In the Matter of the Need for the Central East Transfer-out Transmission Development

And in the matter of the *Electric Utilities Act*, S.A. 2003, c. E-5.1, the *Alberta Utilities Commission Act*, S.A. 2007, c. A-37.2, the *Hydro and Electric Energy Act*, R.S.A. 2000, c. H-16, the Regulations made thereunder, *and Alberta Utilities Commission Rule 007*

Needs Identification Document for Central East Transfer-out Transmission Development

Date: Wednesday, August 12, 2020

Classification: Public

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PART A - APPLICATION

1. Introduction

1.1 Application

Pursuant to Section 34(1) of the *Electric Utilities Act* (Act), the Alberta Electric System Operator (AESO) applies to the Alberta Utilities Commission (Commission) for approval of this *Central East Transfer-out (CETO) Transmission Development Needs Identification Document* (Application).

1.2 Application Overview

This Application describes the need to enable additional generation integration capability in the Central east (CE) and Southeast (SE) sub-regions of Alberta. With a forecasted increase in renewable generation development in the CE and SE sub-regions, an expansion of the transfer-out capability of the transmission system is needed to enable surplus generation to be transferred from the CE and SE sub-regions to adjacent load centres. This Application also describes the AESO's Preferred Transmission Development to meet the need and the proposed timing of the AESO's Preferred Transmission Development.

The AESO, in accordance with its transmission system planning responsibilities, submits this Application to the Commission for approval having determined that the Preferred Transmission Development is required to meet the needs of Alberta and is in the public interest.

1.3 AESO Directions to the Transmission Facility Owners

Pursuant to Section 39 of the Act and Section 14 of the *Transmission Regulation*, the AESO directed the legal owners of the transmission facilities (TFOs), in this case, AltaLink Management Ltd., in its capacity as general partner of AltaLink, L.P. (AltaLink), and ATCO Electric Ltd. (ATCO), to assist the AESO in preparing this Application.[1]

[1] The directions are described in more detail in the following sections of this Application and in Part C, note iv.

2. Central East and Southeast Sub-region Transmission System and Forecast

2.1 Introduction

The AESO performs system planning studies to assess the transmission system and to ensure the safe, reliable, and economic delivery of electricity wherever and whenever it is needed. The system planning studies in the Planning Report[2] conducted for this Application assessed the need for transmission development in the Central and South Planning Regions[3] to enhance the transfer-out capability of forecasted generation growth, specifically in the CE and SE sub-regions (Study Area) of Alberta. Table 1 and Figure 1 identify the 11 AESO planning areas in the Study Area that were assessed in the Planning Report.

Table 1: AESO Planning Areas Included in the Study Area

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

2.2 Existing Central East and Southeast Transmission System

The Planning Report includes an assessment of the transmission system in the Study Area to confirm its generation integration capability and to determine the required transmission development to accommodate forecasted generation growth in the CE and SE sub-regions. The Study Area transmission system is shown in Figure 1 and described below.

2.2.1 Central East Sub-region

In the CE sub-region, the load is predominantly served through an existing 138 kV/144 kV transmission system, which is supplied by a looped 240 kV transmission system. The surplus generation from the CE sub-region is transferred out to the rest of the Alberta interconnected electric system (AIES) through three transfer-out paths[4]. The west transfer-out path is the most limited of these three transfer-out paths in terms of its ability to transfer out surplus generation. It connects the CE sub-region to Red Deer (Area 35) and the Edmonton Planning Region, and consists of:

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[2] The AESO's *Central East Transfer-out Transmission Development Planning Report* is provided in Appendix A of this Application.

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

[4] Additional information about the three transfer-out paths is provided in Appendix A of this Application.

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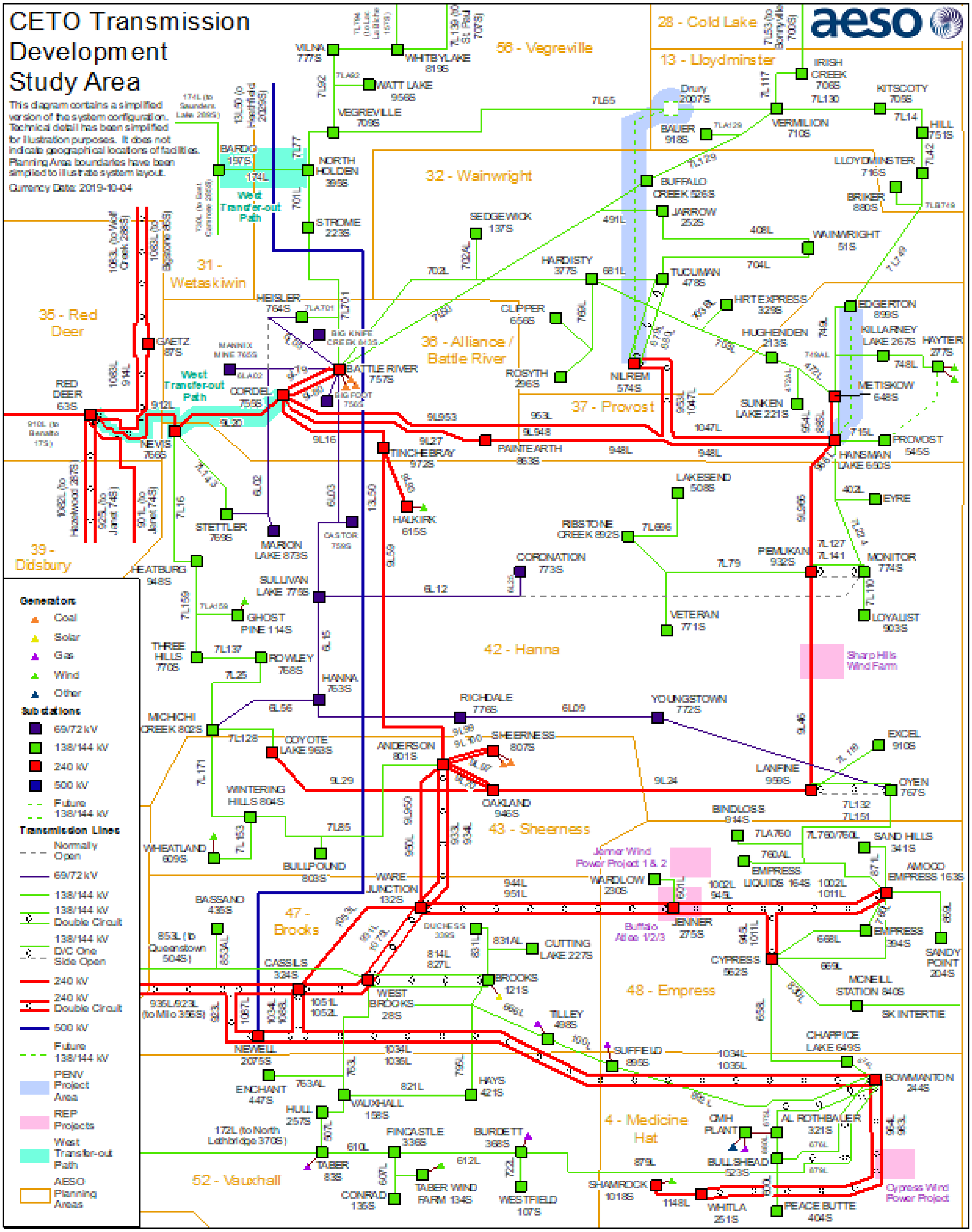
- the 240 kV transmission lines 912L, between the Red Deer 63S substation in Red Deer (Area 35) and the Nevis 766S substation in Hanna (Area 42), and 9L20, between the Nevis 766S substation in Hanna (Area 42) and the Cordel 755S substation, in Alliance/Battle River (Area 36); and
- the 138 kV transmission line 174L, between the Bardo 197S substation in Wetaskiwin (Area 31) and the North Holden 395S substation in Vegreville (Area 56).

