Central East Transfer-out (CETO) Stage 2 Transmission Development

Reaffirmation Study Report

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1. Introduction

The AESO's Needs Identification Document (NID) and the transmission facility owners' Facility Applications (FA) for the Central East Transfer-out (CETO) Transmission Development were approved by the Alberta Utilities Commission in August, 2021. As part of the approved CETO NID, the AESO determined it to be appropriate to specify construction milestones, in accordance with Subsection 11(4) of the *Transmission Regulation*, for the construction and energization of each stage of the Preferred Transmission Development. The construction milestone monitoring process enables the AESO to manage uncertainty regarding the timing and impacts of generation development in the CETO Study Area.[1]

The AESO has been monitoring generation development in the CETO Study Area as incremental generation meets the AESO's project inclusion criteria.[2] Once incremental generation is within the milestone monitoring range, the AESO will reaffirm that congestion is forecast to occur greater than 0.5% of the time annually during the N-0 or N-1 system conditions by performing congestion assessment studies that take into account the locations and sizes of the generation meeting the certainty criteria. The reaffirmation study process is shown in Figure 1.

[1] The CETO Study Area and the Study Area used for this report, are defined in Section 2.0.

[2] The AESO's project inclusion criteria are available in *ID #2018-018T Provision of System Access Service and the AESO Connection Process*, on the AESO website.

