Decision **2003-027**

ATCO Electric Ltd.

Dover to Deerland
Fort McMurray/Fort Saskatchewan Areas
240 kV Transmission Facilities Application

Phase 1 Decision – Need for Facilities

April 23, 2003

Alberta Energy and Utilities Board

ALBERTA ENERGY AND UTILITIES BOARD
Decision 2003-027: ATCO Electric Ltd.
Dover to Deerland
Fort McMurray/Fort Saskatchewan Areas
240 kV Transmission Facilities Application
Phase 1 Decision – Need for Facilities
Application Nos. 1284228, 1284230, 1284240

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PHASE 1 NEED FOR FACILITIES

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1 SUMMARY OF DECISION

This Summary is provided for the benefit of the reader. All persons making use of this Summary are reminded that the remaining text of the Decision should be consulted for all purposes relating to the interpretation and application of the Board's decisions.

The Board, in this Decision, approves the need for a third 240 kV transmission line south from Fort McMurray. The third line will increase the transfer-out capacity from 370 MW to 610 MW. Since the transfer-out capacity required after the in-service date of TransCanada's MacKay River generating plant (expected to be December 2003) is 595 MW, the Board considers that the third 240 kV line should be constructed.

The Board also considers that there is a need to meet increased load growth in the Fort McMurray to Crow Lake area and in the Athabasca area. Most of the potential load growth in these areas is related to pumping stations for potential new pipelines from Fort McMurray to Edmonton.

The Board considers that both the proposed Dover to McMillan to Deerland project (also referred to as the Proposed Project) and a transmission line from Dover to McMillan to Whitefish (referred to as the Dover to Whitefish Alternative or Alternative 4 Option 2) would meet the needs identified above.

Weighing all of the evaluation factors, the Board believes, on the basis of the evidence currently on the record, that the Dover to Whitefish Alternative (Alternative 4 Option 2) may be superior to the Proposed Project in terms of meeting the needs and satisfying the financial, technical and general routing issues required to be resolved in Phase I of these proceedings as set out in Decision 2003-017.

The Board notes that the Dover to McMillan application is common to the Proposed Project (i.e. Dover to Deerland) and Alternative 4 Option 2 (i.e. Dover to Whitefish). For this reason the Board approves the Dover to McMillan end points of AE's first application. The specific routing (i.e. "west proposed" or "east proposed") of the Dover to McMillan application will be dealt with in the Phase II Part A hearing, if required.

However, as a result of the Board's findings, the Board refers AE's second application (i.e. McMillan to Charron) and third application (i.e. Charron to Deerland) back to the TA and AE.

The Board proposes three process options to the TA and AE as follows:

1. Amend the McMillan to Charron and Charron to Deerland applications by replacing these applications with a McMillan to Whitefish application.
2. Amend the McMillan to Charron and Charron to Deerland applications to include a McMillan to Whitefish application as an alternative routing to be formally considered at the hearing.
3. Retain the McMillan to Charron and Charron to Deerland applications but include a supplement to these Applications explaining why a McMillan to Whitefish routing is not a viable alternative.

In addition, as a result of concerns expressed in the Phase I portion of the hearing and as part of AE's expressed intent to address landowner concerns, the Board recognizes that AE may make amendments to the Dover to Deerland route to address landowner issues in the Phase II Part B hearing.

The Board will deal with the alternative chosen by the TA and AE in the Phase II Part B hearing, if required.

The Board also wishes to be clear that no further Need Document or Phase 1 hearing is required for either the Proposed Project (Dover to Deerland) or the Dover to Whitefish Alternative or variants of the same. More specifically, no further Need Statement and Phase I hearing is required for any modified route, including stringing the second circuit on the existing 240 kV double circuit structures to Whitefish.

2 INTRODUCTION

2.1 Details of the Application

On November 27, 2002, ATCO Electric Ltd. (AE) applied to the Alberta Energy and Utilities Board (the Board) for approval to construct and operate a 240 kilovolt (kV) transmission line and three associated 240 kV substations designated as Dover, McMillan and Charron. The proposed transmission line would originate at the Dover substation, north of Fort McMurray in Section 31, Township 92, Range 12 west of the 4th Meridian, and would end at the existing Deerland substation northeast of Fort Saskatchewan in Section 22, Township 56, Range 20, west of the 4th Meridian, a distance of approximately 420 kilometers.

In support of the proposal, AE prepared and submitted the following three applications:

Table 1. Dover to Deerland Application

DOVER TO DEERLAND PROJECT			
	Application Designation	***From - To***	***Application Includes***
First Application	North Section	Dover - McMillan	Dover 888S substation 9L57 and 9L58 (double-circuit 240kV in-out Dover transmission line) 9L07 transmission line McMillan 885S substation
Second Application	Central Section	McMillan - Charron	9L38 transmission line Charron 625S substation
Third Application	South Section	Charron - Deerland	9L982 transmission line

2.2 Details of the Notice

The Board issued a Notice of Application on December 13, 2002. The Notice of Application was published in Calgary and Edmonton major daily newspapers on December 19, 2002 and in local newspapers on January 6 - 8, 2003. The Notice was distributed to advise interested parties that the applications had been filed with the EUB, and that the EUB together with other Government Departments had commenced the review of the applications.

2.3 Pre-Hearing Conference

On January 24, 2003, the Board issued a Notice of Pre-Hearing Conference to be held on February 11, 2003. The Notice was published in Calgary and Edmonton major daily newspapers on January 29, 2003. The purpose of the Pre-Hearing Conference was to provide interested parties with an opportunity to discuss procedural matters and other issues relating to the Transmission Administrator's (TA) role at the hearing, schedule for filing of evidence and filing of alternative transmission line routing information, appropriateness of a two phase proceeding, and any other relevant issues.

The Board also requested interested parties wishing to participate in the pre-hearing conference to provide written notice and an initial position on the issues outlined in the Notice of Pre-Hearing Conference no later than February 4, 2003.

On February 11, 2003, the pre-hearing conference was held at the Board's Edmonton offices before A. J. Berg, P. Eng. (Presiding Member) and J.I. Douglas, FCA (Board Member).

On February 19, 2003, Board Decision 2003-017 was issued which set out the Board's views respecting the issues outlined in the Notice of Pre-Hearing Conference, new issues raised by parties at the pre-hearing conference, and the schedule for the subsequent proceedings.

2.4 Notice of Phase 1 and Phase II Hearings

On February 24, 2003, a Notice of Hearing setting down the Phase I hearing on March 19, 2003, in Smoky Lake was sent to interested parties.

