In the Matter of the Need for the City of Edmonton Transmission Reinforcement

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 the City of Edmonton Transmission Reinforcement

Date: December 7, 2023

Classification: Public

Alberta Electric System Operator

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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 *City of Edmonton Transmission Reinforcement Needs Identification Document* (Application).

1.2 Planning History and Need for Development

The AESO first identified forecast load that could exceed the load serving capability in the northeast Edmonton area starting in 2017.[1] Forecast load growth has now materialized, as a result peak load now exceeds the area load serving capability, as observed during 2021. In addition, the existing transmission infrastructure in the northeast Edmonton area is reaching end of life. Considering the combination of these two factors i) load that exceeds transmission system capability, and ii) aging infrastructure in deteriorated condition, the AESO has determined that the need for transmission system development in the northeast Edmonton area is immediate.

1.3 Application Overview

The AESO has determined that transmission reinforcements are needed to reliably serve the growing demand for electricity in the northeastern portion of the City of Edmonton. Transmission system reinforcements are also required to mitigate risks related to the aging 72 kilovolt (kV) transmission infrastructure in the same area.

This Application proposes an optimized Preferred Transmission Development to address both the need to serve load growth and replace the aging transmission assets in a cost-effective manner.[2] The AESO, in accordance with its transmission system planning responsibilities, submits this Application to the Commission for approval, having determined that its Preferred Transmission Development is required to meet the needs of Alberta and is in the public interest.

1.4 AESO Directions to the Transmission Facility Owner

Pursuant to Section 39 of the Act and Section 14 of the *Transmission Regulation* (TReg), the AESO directed the legal owner of the transmission facilities (TFO), in this case, EPCOR Distribution and Transmission Inc. (EDTI) to assist the AESO in preparing this Application.[3]

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[1] The AESO discussed plans for transmission development in the Edmonton area as early as the *AESO 2017 Long-term Transmission Plan* (2017 LTP), found on the AESO's website at www.aeso.ca

[2] This approach is consistent with *System Criteria #2 – Optimizing with End-of-Life Facilities in the Vicinity of an AESO-identified System Need*, as outlined in the *Summary of AESO System Project Criteria,* available on the AESO website at www.aeso.ca

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

2. City of Edmonton Transmission System and Forecast

2.1 Existing City of Edmonton Transmission System

The City of Edmonton is located within the AESO's Edmonton planning area (Area 60) and is served by 240 kilovolt (kV) and 72 kV transmission systems. 240 kV point-of-delivery (POD) substations serve load in the suburbs, while the inner city is primarily served by a network of 72 kV overhead and underground transmission lines and substations. This 72 kV network is supplied from multiple 240 kV sources, namely, Clover Bar, Lambton, Dome, Bellamy, Victoria, Poundmaker and Jasper substations. The 72 kV network is operated in a primarily radial configuration with normally open points for backup as shown in Figure 2-1 and detailed below:

- Namao, Kennedale and Hardisty substations are each supplied radially from the 240 kV system at Clover Bar substation.
- Strathcona substation is supplied from the 240 kV system at Dome and Lambton substations.
- Rossdale substation is supplied from the 240 kV system at Victoria and Bellamy and is connected to Garneau and Woodcroft substations.
- Woodcroft substation is supplied from the 240 kV system at Jasper.
- Meadowlark is supplied from the 240 kV system at Jasper and Poundmaker substations.

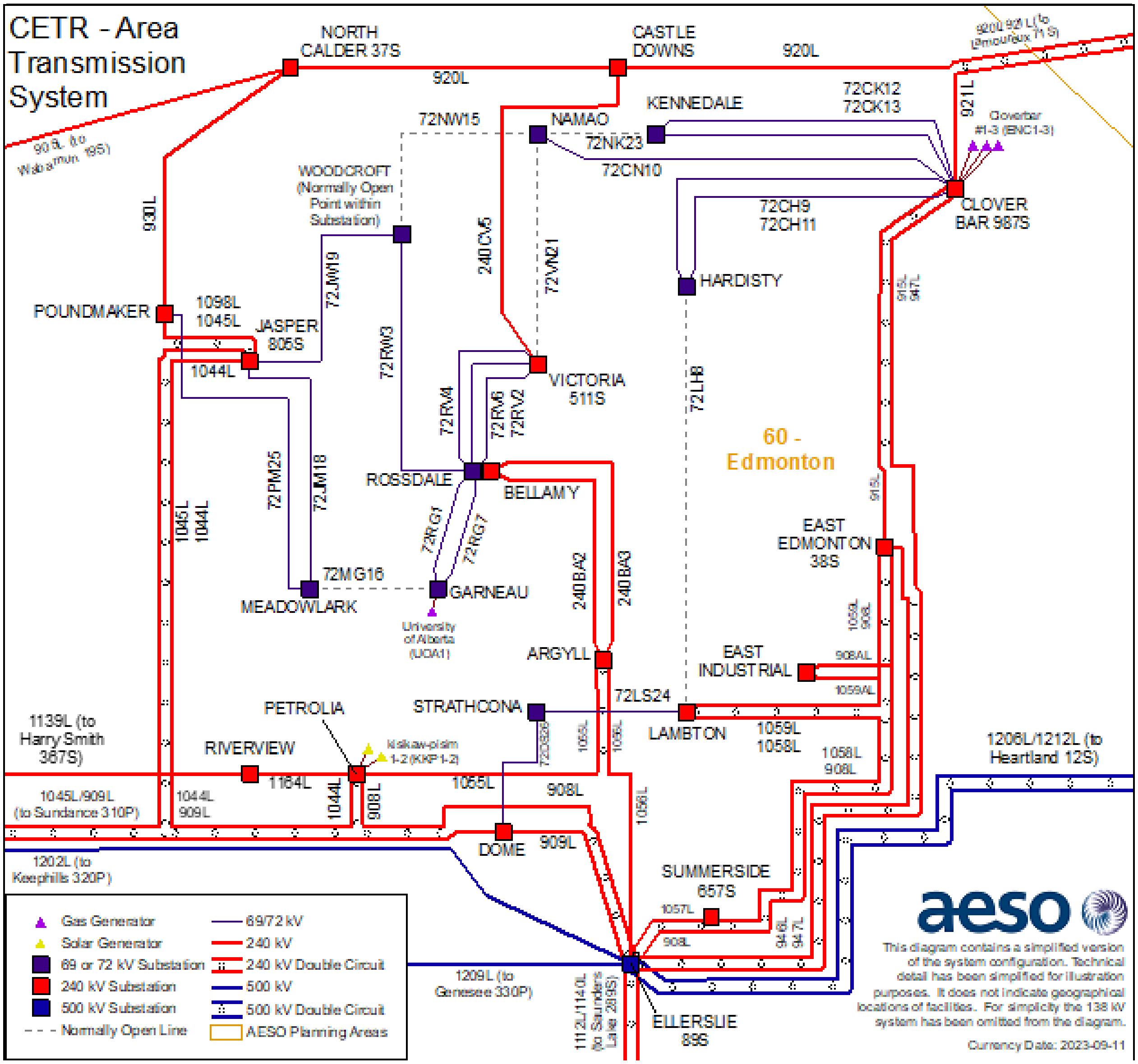

Figure 2-1 City of Edmonton Transmission System

2.1.1 Study Area

The Study Area consists of the service area of the Kennedale and Namao POD substations and the 72 kV system that connects these two substations in the northeastern portion of the City of Edmonton. The Study Area is located within the AESO planning area of Edmonton (Area 60), in the AESO Edmonton Planning Region.

The Planning Report[4] includes an assessment of the transmission system in the Study Area to confirm the current load-serving capabilities and to determine the required transmission development to increase reliability in the Study Area. The existing transmission system in the Study Area consists of the Kennedale and Namao substations and the associated 72 kV system, including the following 72 kV transmission lines:

- underground transmission lines 72CK12 and 72CK13 between Kennedale and Clover Bar substations;
- underground transmission line 72NK23 between Kennedale and Namao substations, which is open under normal operating conditions;
- underground transmission line 72CN10 between Namao and Clover Bar substations;
- underground transmission line 72VN21 between Namao and Victoria substations, which is open under normal operating conditions; and
- overhead transmission line 72NW15 between Namao and Woodcroft substations, which is open under normal operating conditions.