The approved Provost to Edgerton and Nilrem to Vermilion Transmission System Reinforcement[5] (the PENV development) is designed to alleviate the existing and anticipated constraints on the 138/144 kV transmission network (such as 7L50 in Wainwright (Area 32) and 749L in Provost (Area 37)), and to provide reasonable access options for generation in the area. The PENV development is expected to be in service in 2022.

In addition, the 500 kV high-voltage direct current (HVDC) transmission line (Eastern Alberta Transmission Line (EATL)) runs through the CE sub-region and facilitates transmission of power between the Study Area and the Northeast Planning Region.

[5] The *Provost to Edgerton and Nilrem to Vermilion (PENV) Transmission System Reinforcement Needs Identification Document* was originally approved by the Commission on April 10, 2019 in Decision 23429-D02-2019.

Figure 1: Study Area



2.2.2 Southeast Sub-region

In the SE sub-region, the existing 240 kV transmission system delivers power from Medicine Hat (Area 4) and Empress (Area 48) to Brooks (Area 47). The 240 kV transmission system is designed to collect and provide transmission system access to geographically dispersed renewable generation sources and move power to load centres. The 240 kV transmission lines 1034L (between Bowmanton 244S and Cassils 324S substations), 1088L (between Newell 2075S and Cassils 324S substations), and 1035L (between Bowmanton 244S and Newell 2075S substations), 964L and 983L (between Bowmanton 244S and Whitla 251S substations), and 945L (between Jenner 275S and Cypress 562S substations), 1002L (between Jenner 275S and Amoco Empress 163S substations), and 1011L (between Amoco Empress 163S and Cypress 562S substations), serve as integral transmission systems in the SE sub-region to collect and provide transmission system access to generation sources.

2.2.3 Existing Constraints in the Study Area

Existing constraints in the Study Area are managed in accordance with the procedures set out in Section 302.1 of the ISO rules, *Real Time Transmission Constraint Management*.[6] There are currently 17 remedial action schemes (RAS) and automatic protection schemes (APS) used to manage existing constraints in the Study Area.[7] As new generation develops in the Study Area and the transmission system becomes constrained, the RAS and APS will be modified to maintain transmission system reliability.

2.3 AESO Generation and Load Forecast Assumptions

Pursuant to its responsibilities under Section 33 of the Act and Section 8 of the *Transmission Regulation*, the AESO has forecasted generation and load growth in the Study Area.[8] The generation and load data is based on the latest available forecast information and is in alignment with the *AESO 2019 Long-term Outlook* (2019 LTO).[9]

2.3.1 Generation Forecast

Existing generation in the Study Area was approximately 2,321 MW and is comprised of coal-fired, gas-fired (i.e., combined cycle and simple cycle), wind, solar, and other generation as of January 2020.[10] There is high interest in the Study Area for renewable generation development because of its solar and wind potential, with Hanna (Area 42) having the largest solar and wind potential among the 42 AESO planning areas.[11] This has been demonstrated by the fact that there are eight Renewable Electricity

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[6] Also referred to as the TCM Rule.

[7] The existing RASs do not account for the generation projects proposed in the Study Area nor the approved PENV development in the CE sub-region. As new generation develops in the Study Area, some of the RAS and APS will be modified to utilize the existing transmission system and planned transmission development. Refer to Appendix A of this Application for additional information.

[8] Details of the AESO's generation and load forecast are set out in Appendix B of this Application.

[9] The 2019 LTO is available on the AESO website. The 2019 LTO is the AESO's view of Alberta's load and generation requirements over the next 20 years.

[10] A list of the assets providing existing generation capacity in the Study Area, as of January 2020, is provided in Appendix B of this Application. The list of assets totaling 2,321 MW excludes Battle River 3 (BR3) as it was retired on December 31, 2019. In addition, as of July 2020, two solar facilities totaling 47 MW have been energized in Vauxhall (Area 52).

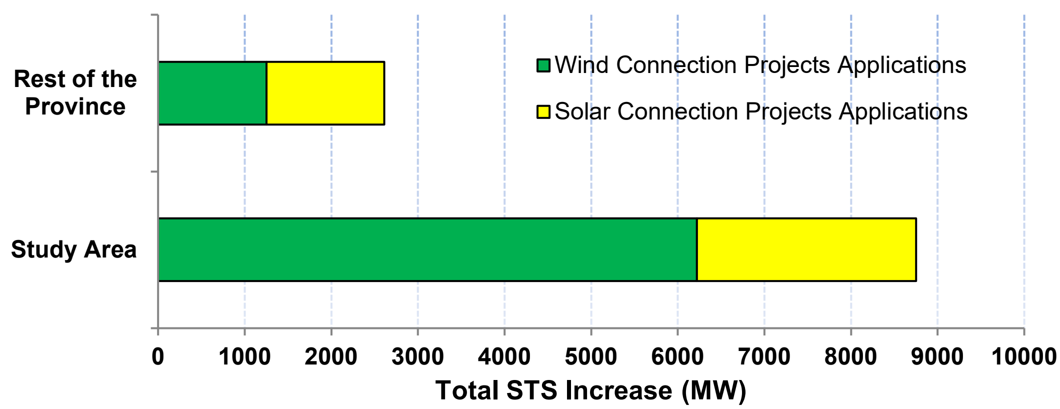
[11] AWS Truepower. June 13, 2018. *Wind and Solar Assessment, Alberta, Canada*. Prepared for the AESO is published as part of the AESO 2019 LTO and is available on the AESO website.

Program (REP) projects in the Study Area, with a total generation capacity of 894 MW anticipated to be in service by 2021. Renewable development interest has continued after REP was terminated in June 2019, as evident by the generation projects in the Study Area that have met the AESO's certainty criteria[12], by paying their Generating Unit Owner's Contribution (GUOC), totaling 320 MW of incremental generation. According to the 2019 LTO Reference Case, wind generation in the South and Central Planning Regions is forecast to grow from an existing capacity of 1,781 MW to 3,831 MW by 2039, while solar generation is forecast to grow from an existing capacity of 15 MW to 481 MW by 2039.[13]

The number of requests for transmission system access service the AESO has received demonstrates high interest for generation development in the Study Area. Based on the AESO's Project List, as of January 2020[14] there were 93 generation projects seeking connection to the transmission system in the Study Area. These projects represent a total requested *Supply Transmission Service* (Rate STS) contract capacity increase of 8,944 MW for the Study Area and include 6,220 MW of wind, 2,530 MW of solar, 138 MW of gas generation, and 56 MW of battery storage development.

Figure 2 illustrates the proposed wind and solar development interest in the Study Area compared to the rest of Alberta based on the AESO's Project List as of January 2020. The Study Area has more than three times as much proposed renewable development compared to the rest of Alberta. While the proposed generation connection projects currently in the AESO's Project List will not necessarily all proceed, the number and size of the proposed generation connection projects in the Study Area provides a strong indication of the interest in renewable development.

Figure 2: Wind and Solar Connection Projects in the Study Area Compared to the Rest of Alberta



[12] The AESO's certainty criteria include awarded REP projects and all generation projects that have paid their Generating Unit Owner's Contribution (GUOC).

[13] The magnitude, pace, and likelihood of new renewable development is uncertain and dependent on a variety of drivers, including changes to capital costs, electricity market fundamentals including natural gas prices, carbon prices, and generation development and mix, and government policies that incent renewable development.