The Board stated that should the Board approve the need and the general routing in Phase I, a Phase II hearing would be held to address the detailed routing of the proposed line and its potential specific impacts on landowners. As well, the Phase II hearing would be separated into two parts:

- Phase II – Part A would address the specific routing for the north and central sections of the proposed transmission line (Applications No. 1284228 and 1284230).
- Phase II – Part B would address the specific routing of the south section of the proposed transmission line (Application No. 1284240) where the most of the intervening landowners are located.

2.5 Motion to Adjourn

On March 3, 2003, The Board received a letter from Mr. J. W. Bodnar representing a group of landowners (the Landowners' Group) having an interest in the Dover to Deerland applications. The Landowners' Group submitted a motion in writing to the Board seeking to have the application adjourned and stayed. On March 4, 2003, the Board issued a letter requesting parties to comment on the Landowners' Group motion by March 5, 2003.

The hearing was adjourned to April 1, 2003. On March 12, 2003, the Board issued a letter and a Notice of Re-Scheduling of the Hearing to all parties with a revised schedule for the proceedings.

2.6 Phase I Hearing

On April 1, 2003, the Board held the Phase I hearing at Smoky Lake before A.J. Berg, P. Eng. (Presiding Member), N. W. MacDonald, P. Eng. (Acting Board Member) and J.R. Nichol, P. Eng. (Board Member). Parties that appeared at the hearing are shown in Appendix 1 to this Decision.

At the end of the hearing, parties agreed to file written argument and reply on April 9 and April 11, 2003 respectively.

On April 8, 2003, the Board received AE's undertaking to the Board (Exhibit 2-22) containing information provided by the TA and AE. Upon reviewing the undertaking, the Board decided that further clarification was required and adjusted the dates for argument and reply to April 14 and April 16, 2003 respectively. The Board requested AE and the TA to file a clarification (pre-marked as Exhibit 2-23) with the Board and interested parties on or before 4:30 p.m. on April 10, 2003. The deadline was extended to Monday Noon, 14 April 2003 and the filing dates for arguments and reply were adjusted to Wednesday Noon, 16 April 2003 and Thursday 4:30 p.m. 17 April 2003 respectively.

Written argument was received from parties on or about April 16, 2003. Written reply was received from parties on April 17, 2003.

The Board considers the record of this proceeding to have closed on April 17, 2003.

3 LEGISLATIVE AND REGULATORY FRAMEWORK

3.1 General

Upon receipt of a transmission facilities application, the Board, pursuant to Section 14 of the *Hydro and Electric Energy Act*, must consider whether the facility for which approval is sought is and will be required to meet present and future public convenience and need. The Board must also take into account the purpose of the *Hydro and Electric Energy Act* to provide for the economic, orderly and efficient development and operation, in the public interest, of hydro energy and the generation and transmission of electric energy in Alberta.

AE, in its application, has relied upon a Need Document[1] prepared by the TA dated October 21, 2002 to support the need for the proposed transmission facilities.

The Need Document prepared by the TA addressed the lack of capacity in the existing transmission system to serve supply customers in the Fort McMurray area and the lack of capacity to serve demand customers in the Athabasca area and the area generally south from Fort McMurray to the Crow Lake area. The TA's Need Document examined a number of transmission facilities alternatives (both south and east of Fort McMurray) before selecting the North-South Dover to Deerland transmission facilities project.

3.2 Phase I – Need for Additional Transmission Facilities

The Board, before approving the proposed facilities, must first be satisfied that the needs of supply and demand customers in the Fort McMurray and Athabasca areas identified by the TA in the Need Document are appropriate and reasonable.

The Board must further be satisfied that the TA, in meeting the established need, has chosen the transmission facilities alternative that provides "for the economic, orderly and efficient development and operation, in the public interest, of hydro energy and the generation and transmission of electric energy in Alberta"[2].

3.3 Phase II – Specific Location and Routing of Transmission Facilities

The Board, in this Decision, will address the need for the additional transmission facilities in the Fort McMurray and Athabasca areas and the general routing of the transmission line. Issues respecting the specific routing will be dealt with in Phase II of AE's applications hearing.

1 Appendix B of each of AE's three Applications
2 Hydro and Electric Energy Act section 2

4 NEED FOR ADDITIONAL TRANSMISSION FACILTIES

4.1 General

The TA submitted in the Need Document included in the Dover to Deerland applications that:

- The existing system was insufficient to maintain acceptable service levels to supply customers in the Fort McMurray area. Generation additions that are expected to occur over the next few years would exceed the limit of the system to deliver excess generation to the AIES.
- The existing transmission system was insufficient to maintain acceptable service levels to demand customers in the Athabasca area during single contingency outage conditions.
- A significant amount of pipeline pumping load south of Fort McMurray to the Crow Lake area was presently supplied via a radial 144 kV line. Additional electric demand for pumping load was expected to develop in this corridor as additional pipelines were being built to support the oil sands development. The lack of an adequate supply to these loads both in terms of long term capacity and reliability would become more critical as these loads increased.

The TA submitted that the Dover to Deerland 240 kV transmission line and associated facilities contemplated by the applications would be the best solution to meet these transmission needs and improve transmission service and reliability for the entire area in a reasonable and timely manner.

4.2 Needs of Fort McMurray Supply Customers

The TA is required to serve four supply customers in the Fort McMurray area by the end of 2003. Each of the supply customers has an on-site load leaving only a portion of the generation capacity available to the AIES. The TA in its Need Document stated that the total generation available to the AIES could be as high as 650 MW (later revised to 630 MW) based on STS capacity. The TA noted that a more typical average amount is likely to be in the order of 520 MW as shown in the table below. The average transfer-out requirement is then determined by subtracting the average Fort McMurray City and Area Load of 64 MW resulting in 456 MW.

The TA, during the course of the proceedings, produced Exhibit 3-19 that illustrated a forecasted cumulative probabilistic distribution of the transfer-out capacity requirement ranging from a maximum of 595 MW to a low of approximately 125 MW. The TA stated that the probabilistic transfer-out capability requirement was determined assuming the following:

- Generators assumed to have a 95% availability factor.
- On-site load assumed to vary between 475 MW and 545 MW.
- Fort McMurray and surrounding area load assumed to be a minimum of 35 MW and an average value of 64 MW.
- A combined STS contract level of 630 MW.

