Alberta Utilities Commission

Alberta Electric System Operator

Provost to Edgerton and Nilrem to Vermilion Transmission System Reinforcement Needs Identification Document

January 12, 2018

Alberta Utilities Commission
Decision 22274-D01-2018
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Needs Identification Document
Proceeding 22274
Application 22274-A001

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1 Decision summary

1. In this decision, the Alberta Utilities Commission decides whether to approve the needs identification document (NID) application filed by the Alberta Electric System Operator (AESO) for the transmission system reinforcement in the Provost to Edgerton and Nilrem to Vermilion area. The Consumers' Coalition of Alberta (CCA) opposed the application, arguing that the AESO's assessment of the need is technically deficient and that approval of the application is not in the public interest.

2. After considering the record of the proceeding, and for the reasons outlined in this decision, the Commission has decided to refer the NID back to the AESO in accordance with Subsection 34(3)(b) of the *Electric Utilities Act*.

2 Introduction and background

2.1 The Provost to Edgerton and Nilrem to Vermilion NID

3. The AESO submitted that there is a need to expand and enhance the transmission system in the Provost to Edgerton and Nilrem to Vermilion (PENV) area to alleviate identified constraints and accommodate load growth, and also to provide options for future generation system access in the area.

4. The AESO's NID for the PENV transmission system reinforcement proposed two options to address the need identified. The preferred option consists of the following elements, proposed to be in service by 2021.

- One new 144-kilovolt (kV) Drury 2007S Substation, expandable to 240/144-kV, in the vicinity of the Vermilion 710S Substation.

- One new 240-kV single circuit from the existing Nilrem 574S Substation to the Drury 2007S Substation with a minimum capacity in the order of 485 megavolt amperes (MVA). The new 240-kV circuit would initially be operated at a nominal voltage of 138 kV.

- One new 240-kV single circuit from the existing Hansman Lake 650S Substation to the existing Edgerton 899S Substation with a minimum capacity in the order of 485 MVA. The new 240-kV circuit would initially be operated at a nominal voltage of 138 kV.

- Connect 7L65 line in/out to Drury 2007S Substation; rename section of line between Drury 2007S Substation and Vermilion 710S Substation as 7L205.

- Provide option for an additional T-tap on the new 240-kV circuit between the Hansman Lake 650S Substation and Edgerton 899S Substation for the 749AL tap.

- Modify, alter, add or remove equipment, including switchgear, and any operational, protections, control and telecommunication devices.

5. The AESO estimated the preferred option would cost $240 million (+/- 30 per cent).

6. The AESO developed an alternative option that would have built the new transmission lines to the 144/138-kV standard. The AESO submitted that this option would cost $210 million (+/- 30 per cent).

7. The AESO selected the 240-kV option as its preferred option because it is more flexible and accommodates the integration of more generation, should it be needed. The option can integrate 410 megawatts (MW) of generation when operated at 138/144-kV, whereas it can integrate 860 MW when operated at 240 kV.

2.2 Amendments to the Central East Transmission Development NID approval

8. The AESO is also seeking to amend the Central East Transmission Development (CETD) NID approval by changing one component and removing other components. The AESO originally applied for the CETD NID on May 20, 2010, and was granted approval on February 10, 2011.[1] It filed an amendment to the NID on December 19, 2011 that was approved by the Commission on March 27, 2013.[2]

9. The AESO requested in this application that the following approved developments be removed from the CETD NID approval because they are no longer required:

Stage I

3. Provost area:

a) Rebuild 144-kV transmission line 7L749 from Edgerton 899S Substation (4-12-44-4-W4) to Lloydminster 716S Substation (SW 26-49-1-W4) using one 477 kcmil ACSR conductor per phase.

b) Build a new single-circuit 138-kV transmission line from Provost 545S Substation (13-7-39-2-W4) to Hayter 277S Substation (1-17-41-1-W4) using one 795 kcmil ACSR conductor per phase.

[1] Decision 2011-048: Alberta Electric System Operator - Needs Identification Document Application, Central East Region Transmission System Development, Proceeding 645, Application 1606218, February 10, 2011.