Figure 2-2 shows the transmission system in the Study Area.

[4] The AESO's *City of Edmonton Transmission Reinforcement Planning Report* is provided in Appendix A of this Application.

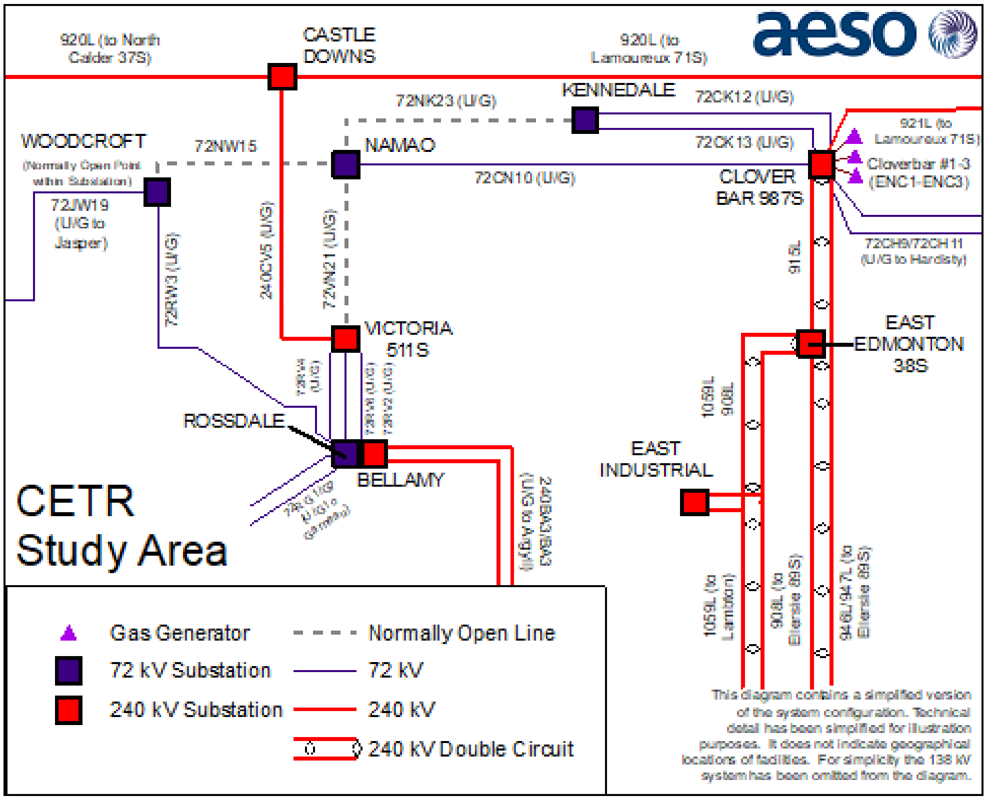

Figure 2-2 Transmission System in Study Area

2.2 AESO Load and Generation Information

Pursuant to its responsibilities under Section 33 of the Act and Sections 8 and 11(3)(c) and (d) of the TReg, the AESO has forecasted generation and load growth in the Study Area[5,6] The generation and load data is based on the latest available information and is in alignment with the preliminary *AESO 2024 Long-term Outlook* (preliminary 2024 LTO).[7]

2.2.1 Historical Load Observations

The load in the Study Area is steadily increasing as shown in Table 1 below. The Kennedale substation has a load serving capability of 55.1 MW due to the rating of 72CK12, which has a summer thermal rating of 60 MVA. The summer peak load at Kennedale substation for 2021 was 63.3 MW. This was the highest historical peak recorded at Kennedale substation and can be attributed to a heat wave that occurred that

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

[6] The Study Area for the AESO load forecast is the existing Kennedale and Namao substations, while the generation forecast includes the AESO planning area of Edmonton (Area 60)

[7] More information about the preliminary 2024 LTO is available here: https://www.aesoengage.aeso.ca/34307/widgets/141824/documents/118661

year. The TFO managed the system by transferring load between substations to maintain reliability during the recorded 37°C weather. The AESO anticipated that Kennedale would surpass its load serving capability and worked with the TFO on an interim distribution solution to shift load from Kennedale to Namao in 2021. The load shift reduced loading at Kennedale in 2022. However, load at Kennedale is expected to continue growing and exceed the substation's load serving capability. As further discussed in section 4.1, neighbouring substations do not have the capacity to shift load away from Kennedale as a long-term solution.

The highest summer peak load at Namao substation (which has a capability of 49.9 MW) was recorded in 2022 at 55.8 MW. The Namao substation has a load serving capability of 49.9 MW due to the rating of 72CN10, which has a summer thermal rating of 55 MVA. The load at Namao now exceeds its load serving capability. This risk is presently being managed through the temporary operational measure of bringing 72VN21 into service during peak load and splitting Namao load between 72VN21 and 72CN10. This measure is temporary due to the deteriorated condition of 72CN10.

Table 1: Historical Summer and Winter Peak Loads for the Study Area

Year	Kennedale Substation		Namao Substation	
	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)
2011	49.3	57	52.2	52.9
2012	54.2	57.8	46	52.8
2013	55.9	59.6	48.5	51
2014	55.6	60.4	47.4	50
2015	59.7	59.4	46.1	46.6
2016	54.1	60.3	48.8	53.6
2017	58.8	55.8	48.9	56.3
2018	57.1	53.7	51.1	53.3
2019	52.3	54.9	49.4	53.5
2020	53.3	55.7	53.6	55
2021	63.3	56.2	54.5	56
2022[a]	51.3	50.9	55.8	57.5

Table note: 4.7 MW of load was transferred from Kennedale to Namao in 2021.

2.2.2 Load Forecast

The Edmonton planning area has seen a steady increase in demand over the past 10 years. The increase has primarily been driven by a growing population, industrial expansion and an increasing reliance on electrified services.

Load forecasts are provided for the Kennedale and Namao substations for the 2023 to 2043 planning horizon. The forecast for the Study Area is aligned with the preliminary 2024 LTO and includes one main case and three sensitivity cases to ensure a range of future demand possibilities.[8] The preliminary 2024 LTO considers historical load patterns and trends and considers substation-level load forecasts provided by the applicable legal owner of an electric distribution system (DFO), and recent project developments.

The Study Area usually peaks in the winter season and the preliminary 2024 LTO expects growth mostly due to organic load growth and some electric vehicle penetration. The forecast compound annual growth rate (CAGR) of the load for the 2023 - 2028 planning horizon for the Kennedale substation is 0.9% for

[8] Please see Appendix B for more information on the forecast main case and sensitivities.

Summer and 1.3% for Winter Peak. The forecast CAGR of the load for the 2023 - 2028 planning horizon for the Namao substation is 0.8% for Summer and 1.4% for Winter Peak. The 2026 and 2043 seasonal Winter Peak and Summer Peak load forecasts for the Main Case are presented in Table 2.

Table 2: Study Area Seasonal Load Forecast - Main Case

Year	Kennedale Substation		Namao Substation	
	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)
2026	55.0	50.7	55.9	59.6
2043	78.3	80.7	85.7	104.5

The preliminary 2024 LTO anticipates the load at Kennedale substation will exceed its load serving capability (55.1 MW) by 2027.

2.2.3 Existing Generation

Existing generation in the Edmonton area (Area 60) is approximately 366 MW and comprised mostly of cogeneration, gas-fired (i.e., simple cycle) and solar generation as of September 2023.[9]

Table 3: Existing Generation in Area 60

Asset Name	Asset MPID	Type	Planning Area	Maximum Capability (MW)
Cloverbar #1	ENC1	Simple Cycle	60	48
Cloverbar #2	ENC2	Simple Cycle	60	101
Cloverbar #3	ENC3	Simple Cycle	60	101
South Edmonton Terminal	SET1	Simple Cycle	60	20
Strathcona	IOR4	Cogeneration	60	43
University of Alberta	UOA1	Cogeneration	60	39
kisikaw-pisim 1	KKP1	Solar	60	7
kisikaw-pisim 2	KKP2	Solar	60	7
Total Generation Capacity				**366**

2.2.4 Generation Forecast Capacity

The preliminary 2024 LTO forecasts potential hydrogen-fueled generation development as early as 2026 in Area 60. No growth in co-generation or solar generation is expected. The capacity of simple cycle generation is expected to decrease over the forecast period.