Table 2. Required Fort McMurray Transfer-Out Capability (MW) (Based on TA)

Supply Customer	In Service Date	Generating MCR Capacity (MW)	Forecast Average On-site Load (MW)	Forecast Average Generation to AIES (MW)	STS Contract Level (MW)
Syncrude	Existing	325	275	50	100
Suncor	Existing	420	200	220	220
Albian	Existing	170	80	90	130
PetroCanada	Dec 2003	190	30	160	180
Total to AIES				**520**	630
Average Fort McMurray City and Area Load				64	
Average Transfer-Out Requirement				**456**	
Hourly Range of transfer-out requirement				**125 to 595**	
Maximum transfer-out requirement				**595**	

Reference: Based on the TA's Exhibit 2-15, which was generally agreed to by the Oil sands and Co-generator panels.

The Fort McMurray area is connected to the rest of the AIES by two 240 kV transmission lines, 9L56/57 and 9L990. The TA retained Sinai Engineering Corporation (Sinai) to assess the transfer-out capability of the transmission system under different system configurations. Sinai, in its technical reports, concluded that the Fort McMurray area transfer-out limits were:

(a) 370 MW with both of the existing 240 kV lines in service. Load flow analysis indicates that this level of transfer-out of Fort McMurray area is feasible without violating post N-1 contingency voltage deviation guidelines[3]
(b) 470 MW with two 240 kV lines and a Remedial Action Scheme to curtail TransCanada's power plant at MacKay River complex; and
(c) Approximately 620 MW with three 240-kV lines in service.

4.3 Views of Interested Parties re Supply Need

AE submitted that, based on the totality of the evidence regarding need, there was simply no question that the applied for facilities were needed as soon as possible and concurred with both the TA panel and the co-generators panel views that the Dover to Deerland project was a good solution for the needs identified by the TA.

Suncor and Syncrude indicated that throughout numerous analyses, and balancing of all interests, the TA had consistently come to the conclusion that the applied-for facilities were the best option for meeting these needs. Suncor and Syncrude supported and agreed with the TA's assessment.

ATCO Power submitted that one of the main drivers of the Dover to Deerland project was the ability to meet AIES supply growth. ATCO Power submitted that none of the East-West alternatives met this objective and would place a 2004 in-service date in jeopardy.

[3] The TA's panel later clarified that the post-contingency transfer-out limit of 370 MW would be available for the first 10 to 20 minutes and thereafter a transfer-out capability of 280 MW would be available.

TransCanada Energy Ltd. stated that the evidence of parties at this hearing as well as the Need Document made it abundantly clear that the existing capacity for the Fort McMurray area fell well short of STS requirements contracted by suppliers.

CNRL, Petro-Canada, TransCanada and TransAlta (the co-generation / oil sands developers) submitted that the proposed Dover to Deerland transmission line was urgently needed and that any delay in the construction of this line or any alternative route being considered would have serious and potentially long-term consequences to their ongoing and future operations.

4.4 Views of the Landowners re Supply Need

The Landowners pointed out that the need analysis contained in the Need Document was never submitted to the Landowners as part of the consultation process. It was completed in October 2002, after the landowner consultation was completed in June 2002.

In addition, the Landowners submitted that the project need analysis did not demonstrate that there was a need for this project in terms of serving as a source of power for all residents in Alberta. The Landowners questioned the integrity of both the TA and AE in this process.

The Landowners suggested that the project and the need for it appeared to be driven primarily by oil and gas companies for their own profit motives, and that the proposed routing of the line was based on the reasoning of "least resistance" as opposed to least impact.

4.5 Views of the Board re Supply Need

The Board notes that the hour-by-hour transfer-out requirement can vary significantly and is the cumulative function of the following variables:

- Available Generating Capacity
- Variation in On-Site Load
- Hourly Load for the City of Fort McMurray and Surrounding Area

The Board observes that the TA did not specifically indicate how the STS contract capacity was used to modify[4] the above hour-by-hour calculation.

Notwithstanding, the Board notes that the TA, by introducing the STS contract capacity of 630 MW into the calculation, may have determined the maximum transfer-out requirement of 595 MW by subtracting the Fort McMurray City and area minimum load of 35 MW from the STS contract capacity of 630 MW. The Board acknowledges the difficulty in forecasting on-site load[5] and the relatively small amount of Fort McMurray generation diversity and therefore accepts, as reasonable in the circumstances, the TA's method and forecast of 595 MW as the required transfer-out capability.

The Board notes that the existing two 240 kV lines out of Fort McMurray are only able to provide reliable service to the existing supply customers. With the addition of the MacKay River generator in 2003, the service to Fort McMurray supply customers is inadequate.

4 For example the STS capacity may have been used as a cap on the net delivery to the AIES.
5 The extreme variation in Syncrude's hourly on-site load is shown on Exhibit 17-6.

Accordingly, the Board is satisfied that there is an immediate need for a total transfer-out capability of approximately 595 MW from the Fort McMurray area. This need cannot be met on a reliable basis with the existing two 240 kV lines. The Board considers that a third 240 kV line is required to be constructed to meet the needs of the Fort McMurray supply customers.

4.6 Needs of Demand Customers

The TA in its Need Document noted the following forecast load growth:

- Approximately 25 MW in the Fort McMurray-Crow Lake Area over the period 2003 to 2011.
- Approximately 10 MW of load growth (other than new pipeline growth) in the Athabasca Area over the period 2003 to 2011 over the period 2003 to 2011.
- Approximately 70 MW of new pipeline growth generally along the Fort McMurray - Fort Saskatchewan corridor over the period 2005 to 2011.

The TA stated the following respecting the potential new pipeline growth:

> The Athabasca region forms the southern half of a corridor stretching between the Fort McMurray oil sands area and the oil refining facilities in the Fort Saskatchewan area. Potential load growth along this corridor in the way of oil sands projects and pipeline pumping loads is expected to continue although the exact details are unknown at this time. The Transmission Administrator has had preliminary discussions with one particular pipeline company on a possible expansion of their pipeline in this corridor. Also, BC Gas Inc., the builders of the Corridor Pipeline, has announced plans to build the Bison Pipeline; the exact routing of this pipeline is yet to be determined although it is expected to be within this same area. However, it is not clear that both of these pipelines will be developed in the next 10-year period. Depending on the designed capacity of the new pipeline an additional 40 to 100 MW of pumping load per pipeline might be required.
>
> Only one of the two new pipelines mentioned above has been added to the forecast at its mid-range value of 70 MW, however, the analytical studies described in later sections of this Document do not include this new load. [6]

4.7 Views of the Interested Parties re Demand Need

Suncor and Syncrude stated that the TA's analysis indicated that additional transmission capacity was needed to serve demand customers in the Athabasca area and demand customers in the areas generally south from Fort McMurray to the Crow Lake area.