[14] The AESO's Project List is available on the AESO website.

The AESO adopted a project-specific approach to develop deterministic generation dispatches, which used assumptions[15] of the 2019 LTO as a basis, with specific dispatch scenarios created within the Study Area. The AESO considered two thermal dispatch scenarios[16]. Scenario 1 assumed reduced thermal generation[17] capacity and dispatch in the Study Area, while Scenario 2 considered similar thermal generation capacity as the historical fleet.[18]

2.3.2 Load Forecast

The historical load in the Study Area is comprised of industrial loads associated with oil and natural gas pipelines, conventional oil and gas drilling, and cryptocurrency, as well as agriculture, residential and commercial load. The Compound Annual Growth Rate (CAGR) of load from 2015 to 2019 in the Study Area was 1.7% for Summer Peak, 1.1% for Winter Peak, and 4.0% for Summer Light.

The project-specific load forecast for the 20-year planning horizon (2019 to 2039) in the Study Area is aligned with the 2019 LTO Reference Case load forecast and represents the AESO's current expectation for long-term load growth.

In developing the seasonal peak load forecast for the Study Area, the AESO used the 2019 LTO as a basis, with considerations for historical load patterns and trends, substation-level load forecasts provided by the applicable legal owners of electric distribution systems (DFOs), and recent project developments. The load growth in the near-term (2023) is due to organic load growth in the Study Area, cannabis operations expected to begin operations over the next five years, and the one approved load connection project in the Study Area. Organic load growth[19] is driven by population, employment, and GDP growth. The load growth in the long-term (2039) is similar to the near-term load growth, where growth is driven by organic load growth in the Study Area, with more growth expected in Hanna (Area 42) and Lloydminster (Area 13).

The CAGR forecast for the 20-year planning horizon in the Study Area is 0.4% for Summer Peak and 0.6% for Winter Peak. The decrease in the load growth rate relative to historic load is driven by a lower gross domestic product (GDP) outlook compared to historic GDP. The 2023, 2031, and 2039 seasonal Winter Peak, Summer Peak, and Summer Light load forecasts for the Study Area are presented in Table 2.

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[15] The 2019 LTO assumptions used to develop deterministic generation dispatch assumptions are provided in Appendix B of this Application.

[16] Additional information on the two thermal dispatch scenarios and methodology is provided in Appendix B of this Application.

[17] Thermal generation commonly refers to generating units that burn fuel and produce steam, which is then used to produce electric power.

[18] Additional information regarding the scenarios is provided in Appendix B of this Application.

[19] Organic load growth refers to any load growth unrelated to projects, cannabis operations, and electric vehicle (EV) load.

Table 2: Seasonal Load Forecasts

Year	Winter Peak (MW)	Summer Peak (MW)	Summer Light (MW)
2023	1,427	1,431	1,019
2031	1,452	1,432	1,077
2039	1,469	1,465	1,097

3. Need for Central East Transfer-Out Transmission Development

3.1 Transmission System Capability

3.1.1 Methodology and Assumptions

With renewable generation development expected to increase in the Study Area, the AESO performed deterministic studies[20] for the years 2023 (near-term) and 2031 (mid-term). The purpose for conducting deterministic studies is to assess the performance of the Pre-Development[21] transmission system. The results of the deterministic studies were used to establish the need for transmission development, evaluate the considered Transmission Development Options[22], and select the Preferred Transmission Development.[23]

Study cases were created and used to perform the deterministic studies. The study cases represent reasonably stressed operating conditions, including various load conditions and generation dispatches for the years 2023 and 2031. Due to uncertainties associated with the timing, volume, and offer behavior of the replacement or retirement of the existing thermal generation in the CE sub-region, generation dispatches using statistical and market simulation methods were developed for two thermal dispatch scenarios.[24]

Studies were first completed to determine the generation integration capability of the Pre-Development transmission system in the Study Area under an optimized distribution of renewable generation integration. In addition, sensitivity studies were performed to understand the impact of various renewable generation distributions in the CE, SE, and SW sub-regions.

3.1.2 Deterministic Study Results

Under these study cases and renewable integration distribution scenarios, generation integration capability was determined as follows:

- The generation integration capability was first determined for reliable operation under Category B contingency conditions. The Category B generation integration capability assessment identifies the maximum amount of new generation that could be dispatched in the Study Area and SW sub-

[20] Additional information about the deterministic studies and results are provided in Appendix A of this Application.

[21] The Pre-Development transmission system is the existing transmission system with approved system and connection projects in service. The 2023 Pre-Development transmission system conditions include the approved PENV project (operating at 138 kV), REP projects, connection projects, and system projects. The 2031 Pre-Development transmission system conditions include the PENV development (operating at 240 kV), REP projects, connection projects, and system projects. Refer to Appendix A for further information.

[22] Presented in Section 4.0 of this Application.

[23] Presented in Section 5.0 of this Application.

[24] The two thermal dispatch scenarios are referred to as Scenario 1 and Scenario 2. A description of the two thermal dispatch scenarios and the statistical and market simulation methodology are provided in Appendix B of this Application.

region without causing Reliability Criteria[25] violations and without RAS to curtail generation following a contingency. Transmission system re-configuration, such as transfer-tripping transmission lines post-contingency, was considered, if such a mitigation could mitigate any Reliability Criteria violations and improve transmission system capability.

- The Category A generation integration capability enabled by generation RAS was assessed, once the Category B generation integration capability was determined, to identify the maximum amount of new generation that could be dispatched in the Study Area and SW sub-region, assuming generation RAS will curtail new generation to mitigate Reliability Criteria violations following a Category B contingency. The maximum generation curtailment cannot exceed the current Most Severe Single Contingency (MSSC) limit of 466 MW.[26]

During the generation integration capability assessment for the Pre-Development transmission system in the Study Area, thermal limits were reached on the transmission system in the Study Area, primarily on the CE sub-region west transfer-out path. The integration capability assessment results are presented in Appendix A.

The 2023 and 2031 results[27] of the Category A and B generation integration capability indicate:

2023

- Under Scenario 1, the Category B generation integration capability in the Study Area is in the range of 450 MW to 565 MW and the Category A generation integration capability enabled by generation RAS is in the range of 760 MW to 990 MW.
- Under Scenario 2, the Category B generation integration capability in the Study Area is in the range of 120 MW to 280 MW and the Category A generation integration capability enabled by generation RAS is in the range of 250 MW to 680 MW.
- The primary limit for both 2023 scenarios is the CE sub-region west transfer-out path 240 kV transmission line 912L between the Nevis 766S and the Red Deer 63S substations.

2031

- Under Scenario 1, the Category B generation integration capability in the Study Area is approximately 555 MW and the Category A generation integration capability enabled by generation RAS is approximately 880 MW.
- Under Scenario 2, the Category B generation integration capability in the Study Area is approximately 50 MW and the Category A generation integration capability enabled by generation RAS is approximately 135 MW.

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[25] AESO's Reliability Criteria, also referred to as the AESO Transmission Planning Criteria, is defined in Part C, note ii and Appendix A.

[26] The MSSC represents the most severe single contingency generator or supply loss on the AIES that may occur as a result of either a generator trip, or the loss of a transmission line that subsequently leads to the simultaneous loss of generation.

[27] The results reflect the overall maximized generation integration capability for the Study Area and SW sub-region. Depending on future generation development, the generation integration capability results may change. See Appendix A of this Application.

- The primary limit for both 2031 scenarios is the CE sub-region west transfer-out path 240 kV transmission line 912L between the Nevis 766S and the Red Deer 63S substations.