[2] Decision 2013-123: Alberta Electric System Operator - Central East Needs Identification Document Amendment and ATCO Electric Ltd. - Watt Lake 956S Substation and Associated Transmission Lines Facility Application, Proceeding 1632, Application 1607984 and Application 1608019, March 27, 2013.

c) Rebuild 138-kV transmission line 748L from Hayter 277S Substation to Killarney Lake 267S Substation (4-1-42-3-W4) using one 795 kcmil ACSR conductor per phase.

d) Rebuild 138-kV transmission line 715L from Hansman Lake 650S Substation (SE-1-40-5-W4) to Provost 545S Substation using one 795 kcmil ACSR conductor per phase.

e) Rebuild 138-kV transmission line 749L from Metiskow 648S Substation (4-6-40-4-W4) to Edgerton 899S Substation and build a 138-kV double-circuit transmission line from the existing Killarney Lake tap on transmission line 749L to Killarney Lake 267S Substation as an in-and-out configuration using one 795 kcmil ACSR conductor per phase.

4. Wainwright area:

a) Build a new single-circuit 138-kV transmission line on the existing 69-kV right-of-way from Wainwright 51S Substation (1-10-45-7-W4) to Edgerton 899S Substation using one 477 kcmil ACSR conductor per phase.

b) Rebuild 138-kV transmission lines 704L and 704AL between Wainwright 51S Substation, Tucuman 478S Substation (2-32-42-9-W4) and Jarrow 252S Substation (8-18-46-10-W4) using one 477 kcmil ACSR conductor per phase.

Stage II

1. Rebuild the existing 138/144-kV transmission line 7L50 from Battle River 757S Substation (SW 29-40-15-W4) to Buffalo Creek 526S Substation (4-12-48-9-W4) using one 477 kcmil ACSR conductor per phase.

10. The AESO also requested that the following Stage I component be changed:

5. Lloydminster and Battle River planning areas:

b) Restore 144-kV transmission line 7L14 from Vermilion 710S Substation to Hill 751S Substation (SE 11-50-1-W4) and 144-kV transmission line 7L701 from Battle River 757S Substation (SW 29-40-15-W4) to Strome 223S Substation (4-2-46-15-W4) to their respective full thermal conductor rating by migrating line clearance issues.

11. The AESO requested that the Stage I component described above be replaced with:

5. Lloydminster and Battle River planning areas:

b) Restore 144-kV transmission line 7L701 from Battle River 757S Substation (SW 29-40-15-W4) to Strome 223S Substation (4-2-46-15-W4) to its respective full thermal conductor rating by migrating line clearance issues.

12. The Commission issued a notice of application for the proceeding and received statements of intent to participate from Dave Miller, the Town of Vermilion, Marion and

Willy Kelch, the Consumers' Coalition of Alberta (CCA) and Asini Wachi Nehiyawak (Mountain Cree)/Bobtail Descendants Traditional Band. The Commission determined that the only parties with standing were Marion and Willy Kelch[3] and the CCA.

3 Discussion

3.1 Legislative framework

13. All new transmission facilities in Alberta, with the exception of those facilities designated as "critical transmission infrastructure", require two AUC approvals. First, the AUC must approve the need for the new transmission facilities pursuant to Section 34 of the *Electric Utilities Act*. Second, the AUC must approve the routing and siting of a new transmission facility and issue a permit to construct and a licence to operate the facility pursuant to sections 14 and 15 of the *Hydro and Electric Energy Act*.

14. The AESO is responsible for preparing the NID and filing it with the Commission for approval. Section 11 of the *Transmission Regulation* and Section 6.1 of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* describe the information that the AESO must include in a NID, including: an assessment of current transmission capacity, load and generation forecasts, studies and analysis that identify the timing and nature of the need for new transmission, and a technical and economic comparison of the technical solutions considered by the AESO. A NID must also state which technical solution the AESO prefers.

15. Subsection 38(e) of the *Transmission Regulation* requires the Commission to consider the AESO's assessment of need to be correct unless an interested person satisfies the Commission that the assessment is technically deficient, or that approval of the NID would not be in the public interest.

16. Section 34(3) of the *Electric Utilities Act* states that the Commission may approve or refuse to approve a NID, or refer the NID back to the AESO with directions or suggestions for changes or additions.