The Co-generation / Oil Sands Developers submitted that based upon the evidence in this proceeding there had been no controversy that there was an immediate and compelling need, both supply and load, for the additional capacity provided by the Dover to Deerland transmission line.

[6] Need Document page 3

Treaty Eight First Nations of Alberta (Treaty Eight) submitted that when canvassing transmission requirements in the Province, a thorough analysis of need could lead to a conclusion that some of the alternatives presented in the course of the proceeding were more capable of dealing with broader system requirements. Treaty Eight considered that East-West alternatives provided transmission service in an area of the Province, parts of which currently do not receive transmission service.

4.8 Views of the Board re Demand Need

The Board is satisfied that there is a need to meet the following forecast load growth:

- Approximately 25 MW in the Fort McMurray-Crow Lake Area over the period 2003 to 2011.
- Approximately 10 MW of load growth (other than new pipeline growth) in the Athabasca Area over the period 2003 to 2011 over the period 2003 to 2011.

The Board accepts the TA assessment in its Need Document, that there is a need to satisfy approximately 70 MW of new pipeline growth generally along the Fort McMurray Fort Saskatchewan corridor over the period 2005 to 2011.

However, the Board notes that the location of the new and existing substations required to serve this load is unknown. The Board notes that prior to the load flows presented in Exhibit 2-23, the TA had not included this pipeline load in any technical analysis of alternatives and specifically noted that the analytical studies carried out in the Need Document did not include this load.[7]

In Exhibit 2-23, the TA allocated 35 MW of new pipeline load to the Crow Lake Substation in the north and 35 MW of new pipeline load to the Flat Lake Substation to compare the Alternative 4 options to the Dover to Deerland Proposed Project. The Board is not persuaded that this selection of substations should necessarily drive the 240 kV alternative approved by the Board. For example, the Board notes that if the southern pumping station for the Bison Pipeline were to be located more towards Lac La Biche than Flat Lake, the Alternative 4 options would appear to be more advantageous.

The TA also stated in Exhibit 2-23 that with an additional 35 MW load at Flat Lake, the Load Flow Figure 2-23-TA-37, which is the base case for Alternative 4 Option 2, demonstrated that the 144 kV line 788L between Lac La Biche and the new substation would be overloaded at 102 MVA in the 2005 winter period. The Board considers that if such future constraints should arise on the 788L 144 kV line, cost efficient methods[8] to alleviate this lower voltage constraint can be studied and addressed at that time.

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7 This is understandable since the pipeline load is not expected to come on line until 2005 and the Need Document was based on summer 2003 data. However, the analytical studies in BR-TA-8 were based on Winter 2005 data and did not include this load.

8 For example upgrading the line to full thermal capability

5 GENERAL ROUTING OF REQUIRED TRANSMISSION FACILITIES

5.1 General

The Board, in Appendix 8 of this Decision, has reviewed the generic planning process used by the TA to identify the need and the general routing of new facilities required to meet the need. The Board will provide its views respecting how the TA's planning process specifically affects the current applications.

The Board agrees with AE that the Board should not normally "get out ahead" of the TA's planning and development of appropriate long-term system additions. The Board agrees that this is particularly true in circumstances where the TA is currently conducting planning studies and refining its long-term planning strategies.

The Board considers that the long range plan to be developed by the TA will set out the timing for the economic, orderly and efficient development of the electric system including appropriate conditions for building with double circuit 240 kV towers or installing 500 kV lines that may initially be operated at 240 kV.

However, the Board is concerned that delay and uncertainty respecting the TA's long range plan may result in the foreclosure of future co-generation as a result of the lack of adequate and timely transfer-out capability. For example, the TA's consideration of the requirement for a fourth, i.e. East-West, line out of Fort McMurray must commence immediately considering construction can only occur during the winter seasons. The Board urges the TA to proceed expeditiously with the long-term plan.

The Board agrees with the TA that since a North-South double-circuit 240 kV line costs more than twice as much as a single circuit 240 kV line,[9] there does not appear to be any economic justification for pre-building for a second 240 kV circuit in the right-of-way for the proposed North-South facilities.

The Board also agrees with the TA that a 500 kV alternative is not a viable option for meeting the identified needs in a timely manner.

[9] See BR-TA-14 Supp, Table "Estimated Incremental Capital Costs For Double Circuit Tower Configurations".

5.2 Final Evaluation of Alternatives

The following table sets out a high level summary of the critical evaluation factors used to compare general routing alternatives:

Table 3. Comparative Summary of Critical Evaluation Factors for Alternatives per Board

Alternative	Supply Transfer-Out Capability (MW)[10]	Capital Cost ($ Million)	Revenue Requirement ($ Million)	Land Ownership for New Construction	Timing
North-South					
Proposed Project [11]	610	120.1	156.0	Private/Public	Aug 2004
Alt 4	580	121.6	162.9	Private/Public	Aug 2004
Alt 4 Opt 1	590	101.3	132.7	All Public	Aug 2004
Alt 4 Opt 2 [12]	610	101.3	132.7	All Public	Aug 2004
DD-NW1	630	209.4	249.2	Private/Public	2005
DD-NW2	610	178.0	207.1	Private/Public	2005
East-West		(Incl. Crow Lake Loop)			
Alt 1	580	197.2	223.4	Private/Public	Mar 2005
Alt 2	470	164.8	182.6	Private/Public	Mar 2005
Alt 3	470	130.0	167.6	Private/Public	Mar 2005
Alt 6	510	162.4	208.9	Private/Public	Mar 2005
Alt 7	530	136.7	183.1	Private/Public	Mar 2005

The Board established in the previous section of this Decision that a transfer-out capability of 595 MW was required to meet the Fort McMurray supply customer needs.

The Board considers that all of the East-West alternatives lack sufficient transfer-out capability from Fort McMurray to meet supply customer needs. Although Alternative 1 is close to meeting the required needs of supply customers, the cost is significantly higher than the cost of the Proposed Project.[13] Further, the East-West alternatives will not meet the forecast increased load growth in the Athabasca area without additional facilities similar to the Crow Lake and Athabasca 240 kV connections. Based on the evidence submitted, the Board believes that the East-West Alternatives would not be constructed in a timely manner to meet the urgent needs of supply customers in Fort McMurray.

However, the Board notes the interest in the East-West alternative for a fourth line by both supply customers and the TA. Further, the Board remains interested in this option for the additional reason of improving transmission reliability to NW Alberta and for addressing TMR costs in this region.