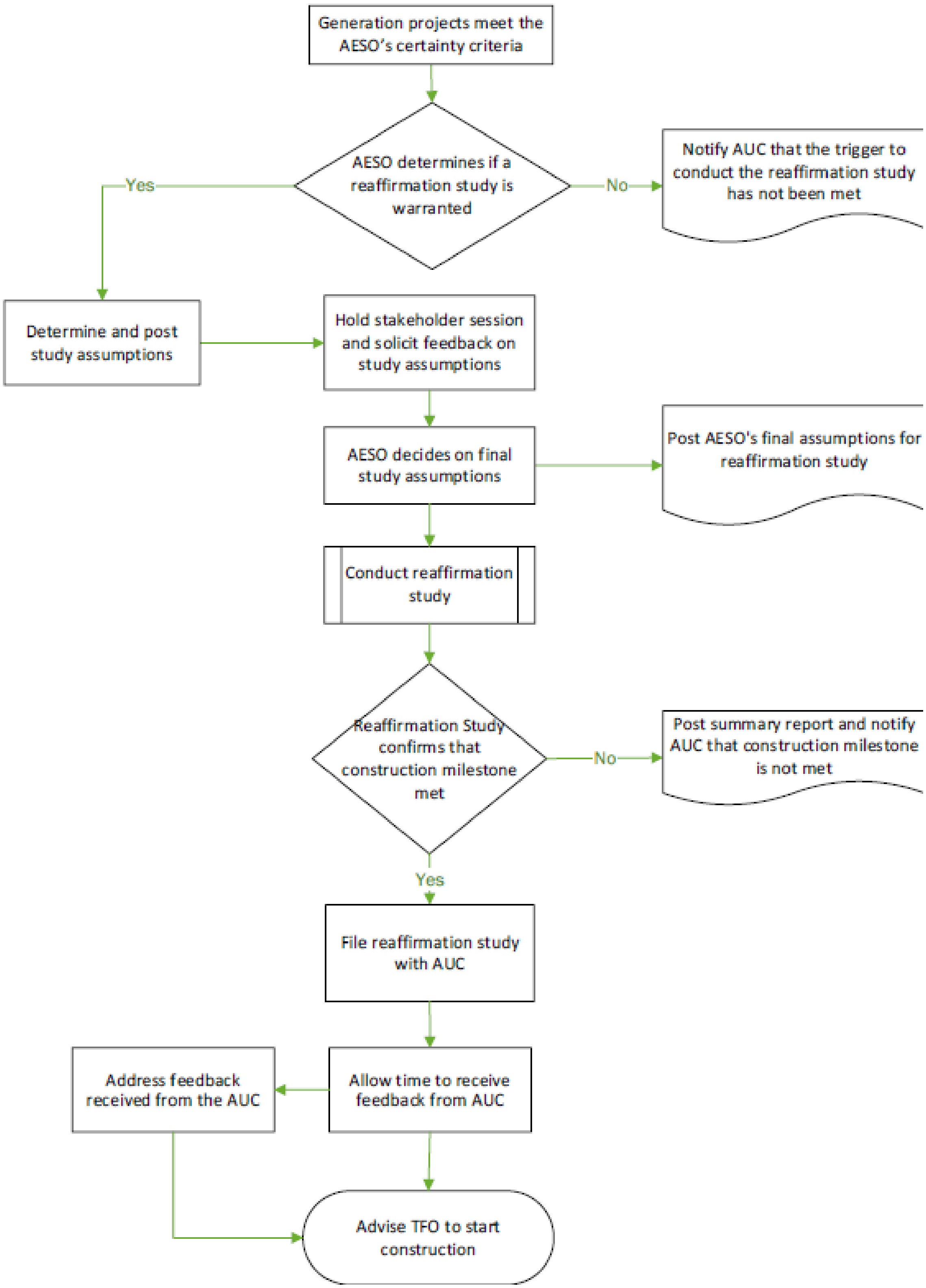

Figure 1: Reaffirmation Study Process

Approximately 3,436 MW of new generation in the study area met AESO's project inclusion criteria in August, 2022. This was on top of the energized renewable generation of 1,487 MW in the study area and was above the upper range of the CETO milestone monitoring range (1,050 MW to 1,550 MW), as identified in the CETO NID. Therefore, a reaffirmation study was completed in 2022 to determine if there was sufficient congestion to trigger the CETO Stage 1 construction milestone. The results of the reaffirmation study indicated the need to trigger CETO Stage 1 construction.

As more generation projects in the Central and South Planning Regions[3] meet the AESO's project inclusion criteria[4] between the August 31, 2022 and November 30, 2023, the AESO initiated another reaffirmation study to determine if there was sufficient congestion to trigger the CETO Stage 2 construction milestone. This Reaffirmation Study Report documents the methodology, assumptions, and results of the CETO Stage 2 reaffirmation study.

2. Modeling and Assumptions

The reaffirmation study was performed for the full year of 2026 to identify the potential risks of congestion. Year 2026 was selected since this is the anticipated in-service year for Stage 1 of the CETO project and will be the likely in-service date of CETO Stage 2 if construction is triggered in Q1 2024.

The Study Area in this study is consistent with the Study Area in the CETO NID and consists of the Central east (CE) and Southeast (SE) sub-regions, which is comprised of the following AESO planning areas:

- CE sub-region: Lloydminster (Area 13), Wainwright (Area 32), Alliance/Battle River (Area 36), Provost (Area 37), Hanna (Area 42) and Vegreville (Area 56).
- SE sub-region: Medicine Hat (Area 4), Sheerness (Area 43), Brooks (Area 47), Empress (Area 48) and Vauxhall (Area 52).

2.1. Load Assumptions

The following subsections describe the AESO's current outlook for load in the Study Area.

2.1.1. Forecast Load

The load forecast used in the reaffirmation study covers the latest information in the Study Area and was based on the AESO's *2021 Long-term Outlook*[5] (2021 LTO) Reference Case. The Reference Case load forecast represents the AESO's current expectations for long-term load growth given uncertainties facing the electricity industry. Using econometric models, the 2021 LTO provides hourly load forecasts at Alberta internal load (AIL), AESO Planning Region, AESO planning area, and Point of Delivery (POD) levels for the next 20 years.[6] The duration curve of the 2026 load used in the study is shown in Figure 2 and the minimum, average, and maximum load are shown in Table 1.

[3] The AESO Planning Regions map is available on the AESO website

[4] Sufficiently certain projects that have provided strong financial backing for their SAS

[5] The 2021 LTO is available on the AESO website.

[6] Please refer to the 2021 LTO, available on the AESO website, for more details on forecast methodology.

The reaffirmation study simulations used the weather-synchronized hourly POD level load forecasts for all the substations in the Alberta interconnected electric system (AIES). This approach captures the localized hourly load patterns and how this load diversity impacts the transmission system power flows.