3.2 The AESO's assessment of need in the PENV area

3.2.1 Views of the AESO

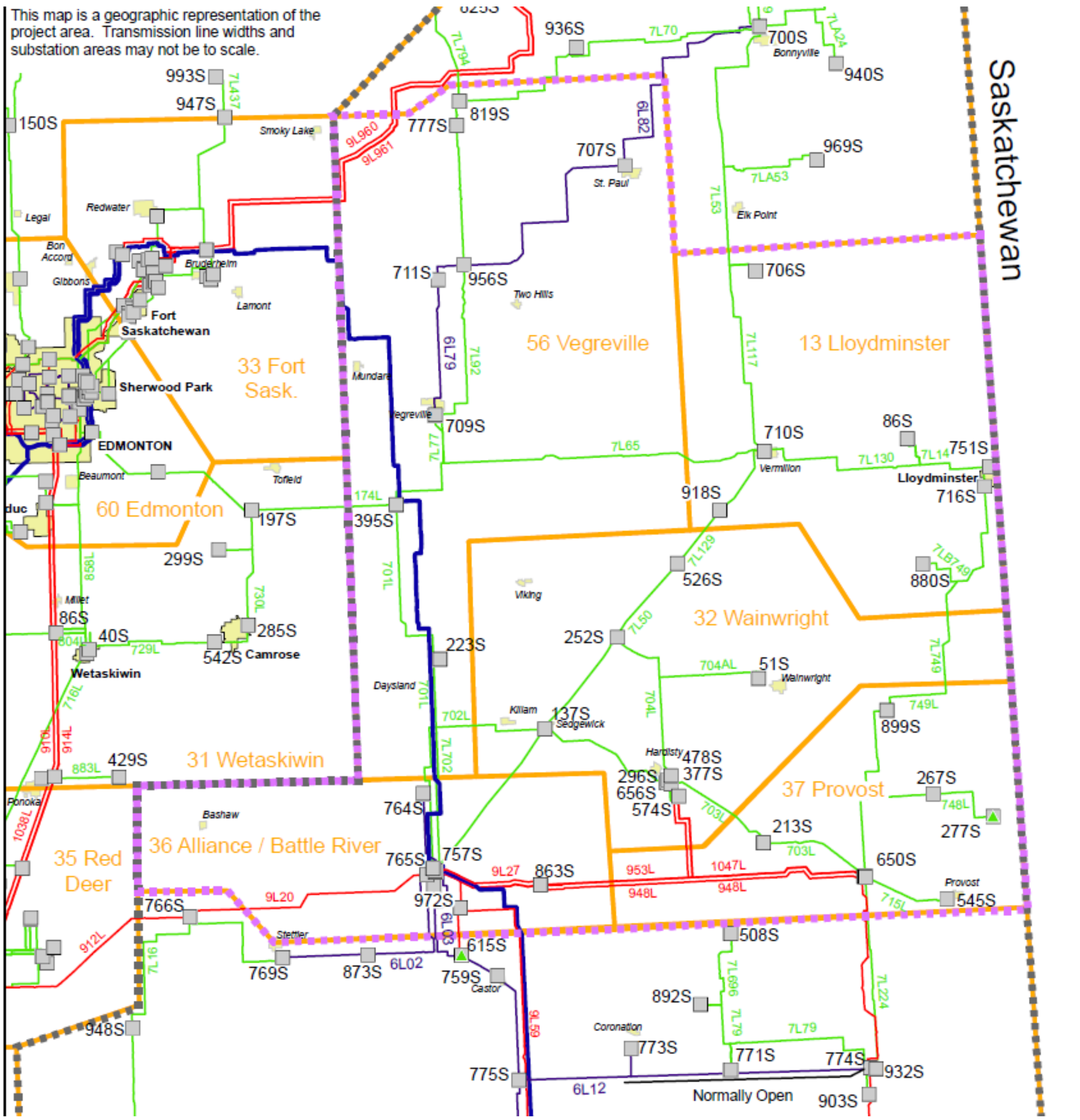
17. The AESO submitted that it is necessary to expand and enhance the transmission system in the PENV area to alleviate identified constraints, accommodate load growth and to provide options for future generation system access in the area. It submitted that its assessment of the need is technically complete and that approval of the NID is in the public interest. The AESO also submitted that its assessment that some approved components of the CETD NID are no longer required and that others should be replaced is technically complete, and that approval of the removal and replacement of those components is in the public interest.

[3] The Kelchs raised concerns with respect to the potential construction of a transmission line through the Ribstone Creek area. After submitting their statement of intent to participate, the Kelchs did not participate further in Proceeding 22274.

18. The AESO stated that the main issue in this proceeding is whether the solution it has proposed meets the need in the area. It submitted that the preferred option identified in its NID meets the 20-year load forecast, satisfies Alberta Reliability Standards with no violations, and is consistent with its long-term forecasts and area transmission plans.

3.2.1.1 Assessment of current transmission capability

19. The AESO indicated that the PENV area has five planning areas: Vegreville, Lloydminster, Wainwright, Provost and Alliance/Battle River, as shown on the map below.[4] It explained that the PENV area is currently supplied by three local 138/144-kV transmission lines (7L701/701L, 7L50/7L129 and 749L/7L749) (the local system).