Table 4 summarizes the forecast generation capacity in Area 60.

[9] A list of the assets providing existing generation capacity in Area 60, as of September 2023, is provided in Appendix B of this Application.

Table 4: Forecast Generation Capacity in Area 60

Technology	Existing (MW)	2026 (MW)	2033 (MW)	2043 (MW)
Cogeneration	82	82	82	82
Simple Cycle	270	270	250	250
Solar	14	14	14	14
Hydrogen	0	93	93	93
Total Capacity	**366**	**459**	**439**	**439**

3. Need for the City of Edmonton Transmission Reinforcement

3.1 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 conducted for this Application assessed the need for transmission development in the Study Area.

3.2 Need for Additional Load Serving Capability

3.2.1 Planning Studies

Methodology and Assumptions

Planning studies were carried out for the years 2026 (near-term) and 2043 (long-term).[10] The year 2026 was selected in consideration of when the need for additional transmission capacity will materialize and the earliest possible in-service year of transmission development. The year 2043 was selected to confirm that the Preferred Transmission Development meets the Reliability Criteria over the 20-year planning horizon. Study cases were created and used to perform the studies. The study cases represent reasonably stressed operating conditions, including both summer and winter coincidental peak load conditions [11]and economic generation dispatches for the years 2026 and 2043. The study cases included all projects within the Edmonton Planning Region deemed relevant and sufficiently certain to warrant inclusion in the study.[12]

Studies were first completed to determine the current load serving capability in the Study Area prior to transmission development and to identify potential system constraints in the Study Area in the near-term. Transmission Development Options were developed to address the transmission system constraints and evaluate the technical performance of each Transmission Development Option to arrive at the Preferred Transmission Development. The performance of the Preferred Transmission Development was verified through Category A and Category B power flow analysis, voltage stability analysis, short-circuit and transient stability studies.

Pre-Development Study Results

Using the near-term study cases, the AESO conducted power flow analyses on the existing transmission system to identify Category A and Category B thermal criteria violations in the Study Area prior to additional transmission development.

The load serving capability of the existing system at Kennedale was determined to be 55.1 MW. Category B (i.e., loss of a single system element) thermal criteria violations were observed for 72 kV transmission lines 72CK12 and 72CK13 when one or the other is out of service. The existing system will no longer be able to reliably serve the load at the Kennedale substation during a Category B event by 2027. There are no operational measures available to increase the capability of the existing Kennedale system.

[10] Additional information regarding the studies and results are provided in Appendix A of this Application.

[11] Summer and winter peak loads were studied at time of Kennedale substation peak.

[12] Refer to Appendix A for a list of all projects included in the studies.

The load serving capability of the existing system at Namao was determined to be 49.9 MW, which the peak load on the existing system already exceeds. A Category A (i.e., all elements in service) thermal overload was observed on 72 kV transmission line 72CN10 (the radial transmission line supplying Namao). The TFO has put temporary operational measures to manage this potential overload, but those operational measures are only effective in the short-term due to the current asset condition of 72CN10, which the TFO indicates will require replacement in the next 10 years.

Sensitivity Case

In addition to the main cases, a sensitivity study was completed to confirm that the existing system in its present configuration (i.e., operated as a normally open system) provides the maximum existing load-serving capability. Testing the configuration by closing normally open points worsened the number and severity of violations on monitored lines as compared to the existing system at Kennedale and Namao substations. Ultimately, the sensitivity could not demonstrate a higher load serving capability when normal operational topology was altered.

3.3 Need for Asset Renewal

3.3.1 Asset Condition

The TFO has indicated that some transmission assets are in deteriorated condition and in need of life cycle replacement. Of particular importance is the condition of the 72 kV underground transmission lines serving the Study Area (72CK12, 72CK13, 72NK23 and 72CN10). A failure of one of these transmission lines would result in a lengthy outage due to the difficulty to locate the fault and the length of time required to repair the fault. All of the transmission lines listed above are Oil Filled Pipe Type (OFPT) cables. OFPT technology is obsolete and being replaced by new cable technology such as cross-linked polyethylene (XLPE) and ethylene propylene rubber (EPR). OFPT technology is not well supported, with only one supplier left in North America and limited technical resources for maintenance and upgrades. This makes sourcing material and contractor expertise a lengthy and difficult process. The TFO provided a report detailing the age, condition, and recommendations for these deteriorated assets. Key conclusions from this report are included in Appendix F.

3.3.2 Risks Associated with Aging Underground Transmission Lines

Recently, the TFO reported a failure on another 72 kV OFPT underground transmission line within the City of Edmonton, 72RG7. 72RG7 is of similar vintage and technology as the underground transmission lines in the Study Area. It took five weeks to locate the fault on 72RG7 and it is expected that repairs will take an additional 27 weeks, at a total estimated cost of approximately $5 million. The TFO took steps to manage reliability risks during the extended outage by working with customers that have generation connected to the distribution system and developing a response plan in case of contingencies.

A similar risk exists for the load at Kennedale substation as an extended unplanned outage of either underground transmission line 72CK12 or 72CK13 will increase the risk of the loss of load under the next contingency. This reliability risk, along with other risks presented by these aging underground transmission lines, need to be mitigated by a solution that addresses both the need for life cycle replacements and the need to serve the growing load reliably in the Study Area. It should be noted that any delay to the in-service-date (ISD) of the preferred transmission development will result in longer exposure to the above-mentioned risks.

4. Evaluation of Project Options

This section explains the non-transmission options that were evaluated by the AESO.

4.1 Distribution Load Transfers

Options to transfer load to other substations were investigated with EDTI, which is both the TFO and the DFO in the Study Area. The investigation resulted in EDTI adding a 265-meter distribution feeder and transferring 4.7 MW of load from Kennedale to Namao in 2021, at a cost of less than $1M.

In exploring other options to transfer load to other substations, EDTI confirmed that the cost of transferring additional load from Kennedale would be $6 M (+50%/-30%). EDTI also confirmed that transferring load from Kennedale and Namao substations to Castle Downs substation after the approved Castle Downs Substation Modification project is in service is not possible. The existing Castle Downs distribution infrastructure at the boundary of the Kennedale and Namao service areas does not have capacity to transfer load without major distribution infrastructure upgrades (including 4 to 6 km of distribution feeders). Such upgrades would introduce significant cost, operational complexity and compromise reliability. Shifting load to Castle Downs would also use up the capacity required to serve loads near Castle Downs, and will accelerate the need for further investment at Castle Downs.

As per the above, there are no reasonable opportunities to transfer additional load and defer the need for development temporarily or permanently. It is also noted that transferring load away from Kennedale and Namao does not eliminate the need for transmission development as a permanent solution is required to address the deteriorated transmission infrastructure.

4.2 System Reconfiguration

As discussed in Section 3.2.1, the load serving capability of the existing system does not improve when modifying the existing system from its current configuration (i.e., operated as a normally open system). In addition, any system reconfiguration in aid of serving load growth will not eliminate the need to address aging transmission infrastructure in the Study Area. Hence, there is no system reconfiguration option suitable to address the complete need of this project.

4.3 Non-Wire Solutions

Energy storage was considered as a potential non-wires option to mitigate load growth, but was dismissed due the need to address aging transmission infrastructure in the near future. A solution comprising energy storage may mitigate peak loads, but the transmission system supply to Kennedale and Namao will remain dependent on aging transmission infrastructure which the TFO has identified for replacement in the near future.

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5. 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.

5.1 Transmission Development Options

The AESO identified the following six Transmission Development Options:

Option 1A – **Replace the 72 kV transmission lines 72CK12 and 72CK13**

- Replace the 72 kV underground transmission lines 72CK12 and 72CK13 with two 72 kV circuits with a minimum capacity of 95 MVA each; and
- Add or modify associated equipment as required for the above transmission developments.