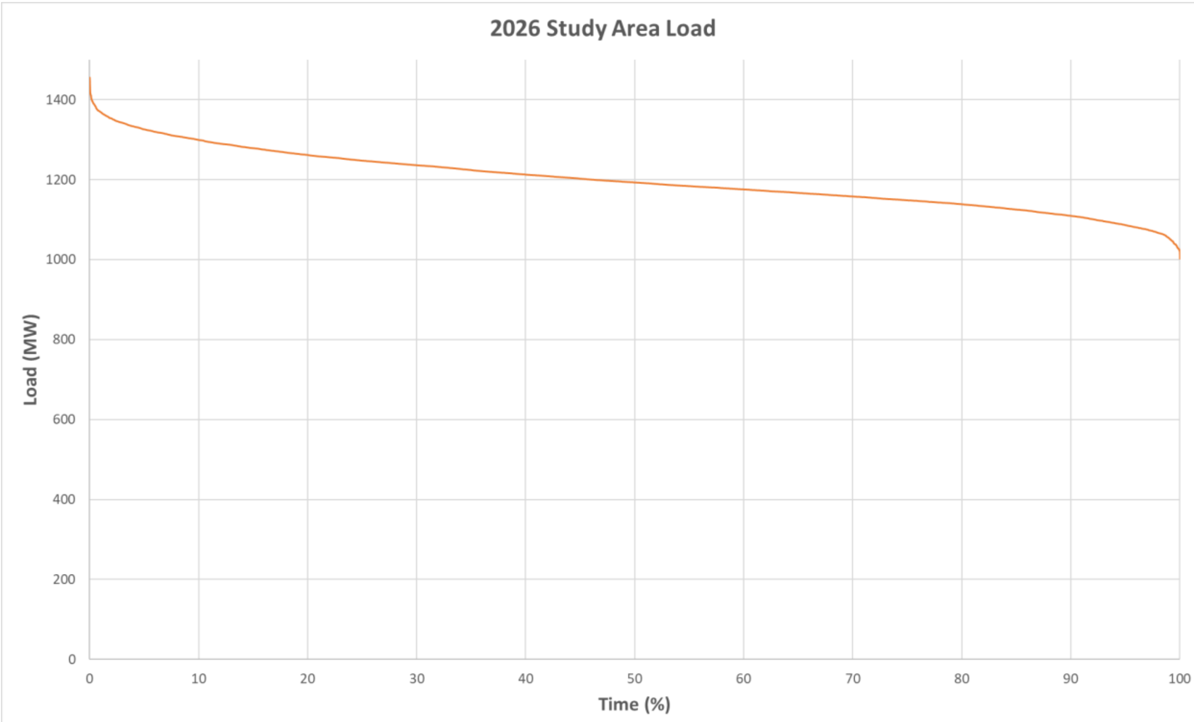

Figure 2: 2026 Study Area Load

Table 1 – Forecast Load in the Study Area for Year 2026

Minimum (MW)	Average (MW)	Maximum (MW)
1,003	1,200	1,456

2.2. Generation Assumptions

The forecast average natural gas price and carbon price for the year 2026 were $2.96/GJ and $110/ton. The forecasted gas price is lower in this study as compared to the $4.16/GJ used in the CETO Stage 1 reaffirmation conducted in Q3 2022. This change is reflecting the latest information as of June, 2023. The carbon price is consistent with the previous study. All other key generation assumptions used in this reaffirmation study are described in the sections below.

2.2.1. Renewable Generation

Table 2 below shows the aggregate maximum capacity of renewable generation in the Study Area.

Table 2 – Aggregate Maximum Capacity of Renewable Generation in the Study Area

Renewable Generation Capacity in Main Scenario (as of end of Nov 2023)	MW
In Service	3,311
CE Incremental (met project inclusion criteria)	357
SE Incremental (met project inclusion criteria)	2,720
Study Area Total	**6,388**

Table 3 has a breakdown of the projects that have met their in-service date between the previous reaffirmation study and this study.