4 Exhibit 22274-X0003, Appendix A Part 1 - AESO PENV Area TP Studies w Appendices A-D and F, PDF page 9.

20. The AESO explained that loading on transmission line 749L/7L749 is currently approaching thermal limits under Category A conditions (where all transmission elements are in service) and surpassing thermal limits under Category B contingency conditions (where one transmission element is out of service). Further, the AESO noted that upon the loss of line 749L, low-voltage violations occur near the Lloydminster and Edgerton substations.

21. The AESO stated that the PENV area could not serve summer load greater than 400 MW under Category B contingencies and noted that in 2013, 2015 and 2016, the actual summer peak loads exceeded that 400-MW capacity. The AESO submitted that the need for the PENV area transmission reinforcement is immediate.

22. The AESO stated that by 2021, thermal and low-voltage violations will occur under Category B contingency conditions on all three lines comprising the local system, and that specifically, when one of the three lines that comprise the local system is out of service, thermal overloads will occur on the remaining paths.

23. The AESO explained that it currently manages constraints in the area using operational procedures such as line reconfigurations, forming radials, and using remedial action schemes. It noted that the Commission had previously found that managing transmission system performance through real-time operational measures is an indication of the need for transmission reinforcement.[5] The AESO added that it is seeking a wires solution to address these constraints.

24. With respect to a non-wires solution, the AESO stated that Section 15(3) of the *Transmission Regulation* allows the use of non-wires solutions only in areas where there is limited load growth potential or where a non-wires solution is required to ensure reliable service due to a shorter lead time. The AESO submitted that neither of those circumstances is present in the PENV area. As the transmission system in the PENV area is already experiencing thermal overloads and voltage violations under Category B contingencies, reliability criteria contraventions will increase with any load growth over the planning horizon. The AESO noted that the curtailment of load under Category A and Category B conditions is not permitted under Alberta Reliability Standards.[6] As a result, the AESO determined that transmission reinforcement is required in the PENV area to reliably serve the forecast load growth in accordance with those standards.

3.2.1.2 Generation and load forecast

25. The AESO acknowledged that need in the PENV area is highly uncertain and difficult to forecast. It asserted that uncertainty exists around the timing of load increases in the area because load increases are caused by specific industrial projects that are subject to changes and delays during implementation. As such, the AESO advised that its annual load forecast should be used recognizing that the forecast load increases are subject to change as new information becomes available from industrial project proponents.[7]

[5] Decision 2014-126: Alberta Electric System Operator – South and West Edmonton Area Transmission System Reinforcement Needs Identification Document, Proceeding 2303, Application 1609123, May 5, 2014.
[6] TPL-001-AB-0, System Performance under Normal Conditions and TPL-002-AB-0, System Performance Following Loss of a Single BES Element.
[7] Exhibit 22274-X0018, PDF pages 6 and 7.

26. In the preparation of its application, the AESO estimated load growth using its 2016 Long-term Outlook (2016 LTO), which was the current long-term outlook at the time. The AESO stated that for the period 2015 to 2021, the 2016 LTO forecast compound annual load growth rate in the area to be 2.7 per cent for the summer peak and 3.5 per cent for the winter peak. The following table summarizes the AESO's forecast peak loads for summer and winter over the planning period.

AESO 2016 Long-term Outlook			
Year	2021	2027	2037
Summer peak load (MW)	496	523	572
Winter peak load (MW)	578	618	676

27. The AESO released its 2017 Long-term Outlook (2017 LTO) on July 20, 2017, after its NID was submitted. It explained that the 2017 LTO was more conservative than the 2016 version because it made adjustments to its model and used revised economic growth and energy efficiency assumptions.

28. The AESO stated that both the 2016 and 2017 LTOs show load growth in the PENV area and demonstrate that transmission reinforcement is required. The AESO stated that both the 2016 and 2017 LTOs forecast summer peak load in 2021 to exceed the 400 MW of existing transmission system load carrying capability in the PENV area.

29. While the 2017 LTO forecast shows a lower growth rate in Alberta, the AESO stated that there are additional connection projects in the area that were not included in the 2017 LTO, including 45 MW in the PENV area with an in-service date of 2021. The AESO submitted that if these projects proceed, the load in the area will be higher than what was estimated using the 2017 LTO.

