ALBERTA UTILITIES COMMISSION

IN THE MATTER OF *the Alberta Utilities Commission Act*, S.A. 2007, c. A-37.2, as amended, and the Regulations made thereunder;

AND IN THE MATTER OF the *Hydro and Electric Energy Act*, R.S.A. 2000, c. H-16, as amended, and the Regulations made thereunder;

AND IN THE MATTER OF an Application for regulatory authorizations required to construct and operate the Central Calgary Transmission Line Replacement Project.

ENMAX POWER CORPORATION

Central Calgary Transmission Line Replacement

FACILITY APPLICATION

October 31, 2024

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APPENDICES

Appendix H **<u>Participant Involvement Program</u>**

1 INTRODUCTION

1. ENMAX Power Corporation ("EPC") is applying to the Alberta Utilities Commission ("AUC" or "Commission") pursuant to sections 14, 15 and 21 of the *Hydro and Electric Energy Act* ("HEEA") for authorizations associated with the replacement of EPC's 138 kV transmission line 138-3.82L ("3.82L") that currently connects ENMAX No. 3 Substation to ENMAX No. 8 Substation ("Project").

2. 3.82L is an underground, low pressure oil filled ("LPOF") cable that was installed in 1977. 3.82L has reached the end of its useful life due to deteriorated asset condition and must, therefore, be decommissioned. The Project is required to address the asset condition of 3.82L, while allowing EPC to continue to meet its obligation under section 39(1) of the *Electric Utilities Act* ("EUA") to operate and maintain its transmission system safely, reliably and economically.

3. The Project is generally comprised of the following elements, all of which require Commission approval:

- the de-energization of 3.82L, deactivation of certain control systems, and nitrogen purging of oil from the segment of 3.82L between ENMAX No. 3 Substation and maintenance hole MH 1979 ("MH 1979"), resulting in the discontinuance of operations of 3.82L ("Discontinuance of 3.82L Operations");
- the physical extension of 138 kV transmission line 138-2.83L ("2.83L") from existing structure 138-2.83-95, located near the intersection of 16 Avenue NE and Deerfoot Trail NE ("2.83L T-Tap Point"[1]) to ENMAX No. 3 Substation ("2.83L Extension");
- work at ENMAX No. 3 Substation to support the Discontinuance of 3.82L Operations and the 2.83L Extension, including the removal of an approximately 30-meter segment of 3.82L, the removal of six oil pressure reservoir tanks and the cutting and capping of the remaining 3.82L cable near ENMAX No. 3 Substation (collectively, the "No. 3 Substation Work"); and
- the reconfiguration of ENMAX No. 13 Substation by adding a 138 kV bus tie breaker and subsequent reconfiguration of short sections of 2.83L and EPC transmission line 138-3.84L ("3.84L") and the reconfiguration of 2.83L at ENMAX No. 2 Substation to

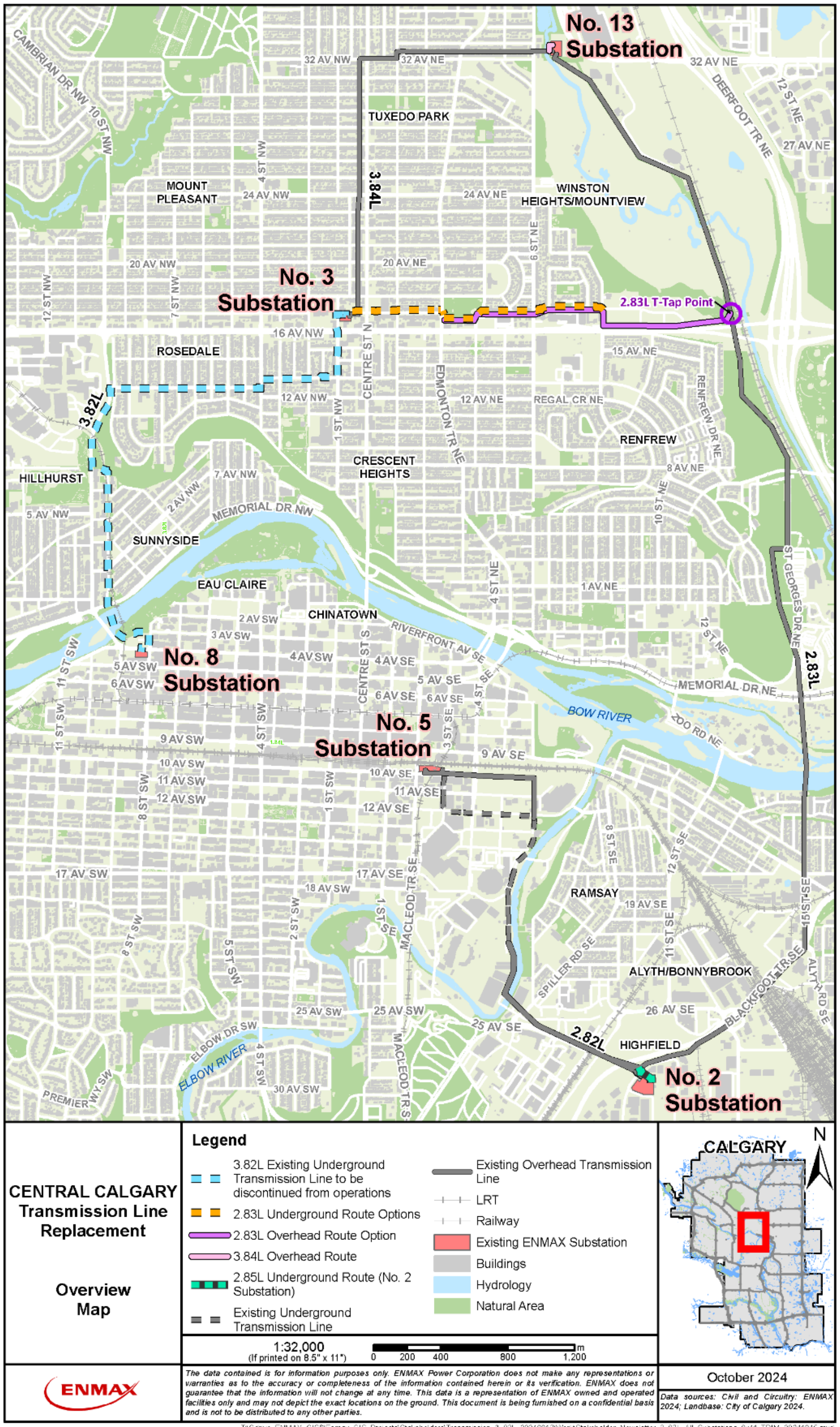
[1] A "T-Tap" exists where the end of one electrical circuit connects to a mid-point of another, resulting in a transmission or distribution line with three substations terminals.

support the Discontinuance of 3.82L Operations and the 2.83L Extension (collectively, the “Reconfiguration Work”).

4. The Project is illustrated in the Project Overview Map at Figure 1-1.

5. EPC continues to evaluate the appropriate scope of work for the final decommissioning and salvage of 3.82L (“Final 3.82L Decommissioning and Salvage”). EPC will finalize that planning and seek the requisite approvals from the AUC after a decision on this Application (including approval of the Discontinuance of 3.82L Operations) has been rendered.

Figure 1-1: Project Overview Map



6. Maskwa Environmental Consulting Ltd. (“Maskwa”) was retained to conduct a transmission line routing and siting assessment to determine the optimal route(s) for the 2.83L Extension.

7. Alternative routes for the Reconfiguration Work related to relatively short spans of transmission lines in the immediate vicinity of ENMAX No. 2 Substation and ENMAX No. 13 Substation, were determined not to be available and, therefore, the Reconfiguration Work was not the subject of Maskwa’s routing and siting assessment.

8. The details and results of Maskwa’s routing and siting assessment for the 2.83L Extension can be found in Maskwa’s Urban Siting Methodology, Siting Technical Report and Route Revision Log (Appendices G-1, G-2, and G-3, respectively). Based on the Maskwa routing and siting analysis and other considerations, EPC identified two technically feasible and comparable route alternatives for the 2.83L Extension:

9. a primarily overhead transmission line configuration that runs along, or in close proximity to, 17 Avenue NW between ENMAX No. 3 Substation and the 2.83L T-Tap Point, which has been identified as the preferred route (“North Route – Primarily Overhead”); and

10. a primarily underground transmission line configuration that runs along, or in close proximity to, 17 Avenue NW between ENMAX No. 3 Substation and the 2.83L T-Tap Point, which has been identified as the alternate route (“North Route – Primarily Underground”) (collectively, the “2.83L Extension Route Alternatives”).