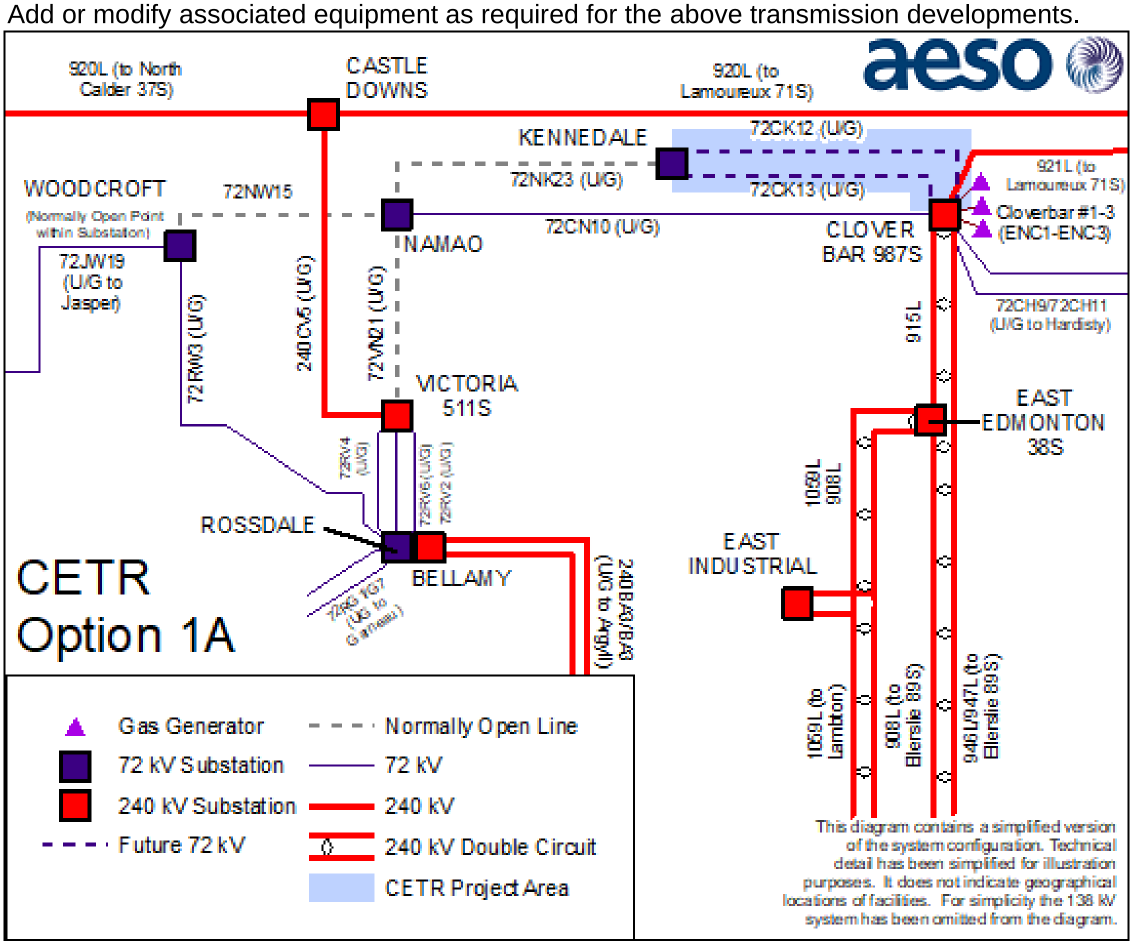

Figure 5-1 Option 1A

Option 1B – Replace the 72 kV transmission lines 72CK12, 72CK13, 72NK23, 72NW15, and 72JW19

- Replace the 72 kV underground lines 72CK12 and 72CK13 with two 72 kV circuits with a minimum capacity of 150 MVA each;
- Replace the 72 kV underground line 72NK23 with a 72 kV circuit with a minimum capacity of 140 MVA;

- Replace the 72 kV overhead line 72NW15 with a 72 kV circuit to a minimum capacity of 90 MVA;
- Replace the 72 kV overhead line 72JW19 with a 72 kV circuit to a minimum capacity of 130 MVA;
- Add a new 240/72 kV transformer of 200 MVA and seven circuit breakers at Clover Bar substation and move the connection point of the three existing generators at Clover Bar from 72 kV to 240 kV yard; and
- Add or modify associated equipment as required for the above transmission developments.

Additionally, the following operational procedural adjustment must occur:

- Operate 72NK23 and 72NW15 as normally closed.
- Operate 72CN10 and 72RW3 as normally open.

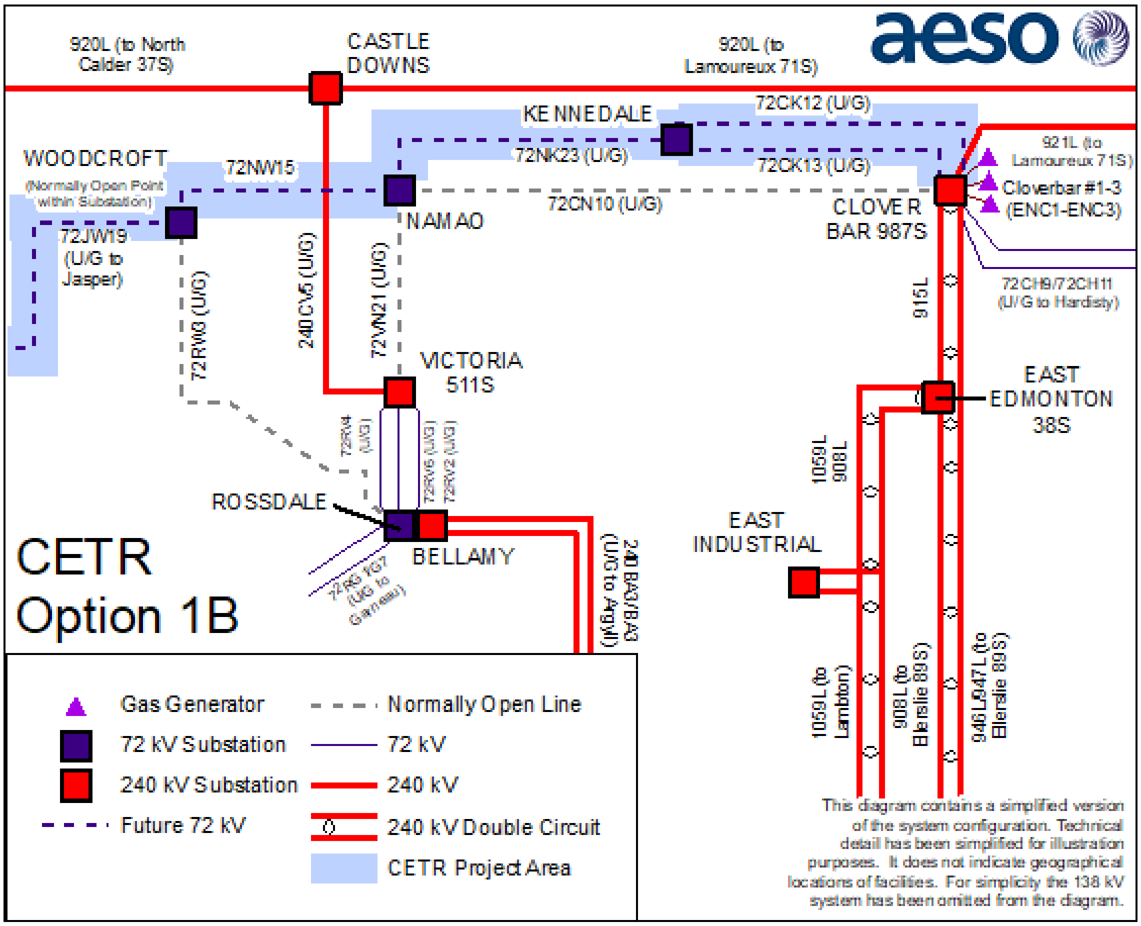

Figure 5-2 Option 1B

Option 2A – Add a 240 kV substation connected to the 240 kV transmission line 915L and reconfigure the 72 kV network

- Add a 240 kV substation including two 240/72 kV transformers (each with a minimum capacity of 200 MVA), five 240 kV circuit breakers and four 72 circuit breakers;
- Connect the proposed substation to the existing 240 kV transmission line 915L in an in-and-out configuration;
- Add one 72 kV circuit with a minimum capacity of 165 MVA to connect the substation to the Kennedale substation;
- Add one 72 kV circuit with a minimum capacity of 170 MVA to connect the substation to the Namao substation;
- Replace the 72 kV transmission line 72NK23 with a 72 kV circuit with a minimum capacity of 95 MVA;
- Discontinue from use for transmission purposes three existing 72 kV transmission lines (72CK12, 72CK13, and 72CN10);
- Modify the Namao substation, including adding one 72 kV circuit breaker; and
- Add or modify associated equipment as required for the above transmission developments.