30. The AESO explained that the summer peak load compound average growth rate for the PENV area between 2010 and 2015 was 3.3 per cent, adding that this is greater than the growth rates in the 2016 LTO of 2.7 per cent from 2015 to 2021, and one per cent from 2021 to 2037. It stated that the forecast growth rate used in the NID is therefore less than what has been observed over a similar historical time frame, and the long-term growth rate is even lower. It observed that because forecast growth rates for the summer season are lower than those that have been experienced historically, the forecast rates it relied upon are supported by historical growth.

31. With respect to generation forecast, the AESO explained that there is a need to provide for the integration of renewable generation in the PENV area to accommodate existing interest from prospective generators. The AESO stated that the current transmission system in the PENV area can accommodate 250 MW of new generation, but observed that its September 2017 Connection Project List shows 410 MW of wind and solar applications in the area. In addition, the AESO submitted that several recent wind projects in the PENV area reduced their project size, in part due to the lack of transmission capacity in the area.

3.2.1.3 Generation dispatch scenarios

32. To stress the transmission system in the local PENV area under Category A and Category B conditions the AESO conducted load supply adequacy studies in which it considered 14 scenarios.[8] Those scenarios considered various combinations of forecast load, including summer and winter peak periods, and generation dispatch. Depending on the generation dispatches at Battle River and in the Cold Lake area, the load serving capability of the local PENV transmission system would be stressed in different ways. The AESO stated that four scenarios covered the range of dispatches in the Battle River and Cold Lake areas that stress the system in summer and winter peak load periods, and that various sensitivities to Battle River retirements and replacements were considered.

33. The AESO stated that it developed credible, stressed study scenarios representing combinations of forecast load and generation dispatches that would result in stressed line loadings or low voltages on the local PENV transmission system under Category A conditions, as well as Category B and select Category C5 contingencies. The AESO explained that these scenarios, developed for the purpose of testing the system, were based on operational experience and not on statistical analysis. It also clarified that its analysis included book-end worst-case scenarios that the system must be able to withstand.

34. For example, the AESO stated that Scenario 2a, which the CCA classified as unreasonably extreme, is for the year 2021 and assumed summer peak load conditions with no wind generation, high PENV generation and low Cold Lake cogeneration, and noted that cogeneration in this area serves internal steam needs before supplying to the grid. The AESO stated that Scenario 2a is a book-end scenario[9] that has a chance of occurring if cogeneration in the Cold Lake area or northeast area is taken offline for regular maintenance, forced outages or business reasons. The AESO stated that Scenario 2a with the Primrose generation unit out of service is a valid dispatch condition because Primrose is the largest single unit in the Cold Lake area and the AESO is developing scenarios to stress the transmission system when a critical generator is out of service.[10] The AESO used this scenario, among others, to test the resiliency of its preferred option for the near-term and long-term. Under its Category B analysis, the AESO found thermal overloading under scenarios 1, 2a and 5a, and that Scenario 2a showed the most instances of thermal overloading.

3.2.2 Views of the CCA

3.2.2.1 Assessment of current transmission capability

35. The CCA agreed with the AESO that transmission reinforcement is required in the PENV area. It retained Grid Power Development and Design (Grid Power) to conduct an assessment of the need for transmission enhancement. Grid Power found that constraints that required reinforcement arose around transmission line 749L or following the loss of line 749L.

36. The CCA argued, however, that the AESO's need assessment is technically deficient because it is based on a now outdated long-term outlook, uses unreasonably extreme generation

[8] Exhibit 22274-X0003, PDF page 22.
[9] Exhibit 22274-X0171, PDF page 7.
[10] Ibid.

dispatch scenarios that are inconsistent with the historical operation of the system, and relies on uncertain future renewable generation development.

37. The CCA argued that the AESO should consider a non-wires solution as a possible option and stated that the AESO can plan the transmission system to re-dispatch in-merit generators following Category B contingencies without violating the *Transmission Regulation.*

3.2.2.2 Generation and load forecast

38. The CCA filed evidence showing a large discrepancy in AESO load forecasts over the years. It stated that AESO forecasts in 2014 showed Alberta reaching an energy level of 75,000 gigawatt hours (GWh) in 2019, but that the 2016 LTO, upon which this project is based, shows Alberta not reaching those energy levels until 2023. In the 2017 and most recent LTO, those energy levels are not expected until 2037.