11. Figure 1-2 and Figure 1-3 illustrate each of the 2.83L Extension Route Alternatives.

Figure 1-2: North Route – Primarily Overhead

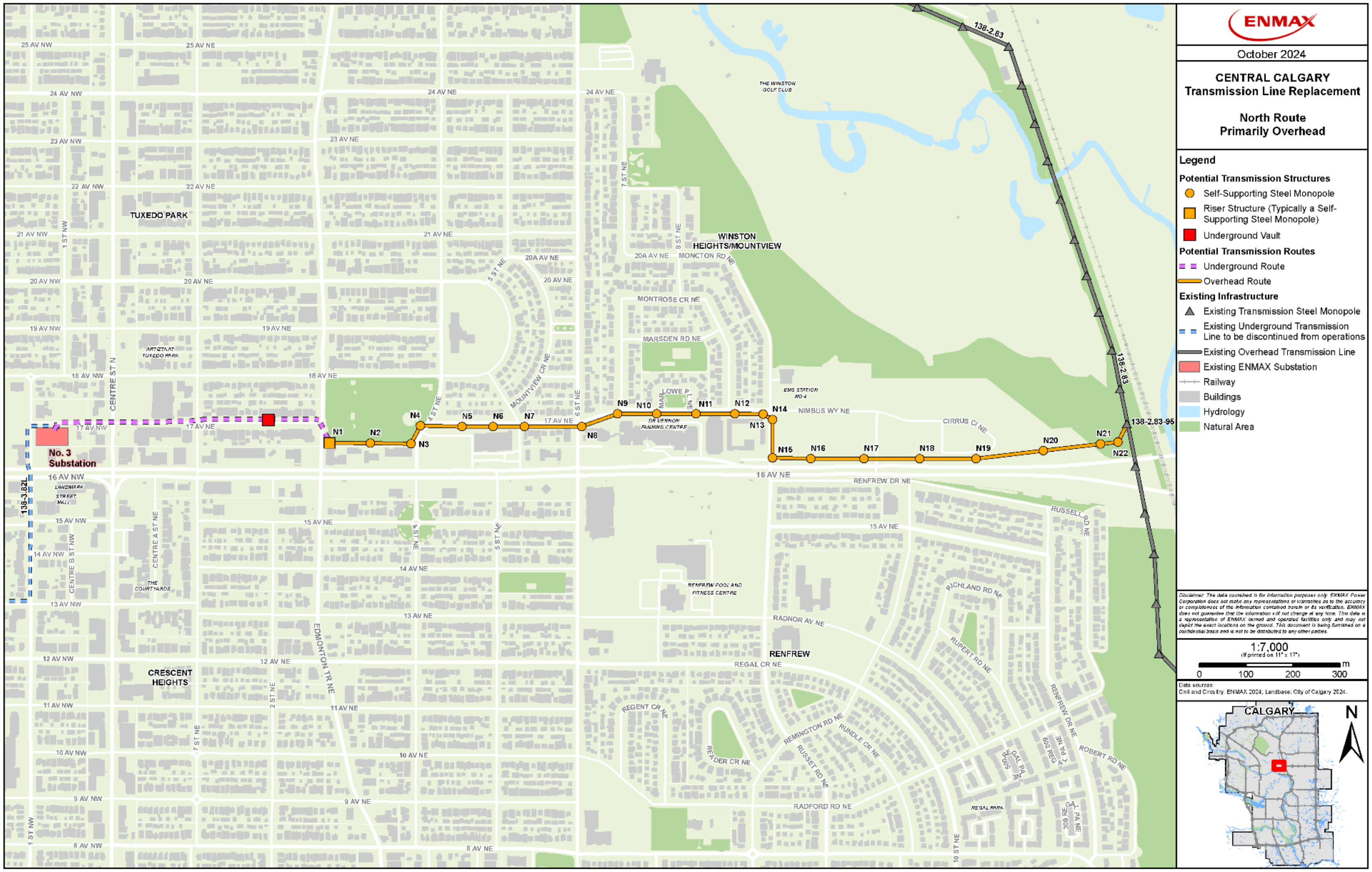
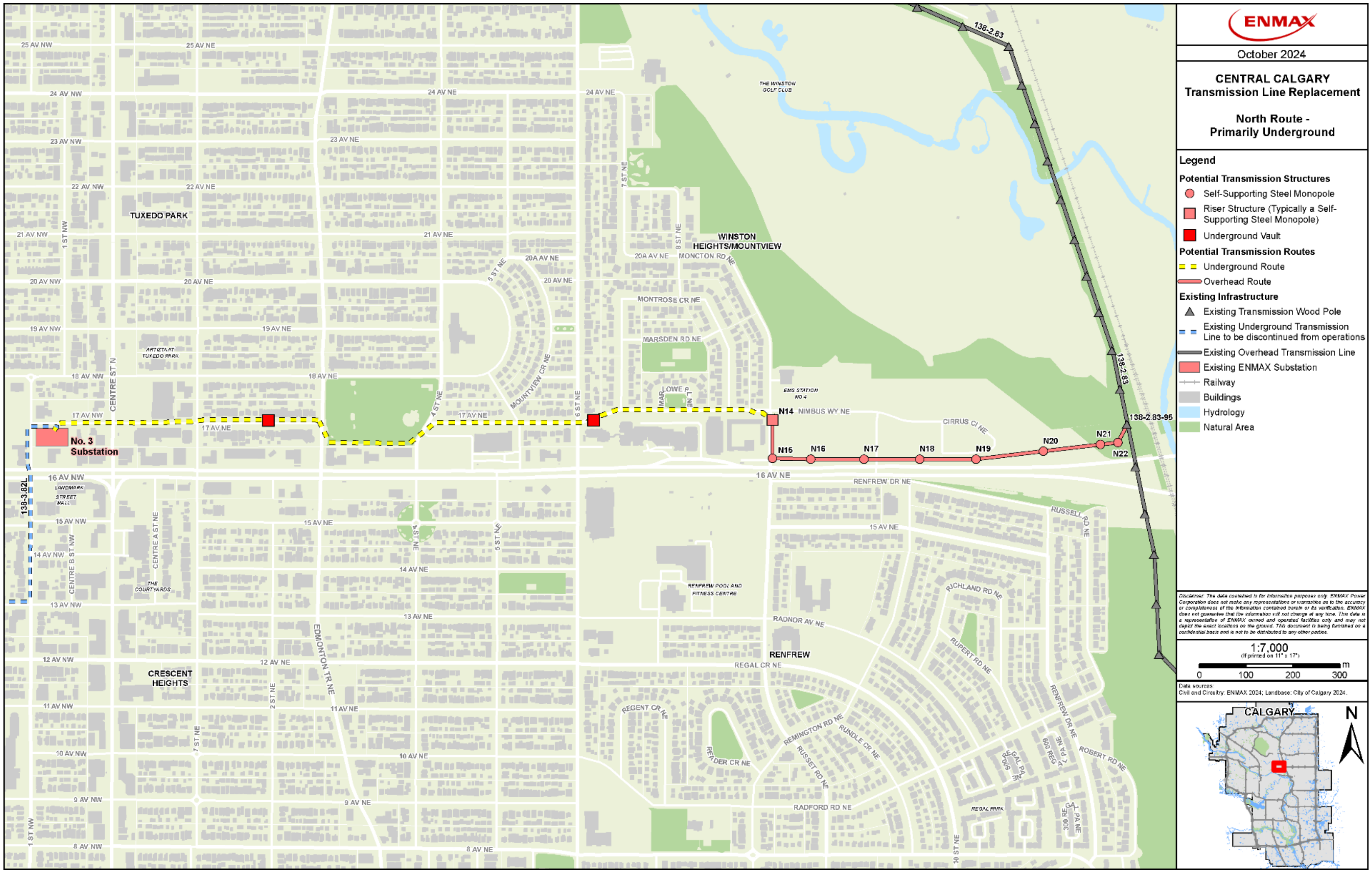


Figure 1-3: North Route – Primarily Underground



12. The 2.83L Extension Route Alternatives essentially follow the same physical footprint and, therefore, the main difference between the routes is that one is in a primarily overhead configuration and one is in a primarily underground configuration. The two routes were determined by Maskwa to be similar in impact, with the North Route – Primarily Overhead having a lower cost than the North Route – Primarily Underground, but a higher potential for residential impact related to the potential visual impacts of an overhead transmission line and requirements for tree clearing or removal. The 2.83L Extension Route Alternatives were determined by Maskwa to be comparable, however, given that cost to ratepayers can constitute a significant factor in the weighing of impacts when other factors are mostly equal,[2] the relatively lower cost of North Route – Primarily Overhead was an important factor in its designation as the preferred route.

13. The Alberta Electric System Operator ("AESO") has been advised of the Project, including the proposed Discontinuance of 3.82L Operations, which is the subject of the Decommission and Salvage Application attached at Appendix A ("Decommission and Salvage Application"). In correspondence dated September 16, 2022 (Appendix B), the AESO confirmed that the Project (which forms part of a larger integrated transmission solution) aligns with EPC's objective as a transmission facility owner to "minimize rate-payer costs by optimizing, prioritizing and deferring projects as applicable." The AESO also confirmed that it "has not identified any material technical concerns" and, therefore, has no objections to the integrated solution. Finally, the AESO confirmed that a Needs Identification Document approval is not required because "the integrated solution does not expand or enhance the capability of the transmission system."

14. The total cost estimates for the Project are $50.6 million for the North Route – Primarily Underground and $40.6 million for the North Route – Primarily Overhead. These cost estimates are based on AACE International, Inc. Class 3 estimating level at an accuracy level of +30/-20% and are attached at Appendix C.

15. The proposed in-service date ("ISD") for the Project is Q4 2026. The proposed ISD and the Project cost estimates are based on several assumptions, including receiving an AUC decision on this Application by Q2 2025.

[2] See: AUC Decision 27965-D01-2023, ENMAX Power Corporation: Transmission Lines 69-15.62L and 69-16.63L Overhead Structures, Proceeding 27965, Application 27965-A001, December 6, 2023, paragraph 24; AUC Decision 27523-D01-2023: AltaLink Management Ltd. – Transmission Line 150L Rebuild, Proceeding 27523, Application 27523-A001, April 28, 2023, paragraph 49.

16. EPC conducted a comprehensive Participant Involvement Program ("PIP") for the Project in accordance with the requirements of AUC Rule 007. The PIP provided an opportunity for EPC to engage with landowners, occupants, residents, Indigenous groups, utilities, municipal and provincial authorities, special interest groups and the general public to provide information about the Project, discuss any Project-related concerns those parties might have and facilitate feedback to EPC. All feedback and information provided was considered and, where reasonably feasible, incorporated into the routing, configuration and construction methods.

17. EPC considers potential environmental effects at all stages of a project. EPC engaged Maskwa to complete an environmental evaluation for the Project ("Environmental Evaluation"), which is located at Appendix D-1. The Environmental Evaluation concluded that the Project would not result in any significant residual effects to environmental components. Mitigation measures for the Project were developed with input from Maskwa and are included in the Environmental Management Plan ("EMP") (Appendix D-2) and will be implemented during Project construction and operation to reduce or eliminate residual environmental effects. In addition, EPC submitted an *Historical Resources Act* ("HRA") application for all areas of the Project with Historic Resource Values to the Alberta Ministry of Arts, Culture and Status of Women. Approval was provided on June 24, 2024 (Appendix D-3).

18. Pending the Final 3.82L Decommissioning and Salvage work, EPC intends to keep the portion of 3.82L from MH 1979 to EPC No. 8 Substation pressurized (i.e., EPC will not purge oil from this segment) and keep all controls equipment associated with this segment activated. This will allow EPC to continue to monitor the condition of this segment of 3.82L for potential oil leaks.

19. The Project as designed best avoids or minimizes potential negative impacts and addresses the need to replace 3.82L, which is at the end of its useful life. For the reasons set out in the Application, EPC submits that the Project is required and is in the public interest.

2 PROJECT OVERVIEW

20. This is an application to undertake the work that is required to replace 3.82L, which has reached the end of its useful life due to deteriorated asset condition.