The AESO forecasts[28] that by 2023, up to 900 MW of incremental renewable generation, above the existing renewable generation and REP projects, will develop in Alberta. The renewable generation forecast is expected to continue to grow. By 2031, between 900 MW and 4,600 MW of incremental renewable generation is forecast to develop in Alberta. The AESO expects that a significant portion of the forecast incremental renewable generation could be developed in the Study Area, which would exceed the generation integration capability of the Pre-Development transmission system in 2023 and 2031 in the Study Area.

In order to meet the forecasted generation in the Study Area over the long-term, the AESO has determined that transmission development is needed to alleviate the constraints on the CE sub-region west transfer-out path, to meet the Reliability Criteria. Without additional transmission development, the transmission system does not have sufficient capability to integrate the forecasted generation in the 20-year planning horizon.

3.2 Congestion Assessment

In addition to running deterministic studies to identify the amount of generation integration capability of the Study Area, hourly probabilistic studies were run to test how much congestion could potentially develop in the Study Area.[29] A congestion assessment[30] was performed for various renewable development levels using two scenarios, in which the operating patterns of thermal generation varied. While renewable generation development was the focus of the congestion assessment, it is expected that, should other types of incremental generation develop in the Study Area, the results would be similar.

The purpose of the congestion assessment was to:

- estimate the probability of congestion arising in the Study Area as new generation develops; and
- inform the establishment of a construction milestone for the Preferred Transmission Development.[31]

Key conclusions of the congestion assessment are:

- the expected percentage of hours that are congested increases steadily as new renewable generation development is added in the Study Area; and
- as the percentage of congested hours increases, the average magnitude of thermal criteria violations resulting in congestion is expected to increase in the Study Area, along the 240 kV transmission line 912L/9L20 of the CE sub-region west transfer-out path as well as the 138 kV transmission lines 174L and 701L in the CE sub-region.

[28] Forecast information is provided in Appendix B of this Application.

[29] A modified forecast was used for the congestion assessment, as described in Appendix C of this Application.

[30] The congestion assessment results and report is provided in Appendix C of this Application.

[31] Refer to Section 8 of this Application for more information on the construction milestones.

Additional information regarding the methodology, assumptions, and results for measuring the hours of congestion within the Study Area are detailed in Appendix C.

4. Evaluation of Transmission Development Options and Selection of the Preferred Transmission Development

This section explains the Transmission Development Options that were evaluated by the AESO and the factors that were taken into consideration in the process of selecting the Preferred Transmission Development.

4.1 Transmission Development Options

The AESO identified the following Transmission Development Options:

Option 1: Add two 240 kV circuits, slightly less than 130 km in length, between the Tinchebray 972S and Gaetz 87S substations. Modify both the Tinchebray 972S and the Gaetz 87S substations, including the addition of 240 kV circuit breakers and associated equipment.

Option 2: Add two 240 kV circuits, slightly more than 130 km in length, between the Tinchebray 972S and Wolf Creek 288S substations. Modify both the Tinchebray 972S and the Wolf Creek 288S substations, including the addition of 240 kV circuit breakers and associated equipment.

Option 3: Upgrade the capacity of the existing 240 kV transmission lines 912L and 9L20, and add one 240 kV circuit, slightly less than 130 km in length, between the Tinchebray 972S and Gaetz 87S substations. Modify both the Tinchebray 972S and Gaetz 87S substations, including the addition of 240 kV circuit breakers and associated equipment.

Option 4: Add one 500 kV circuit, slightly less than 130 km in length, between the Tinchebray 972S and Gaetz 87S substations. Upgrade both the Tinchebray 972S and Gaetz 87S substations, including the addition of one 500/240 kV transformer, 500 kV circuit breakers, 240 kV circuit breakers and associated equipment.

Option 5: Convert the existing 500 kV HVDC transmission line EATL to a bi-pole configuration, and add converter stations at the Newell 2075S and Heathfield 2029S substations and associated equipment.

Option 6: Add one 240 kV circuit, slightly less than 120 km in length, between the Cordel 755S and Gaetz 87S substations and add one 240 kV circuit, slightly less than 130 km in length, between the Tinchebray 972S and Gaetz 87S substations. Modify the Cordel 755S, Gaetz 87S and Tinchebray 972S substations, including the addition of 240 kV circuit breakers and associated equipment.

4.2 Transmission System Performance and Generation Integration Capability Assessment

The AESO evaluated the transmission system performance of the six Transmission Development Options by performing Category B generation integration capability studies.

The Category B generation integration capability studies were performed on the transmission system in the Study Area with each of the six Transmission Development Options in place. The studies determined and compared the amount of generation integration that could occur before thermal criteria violations were observed. The results of the studies are as follows:

- Options 1 and 6 enable the greatest amount of incremental generation integration capability in the Study Area. Compared to Option 6, Option 1 provides flexibility to connect a higher amount of generation in the west Hanna (Area 42) area, an area where there is significant market interest to develop renewable generation.

- The generation integration capability enabled by Options 2, 3, and 4 is approximately 125 MW to 160 MW lower than Option 1. Under outage conditions, the amount of generation in the Study Area that can still be connected by Options 3 and 4 is significantly lower than Option 1. Therefore, Options 3 and 4 were not recommended for further consideration. Option 2 was further considered, as similar to Option 1 and 6, Option 2 offers operational flexibilities during outage conditions.
- Option 5 was not recommended for further consideration as it provides the lowest amount of generation integration capability in the Study Area.

Table 3 provides a summary of the generation integration capability studies for the six Transmission Development Options.[32] Transmission Development Options 3, 4, and 5 were not recommended for further consideration as they provide lower generation integration capability and limited operational flexibility than the other Transmission Development Options. Transmission Development Options 1, 2, and 6 were assessed for further consideration from a land impact and cost perspective, further details provided in Sections 4.3 and 4.4 of this Application.

Table 3: Summary of the Generation Integration Capability Studies for the Transmission Development Options

Option	Additional Generation Integration Capability in the Study Area (approximate MW)	Operational Limitations
1	820 MW	N/A
2	660 MW	N/A
3	695 MW	Line rebuilds generally require lengthy outages. This option is expected to require a lengthy outage on 240 kV transmission lines 912L and 9L20 resulting in operational complexity during construction. Under outage of the new 240 kV circuit, or 240 kV transmission lines 912L or 9L20, renewable generation dispatched for this option would be lower (approximately 300 MW) than Option 1.
4	685 MW	Under outage of the new 500 kV circuit, renewable generation dispatched for this option would be significantly lower (approximately 500 MW) than Option 1.
5	230 MW	N/A
6	800 MW[A]	N/A

Note A: Generation integration capability in the west Hanna (Area 42) area is limited to 350 MW.

[32] Included in Appendix A of this Application.

Additional information regarding the Transmission Development Options and the generation integration capability studies is provided in Appendix A of this Application.

4.3 Information in Regards to Rule 007, Section 6.1, NID7(9)

The AESO directed the TFOs to prepare a report comparing Transmission Development Options 1, 2, and 6[33], according to the environmental and land use effects information contemplated in AUC Rule 007, Section 6.1, NID7(9). In response to this direction, the TFOs each submitted separate NID7(9) reports[34] for their respective service territories, which are included in Appendix D of this Application. The TFOs' conclusions are summarized as follows:

- no features or factors were identified that preclude development of any of the Transmission Development Options and the overall level of impact is likely to be similar in terms of the elements listed in NID 7(9);
- Option 1 has lower potential impacts due to the presence of existing transmission lines to parallel; and
- features on the landscape where transmission developments would be expected to create impacts can likely be avoided or reduced during route development and implementation of mitigation measures.