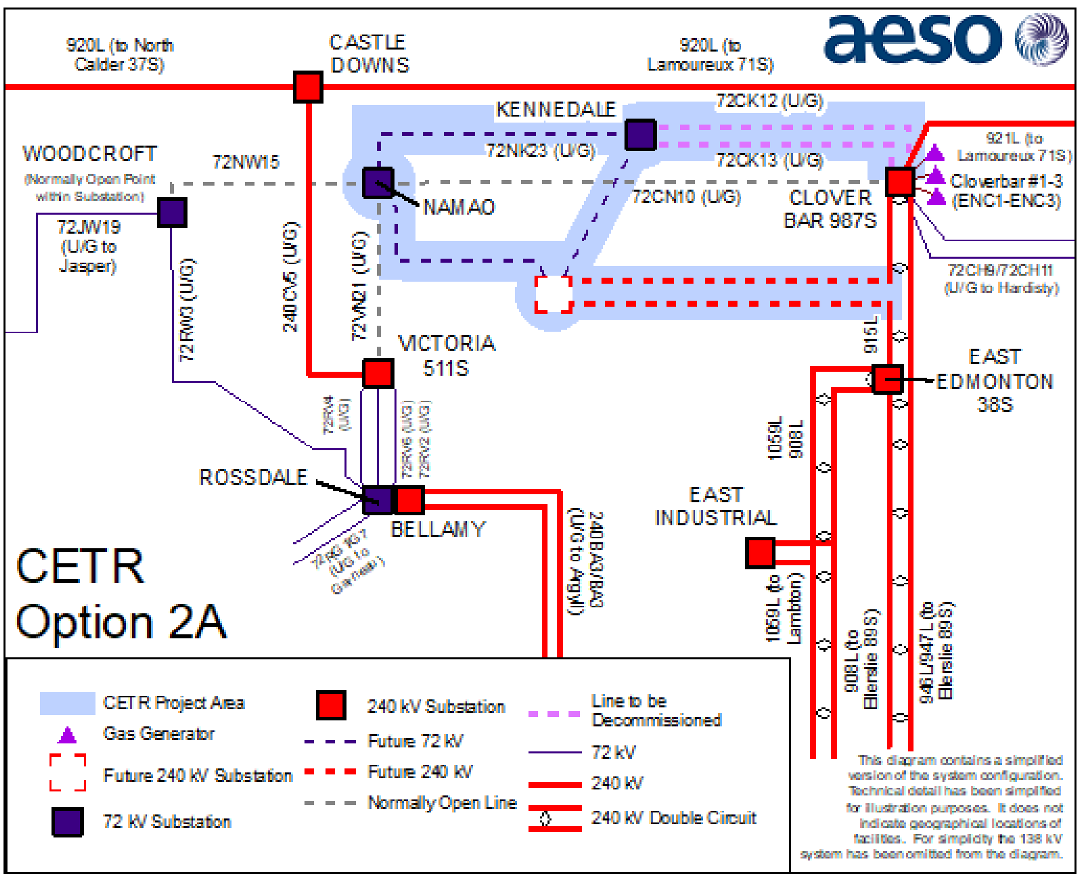

Figure 5-3 Option 2A

Option 2B – Add a 240 kV substation connected to the 240 kV transmission line 240CV5 and reconfigure the 72 kV network

- Add a 240 kV substation including one 240/72 kV transformer with a minimum capacity of 200 MVA, three 240 kV circuit breakers and one 72 kV circuit breaker;
- Connect the proposed substation to the 240 kV underground transmission line 240CV5 in an in-and-out configuration;
- Add one 72 kV circuit with a minimum capacity of 175 MVA to connect the substation and the Namao substation;
- Add one 72 kV circuit with a minimum capacity of 165 MVA to connect the Castle Downs substation and the Kennedale substation;
- Modify the Castle Downs substation, including adding a 240/72 kV transformer with a minimum capacity of 200 MVA, one 240 kV circuit breaker and one 72 kV circuit breaker;
- Replace the 72 kV transmission line 72NK23 with a minimum capacity of 95 MVA;
- Modify the Namao substation, including adding one 72 kV circuit breaker;
- Discontinue from use for transmission purposes the three existing 72 kV transmission lines 72CK12, 72CK13, and 72CN10; and
- Add or modify associated equipment as required for the above transmission developments.

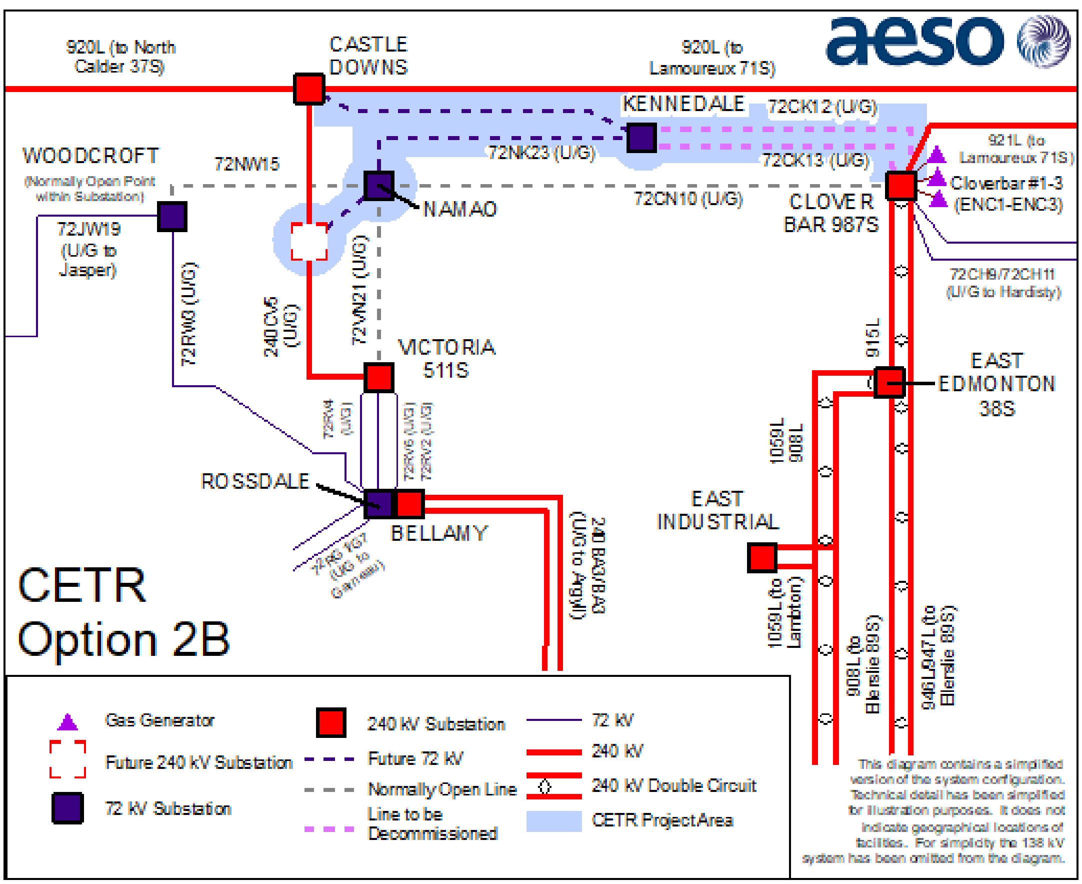

Figure 5-4 Option 2B

Option 3 – Add a 138 kV substation and reconfigure the 72 kV network

- Add a 138 kV substation including two 138/72 kV transformers with a minimum capacity of 200 MVA, four 240 kV circuit breakers and four 72 kV circuit breakers;
- Connect the proposed substation to the 138 kV transmission lines 726L and 761L using a T-tap configuration with two 138 kV transmission lines (one to 726L and one to 761L) having a minimum capacity of 169 MVA and 175 MVA respectively;
- Add one 72 kV circuit with a minimum capacity of 175 MVA to connect the proposed substation and the existing Namao substation;
- Add one 72 kV circuit with a minimum capacity of 165 MVA to connect the substation and the existing Kennedale substation;
- Replace the existing 72 kV underground line 72NK23 with a 72 kV circuit with a minimum capacity of 100 MVA;
- Discontinue from use for transmission purposes the two 72 kV transmission lines 72CK12 and 72CK13; and
- Add or modify associated equipment as required for the above transmission developments.