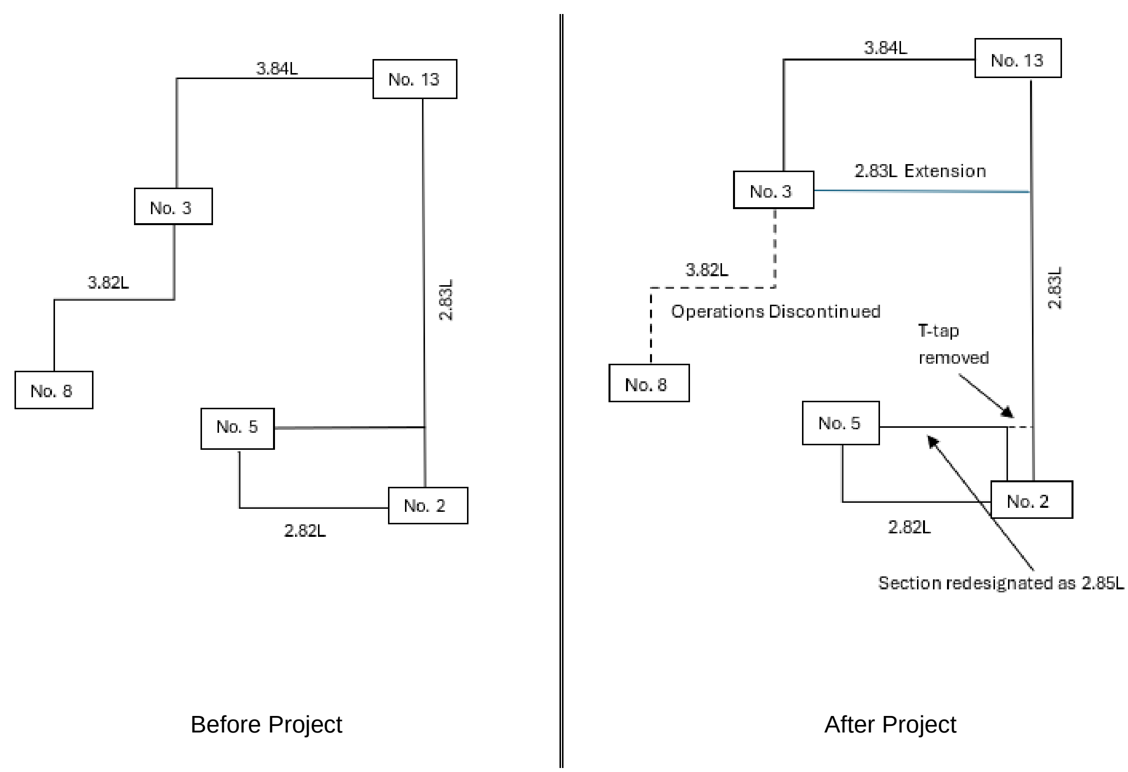
21. EPC is applying to the AUC, pursuant to sections 14, 15 and 21 of the HEEA for the authorizations required to carry out the work associated with the Project and for such further and other relief that EPC may subsequently request, or the Commission may consider appropriate.

2.1 Project Description

22. The location of the Project and associated components are illustrated in Figure 1-2, Figure 1-3 and Appendix E-1. The principal elements of the Project are the "Discontinuance of 3.82L Operations," the "2.83L Extension," the "No. 3 Substation Work" and the "Reconfiguration Work," as defined and described below.

23. An illustration of the Project scope is provided in Figure 2-1.

Figure 2-1: Project Scope Overview



2.1.1 Discontinuance of 3.82L Operations

24. The Discontinuance of 3.82L Operations includes the de-energization of 3.82L, deactivation of certain control systems and purging of oil from the segment of 3.82L between ENMAX No. 3 Substation and MH 1979. EPC plans to undertake three rounds of nitrogen purging to capture as much of the free-flowing oil as reasonably possible: first, at or around the time of de-energization of 3.82L, approximately four months from the time of de-energization and approximately one-year from the time of de-energization.

25. The Discontinuance of 3.82L Operations is the subject of the Decommission and Salvage Application attached at Appendix A. EPC continues to evaluate the appropriate scope of work for the Final 3.82L Decommissioning and Salvage. Given the contingencies between this Application (including approval of the Decommission and Salvage Application) and the Final 3.82L Decommissioning and Salvage, EPC intends to finalize that scope of work after the Commission renders a decision on this Application.

26. The nature and scope of the Discontinuance of 3.82L Operations does not depend on the alternative approved for the 2.83L Extension.

2.1.2 2.83L Extension

27. The 2.83L Extension is the physical extension of 2.83L from existing structure 138-2.83-95, located near the intersection of 16 Avenue NE and Deerfoot Trail NE (i.e., the 2.83L T-Tap Point) to ENMAX No. 3 Substation. The 2.83L Extension is required to maintain reliable service to customers upon the Discontinuance of 3.82L Operations.

28. EPC has proposed two route alternatives for the 2.83L Extension, both of which follow essentially the same physical footprint (one in a primarily overhead configuration and one in a primarily underground configuration): the North Route – Primarily Overhead and the North Route – Primarily Underground.

29. The “North Route – Primarily Overhead” has been designated as the preferred route. It is a primarily overhead transmission line configuration that runs along or in close proximity to 17 Avenue NW between ENMAX No. 3 Substation and the 2.83L T-Tap Point. It exits ENMAX No. 3 Substation and runs underground east along 17 Avenue NW, crossing Edmonton Trail NE. At structure N1, the transmission line transitions from underground to overhead and follows the southern boundary of Munro Park (structures N2 and N3). This route option then turns north at structure N3 and runs along the west side of 4 Street

NE and connects to structure N4. From there, this route option runs east along the south side of 17 Avenue NE, which includes structures N5 to N14. At structure N14, this route option turns south along the east side of Moncton Road NE and connects to structure N15 where it continues east from structure N15 to N22 and connects to the existing 2.83L at structure 138-2.83-95. The North Route – Primarily Overhead is approximately 2.5 kilometers in length.

30. The "North Route – Primarily Underground" has been designated as the alternate route. It is a primarily underground transmission line configuration that runs along or in close proximity to 17 Avenue NW between ENMAX No. 3 Substation and the 2.83L T-Tap Point. It exits ENMAX No. 3 Substation and runs underground east along 17 Avenue NW, routes around the southern boundary of Munro Park, then continues east along 17 Avenue NW until crossing Moncton Road NE. At structure N14, the transmission line transitions from underground to overhead and then turns south along the east side of Moncton Road NE to structure N15. This route option continues east from structure N15 to N22, where it connects to the existing 2.83L at structure 138-2.83-95. The North Route – Primarily Underground is approximately 2.4 kilometers in length.

31. The North Route – Primarily Overhead and the North Route – Primarily Underground are collectively referred to as the "2.83L Extension Route Alternatives" and are illustrated in Figure 1-2 and Figure 1-3.

2.1.3 No. 3 Substation Work

32. The No. 3 Substation Work is required to support the Discontinuance of 3.82L Operations and the 2.83L Extension. The No. 3 Substation Work includes the removal of an approximately 30 meter segment of 3.82L that is connected and directly adjacent to ENMAX No. 3 Substation, the removal of six oil pressure reservoir tanks from within the ENMAX No. 3 Substation and the cutting and capping of the remaining 3.82L cable adjacent to the substation.

33. The nature and scope of the No. 3 Substation Work does not depend on the alternative approved for the 2.83L Extension.

2.1.4 Reconfiguration Work

34. The Reconfiguration Work is required to support the Discontinuance of 3.82L Operations and the 2.83L Extension. The Reconfiguration Work involves the reconfiguration of short

sections of transmission lines that connect with ENMAX No. 2 Substation and ENMAX No. 13 Substation.

35. The Reconfiguration Work at ENMAX No. 2 Substation involves removing the existing 2.83L T-Tap between structures 138-2.83-53 and 138-2.83-54 and re-terminating the existing 2.83L segment between ENMAX No. 5 Substation and structure 138-2.83-1A directly into ENMAX No. 2 Substation. This requires the installation of approximately 120 meters of new cable in new and existing concrete-encased duct bank between structure 138-2.83-1A and ENMAX No. 2 Substation, along with the installation of a new 138kV indoor GIS circuit breaker at ENMAX No. 2 Substation. The resulting connection between ENMAX No. 5 Substation and ENMAX No. 2 Substation will be re-designated as transmission line 138-2.85L ("2.85L").

36. Removal of the existing T-Tap on 2.83L is required to prevent the formation of a four-terminal transmission line after the completion of the 2.83L Extension. Operating 2.83L as a four-terminal transmission line is not acceptable due to reduced reliability and operational complexity.

37. The Reconfiguration Work at ENMAX No. 13 Substation involves splitting the existing 138 kV bus into a north bus and a south bus through the addition of a 138 kV bus tie breaker. Approximately 36 meters of 3.84L will be relocated from the south side of the existing bus to the new north bus within the substation. This work is required to avoid increased risk of customer outage after energization of the 2.83L Extension and the Discontinuance of 3.82L Operations. Without the addition of the bus tie breaker, a breaker fail event[3] at ENMAX No. 13 Substation would result in an unplanned complete de-energization of both ENMAX No. 3 Substation and ENMAX No. 13 Substation.

38. The nature and scope of the Reconfiguration Work does not depend on the alternative approved for the 2.83L Extension.

39. Substation single line diagrams of ENMAX Nos. 2, 3, 5 and 13 Substations and substation layout figures of ENMAX Nos. 3 and 13 Substations are provided in Appendix E-1.

[3] A breaker fail event occurs when a circuit breaker fails a protection and control system detects that a circuit breaker has failed to open on a fault, and automatically opens the upstream circuit breakers to clear the fault, resulting in a larger outage than would typically be required.

2.2 Project Need

40. The primary driver of the Project is the deteriorated asset condition of aging 3.82L infrastructure, which was put into service in 1977 and has reached the end of its useful life.

2.2.1 3.82L Background

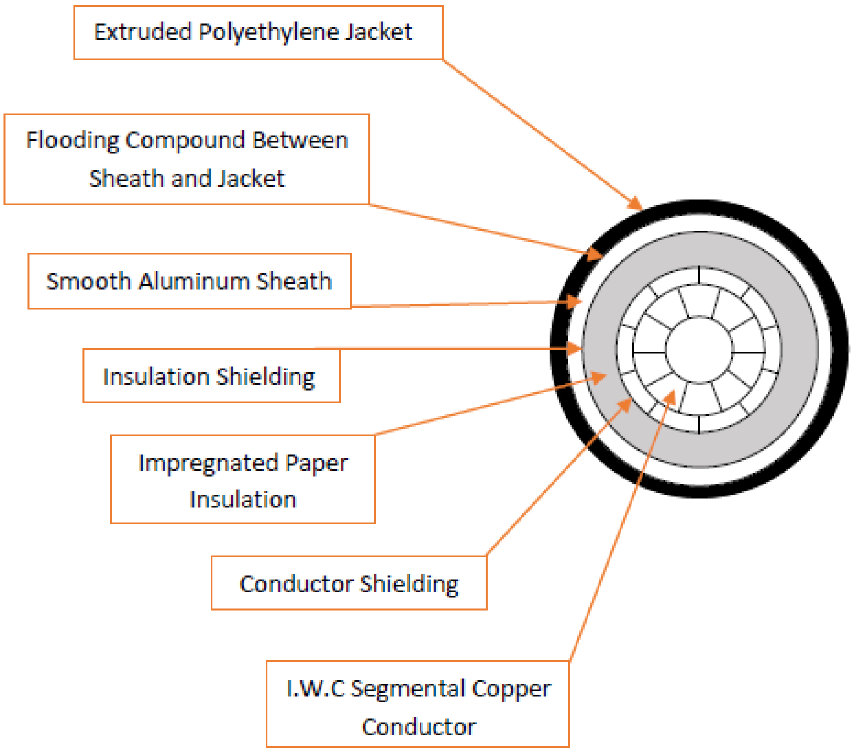
41. 3.82L is comprised of seven sections of LPOF cable connected via joints[4] located in maintenance holes. Each section is comprised of one separate cable for each electrical phase (A, B, C). The oil in the cables is maintained at positive pressure by oil reservoirs at each end of each separate cable, for a total of 12 oil reservoirs. There are two oil reservoirs per phase (total of six) located outdoors at ENMAX No. 3 Substation and two oil reservoirs per phase (total of six) located indoors at ENMAX No. 8 Substation (the indoor reservoirs are protected by a water deluge system). The oil system is sectioned by means of an oil stop joint located at MH 1979.