4.4 Transmission Development Option Costs

To further assist with its evaluation of Transmission Development Options 1, 2, and 6, described in Section 4.1, the AESO prepared cost estimates (+30%/-30%) for these options that meet the requirements of AUC Rule 007, Section 6.1, NID8. The estimated in-service costs of Option 1 is approximately $471 million, the estimated in-service costs of Transmission Development Option 2 is approximately $497 million, and the estimated in-service costs of the Transmission Development Option 6 is approximately $480 million.[35]

4.5 Selection of the Preferred Transmission Development

The AESO has compared Transmission Development Options 1, 2, and 6 by considering transmission system performance, generation integration capability, land impact and environmental effects, and cost estimates, all as presented in Table 4.

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[33] The environmental and land use effects information was prepared by the TFOs for their respective service territories. AltaLink compared Transmission Development Options 1 and 2 and ATCO compared Transmission Development Options 1, 2, and 6.

[34] The TFOs confirmed that the conclusions found in their NID7(9) reports submitted in May 2018 still remain valid for this Application and no substantive changes were made to affect the conclusions.

[35] The cost estimates are in nominal dollars using a base year of 2019 with escalation considered. Further details of these cost estimates, which have an accuracy level of +30%/-30%, can be found in Appendix E of this Application.

Table 4: Comparison of Transmission Development Options 1, 2, and 6

Merits	Transmission Development Option 1	Transmission Development Option 2	Transmission Development Option 6
Transmission System Performance	Provides the best overall technical performance, generation integration capability, and operational flexibility as compared to Option 2 and 6. Provides flexibility to integrate approximately 400 MW more of generation in the west Hanna (Area 42) area where there is strong market interest for renewable development.	Provides lower generation integration capability than Options 1 and 6.	Provides the same technical performance and generation integration capability as Option 1, however, provides less flexibility by only integrating approximately 350 MW of generation in the west Hanna (Area 42) area where there is strong market interest for renewable development.
Generation Integration Capability	820 MW	660 MW	800 MW[1]
Land Impact and Environmental Effects	Feasible; avoidable or manageable impacts during routing and siting. Lower relative land impact due to shorter transmission line length and existing transmission lines to parallel.	Feasible; avoidable or manageable impacts during routing and siting. Higher relative land impact due to longer transmission line length and limited existing transmission lines to parallel.	Feasible; avoidable or manageable impacts during routing and siting. Higher relative land impact due to longer transmission line length and limited existing transmission lines to parallel.
Cost Estimate[2] (2023 ISD – Stage 1) (2027 to 2029 ISD – Stage 2)	$471 million	$497 million	$480 million

Note 1: Generation integration capability in the west Hanna (Area 42) area is limited to 350 MW.

Note 2: As per AUC Rule 007, s.6.1, NID8, the AESO's cost estimate is based on an accuracy level of +30%/-30%.

Option 1 provides the best overall technical performance compared to Transmission Development Options 2 and 6. Generation integration capability is greater with Option 1 and Option 1 provides flexibility to integrate a higher amount of generation in the west Hanna (Area 42) area where there is strong market interest for renewable development. Option 1 has lower potential for environmental and land use impact compared with Transmission Development Options 2 and 6. Further, the estimated capital cost of the Option 1 is lower than Transmission Development Options 2 and 6.

For these reasons, the AESO selected Option 1 as the Preferred Transmission Development for transmission system development in the Study Area.

4.6 Technical Performance of the Preferred Transmission Development

Additional deterministic studies were conducted to assess the impact that the Preferred Transmission Development would have on the transmission system. Voltage stability, transient stability, short circuit, and transmission system loss analyses were performed before and after the energization of the Preferred

Transmission Development. No transmission system performance issues were identified, and transmission system losses with the Preferred Transmission Development are lower than without the Preferred Transmission Development.[36] Based on the probabilistic studies[37], the Preferred Transmission Development is effective at reducing congestion in the Study Area.

[36] Additional information is provided in Appendix A of this Application.

[37] Additional information is provided in Appendix C of this Application.

5. Preferred Transmission Development

This section describes the AESO's Preferred Transmission Development to address the need described in Section 3.

5.1 Preferred Transmission Development

Figure 3 illustrates the Preferred Transmission Development, and includes the following major transmission system elements which will be developed in two stages[38]:

Stage 1

1. Add one 240 kV circuit with a minimum capacity of 485 MVA,[39] to be designated as 962L/9L62, between the existing Gaetz 87S substation and the existing Tinchebray 972S substation;
2. Modify the Gaetz 87S substation, including adding two 240 kV circuit breakers;
3. Modify the Tinchebray 972S substation, including adding one 240 kV circuit breaker; and
4. Modify, alter, add or remove equipment, including switchgear, and any operational, protections, control and telecommunication devices required to undertake the work as planned and ensure reliable integration of the Preferred Transmission Development Stage 1 with the transmission system. [40]

Stage 2

1. Add one 240 kV circuit with a minimum capacity of 485 MVA, to be designated as 986L/9L86, between the existing Gaetz 87S substation and the existing Tinchebray 972S substation;
2. Modify the Gaetz 87S substation, including adding two 240 kV circuit breakers;
3. Modify the Tinchebray 972S substation, including adding four 240 kV circuit breakers; and
4. Modify, alter, add or remove equipment, including switchgear, and any operational, protections, control and telecommunication devices required to undertake the work as planned and ensure reliable integration of the Preferred Transmission Development Stage 2 with the transmission system.[41]

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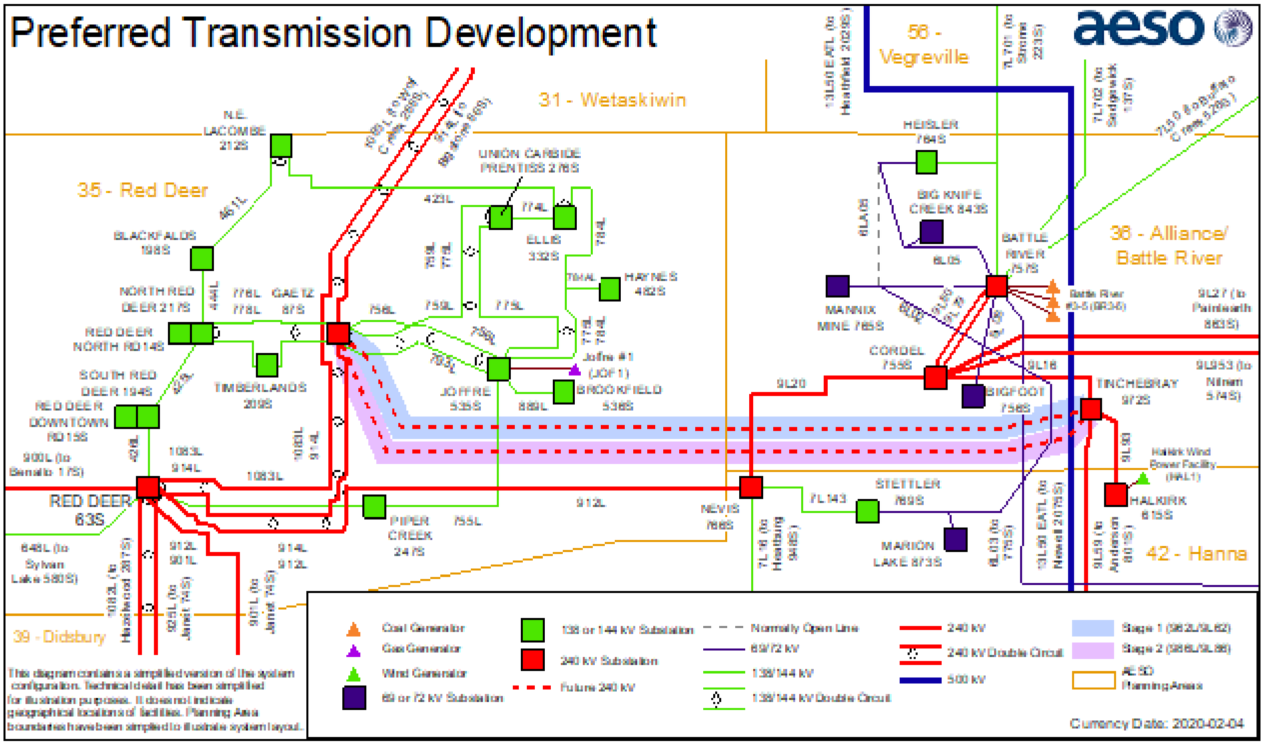
[38] The development of the two stages will depend on the approved configuration.