39. The CCA stated that these are significant changes to forecasts over a short period of time. With respect to the PENV area specifically, the CCA noted that the AESO's CETD NID forecast the 2018 summer peak to be over 700 MW, while the recorded 2016 summer peak demand was 416 MW.[11] The CCA pointed out that in the 2016 LTO, the AESO forecast that the summer peak would be 496 MW in 2021, while the 2017 LTO now forecasts that this level will not be reached until 2036. Similarly, the 2016 LTO forecast that the winter peak would be 578 MW in 2021, but the 2017 LTO does not even reach this level by 2037.[12]

40. The CCA submitted that the AESO's assessment is technically deficient because it relies on outdated and inaccurate load forecasts, and that the 2017 LTO shows a significantly lower forecast for the PENV area that is closer to the historical growth rate.

41. The CCA argued that the AESO did not revise its technical solution following a significant reduction in load forecast in the 2017 LTO. Further, it stated that the forecast load and generation do not appear to be supported by historical load growth, which may lead to the construction of transmission facilities before they are required. The CCA argued that because the AESO relied on its 2016 LTO, and because in the 2017 LTO forecast the 2021 load levels are not expected to occur until 2035 or later, there is a risk of building transmission to accommodate load forecasts that may not materialize.[13] Based on the 2017 LTO, the near-term need in 2021 is to serve approximately 440 MW at the time of summer peak and approximately 510 MW at the time of winter peak. The long-term load need in the PENV area is to serve approximately 500 MW at the time of summer peak and approximately 575 MW at the time of winter peak.[14]

42. The CCA disagreed with the AESO's statement that the average annual growth rate in the PENV area was 3.3 per cent from 2010 to 2015. The CCA stated that the AESO used the lowest load level in the last 10 years as the starting point, and the highest load level in the last 10 years as the end point. It stated that the 2002 to 2016 summer peak load compound annual growth rate for the PENV area is approximately one per cent.

[11] Exhibit 22274-X0166, PDF page 8.
[12] Exhibit 22274-X0139, PDF page 16. Note that the LTO does not look at the forecast for the planning regions.
[13] Exhibit 22274-X0160, PDF page 2.
[14] Exhibit 22274-X0139, PDF page 17.

43. Grid Power submitted that the load forecast used in the NID application appears to significantly overstate the load growth and does not track with the historical trended growth. For example, the AESO's load forecast predicts "a large 45 per cent increase"[15] in load in the Provost planning area from 2016 to 2017, although the area is dominated by heavy oil production loads and has experienced a year-over-year decline for the past two years.

44. With respect to the generation forecast to be connected in the area, the CCA submitted that transmission reinforcement is not immediately required to interconnect renewable generation because the AESO stated that 2,600 MW of renewable generation, including 250 MW in the PENV area, can be accommodated in the existing transmission system. The CCA stated that the AESO, through the Renewable Electricity Program, could prioritize generation in areas that do not require transmission development, and that there was no evidence indicating that the projects on the Connection Project List would proceed without a Renewable Electricity Program contract.

45. With respect to the 45 MW of additional generation identified by the AESO, the CCA stated that one of the projects appeared to be a Keystone XL pump station. The CCA stated that there is uncertainty surrounding the Keystone XL pipeline and that the pump station is served by a substation outside of the PENV area. It also argued that delayed or cancelled loads in the area could offset this new load, which the AESO did not address.

46. The CCA argued that the AESO must distinguish between needs driven by load and needs driven by generation because the AESO's planning obligations are dependent upon the driver. The CCA stated that for load-driven need, the reliability standard does not allow for the curtailment of load following the loss of a single transmission element. For generation-driven need, the AESO must plan for an uncongested system when all transmission elements are in service, not for when a single transmission element is out of service.[16]

47. The CCA also expressed concern that the AESO did not sufficiently contemplate the staging of development. The CCA indicated that the area has experienced a high degree of uncertainty, the load in the area has fluctuated up and down as production increased rapidly in response to high oil prices and declined in times of low oil prices, and that development should be staged to avoid large, one-time transmission developments that could become underutilized.

3.2.2.3 Generation dispatch scenarios

48. Grid Power submitted that the primary driver for constraints in the area was not load growth but increased flow through the PENV area driven by the AESO's generation dispatch scenario, which Grid Power considered "extreme". It stated that historically, the Cold Lake generation output is much higher than what was used in the AESO's studies. It stated specifically that the AESO's Scenario 2a assumed that Cold Lake area generation would produce 243 MW at summer peak and the Fort McMurray Export cutplane would be exporting at 32 MW. The CCA submitted that the Cold Lake area generation during the top 50 summer peak load hours in 2016 was never below 366 MW, and the Fort McMurray Export cutplane was never below 136 MW.[17] Grid Power stated that this lower generation output exacerbated flow-through in the PENV area, and may have led the AESO to mistake load growth as a driver instead of its dispatch scenario.

