's Load	Cumulative Load Shed at stage as % of Connection Applicant's Load
25 MW or more and less than 50 MW	1	59.5	0.3	≥ 35	≥ 35
50 MW or more and less than 100 MW	1	59.5	0.3	≥ 17	≥ 17
	2	59.1	0.3	≥ 18	≥ 35
100 MW or greater	1	59.5	0.3	7 – 9	7 – 9
	2	59.3	0.3	7 – 9	15 – 17
	3	59.1	0.3	7 – 9	23 – 25
	4	58.9	0.3	7 – 9	32 – 34
	Anti-Stall	59.5	10.0	3 – 4	35 – 37

The connection applicant, in conjunction with the H1 transmitter, must also ensure that capacitor banks connected to the same station bus as the load are shed by UFLS facilities at 59.5 Hz with a time delay of 3 seconds.

The maximum load that can be connected to any single UFLS relay is 150 MW to ensure that the inadvertent operation of a single under-frequency relay during the transient period following a system disturbance does not lead to further system instability.

The IESO will review the requirements annually and inform the relevant market participants of their automatic UFLS obligations.

12. In accordance with Section 7.5 of Chapter 4 of the Market Rules, the connection applicant shall provide to the IESO the applicable telemetry data listed in Appendix 4.17 of the Market Rules on a continual basis. The data shall be provided in accordance with the performance standards set forth in Appendix 4.22, subject to Section 7.6A of Chapter 4 of the Market Rules. The whole telemetry list will be finalized during the IESO's Market Registration process.

    The connection applicant must install monitoring equipment that meets the requirements set forth in Appendix 2.2 of Chapter 2 of the Market Rules. As part of the IESO's Market Registration process, the connection applicant must also complete end to end testing of all necessary telemetry points with the IESO to ensure that standards are met and that sign conventions are understood. All found anomalies must be corrected before IESO's final approval to connect any phase of the project is granted.

13. The ORTAC states that the transmission system must be planned such that, following design criteria contingencies on the transmission system, affected loads can be restored with the restoration times listed below:
    a. All load must be restored within approximately a target of 8 hours;
    b. When the amount of load interrupted is greater than 150MW, the amount of load in excess of 150MW must be restored within approximately a target of 4 hours;
    c. When the amount of load interrupted is greater than 250MW, the amount of load in excess of 250MW must be restored within a target of 30 minutes.

The following requirements, i.e. (14) – (19), apply to only Lake Superior Power CGS – Generation Configuration (CAA 2021-695). In the event that LSP CGS generators, exciters and power system stabilizers are not able to meet the prevailing performance requirements as per Market Rules Appendix 4.2 and outlined below, the connection applicant must ensure they meet, at a minimum, the original performance requirements applicable to them when the units were once connected directly to the 115 kV LSP CGS bus.

14. As per Appendix 4.2 of the Market Rules, the connection applicant shall ensure that the generation facility has the capability to operate continuously between 59.4 Hz and 60.6 Hz and for a limited period of time in the region bounded by straight lines on a log-linear scale defined by the points (0.0 s, 57.0 Hz), (3.3 s, 57.0 Hz), and (300 s, 59.0 Hz) and the straight lines on a log-linear scale defined by the points (0.0 s, 61.8 Hz), (8 s, 61.8 Hz), and (600 s, 60.6 Hz).

    The facility has to have the capability to Regulate speed/frequency with an average droop based on maximum active power adjustable between 3% and 7% and set at 4% unless otherwise specified by the IESO. Regulation dead-band shall not be wider than ±0.06%. Speed/frequency shall be controlled in a stable fashion in both interconnected and island operation. A sustained 9% change of rated active power after 10 s in response to a step change of speed of 0.5% during interconnected operation shall be achievable. Due consideration will be given to inherent limitations such as mill points and gate limits when evaluating active power changes. Control systems that inhibit primary frequency response shall not be enabled without IESO approval.