[39] Studied transmission circuit ratings have been approximated to the accuracy level required by the AESO for transmission planning purposes. Actual ratings of constructed facilities may vary.

[40] Details and configuration of equipment required for the Preferred Transmission Development, including substation single line diagrams, will be more specifically described in the AESO's functional specifications that will be included in the TFOs' transmission Facility Proposals. Further specifics will be determined as detailed engineering progresses. Routing and/or siting of the transmission facilities do not form part of this Application and will be addressed in the TFOs' transmission Facility Proposals. Line numbering provided herein is for ease of reference and are subject to change as engineering and design progresses.

[41] *Ibid*

Figure 3: Single-line Diagram of the Preferred Transmission Development



The AESO is proposing a construction milestone for the construction and energization of each stage of the Preferred Transmission Development. Section 8 of this Application discusses the construction milestone and construction milestone monitoring process in greater detail.

The AESO supports the selection of the TFO's recommended configuration of a double circuit structure which consists of the following:

> Add two 240 kV circuits on a double circuit structure with the conductors tied together in Stage 1. The first circuit to be energized and designated as 962L/9L62, between the existing Tinchebray 972S substation and the existing Gaetz 87S substation. The second circuit to be untied and energized when the Stage 2 milestone is met and designated as 986L/9L86, between the existing Tinchebray 972S substation and the existing Gaetz 87S substation.

5.2 Preferred Transmission Development Costs

As mentioned in Section 4.4, the AESO prepared a cost estimate for Option 1, the Preferred Transmission Development, has an approximate in-service cost of $471 million.[42]

[42] The cost is in nominal dollars using a base year of 2019 with escalation considered. Further details of this cost estimate, which has an accuracy level of +30%/-30%, can be found in Appendix E of this Application.

6. Long-term Transmission Plans

The AESO's long-term transmission system plans are high-level assessments of transmission capability and required transmission system development in Alberta focusing on broad technical aspects. More detailed studies are performed in preparation of a needs identification document application to ensure that the AESO's Preferred Transmission Development will address the identified reliability violations in the most efficient manner.

The Preferred Transmission Development proposed by the AESO in this Application is aligned with the *AESO 2020 Long-term Transmission Plan* (2020 LTP) in that transmission development in the CE sub-region is recommended.[43]

6.1 Transmission Development Interdependencies

The Preferred Transmission Development is not dependent on other transmission developments that are currently planned within the AIES in this timeframe. However, to achieve the maximum generation integration capability of the Preferred Transmission Development, the approved PENV development, which was designed to alleviate local 138 kV constraints in the PENV area, is required.

[43] The AESO's 2020 LTP is available on the AESO website.

7. Participant Involvement Program

The AESO conducted a Participant Involvement Program (PIP), in accordance with the requirement of NID11 and Appendix A2 of AUC Rule 007. Between January 2019 and February 2020, the AESO utilized various methods to notify occupants, landowners, residents, market participants, local authorities, agencies, government, and Indigenous communities (collectively, Stakeholders) of the need for transmission development in the area where transmission facilities could be installed to address the identified need.

The AESO responded to all Stakeholder inquiries related to the need for the Preferred Transmission Development. In March 2020, the AESO notified stakeholders of its intention to file this Application with the Commission. Following the filing of this Application, the AESO will notify stakeholders that this Application has been filed with the Commission.

Further information regarding the AESO’s PIP for this Application is included in Appendix F.

8. Construction Milestones and Monitoring Process

The AESO has 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 Study Area.

8.1 Construction Milestones

The proposed construction milestones are based on the results of the congestion assessment indicating when the CE sub-region west transfer-out path is projected to be congested greater than 0.5% of the time annually during the Category A condition.[44] It will take approximately two to three years to construct the Preferred Transmission Development after the Permits & Licences have been received, and the construction milestones have been met. The construction milestones incorporate a 200 MW[45] reduction of incremental generation. This would allow one average sized wind farm to be constructed concurrently[46] with the Preferred Transmission Development.

8.1.1 Stage 1 Construction Milestone

It is expected that the Stage 1 construction milestone will be met with the addition of approximately 1,050 MW to 1,550 MW of incremental generation[47] (above the existing installed generation as of January 2020) that meets the AESO's certainty criteria in the Study Area, as shown in Figure 4. The AESO's certainty criteria for purposes of meeting the milestone will include REP projects and all generation projects that have paid their Generating Unit Owner's Contribution (GUOC).

8.1.2 Stage 2 Construction Milestone

It is expected that the Stage 2 construction milestone will be met with the addition of approximately 1,700 MW to 2,150 MW of incremental generation (above the existing installed generation as of January 2020) that meets the AESO's certainty criteria in the Study Area.

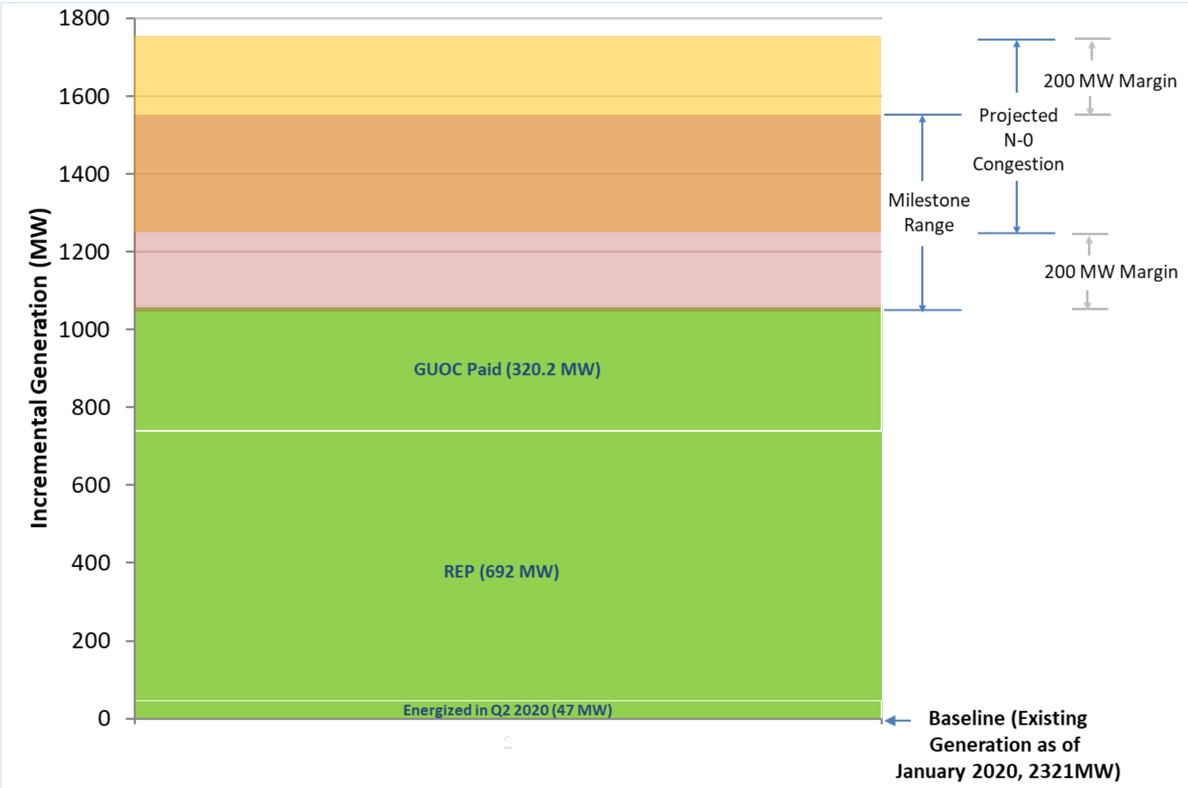
[44] The AESO does not plan to have Category A congestion on the transmission system, it is rather an indication of when the Category A congestion would occur.