[15] Exhibit 22274-X0139, PDF page 9.
[16] Unless the congestion is demonstrated to occur more than five per cent of the time.
[17] Exhibit 22274-X0139, PDF pages 19 and 20.

49. The CCA argued that generation re-dispatch may address the needs identified by the AESO's 2021 assessment. The CCA stated that the AESO's assessment did not attempt to re-dispatch generation to address constraints following a Category B2 contingency which is permitted under the Alberta Reliability Standards and the *Transmission Regulation*. It argued that the use of unsupported generation dispatch scenarios that are unreasonably extreme compared to historical operation, and the failure to test if generation re-dispatch following Category B contingencies would address the need identified, demonstrate that the AESO's 2021 need assessment is technically deficient. The CCA argued that by reducing flow-through in the PENV area, transmission capability can be released to serve load and generation in the area.

3.3 Commission findings

50. While the Commission is satisfied that there is, or may be, a need to expand or enhance the transmission system in the PENV area, the magnitude and timing of that need is uncertain because of the material difference between the load forecast in the 2016 LTO, which the AESO relied upon in preparing the NID, and the significantly reduced load forecast in the AESO's 2017 LTO, which was released in the fall of 2017 after the AESO's application was filed. Because of this uncertainty, the Commission finds that it cannot reasonably assess the suitability of the AESO's preferred option and finds, accordingly, that it would not be in the public interest to approve the NID. Rather, the Commission finds that it is in the public interest to refer the NID back to the AESO with the direction to incorporate its most current load and generation forecasts into its analysis of the need in the PENV area and, if necessary, adjust, or even stage, its preferred solution to address the updated need. The Commission's reasons for this determination follow.

3.3.1 Assessment of current transmission system capability

51. The Commission agrees with the AESO and the CCA that there is an emerging need to expand and enhance the transmission system in the PENV area. The Commission notes that both parties agree, and the evidence supports, that by 2021, under Category B contingencies, thermal and low-voltage violations will occur.

52. The Commission finds that the transmission system must be developed to support both load and generation in the area. Section 15(1)(e) of the *Transmission Regulation* requires that, in exercising its transmission system planning duties, the AESO must consider the characteristics and expected availability of generating units. Among other things, the *Transmission Regulation* requires the AESO to plan a transmission system that is sufficiently robust to allow for transmission of 100 per cent of anticipated in-merit electric energy when all transmission facilities are in service, and 95 per cent when operating under abnormal operating conditions.

53. Section 15(1)(f) of the *Transmission Regulation* further provides that the AESO must make arrangements for the expansion or enhancement of the transmission system so that under normal operating conditions, all anticipated in-merit electric energy referred to above can be dispatched without constraint. The evidence on the record demonstrates that the capacity of the September 2017 Connection Project List exceeds the generation capacity that the area can accommodate. Given the AESO's duties under the *Transmission Regulation* to develop the system to connect generation, integrating generation must be considered as part of the need.

54. The Commission disagrees with the CCA's submission that, because the AESO can prioritize generation through the Renewable Electricity Program, transmission reinforcement is not immediately required to interconnect renewable generation. The CCA's statement that no evidence was provided that projects would proceed without a Renewable Electricity Program contract is irrelevant because the AESO is required under statute to forecast generation and provide connection. In addition, the criteria for future Renewable Electricity Program bids are unknown, and may require transmission development in the area.

3.3.2 Generation and load forecasts

55. Although the parties agree and the evidence supports the need to expand or enhance the transmission system in the PENV area, as illustrated below, the evidence as to the magnitude of the need is inconsistent and ultimately uncertain. Uncertainty about the magnitude of the need, likewise results in uncertainty about the urgency of the need and also the technical solutions to meet it.

56. The evidence before the Commission indicates that the load growth rates in the PENV area may be lower than those relied upon by the AESO in its application. The 2017 LTO shows an overall decrease in forecast provincial load, with a growth rate of 0.9 per cent, as compared to the growth rate of 1.9 per cent used in the 2016 LTO. While this growth rate is for the overall province, the PENV area is captured within the study area. Further, the AESO's revised load forecast based on the 2017 LTO appears to be materially lower than the load levels relied upon by the AESO in the NID application. For example, the forecast summer peak load for 2021 at the time the application was filed was 496 MW. The AESO's latest forecast summer peak load for 2021 is 440 MW, and summer peak load is not expected to reach 496 MW until 2036. The following table highlights the differences between the load forecast in the AESO's 2016 and 2017 LTOs.