Additionally, the following operational procedure adjustment needs to be made:

- Operate 72CN10 as normally open.

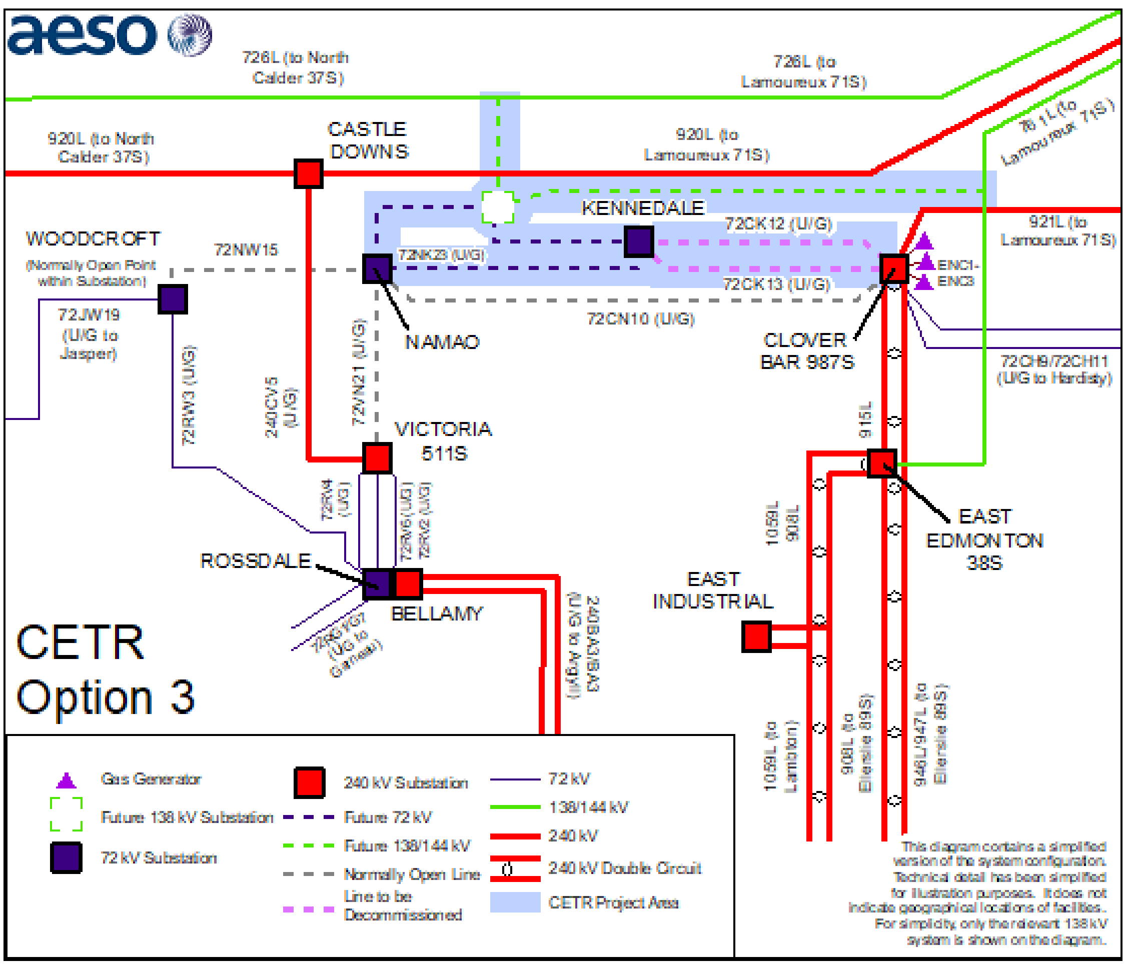

Figure 5-5 Option 3

Option 4 – Add a 240 kV substation connected to the 240 kV transmission line 915L, reconfigure the 72 kV network, and decommission the Kennedale substation

- Add a 240 kV substation including two 240/72 kV transformers (each with a minimum capacity of 167 MVA), two 240/15 kV transformers (each with a minimum capacity of 75 MVA), six 240 kV circuit breakers and four 72 kV circuit breakers;
- Connect the substation to the existing 240 kV transmission line 915L using an in-and-out configuration;
- Add two 72 kV circuits, each with minimum capacity of 85 MVA, to connect the substation and the Namao substation;
- Modify the Namao substation, including adding one 72 kV circuit breaker;
- Discontinue from use for transmission purposes the Kennedale substation and the four 72 kV transmission lines 72CK12, 72CK13, 72NK23 and 72CN10; and
- Add or modify associated equipment as required for the above transmission developments.

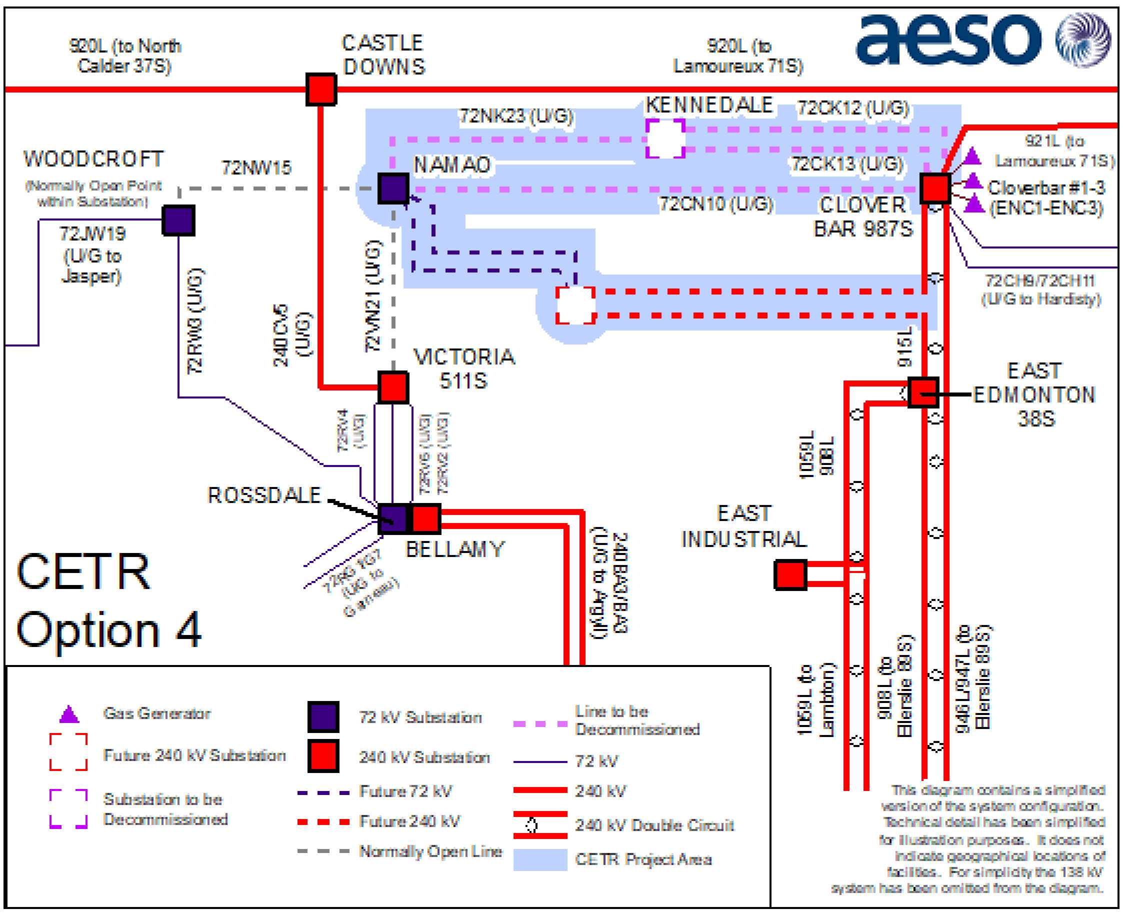

Figure 5-6 Option 4

5.2 Transmission Development Options Assessment

5.2.1 Initial Screening

Option 1B and Option 3 were eliminated from further analysis. The TFO advised that Option 1B is not feasible as Clover Bar substation does not have the physical space for the 240 kV bus modifications required to reconnect the generators at Clover Bar substation from 72 kV to 240 kV.