42. 3.82L itself is comprised of 1,750 thousands of circular mils ("kcmil") copper conductor, covered by oil impregnated paper insulation, an aluminum sheath and an polyethylene outer jacket ("outer jacket"). Figure 2-2 is a cross-section of the 3.82L cables.

43. The cables are direct buried with concrete capping except at the Bow River crossing (where the cables are installed within a metal pipe laid on the riverbed), some roadway crossings (where the cables are installed within a duct bank) and the Calgary Light Rail Transit ("LRT") crossing (where the cables are installed within a split duct).

[4] A joint is a fitting used to join adjacent lengths of cables. A joint is also commonly referred to as a "splice." In LPOF cables, two types of joints are used, a normal joint and a stop joint. A normal joint is designed to allow oil flow through the connection and maintains electrical and oil connections between the two sections of oil cables. A stop joint connects the two cables electrically but separates the two cables oil systems hydraulically.

Figure 2-2: 3.82L Cable Cross Section



44. The oil in the 3.82L cables flows freely within the core of the cables, filling voids and maintaining saturation of the oil impregnated insulation. This oil helps to electrically insulate the cables' conductors from other conductive elements and to protect the cables from moisture ingress. The aluminum sheath contains the oil within the cables and electrically shields the cables. The purpose of the outer jacket is to insulate the aluminum sheath. Therefore, the integrity of the outer jacket is integral to preventing arcing directly to the ground and ensuring that the aluminum sheath is protected from corrosion. Degradation or failure of the outer jacket and corrosion of the aluminum sheath can lead to cable failure[5] and oil leaks.

45. Given the age of 3.82L, EPC understands that polychlorinated biphenyls ("PCBs") could be a potential contaminant of concern. EPC has conducted several rounds of testing on the oil from the reservoir tanks that circulates through the cables as well on oil extracted from the cable itself at the oil stop joint. Results have indicated PCBs to be below the limit of

[5] Failure of 3.82L would result in ENMAX No. 3 Substation being supplied by a single transmission line for up to a year and impact reliability of supply to over 18,000 customers and 47.1 MVA of load.

detection (0.5 mg/kg). As part of Project execution, both the cables and the purged oil will be tested again for PCBs.

2.2.2 3.82L Asset Condition and Reliability

46. EPC continuously monitors the condition of its LPOF cables to ensure that it undertakes appropriate preventative maintenance activities and that replacement, when required, is prioritized and completed proactively. Through this monitoring and subsequent investigations by third-party subject matter experts, EPC determined 3.82L to be at end-of-life due to deteriorated asset condition.

47. ENMAX No. 3 Substation serves 18,583 customers. The risk of an outage for customers served by ENMAX No. 3 Substation is high due to the deteriorated condition of 3.82L. A failure of 3.82L, an N-1 contingency, would result in ENMAX No. 3 Substation being supplied by a single transmission line for an extended period, increasing the risk of losing supply to 18,583 customers under the next contingency (N-1-1). Under N-1-1 conditions, up to 23MVA and approximately 6,769 customers could be without power for an extended period. Additionally, the south end of 3.82L terminates inside the high voltage GIS at ENMAX No. 8 Substation. This critical substation has four 138 kV transmission lines connected to it and is one of three substations that serve Calgary Downtown loads. Should 3.82L fail within the switchgear of ENMAX No. 8 Substation resulting in major damage to the switchgear (e.g., due to fire), this would cause an outage of the entire substation. As of 2021, ENMAX No. 8 Substation serves 5,154 customers and 95 MVA of peak load.

48. EPC considered addressing the deteriorated asset condition of 3.82L through reactive maintenance or a “like-for-like” replacement (i.e., replacing 3.82L with an underground configuration designed to current standards along or in close proximity to its current footprint). However, neither option was determined to be appropriate in the circumstances.

49. EPC determined that a reactive repair of 3.82L was not a prudent long-term maintenance solution. Locating the precise damaged segment(s) of cable can be challenging and once located, the damaged segment(s) must be uncovered (via excavation) in order to carry out the repair. Excavating a direct buried cable in a highly developed, densely populated urban environment is costly and can impact local stakeholders and other underground infrastructure in the area. Further, LPOF cables are no longer commonly used in North America, with only one remaining supplier of LPOF materials; this increases the risk that

EPC will be unable to repair a cable failure in a reasonable timeframe, regardless of other considerations. Repairing a failed section of 3.82L reactively would not improve the overall deteriorated condition of the line, leaving it at increased risk of future faults or failures. For these reasons, EPC dismissed the option to reactively repair 3.82L.

50. EPC determined that a like-for-like replacement of 3.82L would come with significantly greater costs than either of the 2.83L Extension Route Alternatives (or other alternatives under consideration at the time), preclude implementation of integrated transmission planning solutions and the realization of associated cost savings that would otherwise be facilitated, and require an approximately 12-month construction outage. Therefore, EPC, dismissed a like-for-like replacement on the basis that it was not comparable to other alternatives.

2.3 Other System Planning Considerations

51. EPC uses an integrated planning approach for all its transmission projects, seeking to identify opportunities to defer or optimize capital investments. The Commission has found that this approach "has overarching benefits to transmission system planning and should result in lower overall impacts to stakeholders."[6]

52. In addition to representing the optimal approach to addressing the deteriorated state of 3.82L, the Project (specifically, the 2.83L Extension) supports integrated planning and allows for associated cost reductions and increased planning efficiencies.

53. Combined with the 2.82/2.83L Victoria Park Transmission Line Relocation Project (approved by the Commission in Decision 28001-D01-2023), the Project will facilitate the deferral of the EPC Calgary Area Fault Mitigation Project ("CAFMP").[7] EPC estimates that this integrated planning solution will result in the deferral of close to $100 million through the reduction in capital additions and the deferral of CAFMP.

2.4 Ownership Structure

54. The Project will be owned and operated by EPC. EPC is a wholly owned subsidiary of ENMAX Corporation, headquartered in Calgary, Alberta ("Calgary or the "City"). Through

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[6] ENMAX Power Corporation, Victoria Park Transmission Line Relocation Project, Reasons to Decision 28001-D01-2023, para. 32, PDF 8 (July 7, 2023).

[7] CAFMP would involve upgrading the high-voltage switchgear equipment (138 kV Gas Insulated Switchgear) at ENMAX No. 8 Substation to address the fault level that currently exceeds the acceptable limit for the equipment.

EPC, ENMAX Corporation owns and operates transmission and distribution utilities in the City.

2.5 Existing Permits and Licences

55. EPC holds the following permits and licences for the existing transmission facilities that are proposed to be relocated, altered or discontinued from use as part of the Project:

- 3.82L (EN 98-43)
- 2.83L (28001-D03-2023)
- ENMAX No. 2 Substation (29118-D02-2024)
- ENMAX No. 3 Substation (25497-D02-2020)
- ENMAX No. 5 Substation (29003-D01-2024)
- ENMAX No. 8 Substation (23157-D03-2018)
- ENMAX No. 13 Substation (26332-D02-2021)

2.6 Needs Identification Document

56. The AESO has been advised of the Project, which forms part of a larger integrated transmission solution. By correspondence dated September 16, 2022 (Appendix B), the AESO confirmed that a Needs Identification Document ("NID") approval is not required because "the integrated solution does not expand or enhance the capability of the transmission system."

57. In this correspondence, the AESO also confirmed that the Project aligns with EPC's objective as a transmission facility owner ("TFO") to "minimize rate-payer costs by optimizing, prioritizing and deferring projects as applicable" and that it "has not identified any material technical concerns" and, therefore, has no objections to the integrated solution.

3 PROJECT DETAILS

58. This section provides details about various components of the Project.

59. EPC will continue to coordinate with other utilities, landowners and the City, and will refine the design as it proceeds from the preliminary design phase to final design phase and throughout the construction phase.

3.1 Project Design

60. 3.82L and 2.83L are currently energized at a nominal operating voltage of 138 kV. 3.82L has a summer rating of 245 MVA, with a 10-minute emergency rating of 277 MVA (i.e., 113% of its summer rating) (the 3.82L summer rating is lower than its winter rating and, therefore, the summer rating sets the limit to its overall capacity). 2.83L has a summer and winter rating of 287 MVA, with a 10-minute emergency rating of 316 MVA (i.e., 110% of its summer and winter ratings).

61. All of the new transmission line components required for the Project will operate at the same nominal voltages and carry the same ratings (if not slightly higher capacity) as the existing lines they are modifying (including in the case of the 2.83L Extension, regardless of which 2.83L Extension Route Alternative is approved).

3.2 Overhead Portion Details

62. The following provides information about overhead portions of the Project. See the Decommission and Salvage Application in Appendix A for details related to the Discontinuance of 3.82L Operations.

3.2.1 Conductors

63. The conductor proposed for the overhead transmission line portion of the 2.83L Extension is 1033 kcmil Aluminium Conductor Steel Reinforced ("ACSR") Curlew. EPC selected this conductor because it meets the Canadian Standards Association ("CSA") code requirements for sag and clearance and is a standard conductor size recognized by both EPC and the AESO.[8] Further, 1033 kcmil ACSR Curlew has comparable capacity to the 4000

[8] Information Document Bulk Transmission Line Technical Requirements ID#2010-005R.

kcmil underground cable which will be installed for the underground portion of the 2.83L Extension.

64. The conductor proposed for the overhead section of 3.84L at ENMAX No. 13 Substation is 467 kcmil ACCC Glasgow. EPC selected this conductor because it is the same conductor type that will be installed by EPC in 2025 as part of a 3.84L clearance mitigation project.

3.2.2 Structures

65. Steel monopoles[9] are proposed for overhead transmission line portions of the 2.83L Extension Route Alternatives, with 23 steel monopoles proposed to be installed for the North Route – Primarily Overhead and nine steel monopoles proposed to be installed for the North Route – Primarily Underground. EPC proposes to install one steel monopole and one laminated wood structure[10] for the Reconfiguration Work associated with the ENMAX No. 13 Substation. All of these structures are expected to range in height from approximately 22 to 28 meters.

66. EPC proposes to stack conductors on the roadway side of the structures along 17 Avenue N to achieve appropriate clearances for the 2.83L Extension. EPC will otherwise configure the conductors in a delta configuration.

67. Diagrams of the structures to be installed are included in Appendix E-2. A list of structures with approximate height is included in Appendix E-3. Detailed dimensions, including exact diameter, wall thickness, taper and embedment depth, will be determined during detailed design based on the specific loading requirements for each pole location.

68. EPC requests the flexibility to shift individual structure locations along the proposed centerline or laterally from the centerline based on the outcome of detailed design.