With respect to the North-South alternatives, the Board considers that the Proposed Project and Dover to Whitefish (Alternative 4 Option 2) both meet the required transfer-out capability and

10 See Appendix 7
11 Dover to Deerland
12 Referred to as Dover to Whitefish in this Decision
13 The Board notes that the TA agreed at Tr pg 276 that the East-West alternatives and DD-NW 1 and DD-NW 2 could be viewed as a step towards resolving the north west TMR. From this perspective, the East-West alternatives may not be higher a cost than the proposed project.

the expected load growth. Therefore, the Board agrees that a North-South routing is desirable but is not prepared at this stage to approve the receipt points as applied for.

Accordingly, the Board will carry out a more detailed comparison of the Proposed Project with the Dover to Whitefish Alternative (Alternative 4 Option 2) to evaluate which alternative would be the best routing.

5.3 Proposed Project and Alternative 4 Option 2 Evaluation Factors

Timing
The Board considers that timing should receive a heavy weighting in the evaluation of factors that lead to the Board's Phase I Decision. The Board notes the significant monetary losses that can result to Supply Customers in Fort McMurray if the transmission system is not upgraded to meet reliability standards as soon as possible.

The Board notes from Exhibit 2-23 that AE considers both the Dover to Deerland (Proposed Project) and the Dover to Whitefish (Alternative 4 Option 2) could be placed in service by August 2004. However, the Board acknowledges that the timing risk may be marginally higher if the Dover to Whitefish (Alternative 4 Option 2) were to be pursued because there is no specific application before the Board at this time for this alternative.

Transfer-Out Capability
The Board is satisfied that the Proposed Project and the Dover to Whitefish (Alternative 4 Option 2) provide equal transfer-out capability.

New Pipeline Load
The Board considers that the Proposed Project might be marginally better located to meet the probable location of the 35 MW portion of the southern load. However, the Board considers that the Dover to Whitefish (Alternative 4 Option 2) may also be well positioned to also meet the 35 MW portion of the southern load. If and/or when this load materializes, the Board considers that the TA's customer contribution policy will satisfactorily address any cost concerns that may arise under either the Proposed Project or the Dover to Whitefish (Alternative 4 Option 2).

Capital, Revenue Requirement and Right of Way Costs
The Board considers that the alternative with a materially lower cost should receive a high weighting in the evaluation process.

The Board considers that the Dover to Whitefish (Alternative 4 Option 2) appears to have a clear advantage respecting this evaluation factor. The Board does not see the evidence to support the TA's conclusion that all alternatives are higher cost than the Dover Deerland route.

The Board notes that AE, in Exhibit 2-23, suggested that the cost estimates provided for the Dover to Whitefish (Alternative 4 Options 1 and 2) do not have the same level of accuracy as the Dover to Deerland project. AE suggested the costs might only be accurate within a range of plus/minus 25%. The Board observes that the Dover to McMillan portion of the Dover to Whitefish (Alternative 4 Option 2) accounts for $61.6 million, which is relatively firm leaving $39.7 million subject to the plus/minus tolerance. Using a variance of 25%, the Dover to Whitefish (Alternative 4 Option 2) could vary by plus or minus $10 million to the $101.3 million estimate for the Dover to Whitefish (Alternative 4, Option 2). Even with this variance, the cost of the Dover to Whitefish (Alternative 4 Option 2) appears to be lower cost than the proposed Dover to Deerland project.

Use of Existing Infrastructure
The Board considers that the use of existing infrastructure should generally be encouraged.

AE's panel provided evidence of 35 km of pre-built existing infrastructure originally planned and installed for the purposes of constructing a future 240 kV circuit to Fort McMurray, with one side strung on double circuit towers. The Board notes the TA's statement that a fourth line may never be required and further that the preferred alternative for a fourth line may be an East-West line. Further, the Board notes that the TA's customers are paying for this unused capacity in the rate currently charged by the TA.

Landowner Issues
Generally, the Board considers that the alternative that results in the lowest probable landowner and environmental impacts should be chosen, if all other technical and cost considerations are equal.

The Board takes note of AE's, the TA's and other interveners' comments that landowners' issues should be dealt with in Phase II and the Board generally agrees with this statement. However, in comparing the receipt points of the two alternatives, the Board believes it has to take into account certain evidence presented at the Phase I hearing.

The Board notes that the Need Document does not include a consideration of the nature and use of the land affected by the transmission line in selecting a delivery and receipt point to meet identified needs. The TA, in its Need Document, appears to have relied solely on the technical merits of the various alternatives.

The Board notes the evidence[14] of AE that it is very difficult to avoid dealing with landowner issues when trying to come up with the best technical and economic solution and that landowner issues play a role and have always played a role in deciding on the best endpoints for a transmission enhancement.

AE's panel also advised the Board that the 35 km of pre-built facilities was on agricultural land and that, apart from this section, any new construction consistent with Alternative 4 would be on Crown land. AE stated that using the vacant space on existing double circuit line structures under Alternative 4 would likely diminish landowner issues. The Board would have expected the TA to consider these factors in its analysis of Alternative 4 in the Need Document and to recognize that costs estimates did not have to include a new line to be constructed along this 35 km portion of Alternative 4.

The Board agrees with AE that landowner issues should play a role and have always played a role in deciding on the best endpoints for a transmission enhancement. The Board considers that high level landowner issues should play a role in the selection of an appropriate route in the Phase I proceeding.

[14] Tr pg 999

In this instance and considering the evidence to date, the Board considers that the Dover to Whitefish (Alternative 4 Option 2) appears to have a clear advantage respecting this evaluation factor. The new construction would all be on public (i.e. Crown) land and stringing of conductors on existing structures that traverse privately owned agriculture land is expected to have less surface impact than the construction of new facilities on a new route that traverses privately owned agricultural land.

Consistency with Long Term Plan

The Board acknowledges the concern raised by the TA in Exhibit 2-23 that "The TA cannot at this time confirm that Alternative 4A, Alternative 4 Option 1 or Alternative 4 Option 2 will not create additional problems or the need for additional reinforcements elsewhere on the AIES."

Ideally, interested parties and the Board should be clear how the proposed project and/or the Dover to Whitefish (Alternative 4 Option 2) fit with the overall long-term plan of the AIES. In an ideal world, with no timing constraints, the Board considers that these concerns, along with double circuit 240 kV and 500 kV issues in the North East and elsewhere on the AIES, would be addressed in the TA's long-term plan. The Board considers that timing concerns are such that the Board's Decision cannot wait for a comprehensive long-term plan.