Table 3 – Renewable Generation Projects Energized between Aug 2022 and Nov 2023

Generator	Project Name	Subregion	Fuel Type	Maximum Capability (MW)
Kneehill Solar (TRH1)	P2059 ATCO Three Hills 770S DER Solar 1	CE	Solar	25
Michichi Creek (MCH1)	P2248 ATCO Michichi Creek 802S DER Solar	CE	Solar	14
Michichi Solar (MIC1)	P2061 ATCO Michichi Creek 802S DER Solar	CE	Solar	25
Youngstown Solar (YNG1)	P2361 ATCO Youngstown 772S DER Solar	CE	Solar	6
Garden Plain (GDP1)	P1909 Garden Plain Wind	CE	Wind	130
Grizzly Bear (GRZ1)	P1250 Wild Run Grizzly Bear Wind, P2065 Wild Run Grizzly Bear Wind Phase 2	CE	Wind	152
Hand Hills (HHW1)	P2263 BER Hand Hills MPC Wind	CE	Wind	145
Lanfine Wind (LAN1)	P1898 Pattern Lanfine North Wind	CE	Wind	151
Sharp Hill Wind (SHH1)	P1567 EDPR Sharp Hills Wind Farm	CE	Wind	297
Chappice Lake (CHP1)	P2216 FortisAlberta Chappice Lake 649S DER Solar	SE	Solar	14
Clydesdale 1 (CLY1)	P2362 Fortis Enchant 447S DER Solar, P2363 Fortis Enchant 447S DER Solar	SE	Solar	41
Clydesdale 2 (CLY2)	P2364 Fortis Enchant 447S DER Solar, P2365 Fortis Enchant 447S DER Solar	SE	Solar	34
Empress Solar Park (EMP1)	P2249 FortisAlberta Empress 394S DER Solar 1, P2250 FortisAlberta Empress 394S DER Solar 2	SE	Solar	39
Wheatcrest (WCR1)	P2348 BluEarth Wheatcrest MPC Solar	SE	Solar	50
Buffalo Atlee 1 (BFL1)	P1853 Fortis Buffalo Atlee Cluster 1 WAGF	SE	Wind	18
Buffalo Atlee 2 (BFL2)	P2199 FortisAlberta Buffalo Atlee Cluster 2	SE	Wind	16
Buffalo Atlee 3 (BFL3)	P1892 Fortis Buffalo Atlee Cluster 3 WAGF DER	SE	Wind	18
Buffalo Atlee 4 (BFL4)	P2412 Fortis Buffalo Atlee Cluster 4 DER Wind	SE	Wind	10
Cypress 1 (CYP1)	P2122 Cypress Wind Project Connection	SE	Wind	196
Cypress 2 (CYP2)	P2413 EDF Cypress 2 Wind	SE	Wind	46
Hilda Wind (HLD1)	P2254 RESC Hilda MPC Wind	SE	Wind	100
Jenner 1 (JNR1)	P1533 Joss MPC WAGF	SE	Wind	122
Jenner 2 (JNR2)	P1698 Joss Jenner WAGF - Phase 2	SE	Wind	71

Jenner 3 (JNR3)	P2234 Jenner Wind Phase 3	SE	Wind	109

Maximum capacity of renewable generation in the Southwest (SW) sub-region as of the end of November, 2023 was 2,738 MW (2,295 MW existing generation and 443 MW based on projects that met the AESO's project inclusion criteria). The SW sub-region is outside the Study Area and its generation information is only included here as a reference.

2.2.2. Major Thermal Generation in the Study Area

Table 4 below lists the major thermal generators in the Study Area that were included in the reaffirmation study.

Table 4 – Major Thermal Generators in the Study Area

Asset	Type	Maximum Capability (MW)	Subregion
Battle River #4 (BR4)	Coal to Gas	155	CE
Battle River #5 (BR5)	Coal to Gas	385	CE
Sheerness #1 (SH1)	Coal to Gas	400	SE
Sheerness #2 (SH2)	Coal to Gas	400	SE

2.2.3. Projects that Met the AESO's Project Inclusion Criteria

Generation projects in the Study Area that met the AESO's project inclusion criteria as of the end of November, 2023 and had an ISD within or before the year 2026 were included in the studies. Table 5 below lists the projects in the Study Area that were included in the studies.

Table 5 – Projects in the Study Area that Met the AESO's Project Inclusion Criteria

Project Name	Type	Maximum Capability (MW)	Planning Area
P1704 Paintearth Wind Power	Wind	150	42-Hanna
P1978 ATCO Michichi DER Solar	Solar	75	42-Hanna
P2259 FortisAlberta Metiskow 648S DER Solar*	Solar	23	37-Provost
P2292 FortisAlberta Killarney Lake 267S DER Solar/Battery Storage*	Solar	23	37-Provost
P2424 ATCO Oyen 767S DER Solar*	Solar	15	42-Hanna
P2469 ATCO Vermilion 710S DER Gas*	Gas	5	13-Lloydminster
P2548 ATCO Irish Creek 706S DER Gas*	Gas	5	13-Lloydminster
P2562 Paintearth Wind Phase 2*	Wind	40	42-Hanna
P2574 Fortis Aura Provost DER Solar*	Solar	23	37-Provost
P0693 Wild Rose 2 Wind Farm	Wind	192	04-Medicine Hat
P1926 Solar Krafte Vauxhall*	Solar	60	52-Vauxhall
P1927 Solar Krafte Brooks (RWE Beargrass)	Solar	360	47-Brooks
P2137 Enerfin Winnifred MPC Wind*	Wind	90	04-Medicine Hat
P2195 FortisAlberta Bassano 435S DER Solar	Solar	9	47-Brooks