Option 3 was ruled out for the following reasons:

- The TFO in the project area has limited 138 kV asset base, spare parts inventory, and tools to manage additional 138 kV fleet.
- 138 kV development requires upgrading existing substations to be compatible with 138 kV which is technically challenging due to limited space available for site expansion at many of the existing substations.

5.2.2 Transmission System Performance

The AESO evaluated the transmission system performance of the remaining four Transmission Development Options by performing 2026 Summer Peak power flow studies.

The power flow studies were performed on the transmission system in the Study Area with each of the four Transmission Development Options in place. The studies assessed the performance of each Transmission Development Option to reliably serve forecasted load in the Study Area. The results of the studies are as follows:

- Option 1A – Category A overloads were observed on 72CN10. Therefore, the minimum capacity of 72CN10 would need to be increased to address this overload. This additional scope would result in greater costs for Option 1A than are presented in Table 4 below.

- Options 2A, 2B and 4 - allow for the reliable growth of electricity demand in the Study Area and mitigate Category A and Category B thermal criteria violations.

All options were assessed for further consideration from a cost and environmental and land use effects perspective, with further details provided in Sections 5.2.3 and 5.2.4 of this Application. Additional information regarding the Transmission Development Options and the power flow studies is provided in Appendix A of this Application.

5.2.3 Transmission Development Option Costs

To further assist with its evaluation of Transmission Development Options 1A, 2A, 2B, and 4 described in Section 5.1, the TFO prepared cost estimates (+50%/-30%) for these options that meet the requirements of AUC Rule 007, Section 7.1.1, NID4.

Options 1A, 2A, 2B and 4 are compared in terms of their initial capital cost and their impact to future lifecycle replacement costs anticipated on remaining transmission infrastructure in the near and long-term. Table 4 provides a summary of the capital costs of options along with life cycle cost offsets resulting from each option. The TFO estimates the life cycle replacement cost required for Kennedale substation to be $47M[13] which will be required for all options except Option 4 within the next twenty years.[14] Option 4 includes the decommissioning of the existing Kennedale substation and serving Kennedale load out of a new 240 kV substation hence avoiding the life cycle replacement cost of Kennedale.

The AESO reviewed the cost estimates provided by the TFO against cost benchmark data and found the cost estimates to be reasonable. The estimated transmission capital and lifecycle replacement costs[15] are summarized in Table 4 and provided in Appendix C of this Application.

Table 4: Transmission Development Options Capital and Lifecycle Cost Offset

Transmission Development Option	Transmission Capital Cost (+50%/-30%)	Lifecycle Cost Offset (Kennedale)	AltaLink Scope of Work[b] (+30%/-30%)	Total Cost
1A	$260M[a]	$47M	N/A	$307M
2A	$265M	$47M	$6M	$318M
2B	$270M	$47M	N/A	$317M
4	$270M	N/A	$6M	$276M

Table Notes:

[a]Costs for 72CN10 replacement are not included, see Section 5.2.2.

[b]AltaLink Management Ltd., in its capacity as general partner of AltaLink L.P., has a small scope of work that includes cutting into the existing 240 kV transmission line 915L to connect the proposed substation to 915L via an-in-and-out configuration. More information can be found in Appendix A.

Taking into account capital costs, the cost of the Kennedale substation lifecycle replacement, and AltaLink costs, the lowest overall cost option is Option 4.

5.2.4 Environmental and Land Use Effects

The AESO directed the TFO to prepare a report (see Appendix E) comparing all Transmission Development Options according to the environmental and land use effects (ELUE) information contemplated in AUC Rule 007, *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines*, Section 7.1.1, NID2. The TFO's conclusions are summarized as follows:

- From an environmental and land use effects perspective, the TFO concludes that all the options - Options 1A, 2A, 2B and 4 are viable.
- Option 2B poses higher potential residential impact than Option 2A.
- Options 2A and 4 have lowest environmental and land use effects and approximately similar potential residential impacts. Options 2A and 4 present a net benefit due to reduced potential environmental risk following the decommissioning of four existing OFPT cables.

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[13] EDTI-AESO-2020MAY27-028(Revised) - Response to the AESO's Information Requests ("IRs") for the City of Edmonton Transmission Development – AESO Project No. 7008. Attached to Appendix A as Attachment H.

[14] EDTI forecasts the power transformers to be due for replacement in the 2027 to 2028 time frame, medium voltage switchgear in the 2033-2036 time frame and high voltage breakers sometime after 2040.

[15] The cost estimates are in nominal dollars using a base year of 2023 with escalation considered and an accuracy level of +50%/-30%.

- Based on the above conclusions, Option 4 would pose the lowest overall levels of impacts and highest net benefit.

5.3 Selection of the Preferred Transmission Development

The AESO investigated six transmission development options to address the need, taking into consideration the cost, future capability, and land use and environmental effects. Option 4 had the lowest overall cost and is one of the options with the lowest potential for land use and environmental effects. Option 4 was selected as the Preferred Transmission Development for the following reasons:

- Option 4 meets the technical requirement and will serve required load reliably in the long-term.
- Option 4 is the lowest cost option when considering both initial capital cost and future life cycle replacements offsets.
- Option 4 has lower environmental and land use impacts
- Option 4 provides the provision to expand to serve additional load in the area.
- Option 4 provides an alternative option for the future lifecycle replacement of Victoria to Rossdale underground transmission lines when these circuits reach end of life.

5.4 Technical Performance of the Preferred Transmission Development

Additional planning studies were conducted to assess the impact that the Preferred Transmission Development would have on the transmission system and confirm that the Preferred Transmission Development would serve the long-term 20 year load forecast in the Study Area. Category A and B power flow, voltage, short circuit, and transient stability analyses were performed before and after the energization of the Preferred Transmission Development.

The 72 kV circuits serving Namao substation were sized at a minimum capacity of 85 MVA to align with the load serving capability of the transformers at Namao substation, which is 80 MVA. The transformers at Namao are in good condition and there is no immediate plan to replace them. If further load growth materializes, the load can be served from another substation to avoid Category B thermal criteria violations on these circuits. In addition, the proposed substation can be expanded to serve more load and provide additional 72 kV connections if required in the future.

The observed short-circuit fault levels following the energization of the Preferred Transmission Development were not significantly higher than the levels of the pre-energized system. Voltage stability analysis showed no voltage criteria violations.

Finally, the transient stability analysis found the transmission system to be stable for Category B and select Category C contingencies after the energization of the Preferred Transmission Development.[16]

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

6. Preferred Transmission Development

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

6.1 Preferred Transmission Development

Figure 6-1 illustrates the Preferred Transmission Development, and includes the following major transmission system elements:

- Add a 240 kV substation, to be designated the Fort Road substation, including two 240/72 kV transformers (each with a minimum capacity of 167 MVA), two 240/15 kV transformers (each with a minimum capacity of 75 MVA), six 240 kV circuit breakers and four 72 kV circuit breakers;
- Connect the substation to the existing 240 kV transmission line 915L using an in-and-out configuration;
- Add two 72 kV circuits, each with minimum capacity of 85 MVA, to connect the substation and the Namao substation;
- Modify the Namao substation, including adding one 72 kV circuit breaker;
- Discontinue from use for transmission purposes the Kennedale substation and the four 72 kV transmission lines 72CK12, 72CK13, 72NK23 and 72CN10; and
- Add or modify associated equipment as required for the above transmission developments.