In the absence of such a long-term plan, the Board notes from the 2002 Transmission Development Plan (TDP) that load in the Cold Lake Area is expected to grow by some 60 MW over the period 2003-2011. The Board observes that the Dover to Whitefish (Alternative 4 Option 2) is well positioned to address this possible increase in load.[15]

The Board notes that reliability was one of the reasons that the TA chose Deerland for an endpoint for the third line. The TA stated[16] it was trying to avoid transporting the energy over the two existing 240 kV lines (which are on a double circuit tower) from Whitefish to Deerland.[17]

The Board also notes that the TA indicated in the 2002 Transmission Development Plan[18] that such selective N-2 reliability considerations have not been adopted as part of the AIES reliability criteria and are the subject of further study and review of risks and reinforcement costs.

The Board accepts that a third line at this point in time is needed. The TA, in its argument, appears to consider the Alternative 4 routings to be viable as a potential fourth line as appears from the following quote:

> even if an additional 240kV North-South circuit is the preferred alternative for a fourth line out of Fort McMurray, it could be constructed separately while still reducing impacts on agriculture. Constructing the fourth line along the route proposed by Alternative 4(a), where it would connect with the existing double-circuit 240kV line approximately 35 kilometers north of Whitefish, would virtually avoid any new construction on agricultural land. Note that the existing double circuit already crosses most of the agricultural land along that route.[19]

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15 The Board recognizes that the amount of Cold Lake co-generation and load is uncertain at this point in time.
16 Tr Pg 169
17 Whitefish to Deerland circuits have not been identified load flow analysis as being overloaded under N-1 post contingency events
18 Page C-2
19 TA Argument page 13

The Board considers that the Alternative 4 routings should be also considered for the third line, not only the fourth line.

5.4 Summary of Evaluation Factors

The following table summarizes the Board's preliminary evaluation based on the evidence at this point of the critical factors used to compare the Proposed Project with the Dover to Whitefish (Alternative 4, Option 2):

Table 4. Board Summary of Proposed Project / Alt 4 Option 2 Evaluation Factors

Evaluation Factor	Proposed Project (Dover Deerland)	Alternative 4 Option 2 (Dover Whitefish)
Timing	Advantage	Disadvantage (Marginally higher risk of delay)
Transfer-Out Capability	Neutral (610 MW)	Neutral (610MW)
Southern portion of New Pipeline Load	Advantage (Marginally better situated although a new pipeline load at Lac La Biche or Winefred Lake would likely eliminate this advantage)	Disadvantage (Although a new pipeline load at Lac La Biche or Winefred Lake would likely eliminate this disadvantage)
Capital Cost	Disadvantage	Advantage (Lower by approximately $20 Million)
Right of Way Costs	Unknown (However, higher proportion on private lands)	Unknown (However, lower proportion on private lands)
Amount of Public/Private Land	Disadvantage (Due to higher proportion of private lands)	Advantage (Lower due to higher proportion of public lands)
Use of Existing infrastructures	Disadvantage	Advantage (Uses existing double circuit towers originally planned for third line to Fort McMurray)
Agricultural Land Impact	Disadvantage (Higher proportion of private land)	Advantage given less distance on agricultural land
Fit with Long Term Plan	Neutral	Neutral

Weighing all of the above evaluation factors, the Board concludes, on the basis of the information currently on the record, that the Dover to Whitefish (Alternative 4 Option 2) appears to be superior to the Dover to Deerland (Proposed Project) in terms of meeting the needs and satisfying the financial, technical and general routing issues required to be resolved in Phase I of these proceedings as set out in Decision 2003-017.

Based on the evidence currently on the record, the Board is satisfied that the Dover to Whitefish (Alternative 4 Option 2):

- Could likely be placed in service by August 2004.
- Has the capability to meet the Fort McMurray transfer-out need.
- Has the capability to meet the forecast growth (excluding new pipeline growth in the Fort McMurray area and Athabasca area).
- Is well positioned to meet the expected 2005 new pipeline growth of 35 MW in the northern portion of the Fort McMurray to Fort Saskatchewan corridor the location of which is not known.
- Is satisfactorily positioned to meet the expected 2005 new pipeline growth of 35 MW in the southern portion of the Fort McMurray to Fort Saskatchewan corridor, the location of which is not known.

- Utilizes existing infrastructure (i.e. 35 km of vacant double circuit tower space) that is currently in rate base and being paid for by customers.
- Potentially has lower landowner impacts since the construction of new infrastructure would be entirely on public (i.e. Crown) lands.
- Has a capital cost approximately $20 million less than the proposed project.
- Has less right of way leases on private lands.

The Board notes that the Dover to McMillan application is common to the Proposed Project (i.e. Dover to Deerland) and Alternative 4 Option 2 (i.e. Dover to Whitefish). For this reason, the Board is prepared to approve the Dover to McMillan end points of AE's first application. The specific routing (i.e. "west proposed" or "east proposed") of the Dover to McMillan application will be dealt with in the Phase II Part A hearing, if required. The Board will issue an amended Notice to deal with AE's first application that removes the McMillan to Charron section from the Part A proceeding. Further, the Board will include in its amended Notice that it may approve the Dover to McMillan application without further Notice in the absence of bona fide objections.

The second application (i.e. the McMillan to Charron section) will be moved to Part B of the hearing. This should partially address issues raised by the Charron landowners respecting the inclusion of the Charron substation in the Phase A part of the proceeding.

Accordingly the Board sets down the following Schedule for Phase II Part A:

Table 5. Board Approved Revised Phase II Hearing Schedule (Dover to McMillan), Part A

	Revised Phase II Schedule	**Current Phase II Schedule**
IRs to Applicant (Phase II, Part A)	April 29, 2003	April 17, 2003
Responses from Applicant to IRs (Phase II, Part A)	May 13, 2003	April 29, 2003
Intervener Evidence (Phase II, Part A)	May 20, 2003	May 20, 2003
Rebuttal Evidence (Phase II, Part A)	May 26, 2003	May 26, 2003
Phase II Hearing Part A (Application No. 1284230 – Dover to McMillan)	May 27, 2003	May 27, 2003

However, as a result of the above Board findings, the Board refers AE's second application (i.e. McMillan to Charron) and third application (i.e. Charron to Deerland) back to the TA and AE. The Board expects the TA and AE to proceed with preparations to evaluate and prepare the Dover to Whitefish (Alternative 4 Option 2) for further detailed consideration immediately.