Year	PENV summer peak load from 2016 LTO[18]	PENV summer peak load from 2017 LTO[19]
2021	496 MW	425 MW
2027	523MW	456 MW
2037	573 MW	499 MW

57. It also appears to the Commission that 25 MW of the 45 MW of additional load from new project connections that the AESO relied upon as continued support for its load forecast for the PENV area relates to the TransCanada Keystone XL pump station #2-Eyre pump station. This project resides in the Hanna planning area and not in the PENV area. The Commission finds that even with the inclusion of the remaining 20 MW, the load in the PENV area would still be less than the load forecast in the 2016 LTO.

58. Additionally, while the AESO provided some limited evidence on historical growth rates in the PENV area in support of its load forecast, that evidence conflicted with that filed by the CCA. The AESO, relying on data from 2010 to 2015, calculated the historical summer peak growth rate for the area to be 3.3 per cent whereas the CCA, using data from 2001 to 2016, calculated the historical summer peak growth rate to be one per cent. This conflicting evidence

18 Exhibit 22274-X0018, Tables 3-1 and 3-2, PDF page 6.
19 Exhibit 22274-X0123.

contributes to the uncertainty regarding the timing and magnitude of load growth in the PENV area.

59. Given the material change in load forecasts illustrated above, the urgency to develop the transmission system in the PENV area also may be overstated in the NID. Since the PENV area already experiences peak loads greater than 400 MW, and that load growth now appears to be lower than anticipated in the NID, the Commission considers that there is a reasonable opportunity to reassess the need in the PENV area to ensure that the AESO's preferred alternative continues to be the best option to meet the need identified.

60. Because the Commission has decided to refer the NID back to the AESO for the reasons set out above, it is not necessary to make a decision on the remaining concerns raised by the CCA about the AESO's assessment of need. However, because the Commission anticipates that the AESO will refile its NID for the PENV area, it is of the view that the parties will benefit from some guidance on two of the issues raised: (a) the use of a non-wires solution, and (b) the AESO's dispatch scenarios.

61. Notwithstanding the AESO's ability to maintain the system using operational procedures pending a reassessment of need, the Commission agrees with the AESO that the non-wires solution suggested by the CCA is not an option available to the AESO in light of its obligations in the *Transmission Regulation*. It also agrees with the AESO that the PENV area does not meet the criteria in the *Transmission Regulation* which allows for a non-wires solution, and notes that the CCA did not provide any evidence to support its claim that re-dispatch of in-merit generation following a Category B contingency can alleviate constraints.

62. The Commission finds, with respect to the generation dispatch scenarios used by the AESO, that the AESO's use of Scenario 2a does not demonstrate that the AESO's need assessment is technically deficient. The Commission accepts the AESO's argument that it was reasonable to include Scenario 2a as a book-end scenario that has a potential of occurring. The Commission also observes that Scenarios 1 and 5a, which the CCA did not consider to be extreme, also demonstrated thermal overloading under Category B contingencies in 2021.

3.3.3 Central East Transmission Development NID amendment

63. With respect to the Central East Transmission Development amendment, the AESO stated that its preferred option for transmission reinforcement in the PENV area would alleviate identified thermal and voltage violation in the PENV area without requiring the CETD developments it proposes to remove.

64. The CCA raised a concern that the AESO did not evaluate whether the facilities included in the original CETD NID, or a subset of those facilities, would meet the forecast need in the PENV area.

65. The Commission cannot make a decision on the CETD amendment at this time because the removal of the previously-approved components are connected to the development of the AESO's preferred option. The Commission will defer its decision on the CETD amendment until the AESO has completed its re-examination of the need, using the latest forecasts, to determine whether its preferred option for the PENV reinforcement changes and, if it does, how the change may affect the CETD area.

4 Decision

66. Pursuant to Section 34(3)(b) of the *Electric Utilities Act*, the Commission refers the NID back to the AESO and directs the AESO to incorporate the most current load and generation forecasts into its analysis of the need in the PENV area and, if necessary, adjust its preferred solution to address the updated need. Should the AESO's reassessment of the need in the PENV area result in material changes to the need identified, the Commission expects that the AESO will adapt its preferred alternative accordingly and consider whether project staging based on established milestones is necessary in the circumstances.

Dated on January 12, 2018.

Alberta Utilities Commission

(original signed by)

Anne Michaud
Panel Chair

(original signed by)

Carolyn Hutniak
Commission Member

(original signed by)

Joanne Phillips
Commission Member