[45] The 200 MW value is based on the average sized wind farm currently operating in Alberta.

[46] The generation construction timelines for a typical wind farm is approximately 1 to 2 years.

[47] For the milestone calculation, incremental generation could be renewable or thermal. For the thermal, anything beyond 1,479 MW of installed thermal generation capacity would be considered incremental. This 1,479 MW is the highest level of installed thermal generation capacity in the Congestion Assessment baseload thermal generation scenario.

Figure 4: Stage 1 Construction Milestone for the Preferred Transmission Development



8.2 Milestone Monitoring Process

The AESO will monitor the generation development in the Study Area as incremental generation meets the certainty criteria. Once incremental generation is within the range of 1,050 MW to 1,550 MW, the AESO would re-affirm that congestion is forecast to occur greater than 0.5% of the time annually during the Category A condition by performing congestion assessment studies that take into account the locations and sizes of the generation meeting the certainty criteria. In the event that these planning studies re-affirm that Category A congestion is forecast to occur greater than 0.5% of the time annually, the AESO will notify the Commission that the Stage 1 construction milestone has been met and advise the TFOs to commence construction for Stage 1.

Prior to filing this application, 1,059 MW of incremental generation has already met the certainty criteria. The AESO anticipates additional generation to reach the certainty criteria prior to the end of 2020. As such, the AESO expects to commence the congestion assessment studies prior to a Commission decision on the NID. Should the results re-affirm Category A congestion is forecast to occur greater than 0.5% of the time annually, the AESO would notify the Commission that the Stage 1 construction milestone has been met. If the Commission has already rendered a decision on the NID, the AESO will notify the Commission that the Stage 1 construction milestone has been met and advise the TFOs to commence construction for Stage 1.

For the Stage 2 construction milestone, once incremental generation is within the range of 1,700 MW to 2,150 MW, the AESO would re-affirm that congestion is forecast to occur greater than 0.5% of the time annually during the Category A condition by performing congestion assessment studies that take into account the locations and sizes of the generation meeting the certainty criteria. In the event that these planning studies re-affirm that Category A congestion is forecast to occur greater than 0.5% of the time annually, the AESO will notify the Commission that the Stage 2 construction milestone has been met and advise the TFOs to commence construction for Stage 2.

The AESO will use operational measures, as necessary, should congestion arise prior to the energization of the Preferred Transmission Development.

Upon a TFO receiving formal written notice from the AESO that a construction milestone has been met, the TFO may commence construction of the appropriate stage, subject to the TFO having received the requisite approvals from the Commission to construct and operate the Preferred Transmission Development.

As set out in Section 9, the AESO is requesting that this application be combined with the related Facility Proposals to be filed by the TFOs. To address the matter of construction milestones being met, the AESO requests that any Permits & Licences that may be issued by the Commission in respect of the TFOs' Facility Proposals be made subject to appropriate terms and conditions restricting the commencement of construction activities until such time as the AESO has determined, in accordance with the construction milestone monitoring process, that a construction milestone has been met.

9. Preferred Transmission Development Schedule

9.1 Information Regarding Rule 007, Section 6.1 – NID9(2)

The TFOs have provided an approximate implementation schedule for the Preferred Transmission Development that meets the AESO's estimated in-service date (ISD) of 2023 for Stage 1 and 2027 to 2029 for Stage 2, taking into account the requirements of AUC Rule 007, Section 6.1, NID9(2). Estimated ISDs will be confirmed when the construction milestones are met. The AESO considers these ISDs to be acceptable in the circumstances; however, the TFOs have advised the AESO that because their schedules contain numerous assumptions, the estimated ISDs are subject to change as more detailed engineering and project planning is undertaken and regulatory and permitting activities are conducted.

9.2 Information Regarding Rule 007, Section 6.1 – NID10

The AESO has issued an unconditional direction to the TFOs for preparation and submission of the TFOs' Facility Proposals[48] to the Commission for the Preferred Transmission Development. As explained in Section 8.2, the AESO will issue formal written notice to AltaLink and ATCO once the construction milestone has been met for both Stage 1 and 2 of the Preferred Transmission Development.

If Stage 1 of the Preferred Transmission Development is not in service by December 31, 2025, which is two years following the AESO's estimated Stage 1 ISD, the AESO will notify the Commission if the need to expand or enhance the transmission system described in this Application continues, and if the Preferred Transmission Development continues to be the AESO's preferred technical solution. In addition, if Stage 2 of the Preferred Transmission Development is not in-service by December 31, 2030, the AESO will provide an update to the Commission on the status of Stage 2.

[48] Also referred to as facility application, or FA, under AUC Rule 007.

10. Request to Combine this Application with the Facility Proposals for Consideration in a Single Process

Pursuant to Subsection 35(1) of the Act, the AESO has directed each TFO to each prepare a Facility Proposal that corresponds with this Application. The AESO understands that the TFOs' Facility Proposals will be filed shortly. The AESO requests, and expects the TFOs will request, that this Application be combined with the Facility Proposals for consideration by the Commission in a single process. This request is consistent with Section 15.4 of the *Hydro and Electric Energy Act* and Section 6 of AUC Rule 007.

While it is believed that this Application and the Facility Proposals will be materially consistent, the AESO respectfully requests that in its consideration of both, the Commission be mindful of the fact that the documents have been prepared separately and for different purposes. The purpose of this Application is to obtain approval of the need for transmission system development and to provide a preliminary description of the manner proposed to meet that need. In contrast, the Facility Proposals will contain more detailed engineering and designs for the Preferred Transmission Development and seek approval for the construction and operation of specific facilities.

11. Relief Requested

11.1 Approval is in the Public Interest

Having regard to the following:

- the transmission planning duties of the AESO as described in Sections 33 and 34 of the Act, and
- the requirements in Section 6 of AUC Rule 007,

the AESO also submits that:

- the AESO's assessment of the need to enable additional generation integration capability in the Study Area is technically complete; and
- the Preferred Transmission Development meets the identified need; satisfies the Alberta reliability standards; and is consistent with the AESO long-term forecasts and area transmission system plans.

Therefore, approval of the Application is in the public interest, having regard to the factors set out in Section 38 of the *Transmission Regulation*, and in particular, Subsection 38(d) and (e).