3.3 Underground Portion Details

69. Unless otherwise noted, the same construction materials (i.e., civil duct bank, maintenance holes, and cables) will be used for underground components of the Discontinuance of 3.82L Operations, the 2.83L Extension and the Reconfiguration Work.

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[9] Steel monopoles are self-supporting structures with concrete direct embedment for tangent, running corner and dead-end application.

[10] Laminate wood structures are engineered laminated self-supporting structures with direct embedment either in concrete or compact gravel.

The following provides information about the underground portions of the Project. See the Decommission and Salvage Application in Appendix A for details related to the Discontinuance of 3.82L Operations.

3.3.1 Civil Duct Bank and Maintenance Holes

70. The new underground cable portions of the Project (i.e., associated with the 2.83L Extension and 2.85L) will be routed through new concrete encased ductbank.

71. EPC will install maintenance holes to facilitate access to, and use of, the existing underground infrastructure (including cable splices). EPC currently expects to install one maintenance hole for the North Route – Primarily Overhead or two maintenance holes for the North Route – Primarily Underground. The final number and location of maintenance holes will be determined during detailed design.

3.3.2 Cable

72. 4000 kcmil XLPE cable will be installed for the new underground portions of the Project (i.e, associated with the 2.83L Extension and 2.85L). This is the EPC-standard size for all new cable installations and will allow EPC to align with and connect to the existing cable and maintain capacity.

3.4 Land Rights

73. The right of way width encompasses the area that is required for EPC to locate, safely operate and maintain the Project. The right of way width includes the area to ensure that the transmission line is a safe distance from trees and other structures, and that any proximate development is not incompatible with transmission line operations.

74. The right of way widths, which encompass areas of utility right of way and temporary workspace, are illustrated in the maps at Appendix E-4.

75. In order to secure the land rights that EPC requires to construct, operate and maintain the Project, EPC will obtain a Utility Alignment Permit in City service corridors, or negotiate a utility right of way agreement or a temporary workspace agreement on titled lands.

3.5 Substation Equipment

76. At ENMAX No. 13 Substation, the 138kV bus is being split into a north bus and a south bus, with a new 138kV bus-tie breaker installed between them. Feeding ENMAX No. 3 Substation from separate buses at ENMAX No. 13 Substation will require 3.84L to be re-located to the north bus and 2.83L to be located at the south bus. This work is required to allow both 3.84L and 2.83L to run between ENMAX No. 3 Substation and ENMAX No. 13 Substation.

77. To accommodate the addition of 2.85L into ENMAX No. 2 Substation, a new 138kV GIS breaker and line position must be added to the spare bay location in the existing 138kV GIS switchgear at ENMAX No. 2 Substation, along with the associated line protection and breaker controls.

3.6 Protection and Controls

78. The Project includes upgrading the protection systems at the ENMAX Nos. 2, 3, 5, 8 and 13 Substations to meet EPC's current protection standard.

3.7 SCADA

79. The SCADA system will be updated to accommodate the new substation equipment at ENMAX Nos. 3 and 13 Substations and to accommodate the protection systems at ENMAX Nos. 2, 3, 5, 8 and 13 Substations.

3.8 Electrical Considerations

80. Underground utilities in the Project area include water, storm water, sanitary, telecom, gas lines and EPC's electric distribution network. The Project is also located in proximity to various buildings and surface structures. There are no expected electrical interactions or associated adverse impacts or safety concerns given the separation between the Project infrastructure and these utilities and surface structures.

3.9 Induction

81. Potential induction to adjacent facilities, including utility infrastructure and buildings, was considered during routing and siting work and the preliminary engineering process.

Technical collaboration with adjacent facility owners along the Project footprint will continue through further detailed design and construction planning.

82. EPC does not anticipate any induction impacts as a result of the Project.

3.10 Radio and Communication Interference

83. EPC does not anticipate any adverse interference to radio or communication systems as a result of the Project.

3.11 Electric and Magnetic Fields

84. As illustrated in Appendix F, EPC does not anticipate any negative or adverse electric and magnetic field ("EMF") effects as a result of the Project.

85. EMF are found everywhere electricity is used, from household wiring and appliances to power lines. EPC continues to monitor EMF-related developments through its work with the Electricity Canada's EMF Task Group. Scientific evidence to date has not established adverse health effects resulting from exposure to power frequency EMF at levels normally encountered in homes, schools or offices.

86. EPC will provide EMF estimates, as well as onsite EMF measurements, to any party that requests them.

3.12 Transmission Line Configuration

87. As described above, the Project is proposed to comprise a combination of overhead and underground transmission line configurations.

88. Transmission line projects are evaluated on a case-by-case basis to determine whether they should be located overhead or underground, or a combination of both. Factors such as cost, clearances, physical space, area land use planning, incremental stakeholder impacts and technical considerations (e.g., the impact on system reliability related to the introduction of an overhead to underground transition) are considered when choosing the appropriate configuration. Where an overhead line is technically feasible, and there is not a comparable underground alternative, EPC does not generally propose an underground configuration.

89. EPC determined that there are certain areas of the Project where it is practical and cost effective to construct an underground configuration. In particular, the following segments of the North Route – Primarily Overhead and the North Route – Primarily Underground are proposed to be constructed in an underground configuration:

- The 2.83L Extension Route Alternatives share a common underground segment from ENMAX No. 3 Substation to Edmonton Trail NE ("Common 2.83L Extension Segment"). An underground configuration for the Common 2.83L Extension Segment is necessary to avoid electrical clearance and constructability constraints associated with proximate commercial and residential parcels. The Common 2.83L Extension Segment utilizes an existing underground bay and continues underground to cross under the existing 3.84L and Centre Street in order to avoid the electrical clearance and constructability constraints associated with these crossings as well as the commercial and residential buildings that are minimally set back from 17 Avenue N.
- An underground segment specific to the North Route – Primarily Underground is proposed to be constructed from Edmonton Trail NE to Moncton Road NE. Maskwa determined that despite the relatively greater cost (driven in large part by the more extensive underground component), the North Route – Primarily Underground is comparable to the North Route – Primarily Overhead when the relative impacts associated with each alternative are taken into account.

90. EPC understands that while cost is not necessarily a deciding factor and that the Commission is not required to approve the lowest cost option, the lowest cost option is a critical discriminator where all other factors are mostly equal.[11] Given this guidance and the fact that the 2.83L Extension Route Alternatives were determined by Maskwa to have similar impacts (with the North Route- Primarily Overhead having a lower cost), EPC designated the North Route – Primarily Overhead as the preferred route and the North Route – Primarily Underground as the alternate route.

91. EPC has also proposed an underground configuration for 2.85L associated with the Reconfiguration Work at ENMAX No. 2 Substation, which is required to accommodate the existing substation equipment.

[11] See, for example: Decision 27523-D01-2023: AltaLink Management Ltd. – Transmission Line 150L Rebuild, Proceeding 27523, Application 27523-A001, April 28, 2023, paragraph 49.

92. Aside from the underground segments of the Project discussed above, EPC determined that it is technically feasible, practical and cost effective to otherwise construct the transmission lines associated with the Project in an overhead configuration.

3.13 Outage Considerations

93. For the Project work that requires transmission outages, all switching, grounding and isolation will be performed in accordance with ENMAX safe operating procedures. Outages will be planned in coordination with EPC and AESO system operations and other projects in the area. No customer outages are anticipated as a result of Project construction.

3.14 Operational Considerations

94. At ENMAX No. 13 Substation, the existing 138kV bus will be split into a north bus and a south bus through the addition of a bus tie breaker. Approximately 36 meters of EPC transmission line 138-3.84L ("3.84L") will be relocated from the south side of the existing bus to the new north bus within the substation. This work is required to avoid increased risk of customer outage after the completion of the Discontinuance of 3.82L Operations and 2.83L Extension. Without the addition of the bus tie breaker, a breaker fail event at ENMAX No. 13 Substation would result in a complete trip of both ENMAX Nos. 3 and 13 Substations.

3.15 Project Schedule

95. The proposed Project schedule is outlined below.

96. Because there are two different configurations proposed for the 2.83L Extension (one primarily overhead and one primarily underground), the permit and licence issuance date will be critical to maintaining schedule; currently, the procurement lead time is approximately 12 months for underground transmission cable and approximately eight months for steel monopoles. Because each 2.83L Extension Route Alternative has its own design requirements, these long-lead items cannot be pre-ordered (i.e. the materials for the 2.83L Extension cannot be ordered prior to AUC approval).

3.15.1 Approvals and Direction

- Facility Application Submission to AUC — October 2024
- Anticipated AUC Approval — June 2025

3.15.2 Project Schedule

- Order Long Lead Material: Sub 2 GIS Gear — October 2024
- Substation Design (Nos. 2, 3, 5 and 13) — January 2025
- Permit and License — June 2025
- Transmission Design — June 2025
- Order Long Lead Material: transmission structures and underground transmission cable — July 2025
- Construction Begins — January 2026
- Discontinuance of 3.82 Operations — Q1 2026
- Proposed ISD — Q4 2026

97. The proposed ISD for the Project is subject to certain contingencies, such as the receipt of all necessary approvals and outage availability. A corresponding delay to the ISD may result if the permits and licences are issued after the date of anticipated AUC approval.

4 ROUTE SELECTION

98. EPC retained Maskwa to provide professional routing and siting expertise in relation to the development and implementation of the routing methodology for the 2.83L Extension. The routing methodology was applied to identify a route(s) that poses the lowest overall potential impact when compared to other potential routing alternatives. Maskwa's Urban Siting Methodology, Siting Technical Report and Route Revision Log are provided in Appendix G.

99. Because the transmission lines associated with the Reconfiguration Work at ENMAX No. 2 Substation and ENMAX No. 13 Substation involve relatively short spans with no alternative routing options, Maskwa's transmission line routing and siting assessment was limited to the 2.83L Extension.

4.1 Route Selection

100. The 2.83L Extension is located in a developed urban area along or in the vicinity of 16 Avenue N, within the communities of Tuxedo Park, Crescent Heights, Winston Heights/Mountainview and Renfrew.

101. The area includes residential communities, transportation corridors (such as 16 Avenue N, Centre Street N and Edmonton Trail NE) and commercial land uses that are primarily located along transportation corridors. There are schools, parks, recreation areas and urban nature areas located throughout, as well as buried infrastructure (water, sewer, distribution network, gas and telecom) and planned developments (such as Midfield Heights).