P2237 RESC Forty Mile MPC Wind*	Wind	266	04-Medicine Hat
P2247 Buffalo Plains MPC Wind	Wind	466	47-Brooks
P2337 Dunmore Solar	Solar	216	04-Medicine Hat
P2347 Forty Mile Granlea Solar Phase 2	Solar	220	04-Medicine Hat
P2369 ATCO Anderson 801S DER Solar*	Solar	13	43-Sheerness
P2411 Northland Power Jurassic MPC Solar Battery*	Solar	300	48-Empress
P2421 RESC Big Sky Solar*	Solar	140	48-Empress
P2446 Fortis Tilley 498S DER Solar*	Solar	24	47-Brooks
P2465 Enerfin Winnifred Wind Modification*	Wind	150	04-Medicine Hat
P2537 Fortis Duchess 339S DER Solar Battery*	Solar	20	47-Brooks
P2564 ATCO Bullpound 803S DER Solar*	Solar	15	43-Sheerness
P2593 Forty Mile Wind Phase 2*	Wind	134	04-Medicine Hat
P2629 Taber Solar*	Solar	45	52-Vauxhall
Total		**3077**	

* Project met AESO's inclusion criteria between August, 2022 and November, 2023

2.3. Transmission System Assumptions

The Alberta interconnected electric system (AIES) was modeled in its entirety. The transmission system's three interties, to British Columbia, Saskatchewan, and Montana, were modeled and the neighboring jurisdictions had simplified representations. Intertie available transfer capability was established based on historical performance. Flows on interties were predicted based on price differentials yielded by production cost modeling. The Provost to Edgerton and Nilrem to Vermilion (PENV) was excluded from the model in the Main Scenario of the reaffirmation study.

2.3.1. Contingencies

The contingencies listed in Table 6 were simulated in the reaffirmation study.

Table 6 – Contingencies

Transmission Element	Voltage Class (kV)
7L42	138
7L50	138
7L130	138
7L701	138
7L749	138
9L16	240
9L20	240
9L24	240

9L27	240
9L29	240
9L46	240
9L59	240
9L80	240
9L950	240
174L	138
408L	138
701L	138
704L	138
749L	138
912L	240
923L	240
924L	240
927L	240
931L	240
933L/9L933	240
934L/9L934	240
935L	240
944L	240
948L/9L948	240
951L	240
953L/9L953	240
966L/9L966	240
1034L	240
1035L	240
1047L	240
1051L	240
1052L	240
1053L	240
1075L	240
1087L	240
1088L	240
CETO Stage 1	240

EATL	500
WATL	500

2.3.2. Monitored Transmission Lines and Ratings

Seven key transmission lines in the CE sub-region were monitored in this reaffirmation study. The normal ratings for the monitored transmission lines are listed in Table 7. The software used to perform the reaffirmation study, AURORA, uses a linearized DC model for power flow calculations which assumes a voltage of 1 p.u. at each bus. The thermal ratings of the transmission lines were adjusted accordingly. The ratings were converted from MVA to MW using a power factor of 0.95 to account for the capacity that might be used for reactive power flow.

Table 7 – Ratings of Monitored Transmission Lines

Transmission Line	Substation 1	Substation 2	Voltage Class (kV)	Summer Rating (MVA)	Winter Rating (MVA)
912L	Red Deer 63S	Nevis 766S	240	507	624
9L20	Cordel 755S	Nevis 766S	240	489[7]	540
174L	North Holden 395S	Bardo 197S	138	120	145
701L	North Holden 395S	Strome 223S	138	119	146
7L701	Battle River 757S	Strome 223S	138	142	192
9L16	Tinchebray 972S	Cordel 755S	240	499	499
CETO Stage 1	Tinchebray 972S	Gaetz 87S	240	831	831

2.3.3. HVDC Dispatch

The high voltage direct current (HVDC) transmission lines called Western Alberta Transmission Line (WATL) and Eastern Alberta Transmission Line (EATL), were dispatched to minimize transmission system losses in the reaffirmation study. A formula that estimates the minimum loss dispatch based on flows measured on certain alternating current transmission lines was used to determine the HVDC dispatch that should be used for each hour in the simulation.