The Board agrees with AE's submission that the Board has broad powers pursuant to section 19 of the *Hydro and Electric Energy Act*, to decide and prescribe as precisely as it considers suitable the location and route of a transmission line. However, the Board considers that it may only exercise this power once an application has been filed. For that reason, the Board would propose three process options to the TA and AE as follows:

1. Amend the McMillan to Charron and Charron to Deerland applications by replacing these applications with a McMillan to Whitefish application.
2. Amend the McMillan to Charron and Charron to Deerland applications to include a McMillan to Whitefish application as an alternative routing to be formally considered at the hearing.

3. Retain the McMillan to Charron and Charron to Deerland applications but include a supplement to these applications explaining why a McMillan to Whitefish routing is not a viable alternative.

If the TA and AE select the first or second process option, then they will need to provide a proposed filing date for the amended applications, together with their suggested revised hearing process steps that would be required to achieve a similar in-service date as the Dover to Deerland project assuming that an oral proceeding may be required. Under the first and second option, it may not be necessary for the TA to be present at the Phase II proceeding to address need or general routing. For clarity, the Board in this Decision, has determined that either Dover to Deerland or Dover to Whitefish represent acceptable end-points.

If the TA and AE select the third option, then the Board requires that a supplement to the existing Dover to Deerland application be included explaining why the Dover-Whitefish general routing is not a viable alternative. The Board will require the TA to be present at the Phase II Part B hearing to address its portion of the supplement to the application. The Board intends to fully examine the advantages and disadvantages of the Dover to Whitefish Alternative against the Proposed Project.

In addition, the Board expects the following information to be included in the supplement to the application:

- The TA/AE's assessment of the Board's preliminary evaluation of the advantages and disadvantages of the two routes in substantive detail.
- The collection and organization of evidence already on the record in the Phase 1 portion of this proceeding as it relates to the two routes (i.e. Dover to Deerland versus Dover to Whitefish).
- Economic analysis that demonstrates that the Dover to Whitefish Alternative would cause the present worth of future additional reinforcements elsewhere on the system to be materially in excess of the apparent cost advantage of Dover to Whitefish compared to Dover to Deerland.

In addition, as a result of concerns expressed in the Phase I portion of the hearing and as part of AE's expressed intent to address landowner concerns, the Board recognizes that AE may make amendments to the Dover to Deerland route to address landowner issues in the Phase II Part B hearing.

Again, for clarity, the Board wishes to emphasize that both the Dover to Deerland project and the Dover to Whitefish Alternative appear to meet the identified supply and demand needs in a reasonable manner and for that reason the Board has decided on the above approach.

The Board also wishes to be clear that no further Need Document or Phase I hearing is required for either the Proposed Project or the Dover to Whitefish Alternative (Alternative 4 Option 2) or variants of the same. More specifically, no further Need Document and Phase I hearing is required for the modified routes, including stringing the second circuit on the existing 240 kV double circuit structures from Whitefish to the transition point.

Further, the Board expects that AE will proceed as necessary and prudent to achieve the necessary transfer-out capability in a timely manner.

The Board directs the TA and AE to advise the Board and all interested parties on or before **May 19, 2003** whether the McMillan to Charron and Charron to Deerland applications will be amended.

If the McMillan to Charron and Charron to Deerland applications are not amended, the Board sets down the following Schedule for Phase II Part B:

Table 6. Board Approved Revised Phase II Hearing Schedule, Part B provided the McMillan to Charron Applications are not Amended

	Revised Phase II Schedule	Current Phase II Schedule
IRs to Applicant (Phase II, Part B)	May 26, 2003	April 17, 2003
Responses from Applicant to IRs (Phase II, Part B)	June 2, 2003	April 29, 2003
Filing of Supplemental Information	May 26, 2003	N/A
IRs on Supplemental Information	June 2, 2003	N/A
Responses from Applicant to Supplemental Information IRs	June 4, 2003	N/A
Intervener Evidence (Phase II, Part B) incl Intervener Evidence on Supplemental Information	June 6, 2003	May 20, 2003
Rebuttal Evidence (Phase II, Part B) incl Rebuttal Evidence on Supplemental Information	June 9, 2003	May 26, 2003
Phase II Hearing Part B (Application No. 1284228 – McMillan to Charron and Application No. 1284240 – Charron to Deerland)	June 10, 2003	June 10, 2003

The Board will select the location of the Phase II Part B hearing following the advice from the TA and AE on whether the existing McMillan to Charron and Charron to Deerland applications will be amended.

6 SUMMARY OF BOARD APPROVALS

7 SUMMARY OF BOARD DIRECTIONS/EXPECTATIONS

This section is provided for the convenience of readers. In the event of any difference between the Board's expectations and directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. However, as a result of the above Board findings, the Board refers AE's second application (i.e. McMillan to Charron) and third application (i.e. Charron to Deerland) back to the TA and AE. The Board expects the TA and AE to proceed with preparations to evaluate and prepare the Dover to Whitefish (Alternative 4 Option 2) for further detailed consideration immediately.. 17
2. The Board also wishes to be clear that no further Need Document or Phase I hearing is required for either the Proposed Project or the Dover to Whitefish Alternative (Alternative 4 Option 2) or variants of the same. More specifically, no further Need Document and Phase I hearing is required for the modified routes, including stringing the second circuit on the existing 240 kV double circuit structures from Whitefish to the transition point. 18
3. The Board directs the TA and AE to advise the Board and all interested parties on or before **May 19, 2003** whether the McMillan to Charron and Charron to Deerland applications will be amended. 19

Dated in Calgary, Alberta on April 23, 2003.