102. The constraints of the subject area informed the route development process.

4.2 Siting Methodology

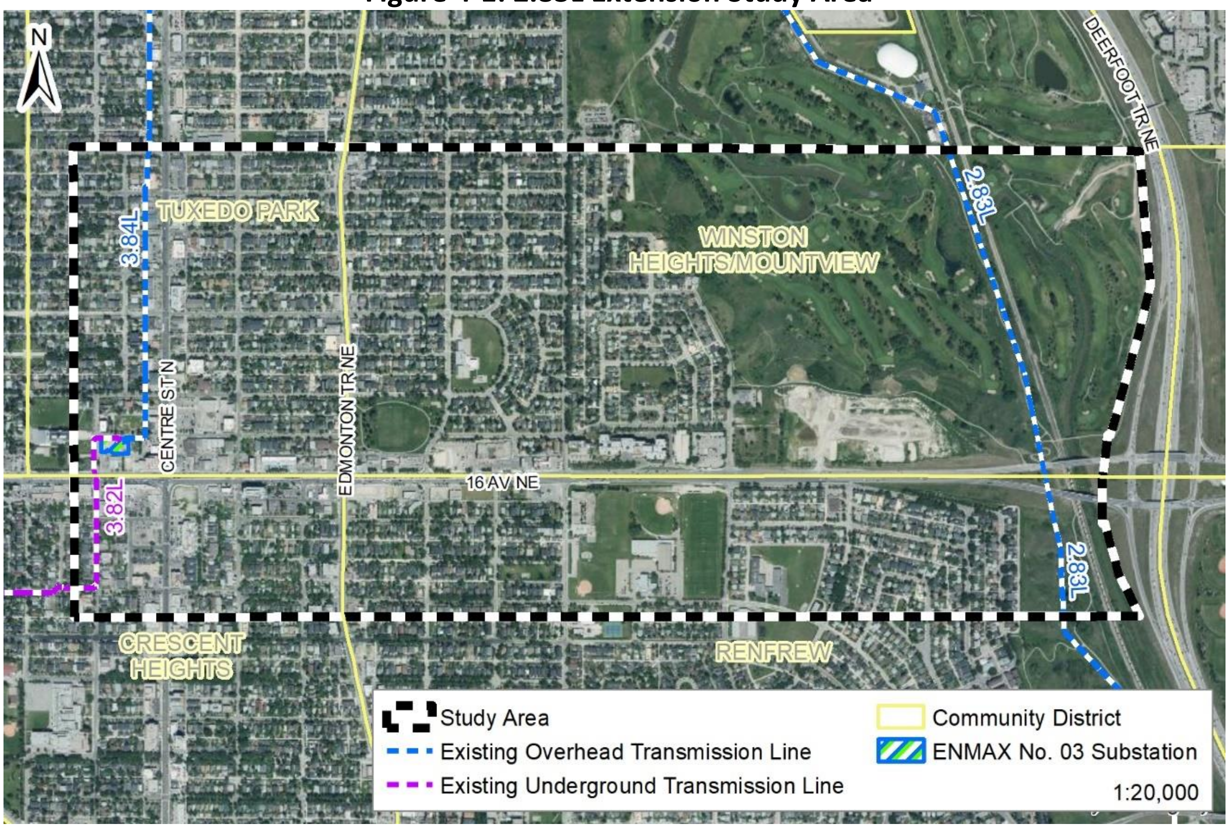
103. The route development process is iterative and draws upon existing and new information as it is collected from stakeholders and the professional judgment and experience of utility and siting experts. Generally, routes evolve as information is acquired from numerous sources, including internal and external stakeholders, engineering work and field evaluations. As such, routing decisions were revisited and reassessed throughout the development of the 2.83L Extension, with final routing decisions based on the best

information available at the time. Route modifications and retirements are discussed in the Route Revision Log (Appendix G-3) and the Siting Technical Report (Appendix G-2).

4.3 2.83L Extension Study Area

104. The study area for the 2.83L Extension (Figure 4-1) was developed to provide a large enough area to encompass reasonable route scenarios without making the area so large as to unnecessarily increase evaluation costs and efforts.

Figure 4-1: 2.83L Extension Study Area



4.4 Route Corridor Development Stage

105. The route corridor development stage identified areas where the 2.83L Extension would be considered more compatible and constructible from an overall development and land use perspective, as compared to other areas within the study area. Siting efforts focused on areas of higher compatibility.

106. Based on discussions with the City and past experience with similar projects, Maskwa sought to avoid or minimize traffic disruptions wherever possible. Therefore, Maskwa

removed traffic corridors with high traffic volumes from its initial consideration (e.g., 16 Avenue N) and only factored them back in when necessary to maintain connectivity.

4.5 Preliminary Route Development Stage

107. Following the route corridor development stage, preliminary routing was developed in accordance with the routing and siting principles described in the Siting Technical Report (Appendix G-2), with the goal of avoiding or minimizing potential conflicts and impacts.

108. Siting principles, key stakeholder input and other information were used to identify potential low impact preliminary routes within the established routing corridor. The following 2.83L Extension route alternatives (illustrated in Figure 4-2) were identified in the Preliminary Route Development ("PRD") stage:

- South Route: a primarily overhead route, largely located in the alley between 16 Avenue NE and 15 Avenue NE;
- North Route – Primarily Overhead: a primarily overhead route, largely located along 17 Avenue N;
- North Route – Primarily Underground: a primarily underground route, largely located along 17 Avenue N; and
- Variant: an option for all of the above route alternatives, involving a variant segment located along the north side of the Midfield Heights development (instead of the south side of the Midfield Heights development).

109. Each of these preliminary route alternatives share a common route segment where 2.83L exits the north side of ENMAX No. 3 Substation in an underground configuration and continues underground along 17 Avenue N to Edmonton Trail NE (described in Section 3.12). From this point, the preliminary route alternatives diverge as described above and illustrated in Figure 4-2.

Figure 4-2: Preliminary Routes

4.6 Detailed Route Development Stage

110. The purpose of the Detailed Route Development ("DRD") stage is to further refine the preliminary routes identified in the PRD stage through consideration of overall constructability and potential impacts. Preliminary routes were used as the basis for engagement with key infrastructure stakeholders in the DRD stage to acquire additional data, gather information and feedback, and facilitate additional engineering and design field verification, surveys and general construction information to further refine route options.

111. Potential conflicts with certain of the preliminary route alignments were identified through engagement with the City and utility companies. The City noted the following primary sources of conflict:

- routing in narrow alleys where it is not possible to meet design standards for safety and waste management services;

- overhead routing that may limit development of new zoning and/or conflict with ongoing beautification efforts;
- required setbacks from water mains and sanitary and stormwater lines; and
- geotechnical instability and unsuitability for a transmission line along the northern edge of the Midfield Heights development.

112. Of the preliminary routes, TELUS Communications Inc. expressed its preference for the North Route – Primarily Overhead and the North Route – Primarily Underground, as the alley south of 16 Avenue NE (that would be used for the South Route) houses aerial and underground communication lines. ATCO Gas Ltd. also noted that the South Route has more potential for conflict than the North Route – Primarily Overhead and the North Route – Primarily Underground.

113. The DRD process led to refinements of route alternatives or retirements where determined to be technically unfeasible or, in comparison to other options, impractical, more impactful or posing risks to reliability and safety. By the conclusion of the DRD stage, a portion of the North Route – Primarily Overhead was shifted to the southern edge of Munro Park and the Variant was determined to be unfeasible and, therefore, retired from further consideration.

114. Three routes remained for consideration at the end of the DRD stage: the South Route, the North Route – Primarily Overhead and the North Route – Primarily Underground (depicted in Figure 4-3).

Figure 4-3: Detailed Routes

4.7 Final Route Development Stage

115. The purpose of the Final Route Development ("FRD") stage is to further refine the remaining routes to optimize constructability and reduce potential impacts. During the FRD, the detailed routes were presented to stakeholders and were the subject of further detailed engineering and design.

116. This resulted in refinements to portions of the North Route – Primarily Overhead and the North Route – Primarily Underground and the retirement of the South Route on the basis of comparatively higher impacts overall (i.e., the South Route was cost-comparable to the North Route – Primarily Underground, with greater impacts than the North Route – Primarily Underground). The remaining routes (i.e., the North Route – Primarily Overhead and the North Route – Primarily Underground) were presented to stakeholders and Indigenous groups as part of the PIP process.

117. The North Route – Primarily Overhead and the North Route – Primarily Underground are located in similar alignments. They are both compatible with existing and planned land uses, meet the technical requirements for the Project, are constructable using typical overhead or underground construction methods, require minimal or no permanent private land easement and have no outstanding conflicts with existing utilities or infrastructure.

118. The differences between the North Route – Primarily Overhead and the North Route – Primarily Underground are mainly related to short-term impacts associated with underground construction (largely associated with the North Route – Primarily Underground) versus the longer-term impacts associated with overhead construction and operation (largely associated the North Route – Primarily Overhead).

4.8 Proposed Routes

119. While closely comparable, EPC identified the North Route - Primarily Overhead as the preferred route based on its somewhat lower overall potential impacts when compared to the North Route – Primarily Underground (which has been designated as the alternate route).

120. The primary considerations supporting the selection of the North Route – Primarily Overhead as the preferred route are:

- relatively few stakeholder concerns identified regarding visual impacts of the new transmission line or related tree removal or trimming;
- low impacts to special constraints such as land use and maintenance requirements; and
- lower estimated costs when compared to the North Route – Primarily Underground.

121. The North Route – Primarily Underground was determined to have slightly higher overall impacts when compared to the North Route – Primarily Overhead (although was still considered comparable by Maskwa). The primary considerations for designating this route as the alternate route are:

- lower potential for residential and visual impacts due to less required tree trimming or removal compared to the North Route – Primarily Overhead; and
- higher estimated cost compared to the North Route – Primarily Overhead.

122. The proposed routes are depicted in Figure 4-4.

Figure 4-4: Proposed Routes

5 LAND USE, CONSTRUCTION ACCESS AND METHODS

5.1 Construction Considerations

123. Industry safe work practices and the Project's safety and environmental management plans will be adhered to during Project construction. The sequence of construction activities will be planned in detail and necessary transmission outages will be coordinated with the AESO System Control and EPC operational personnel.

124. Construction activities are generally planned to occur on weekdays between 7:00 am and 10:00 pm. Construction may occur in localized areas outside these times to accommodate stakeholder commitments and traffic and/or outage requirements and to reduce potential impacts to area users. Construction activities will comply with City of Calgary bylaws and AUC Rule 012: Noise Control ("AUC Rule 012"). All temporary traffic accommodation will be coordinated with and approved by the City.

125. Construction is anticipated to start in Q1 2026. The following is a high-level sequence of construction activities associated with the Project:

- Work at ENMAX No. 2 Substation February-July 2026
- Work at ENMAX No. 13 Substation March-July 2026
- 3.82L Removals March-May 2026
- 2.83L – North Route – Primarily Overhead June-August 2026
- 2.83L – North Route – Primarily Underground May-August 2026
- 2.83L Commissioning September-October 2026

126. EPC will work with landowners, residents and occupants, the City, and City Parks to determine the laydown areas and access requirements.

127. Once the above work is complete, EPC will conduct a post-construction inspection and ensure that all construction material is removed from the Project site, and that any damage to landscaping or sidewalks is repaired.

6 ENVIRONMENTAL MANAGEMENT

6.1 Environmental Evaluation

128. EPC retained Maskwa to conduct an Environmental Evaluation[12] ("EE") to assess the potential effects of construction and operation of the Project and to compare the potential effects of construction and operation of the North Route – Primarily Overhead and the North Route – Primarily Underground. The EE is provided as Appendix D-1.