11.2 Request

For the reasons set out herein, and pursuant to Section 34 of the Act, the AESO requests that the Commission:

approve this Application, including the Preferred Transmission Development, which will be comprised of the following:

Stage 1

1. Add one 240 kV circuit with a minimum capacity of 485 MVA, to be designated as 962L/9L62, between the existing Gaetz 87S substation and the existing Tinchebray 972S substation;
2. Modify the Gaetz 87S substation, including adding two 240 kV circuit breakers;
3. Modify the Tinchebray 972S substation, including adding one 240 kV circuit breaker; and
4. Modify, alter, add or remove equipment, including switchgear, and any operational, protections, control and telecommunication devices required to undertake the work as planned and ensure reliable integration of the Preferred Transmission Development Stage 1 with the transmission system.

Stage 2

1. Add one 240 kV circuit with a minimum capacity of 485 MVA, to be designated as 986L/9L86, between the existing Gaetz 87S substation and the existing Tinchebray 972S substation;
2. Modify the Gaetz 87S substation, including adding two 240 kV circuit breakers;
3. Modify the Tinchebray 972S substation, including adding four 240 kV circuit breakers; and
4. Modify, alter, add or remove equipment, including switchgear, and any operational, protections, control and telecommunication devices required to undertake the work as planned and ensure reliable integration of the Preferred Transmission Development Stage 2 with the transmission system.

All of which is respectfully submitted this 12th day of August 2020.

Alberta Electric System Operator

“Electronically Submitted by”

Dennis Frehlich, P.Eng.
Vice President, Grid Reliability

PART B – APPLICATION APPENDICES

The following appended documents support the Application (Part A).

APPENDIX A – AESO Planning Report

Appendix A contains the AESO's *Central East Transfer-out Transmission Development Planning Report*, which describes the deterministic studies, milestones, and conclusions of the probabilistic assessments completed by the AESO in support of this Application.

APPENDIX B – AESO Load and Generation Forecast

Appendix B contains the AESO's *Central East Transfer-out Transmission Development Load and Generation Forecasts* used in the *Central East Transfer-out Transmission Development Planning Report,* contained in Appendix A.

APPENDIX C – AESO Congestion Assessment

Appendix C contains the AESO's *Congestion Assessment Report for the Central East Transfer-out Transmission Development* which describes the probabilistic studies performed by the AESO in support of this Application.

APPENDIX D – TFO Environmental and Land Use Effects

Appendix D contains the Environmental and Land Use Effects information provided by the TFOs in consideration of the aspects of AUC Rule 007, Section 6.1, NID7(9).

APPENDIX E – AESO Cost Estimates

Appendix E contains the AESO's cost estimates corresponding to Option 1 (the Preferred Transmission Development), Option 2, and Option 6. These estimates have been prepared by the AESO to an accuracy level of +30%/-30%, which meets the accuracy required by AUC Rule 007, NID8.

APPENDIX F – AESO Participant Involvement Program (PIP)

Appendix F provides a summary of the PIP activities conducted, in accordance with requirements of NID11 and Appendix A2 of AUC Rule 007, regarding the need for the transmission development to address the identified constraints and the Preferred Transmission Development described in this Application. Copies of the relevant materials distributed during the PIP are attached for reference.

APPENDIX G – AESO Transmission Planning Criteria – Basis and Assumptions

Appendix G contains the *Transmission Planning Criteria – Basis and Assumptions*, Version 1.1, which includes the applicable thermal and voltage limits in support of the Alberta reliability standards, TPL-001-AB-0, *System Performance Under Normal Conditions* (TPL-001-AB-0) and TPL-002-AB1-0, *System Performance Following Loss of a Single BES Element* (TPL-002-AB1-0).[49] Planning studies that are

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[49] TPL-001-AB-0 and TPL-002-AB1-0 are available on the AESO website.

included in this Application meet the relevant performance requirements of TPL-001-AB-0 and TPL-002-AB-0.

PART C – REFERENCES

i. **AESO Planning Duties and Responsibilities and Duty to Forecast Need –** Certain aspects of the AESO's duties and responsibilities with respect to planning the transmission system are described in the Act. For example, Section 17, Subsections (g), (h), (i), and (j), state the general planning duties of the AESO. Section 33 of the Act states that the AESO "must forecast the needs of Alberta and develop plans for the transmission system to provide efficient, reliable and non-discriminatory system access service and the timely implementation of required transmission system expansions and enhancements." As stated in Subsection 34(1) of the Act, when the AESO determines that an expansion or enhancement of the capability of the transmission system is or may be required to meet the needs of Alberta and is in the public interest, the AESO must prepare and submit to the Commission for approval of a needs identification document that describes the constraint or condition affecting the operation or performance of the system and indicates the means by which or the manner in which the constraint or condition could be alleviated. In determining the means by which, or the manner in which, the constraint or condition affecting the operation or performance of the transmission system could be alleviated, the AESO has applied engineering judgments and made assumptions as necessary. Such judgments and assumptions being required and permitted by its prescribed responsibilities and authorities under the Act. In accordance with Section 11 of the *Transmission Regulation*, the AESO has considered technical, economic, environmental and other factors as necessary in determining its preferred option for system expansion. Pursuant to Section 11(4) of the *Transmission Regulation*, the AESO has determined it to be appropriate to specify construction milestones for Stage 1 and Stage 2 of the Preferred Transmission Development.

ii. **AESO Transmission Planning Criteria** In accordance with the Act, the AESO is required to plan a transmission system that satisfies applicable reliability standards. Alberta reliability standards, TPL-001-AB-0, *System Performance Under Normal Conditions* (TPL-001-AB-0) and TPL-002-AB1-0, *System Performance Following Loss of a Single BES Element* (TPL-002-AB1-0) are available on the AESO website. In addition, the AESO's *Transmission Planning Criteria – Basis and Assumptions* is included in Appendix G.

iii. **Application for Approval of the Need for Expansion or Enhancement of the Capability of the Transmission System –** This Application is directed solely to the question of the need for expansion or enhancement of the capability of the transmission system as more fully described in the Act and the *Transmission Regulation*. This Application does not seek approval of those aspects of transmission development that are managed and executed separately from the needs identification document approval process. Other aspects of the AESO's responsibilities regarding transmission development are managed under the appropriate processes, including the ISO rules, Alberta reliability standards and the ISO tariff, which are also subject to specific regulatory approvals. While the Application or its supporting appendices may refer to such other processes or information from time to time, the inclusion of such information is for context and reference only.

Any reference within the Application to market participants or other parties and/or the facilities they may own and operate or may wish to own and operate, does not constitute an application for approval of such facilities. The responsibility for seeking such regulatory or other approval remains the responsibility of the market participants or other parties.

iv. **Directions to AltaLink and ATCO** – Pursuant to Subsection 35(1) of the Act, the AESO has directed AltaLink and ATCO, in its capacity as a legal owner of transmission facilities, in whose service territories the need is located, to each prepare a Facility Proposal to meet the need identified. The Facility Proposal is also submitted to the Commission for approval. The AESO has also directed AltaLink and ATCO, pursuant to Section 39 of the Act and Section 14 of the *Transmission Regulation*, to assist in the preparation of the AESO's Application. AltaLink and ATCO have also been directed by the AESO under Section 39 of the Act to each prepare a service proposal to address the need for the Preferred Transmission Development.

v. **Capital Cost Estimates** – Capital cost estimates provided in the Application are planning cost estimates used by the AESO for the sole purpose of comparing Transmission Development Options. The requirements applicable to cost estimates that are used for transmission system planning purposes are set out in Section 25 of the *Transmission Regulation*, AUC Rule 007, and Section 504.5 of the ISO rules, *Service Proposals and Cost Estimating*.