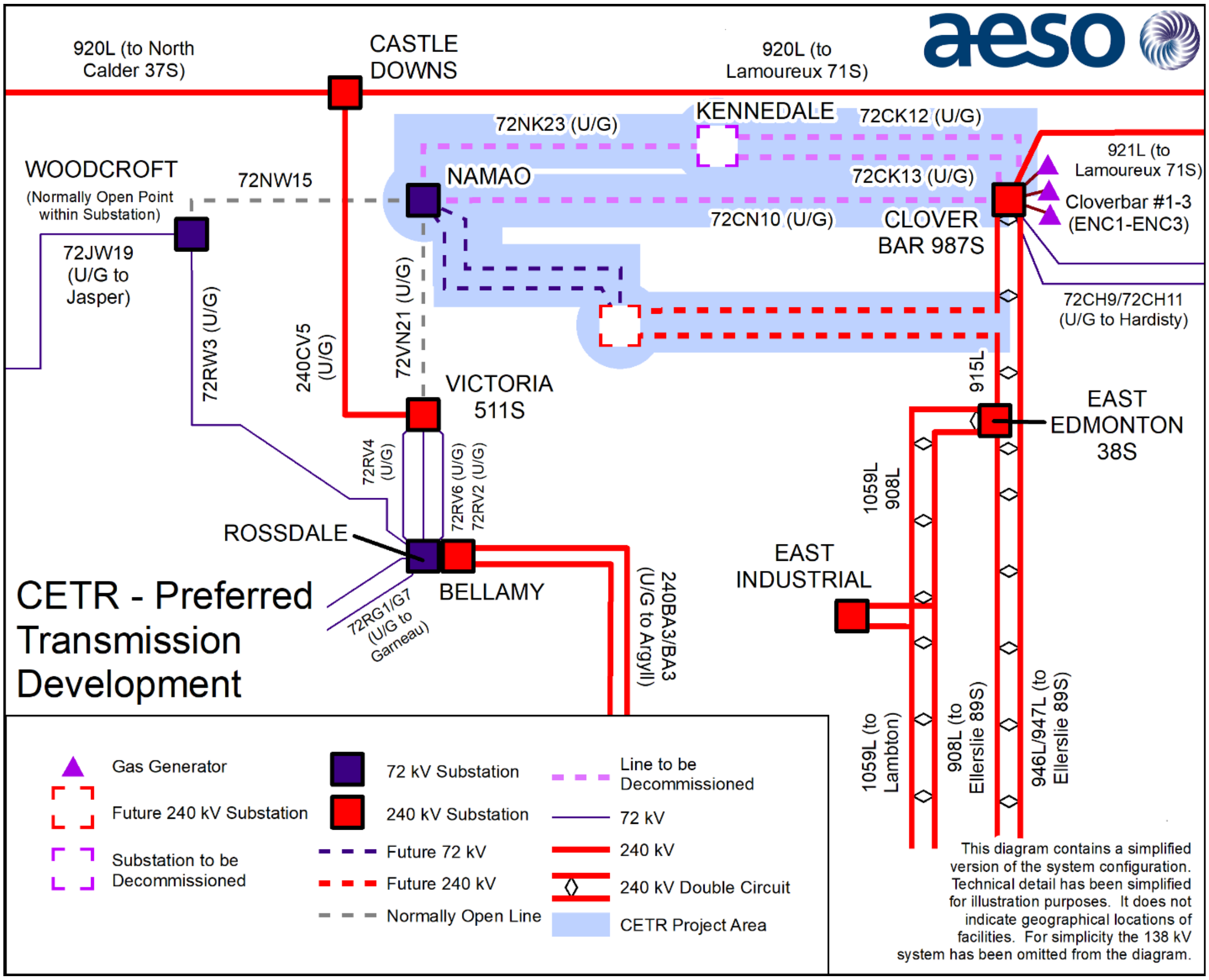

Figure 6-1 Preferred Transmission Development

6.2 Preferred Transmission Development Costs

As mentioned in Section 5.2.3, the TFO and AltaLink prepared a cost estimate for Option 4, the Preferred Transmission Development, which has an approximate in-service cost of $276 million.[17][18]

[17] The TFO's cost estimate is in nominal dollars using a base year of 2023 with escalation considered. Further details of this cost estimate, which has an accuracy level of +50%/-30%, can be found in Appendix C of this Application.

[18] AltaLink's cost estimate is in nominal dollars using a base year of 2023 with escalation considered. Further details of this cost estimate, which has an accuracy level of +30%/-30%, can be found in Appendix C of this Application.

6.3 Preferred Transmission Development Schedule

The scheduled in-service date for the Preferred Transmission Development is Q1 2027.

As mentioned in Section 3.3.2 above, any delay to the scheduled in-service date increases the risk of failure on the aging underground transmission lines. Failure of those lines results in the inability to reliably serve load in the Study Area. In addition, Kennedale substation is forecasted to exceed its load serving capability in 2027.

7. 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 2022 Long-term Transmission Plan* (2022 LTP) ,[19] which identifies the need for transmission system development in the City of Edmonton area driven by load growth in the City of Edmonton including the following planned developments:

- Create a new 240/72 kV substation called East Terminal[20]
- Cut into 915L (Clover Bar – East Edmonton 38S) and bring two 240 kV circuits into East Terminal
- Decommission the Kennedale substation and cables
- Redistribute load from Kennedale, Namao, and Hardisty among East Terminal, Namao, and Hardisty, with the bulk of Kennedale load going to East Terminal
- Add two 72 kV circuits from East Terminal to Namao

This Application addresses the need for reliability in the Study Area. For more information regarding other plans for the City of Edmonton transmission system, please refer to the 2022 LTP.

7.1 Transmission Development Interdependencies

The Preferred Transmission Development is not dependent on other transmission developments that are currently planned within the AIES in this timeframe.

[19] The AESO's 2022 LTP is available on the AESO website.

[20] East Terminal substation was later renamed to Fort Road substation, as presented in this Application.

8. Participant Involvement Program

8.1 Stakeholder Engagement

The AESO conducted a Participant Involvement Program (PIP), in accordance with the requirement of NID6 and Appendix A2 of AUC Rule 007. The AESO directed the TFO to assist the AESO in conducting the AESO's PIP. Between January and November 2023, the TFO and the AESO used various methods to notify stakeholders and Indigenous groups 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 November 2023, 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 D.

8.2 Consumer Group Engagement

In December 2021, the AESO met with three consumer groups (the Utilities Consumer Advocate, the Consumers Coalition of Alberta, and the Industrial Power Consumers Association of Alberta) to discuss the City of Edmonton Transmission Reinforcement application. The purpose of the meeting was to provide:

- greater openness and transparency on the AESO alternative selection process; and
- early opportunity for consumer groups to ask questions and understand the AESO's analysis prior to selection of the preferred transmission development.

9. Relief Requested

9.1 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 7.1, subsection 7.1.1, of AUC Rule 007,

the AESO submits that:

- the AESO's assessment of the need to reliably serve the growing demand for electricity in the northeastern portion of the City of Edmonton and mitigate risks related to the aging 72 kV transmission system 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 TReg and, in particular, subsections 38(d) and (e).

9.2 Request

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

1. Approve this Application, including the Preferred Transmission Development, which will be comprised of the following:

    - Add a 240 kV substation, to be designated the Fort Road substation, including two 240/72 kV transformers, two 240/15 kV transformers, and associated 240 kV and 72 kV circuit breakers;
    - Connect the substation to the existing 240 kV transmission line 915L using an in-and-out configuration;
    - Add two 72 kV circuits to connect the substation and the Namao substation;
    - Modify the Namao substation, including adding associated 72 kV circuit breakers;
    - Discontinue from use for transmission purposes the Kennedale substation and the four 72 kV transmission lines 72CK12, 72CK13, 72NK23 and 72CN10; and
    - Add or modify associated equipment as required for the above transmission developments.

All of which is respectfully submitted this 7th day of December 2023.

Alberta Electric System Operator

"Electronically Submitted by"

Robert Davidson, P.Eng.
Vice President, Grid Reliability – Projects and Planning

PART B – APPLICATION APPENDICES

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

APPENDIX A – AESO Planning Report

APPENDIX B – AESO Load and Generation Forecast

APPENDIX C – TFO Cost Estimates

APPENDIX D – AESO Participant Involvement Program (PIP)

APPENDIX E - TFO Environmental and Land Use Effects Assessment

APPENDIX F – TFO Asset Condition Report

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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) of the Act, 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.

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 A.

iv. **Application for Approval of the Need for Expansion or Enhancement of the Capability of the Transmission System –** This Application is directed, in part, 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.

v. **Directions to the TFO**– Pursuant to subsection 35(1) of the Act, the AESO has directed the TFO, in its capacity as a legal owner of transmission facilities, in whose service territory the need is located, to prepare a Facility Proposal to meet the need identified.

vi. **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*.