129. The following ecological components with the potential to be adversely affected by the Project (identified as valued ecosystem components ["VECs"]) were assessed in the EE to determine residual effects and significance: soils and terrain; surface water; groundwater; vegetation species and communities; wildlife species and wildlife habitat; and aquatic species and habitat. The EE concluded that the identified potential adverse effects for each VEC could be appropriately mitigated with standard mitigation and industry best management practices. The Project (regardless of the 2.83L Extension Route Alternative approved) was predicted to have limited, non-significant residual effects.

6.2 Environmental Impact Analysis

130. As no part of the Project is located on federal lands, an environmental impact analysis was not completed.

6.3 Environmental Management Plan

131. The Environmental Management Plan ("EMP") for the Project is provided as Appendix D-2. The EMP describes the mitigation measures to be implemented during Project-related activities throughout construction and operation. Implementation of the mitigation measures identified in the EMP will suitably reduce or eliminate residual environmental effects.

[12] The Environmental Evaluation describes the present environmental and land use conditions surrounding the Project and assesses how the Project is predicted to affect the environment. It also assesses how any effects will be avoided or mitigated. Any adverse residual environmental effects (effects that remain after mitigation and best management practices are applied) are evaluated and rated for their significance.

6.4 Decommissioning and Restoration

132. EPC will complete site clean-up and restoration associated with Project construction and operations. Where restoration activities are required (e.g., works around newly installed poles, buried cables or temporary workspaces) the areas will be put back to pre-construction conditions, and will be reviewed by an EPC environment specialist.

133. In addition, EPC will be discontinuing operation of 3.82L as part of the overall scope of work proposed for the Project. Additional information applicable to the Discontinuance of 3.82L Operations is addressed in the Decommission and Salvage Application at Appendix A.

6.5 Noise

134. As the Project does not require the addition of any noise producing equipment that will increase ambient sound levels, EPC has not completed a noise impact assessment. EPC will construct and operate the Project in compliance with AUC Rule 012 and the City of Calgary Noise By-Laws.

7 OTHER APPROVALS

135. EPC will comply will all applicable legislation, regulations, rules and guidelines, including but not limited to:

- AUC Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments;
- AUC Rule 012: Noise Control;
- *Electrical Code Regulation,* AR 209/2006;
- *Electric Utilities Act*, SA 2003, c E-5.1;
- *Environmental Protection Guidelines for Transmission Lines, Alberta Environment R&R/11-03;*
- *Historical Resources Act*, RSA 2000, c H-9;
- *Hydro and Electric Energy Act*, RSA 2000, c H-16;
- *Migratory Birds Convention Act,* 1994, SC 1994, c 22;
- *Occupational Health and Safety Act*, SA 2017, c O-2.1;
- *Radiocommunication Act, RSC 1985, c R-2;*
- *Reclamation Practices and Criteria for Powerlines, ISBN 978-1-4601-4732-0;*
- *Safety Codes Act*, RSA 2000, c S-1;
- *Soil Conservation Act, RSA 2000, c. S-15;*
- *Species at Risk Act*, SC 2002, c 29;
- *Surface Rights Act*, RSA 2000, c S-24;
- *Weed Control Act*, SA 2008, c W-5.1; and
- *Wildlife Act*, RSA 2000, c W-10.

136. Applications for approvals or agreements required from other government or regulatory agencies having jurisdiction will be submitted directly to those agencies.

137. Upon completion of the Project, EPC will provide the Commission with written confirmation from a Professional Engineer registered with the Association of Professional Engineers and Geoscientists of Alberta (“APEGA”) that the facilities have been constructed as described in this Application and that the facilities have been inspected. The written confirmation will also provide the nominal voltage level for the line and the date of energization.

7.1 Alberta Environment and Protected Areas Engagement

138. EPC contacted Alberta Environment and Protected Areas ("AEPA") – Fish and Wildlife Stewardship about the Project. AEPA found the North Route – Primarily Overhead and the North Route – Primarily Underground to be comparable from a wildlife and wildlife habitat perspective and had no further feedback or concerns about the Project.

7.2 Historical Resources Act Clearance

139. EPC applied for *Historical Resources Act* approval with the Alberta Ministry of Arts, Culture and Status of Women for all areas of the Project with Historic Resource Values. A copy of the *Historical Resources Act* approval issued on June 24, 2024 is included as Appendix D-3.

8 PARTICIPANT INVOLVEMENT PROGRAM

140. The following is a summary of the PIP that was undertaken for the Project. Further details are set out in the PIP Report, which is provided at Appendix H-6.

141. EPC began its PIP in March 2024 in accordance with the applicable sections of AUC Rule 007. The PIP was developed to ensure that all potentially impacted stakeholders and Indigenous groups have a clear understanding of the Project, that any Project-related issues or concerns were identified and, where possible, resolved and that EPC communicated with stakeholders and Indigenous groups in a timely fashion.

8.1 Participant Involvement Approach – Notification and Consultation

142. An engagement plan was developed to identify those parties that should be included in EPC's public consultation program and to outline objectives and communication methods to be used for delivery of Project information. Information management software was used to manage contact information, feedback received through engagement, issue tracking and follow-up.

143. EPC's approach was to personally notify all occupants, residents, landowners and Indigenous groups within the first row of development surrounding the 2.83L Extension, the No. 3 Substation Work and the Reconfiguration Work, or on or directly adjacent to the existing 3.82L in accordance with Appendix A1 of Rule 007. EPC also undertook engagement activities with other parties that may have an interest in activities occurring in the area surrounding the Project, including utilities, Alberta Infrastructure, AEPA, as well as community associations and City of Calgary department representatives. The Labelled Landowner Map is provided at Appendix H-2 and the Stakeholder List and Mailing Labels are provided at Appendix H-3.

144. EPC mailed and door dropped Project Information Packages[13] in March and August 2024. The Project Information Packages were posted on the EPC website[14] on March 14, 2024 and August 21, 2024.

145. Personal consultation was attempted at six locations along the 2.83L North Route – Primarily Overhead where tree trimming or removal would be required on or near private property. For these six properties, EPC door knocked, and where it was unable to reach

[13] Both versions of the Project Information Packages can be found at Appendix H-1.
[14] www.enmax.com/centralcalgaryproject

stakeholders via door knocking, provided a tailored Project Information Package via registered mail to ensure that those stakeholders are aware of potential impacts.

146. Personal consultation was also undertaken with a relatively small number of stakeholders who received the Project Information Packages and had questions or concerns on various issues, including the Project scope of work, Project timelines, potential vegetation impacts, potential construction impacts, Project routing and siting, Project costs and EMF.

147. EPC held a total of six open houses at two locations (The Winston Golf Club located at 2502 6 Street NE and the Best Western Village Park Inn located at 1804 Crowchild Trail NW) throughout April 2024. The open houses were set up in an informational walk-about format, with poster board displays around the room and subject matter experts from the Project team available to discuss the Project, listen to concerns or issues and answer questions from attendees. A total of 50 stakeholders attended the open houses. Copies of the poster boards from the open houses can be viewed on the Project website and are included in Appendix H-4.

148. EPC has responded to all questions and concerns raised to date have been responded to and closed.[15] A full summary of questions/concerns and EPC responses are provided in the Issues List in Appendix H-5.

8.1.1 Indigenous Engagement

149. The Project comprises a total of approximately 2.5 km of new transmission line construction, the discontinuance of operations of 3.82L (approximately 3.8 km in length), approximately 0.05 km of transmission line removal and other localized work at the subject substations, all of which is located within the highly developed downtown urban area, along an existing transmission line alignment and/or along the City's road corridors.

150. The Project does not require provincial regulatory permits, licenses or approvals under the *Water Act*, *Environmental Protection and Enhancement Act* or *Public Lands Act*, and thus, referral to the Alberta Aboriginal Consultation Office was not required.

151. EPC provided notification to all Treaty 7 First Nations, through their consultation contacts, for both rounds of public engagement and offered to consult to obtain feedback and

[15] Status "closed" indicates contact was made or attempted, although the concern may not have been resolved to the satisfaction of that particular party.

answer any questions or concerns in advance of filing the Application. To date, no feedback has been received from Indigenous groups.

8.1.2 Ongoing Engagement and Construction Notification

152. A Notice of Filing will be distributed to potentially impacted stakeholders and Indigenous groups and posted on the Project website within a week from the date of filing the Application.

153. EPC will continue its participant involvement efforts throughout the regulatory process to respond to any questions raised. If the Project is approved, engagement will continue during the construction phase and will be handled directly by the EPC Customer Relations department.

154. Construction-related engagement will be carried out in accordance with a communications plan which will include initial construction notices delivered a minimum of one week in advance of the construction start, additional construction notices delivered as required, on-site meetings, as required, and the dissemination of EPC's Customer Relations business cards to parties who request additional Project information.

155. Examples of construction notification documents from other EPC projects are provided in Appendix H-7.

9 PROJECT COSTS

9.1 Project Costs

156. The total cost estimate for the Project is $40.6 million (+30/-20%) if the North Route – Primarily Overhead is implemented and $50.6 million (+30/-20%) if the North Route – Primarily Underground is implemented, based on an AACE Class 3 estimating level. The estimate is based on EPC's current knowledge of the Project scope of work and recent construction cost experience.

157. The estimate includes escalation, interest, overhead and contingency costs, and has been determined in 2024 Canadian dollars.

158. The AUC Cost Breakdown Schedules are found in Appendix C.

10 CONCLUSION

159. As demonstrated by this Application, the Project is required to address the fact that 3.82L has reached the end of its useful life. EPC submits that the Project is technically feasible, needed and in the public interest.

160. EPC requests that the Commission approve the Project as applied for and provide such further and other relief that EPC may subsequently request or that the Commission may consider appropriate.