2.4. Study Scenarios

The main scenario of the reaffirmation study was based on the assumptions stated in Sections 2.1 – 2.3. However, to consider the uncertainties of the future, additional sensitivity studies were performed by considering retirement of the following major thermal generators in the Study Area: Battle River #4 (BR4), Battle River #5 (BR5), Sheerness #1 (SH1), and Sheerness #2 (SH2). An additional study was also

[7] Transmission Capital Maintenance (TCM) works required. The AESO will be engaging ATCO as the Transmission Facility Owner to coordinate the required maintenance work.

performed by assuming the CETO Stage 2 lines are in service to verify the effectiveness of CETO to relieve congestion. Table 8 below lists the scenarios studied.

Table 8 – Study Scenarios

Scenario	BR4	BR5	SH1	SH2	CETO
Main Scenario	In Service	In Service	In Service	In Service	Stage 1
Sensitivity 1	Out of Service	Out of Service	Out of Service	Out of Service	Stage 1
Sensitivity 2	In Service	In Service	In Service	In Service	Stage 1 and Stage 2

3. Reaffirmation Study Results

The nodal simulations for each scenario were run as if there were no transmission system constraints. Renewable generators in the CE and SE area were treated as must run units to capture the potential impact of these dispatches. Congestion statistics were then calculated using the transmission line ratings shown in Table 7 of Section 2.3.2. Congestion statistics were calculated for both N-0 and N-1 system conditions based on the contingencies shown in Table 6 of Section 2.3.1. Under N-0, the system must be able to operate congestion free without needing to curtail generation. As such, any hour where flow on lines exceed their thermal ratings is a congested hour. Generation curtailment is allowed post contingency up to the Most Severe Single Contingency (MSSC) value of 466 MW. Thus, an hour under N-1 conditions is considered a congested hour if it requires curtailment greater than 466 MW in order to mitigate line overloads as generation would need to be curtailed pre-contingency (N-0 condition) to avoid curtailing more than 466 MW post-contingency.

While calculating N-1 congestion, dispatch of recently energized generation and generation projects that met the AESO’s project inclusion criteria was allowed to be curtailed up to 466 MW via Remedial Action Scheme (RAS) to mitigate overloads on any of the monitored elements mentioned in Table 7 of Section 2.3.2. Hours where the amount of generation curtailment required to mitigate overloads under contingency conditions exceeded the MSSC value of 466 MW were considered and included as hours with congestion. For N-0, generation was not curtailed and any hour with a line overload was included as a congested hour.

Table 9 below presents the congestion results for all the monitored transmission lines in the Study Area. The table shows the percentage of congested hours expected in 2026 for the scenarios listed in Table 8 of Section 2.4 under both N-0 and N-1 system conditions.

Table 9 – Reaffirmation Study Results

Scenario	Annual Congestion (% of Hours)	
	N-0	N-0 & N-1 with RAS
Main Scenario	0.0	1.29
Sensitivity 1	0.0	0.49
Sensitivity 2	0.0	0.50

The results in Table 9 show that N-1 congestion even after an optimized RAS is applied would exceed the AESO's annual threshold of 0.5% of hours for the Main Scenario. This indicates that without CETO Stage 2, the AESO anticipates congestion that is higher than the established 0.5% trigger threshold. Even when the two major thermal generation facilities of Battle River and Sheerness are both assumed to be out of service, congestion is close to the 0.5% trigger threshold.

Sensitivity 2, where the CETO Stage 2 was included as part of the model, was also completed to verify the effectiveness of the project in relieving congestion. As the results indicate, congestion is at the threshold with CETO Stage 2 in service.

4. Conclusion

The results of the Main Scenario of this reaffirmation study show that the anticipated congestion in the Study Area would exceed the 0.5% trigger threshold without CETO Stage 2 transmission development. Furthermore, the results of the Sensitivity 1 scenario indicate that even if both thermal generators in the Study Area (Battle River & Sheerness) are out of service, congestion is still at the 0.5% trigger threshold in 2026.

These results indicate that with generation projects that have met the AESO's project inclusion criteria, congestion will exceed the AESO's annual threshold of 0.5%. Therefore, the CETO Stage 2 construction milestone has been met. The results of the Sensitivity 2 scenario confirm that CETO Stage 2 is an effective solution in relieving the anticipated congestion.