15. The project is directly connected to the IESO-controlled grid, and thus, according to Appendix 4.2 of the Market Rules, the connection applicant shall ensure that the project has the capability to:
    - continuously supply all levels of active power output within a +/- 5% range of its rated terminal voltage. Rated active power is the smaller output at either rated ambient conditions (e.g. temperature, head, wind speed, solar radiation) or 90% of rated apparent power. To satisfy steady-state reactive power requirements, active power reductions to rated active power are permitted.;
    - Continuously (i.e., dynamically) inject or withdraw reactive power at the high-voltage terminal of the main output transformer up to 33% of rated active power at all levels of

active power output, and at the typical transmission system voltage, except where a lesser continually available capability is permitted with the IESO's approval. A conventional synchronous unit with a power factor range of 0.90 lagging and 0.95 leading at rated active power connected via a main output transformer impedance not greater than 13% based on generation unit rated apparent power is acceptable. Reactive power losses or charging between the high-voltage terminal of the main output transformer and the connection point shall be addressed in a manner permitted by IESO approval;

Regulate voltage automatically within ±0.5% of any set point within ±5% of rated voltage at the low-voltage terminal of the main output transformer if the transformer impedance is not more than 13% based on the rated apparent power of the generation facility, or at a point approved by the IESO. Reactive power-voltage droop or AVR reference load current compensation shall not be enabled without IESO approval. The equivalent time constants shall not be longer than 20 ms for voltage sensing and 10 ms for the forward path to the exciter output. AVR reference compensation shall be adjustable to within 10% of the unsaturated direct axis reactance on the unit side from a bus common to multiple units.

16. In accordance to Appendix 4.2 of the Market Rules, the connection applicant shall ensure that the excitation systems of the project shall have (a) Positive and negative ceilings not less than 200% and 140% of rated field voltage, respectively, while supplying the field winding of the generation unit operating at nominal voltage under open circuit conditions; (b) An excitation transformer impedance not greater than 10% on excitation system base; (c) A voltage response time to either ceiling not more than 50 ms for a 5% step change from rated voltage under open-circuit conditions; and (d) a linear response between ceilings. Rated field current is defined at rated voltage, rated active power and required maximum continuous reactive power.

    In accordance to Appendix 4.2 of the Market Rules, the connection applicant shall ensure that the Power System Stabilizers (PSS) of the project shall have (a) a change of power and speed input configuration; (b) positive and negative output limits not less than ±5% of rated AVR voltage; (c) phase compensation adjustable to limit angle error to within 30° between 0.2 Hz and 2.0 Hz under conditions specified by the IESO, and (d) gain adjustable up to an amount that either increases damping ratio above 0.1 or elicits exciter modes of oscillation at maximum active output unless otherwise specified by the IESO. Due consideration will be given to inherent limitations.

17. In accordance to Appendix 4.2 of the Market Rules, the connection applicant shall ensure the project shall have the capability to ride-through routine switching events and design criteria contingencies assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times, unless disconnected by configuration.

    The connection applicant will be required to demonstrate the project's voltage ride-through capability during commissioning by either providing manufacturer test results or monitoring several variables under a set of IESO specified field tests, and the test results must be verifiable using the dynamic models provided for the project.

18. The connection applicant shall install a permanent device for disturbance recording that meets the technical specifications provided in Section 2.7 of Market Manual 1.6: Performance Validation (formerly Market Manual 2.20). The quantities to be recorded and the trigger settings will be provided by the IESO during the Market Registration process.
19. If applicable according to Section 7.3 of Chapter 4 of the Market Rules, the connection applicant shall provide to the IESO the applicable telemetry data listed in Appendix 4.15 of the Market Rules on a continual basis. The data shall be provided with equipment that meets the requirements set forth in Appendix 2.2, Chapter 2 of the Market Rules, in accordance with the performance standards set forth in Appendix 4.19, subject to Section 7.6A of Chapter 4 of the Market Rules. The whole telemetry list will be finalized during the IESO's Market Registration process.

    As part of the IESO's Market Registration process, the connection applicant must also complete end to end testing of all necessary telemetry points with the IESO to ensure that standards are met and that sign conventions are understood. All found anomalies must be corrected before IESO's final approval to connect any phase of the project is granted.

Appendix B: Project Data (Confidential)

Appendix C: Facility Classification (Confidential)

Appendix D: Study Scope of Work (Confidential)

Appendix E: Detailed Study Results (Confidential)

Appendix F: Remedial Action Scheme Selection Matrices (Confidential)

Appendix G: Commissioning Tests (Confidential)

Appendix H: Protection Impact Assessments (Confidential)

Appendix I: Telemetry Requirements (Confidential)

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