11 CONCORDANCE TABLE

Section	Concordance Table for AUC Rule 007	Location
7.2.1	**Transmission Line/Substation Applications** Please use the Transmission/substation facility application form to assemble the information requirements for the project. Transmission/substation facility is abbreviated as TS below.	
	Project Description	
TS1)	Provide a description of the proposed project.	Section 2.1 Section 3
TS2)	Confirm if the application is for a customer project or an application related to a proposal for a market participant under Section 24.31 of the *Transmission Regulation*.	Section 2.2
TS3)	Provide details of the ownership structure, including the names of all companies having an ownership interest in the project and their ownership share, and if applicable, the name of the operator of the facilities that is seeking to acquire the permit or licence. Confirm that the applicant is a qualified owner.	Section 2.4
TS4)	Provide a list of existing approvals for facilities directly affected by this project, if any.	Section 2.5
TS5)	Provide a copy of the ISO direct assignment letter pursuant to the *Electric Utilities Act*. Alternatively, if a needs identification document was not required, provide a copy of the ISO approval letter pursuant to the abbreviated needs approval process, or provide a statement in the application that the project was exempt pursuant to the *Transmission Regulation* (as described in subsection 7.1 of this rule).	Section 2.6
TS6)	Provide the most up-to-date functional specification issued by the ISO.	Not applicable
TS7)	Describe the design and ratings of the transmission line and major elements of the substation.	Section 3.1 Section 3.2 Section 3.3 Section 3.5
TS8)	If the ISO requires the facility applicant to determine the choice of conductors, describe the conductor size and arrangement selected and the basis for the conductor selection.	Not applicable
TS9)	If the application is not direct assigned by the ISO, provide the rationale for the rating/size of any proposed conductor or piece of major substation equipment.	Section 3.2.1

TS10)	Describe the proposed transmission line structure type, including height and spacing; if more than one type of structure is proposed, state where each type will be used.	Section 3.2.2 Appendix E-2 Appendix E-3
TS11)	State the right-of-way width and the basis for determining the width.	Section 3.4 Appendix E-4
TS12)	Describe all major substation equipment being applied for, including the height of any telecommunications structure, and provide a list of the final major equipment that would be in the substation.	Section 3.5
TS13)	Describe the switching and protection features of the proposed transmission facilities.	Section 3.6
TS14)	Describe the electrical interaction of proposed transmission facilities with other facilities, such as pipelines, railways, telephone, radio and television transmission facilities, and other surface structures.	Section 3.8
TS15)	Describe the changes to existing facilities required to accommodate the proposed facilities.	Section 2.1.3 Section 2.1.4 Section 3.5
TS16)	Describe any transmission line routing alternatives to the proposal, and compare the relative effects (environmental, social and economic, including any associated distribution costs) of these alternatives with the proposal. If the alternatives are segmented, include a comparison of the effects of each segment to the effects of its corresponding alternative segments.	Section 4 Appendix G-2 Appendix G-3
TS17)	Provide an electric single-line diagram or switching map showing new facilities in place in the system. In the case of a substation, provide an electric single-line diagram and a substation layout diagram, including major items of equipment and the fenced boundary of the substation, with units of measure/scale.	Appendix E-1
TS18)	Discuss the construction schedule, equipment and method of construction, and method of eventual right-of-way maintenance.	Section 5
TS19)	Provide the requested approval date from the AUC, the expected construction start date, the expected in-service date of the project and the requested construction completion date to be stipulated in the project permit(s) and licence(s).	Section 1 Section 3.15
TS20)	If available, provide the location of any required temporary or permanent workspace areas and access roads, and state whether these locations are requested to be listed in a permit and licence.	Section 5
TS21)	Provide the following drawings and maps with units of measure/scale and the direction of north specified:	

	1. A legible map defining the study area and state the reasons for the chosen area.	Section 1 Appendix G-2
	2. Legible maps of the proposed facilities showing: • The preferred transmission line route and any alternative routes or segments. • Right-of-way widths. • Location of the transmission line on the right-of-way. • Location of the transmission line relative to property lines. • Kilometre points along each transmission line route.	Section 1 Appendix G-2 Appendix E-4
	3. Legible maps and air photo mosaics upon which the proposed transmission line route(s) and/or substation have been imposed and showing the residences, landowner names, and major land use and resource features along the routes and/or adjacent to the substation (e.g., agricultural crops or pasture, topography, soil type, existing land use, existing rights-of-way, existing or potential historical, archaeological or paleontological sites, and superficial and mineable resources).	Appendix D-1 Appendix G-2
	4. Legible maps showing the most relevant environmental features, wildlife and aquatic habitat, ecological communities, environmentally sensitive areas, protected areas and designations present in the local study area.	Appendix D-1
TS22)	Provide a Keyhole Markup Language (.kml/.kmz) file that contains the geographic data of the transmission line centre lines for all applied for transmission route options and substation locations. This file should reflect the information shown on the drawings and maps submitted to address information requirement TS21.	Appendix E-5
TS23)	If applicable, describe the measures proposed to minimize potential visual effects of the proposed development, including the identification of project components and locations that require screening and the screening measures (e.g., fences, earth berms, painting, landscaping) to be used.	Section 4
	Environmental Information	
TS24)	Submit an environmental evaluation of the project. The environmental evaluation must:	
	• Describe the present (pre-project) environmental and land-use conditions for the proposed route, substation location and any alternatives.	Section 6 Appendix D-1
	• Identify and describe the potential effects of construction and operation of the project on the environment. In particular, describe any	

	potential adverse effects on soils, terrain, vegetation species and communities, wetlands, wildlife species and wildlife habitat, aquatic species and habitat, groundwater, surface water bodies and hydrology, environmentally sensitive areas, and land use within the local study area following and referencing published Alberta Environment and Protected Areas (AEPA) guidelines if applicable.	
	• Describe the methodology used and any field surveys conducted to identify, evaluate, and rate any potential environmental effects and determine their significance, along with an explanation of the scientific rationale for choosing this methodology.	Section 6 Appendix D-1
	• Describe the mitigation measures the applicant proposes to implement during the life of the project to reduce the potential adverse effects.	Section 6 Appendix D-1
	• Describe the predicted residual adverse effects of the project and their significance after implementation of the proposed mitigation.	Section 6 Appendix D-1
	• Describe any monitoring activities the applicant proposes to implement during the life of the project to verify the effectiveness of the proposed mitigation.	Section 6 Appendix D-1
	• List the qualifications of the individual(s) who conducted or oversaw the environmental evaluation.	Section 6 Appendix D-1
	• Present an overall comparison of the proposed routes, in particular, identify the environmental features and any potential environmental effects (e.g., on native vegetation communities, rare plants, wetlands, topography, unique terrain features, sensitive soils, wildlife species setbacks and wildlife habitat, and environmentally significant areas), and identify land use and resource features (e.g., agricultural, residential, recreational, forestry, trapping and hunting areas, protective notations, and existing or potential archaeological sites) for each route in a table with stated units (kilometre, total number, etc.).	Section 6 Appendix D-1
	• Summarize the compatibility of the proposed facility with various municipal services if a proposed transmission line passes through or immediately adjacent to an urban centre.	Section 6 Appendix D-1
	• If the project crosses agricultural land, describe any plans to prevent the spread of weeds and pests on agricultural land.	Section 6 Appendix D-1
	• If the project involves the modification or repair of an existing substation, describe any current or past on-site use of polychlorinated biphenyls (PCB) and summarize any site-specific incident spill records. Where soil disturbance will occur on or immediately adjacent to the substation site, describe any soil sampling or contamination assessment	Section 6 Appendix D-1

	to be undertaken and describe any plans to safely manage, transport and dispose of contaminated soils.	
TS25)	For projects wholly or partially located on federal lands (First Nation reserves, national parks or military bases), provide a copy of the environmental impact analysis completed for the corresponding federal government department. Indicate whether the project has the potential to cause effects that may cross into another jurisdiction. Environmental effects that originate on federal lands, but cross into another jurisdiction, must be addressed as part of the environmental review process. Projects on federal lands may be subject to provincial laws, standards and permits. The applicant must address how it has considered AUC Rule 007 and Rule 012 and describe the steps taken, if any, to address specific requirements set out in these rules.	Not applicable
TS26)	Submit a stand-alone, project-specific environmental protection plan (or environmental management plan) that itemizes and summarizes all of the mitigation measures and monitoring activities that the applicant is committed to implementing during construction and operation to minimize any adverse effects of the project on the environment.	Appendix D-2
TS27)	Describe any decommissioning of existing transmission facilities and describe the reclamation plan that will be carried out, including for any temporary workspace areas and temporary access roads following commissioning.	Section 6.4
	Noise	
TS28)	Provide a noise impact assessment in accordance with Rule 012 for new substations and transformer additions within an existing substation, clearly indicating the impact of the new substation and/or transformer addition.	Section 6.5
	Approvals from Other Agencies	
TS29)	Identify any other acts (e.g., *Environmental Protection and Enhancement Act, Water Act, Public Lands Act* and *Wildlife Act)* that may apply to the project, identify approvals the project may require, and provide the status of each of these approvals.	Section 7
TS30)	For the preferred route and possible alternatives, applicants must provide a summary of feedback received to date from AEPA (including the local wildlife biologist of AEPA) addressing the environmental aspects of the project, and confirmation that AEPA is satisfied with any proposed mitigation measures and monitoring activities, or identify any unresolved project aspects where agreement with AEPA was not achieved.	Section 7.1
TS31)	Confirm that a *Historical Resources Act* approval has been obtained or has been applied for. If a historic resource impact assessment is required,	Section 7.2 Appendix D-3

	briefly describe any known historical, archaeological sites, palaeontological sites, or traditional use sites of a historic resource nature. If a *Historical Resources Act* approval has been obtained, provide a copy of it.	
	Participant Involvement Program	
TS32)	Summarize the participant involvement information, including a description of the activities undertaken and include any engagement materials provided. (See Appendix A1 – Participant involvement program guidelines and Appendix A1-B – Participant involvement program guidelines for Indigenous groups).	Section 8 Appendix H-6
TS33)	List all occupants, residents and landowners within the appropriate notification radius as determined using Appendix A1 – Participant involvement program guidelines, as well as Indigenous groups and other interested persons that were notified or consulted as part of the participant involvement program.	Section 8 Appendix H-2 Appendix H-3 Appendix H-6
TS34)	Supply a list of contact information for all persons who had been contacted as part of the participant involvement program in a spreadsheet in accordance with the template included in Appendix A1 – Participant involvement program guidelines.	Appendix H-3
TS35)	Summarize consultation with local jurisdictions (e.g., municipal districts, counties).	Appendix H-6
TS36)	Identify all person(s) who expressed a concern(s) about the project. For each person, include the following information: • The specifics of the concern(s). • Steps taken to resolve the concern(s). • Whether the concern(s) was resolved.	Appendix H-5
	Economic Assessment	
TS37)	Provide an AACE Class 3 cost estimate for the preferred route and all alternatives on a common basis, in accordance with the requirements in ISO Rules Section 504.5 and the AESO Information Document #2015-002R, Service Proposals and Cost Estimating. The format of the cost estimate provided must take the form of the estimate summary that is obtained by completing the AESO's cost estimate template (available on the AESO web page). Where identifiable, include costs to be borne by persons other than the applicant and the applicant's customer(s) in the comparison. This information requirement may not be applicable to market participant and merchant line applications.	Section 9 Appendix C

	Market Participant Choice	
TS38)	In addition to the above, if the applicant is a market participant applying under Section 24.31 of the *Transmission Regulation*, the applicant must also: • Provide confirmation that all required agreements are in place with the TFO including the asset transfer agreement, the written agreement with the TFO for the temporary operation of the transmission facilities, if available, and confirmation of ISO approval of the connection proposal. • Specify the temporary period for which the market participant expects to hold the operating licence, which may not exceed the term specified in the written agreement with the TFO for the temporary operation of the transmission facilities.	Not applicable
	Energy Storage Facility	
TS39)	If an energy storage facility is to be constructed and operated as part of a transmission line, the applicant must also submit the information specified in Section 10.	Not applicable
TS40)	An applicant seeking to construct and operate an energy storage facility as part of a transmission line must provide the approval number for the associated needs identification document application.	Not applicable