ALBERTA ENERGY AND UTILITIES BOARD

(original signed by)

A.J. Berg, P. Eng.
Presiding Member

(original signed by)

J. R. Nichol, P. Eng.
Member

(original signed by)

N. W. MacDonald, P. Eng.
Acting Member

APPENDIX 1 – PARTIES PARTICIPATING IN THE PROCEEDINGS

Name of Organization Principals and Representatives	Witnesses
ATCO Electric Ltd. (AE) L. G. Keough S. M. Munro	K. Kadis A. Lai
Transmission Administrator (TA) D. Holgate	D. McMaster N. Brausen F. Ritter
AltaLink Management Ltd. S. Lee	
Buffalo Lake Metis Settlement B. McElhanney	
Canadian Natural Resources Limited (CNRL) **Petro-Canada Resources (Petro-Canada)** **TransAlta Corporation (TransAlta)** **TransCanada Energy Ltd. (TransCanada)** **(The Co-generation / Oil Sands Developers)** B. Andriachuk	D. Way V. Kosteksy G. Murray E. Wittstock J. Roberts D. Mitchell D. Chesterman
ATCO Power Ltd. J. Lowe	
Suncor Energy Inc. and Syncrude Canada Ltd. K. Hughes A. W. Carpenter	
TransCanada Energy Ltd. A. L. Ross	
Treaty 8 First Nations (Treaty Eight) J. Graves	
Waskatenau Landowner Interests J. W. Bodnar R. Strom	**Panel 1 North Central Surface Rights/Waskatenau Landowners** D. Trenholm, B. Feniak K. Phillips, B. Rozak D. Moschansky, L. Shwetz D. Kurylo **Panel 2 Waskatenau Landowners** J. Baschuk, J. Baschuk W. Domke, E. Breadon-Peiche P. Lashcuk, A. Laschuk H. West **Panel 3 Waskatenaeu Landowners (Charron Group)** K. Kachur, N. Kachur L. Chamzuk, A. Chamzuk

Name of Organization Principals and Representatives	Witnesses
Saddle Lake First Nation R. Secord P. Brertton	E. Large D. Brertton F.Wahsatnow
Victorian Home Guard Historical Society H. West	H. West M. Bielish B. Sadoway
Landowners (Svitch and Chopadylo) D. Carter M. Carter	
T. Lysyk (For Herself)	
Alberta Energy and Utilities Board Staff L. LaCasse, Board Counsel T. Chan R. Schroeder J. Hamre R. Guzman W. Taylor J. Soon	

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APPENDIX 2 – ABBREVIATIONS

“AIES” means “Alberta’s Interconnected Electric System” as that term is defined in the EU Act.

“AESO” means Alberta Electric System Operator.

“Cogeneration” means generation of electricity from steam, heat or other forms of energy produced as a by-product of another.

“CM” means Congestion Management.

“EU Act” means the *Electric Utilities Act*, RSA 2000, c. E-5.

“HEEA” means *Hydro and Electric Energy Act.*

“Interconnection” refers to the facilities that connect two control areas or AIES zones.

“ISO” means Independent System Operator.

“Losses” means electric energy losses in the electric system.

“MCR” means Maximum Continuous Rating. MCR is the maximum net power output that can be sustained by a generator over a long period.

“RAS” means Remedial Action Scheme.

“RFP” means Request for Proposal.

“STS” means Supply Transmission Service.

“TA” means Transmission Administrator.

“TA Tariff” means the Transmission Administrator’s Rate Schedules and Terms and Conditions, as approved by the Board.

“TDP” means Transmission Development Plan.

“TFO” means Transmission Facilities Owner.

“TMR” or “Transmission Must-Run” means Constrained On dispatch of a Generating Unit to a specific level in accordance with a Dispatch Instruction to maintain System Security.

“TPG” means Transmission Planning Guidelines.

“ZIC” means Zonal Interconnection Charge.

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APPENDIX 3 – HISTORY OF THE DOVER-DEERLAND APPLICATION

The following is an excerpt from Information Request WASK-LANDOWNER-TA-20.

On 25 May 1999, Alberta Energy issued the Transmission Planning Guidelines (the "TPG"). Section 4.3.1 of the TPG required that a competition be conducted, at the discretion of the TA, to identify the TFO that would own and build certain transmission facilities, including new 240 or 500 kV transmission lines.

Appendix A of the TPG, which sets out the mechanics of the competitive procurement or direct assignment processes, outlined a "general competitive process model" that involves the TA setting the functional specifications for a new project, conducting an RFP, evaluating bids and selecting the successful TFO. The TFO would then make application to the EUB for the facilities.

The TPG provides the TA with two mutually exclusive options:

i) entering into a long-term contract with the TFO and seeking to have that contract approved by the EUB pursuant to the *Transmission Administrator Deficiency Correction Regulation* (AR 150/2000, replacing AR 163/98);

ii) have the successful TFO apply for the new facility and also apply for a cost of service regulated tariff.

The TA identified the need for a solution to the voltage and system access problems in the Fort McMurray/Athabasca area as early as 1999. In December 1999 when the 2000-2009 Transmission Development Plan was published, it was considered that a line from the Fort McMurray area to Lubicon would be sufficient. However, load and supply in the Fort McMurray area were growing so that by the time the 2001-2010 Transmission Development Plan was released in December 2000, a three-stage line from Ruth Lake (near Dover) to Deerland was the preferred solution.

It was intended that a 240 kV line would be constructed down from Ruth Lake to Crow Lake and another 240 kV line constructed between Deerland and the Athabasca area. The third stage of the solution, which would connect the other two stages, was to be constructed at a future time when it became necessary. However, it soon became clear that rapid development in the Fort McMurray area would require the third stage sooner than expected and that the three-stage solution should be constructed as one project.

Final design of the solution produced the Dover to Deerland project for which an RFP was issued on 14 September 2001 for an in-service date of 31 March 2003. On 25 March 2002 the TA executed a contract with ATCO Utility Services Ltd. for construction of the proposed line by the proposed in-service date.

On 15 May 2002 an application was filed with the EUB under the *Transmission Administrator Deficiency Correction Regulation*, as contemplated by the TPG, for an order binding future TA's to the long-term contract with ATCO Utility Services. However, on 7 August 2002 Alberta Energy suspended the competitive procurement process in the TPG and directed the TA to re-assign four contracts that had been awarded through competitive procurement, including the contract with ATCO Utility Services Ltd for the Dover-Deerland project. On 22 October 2002 the Board denied the application under the *Transmission Administrator Deficiency Correction Regulation* for reasons other than need. As noted in the AE application, on 30 October 2002 the Dover-Deerland project was re-assigned to AE.

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APPENDIX 4 – NORTH-SOUTH EVALUATION FACTORS

General

A number of North-South Alternatives were considered and examined by AE and the TA in the proceeding, which are shown below:

Proposed Line

The proposed 240 kV single-circuit transmission line consists of three segments including Dover to McMillan, McMillan to Charron, and Charron to Deerland. See Appendix 6 Proposed Plan Map.

Alternative 4 Option 2

Alternative 4 Option 2 consists of a 240 kV single-circuit transmission line from Dover to McMillan, McMillan to a substation designated as Point X (located in the vicinity where 9L990 and 788L crossover) and a new transmission line from Point X substation to Whitefish Lake. This Alternative would utilize the vacant side of existing double-circuit transmission line 9L990 for 35 km. See Appendix 6 Alternative 4 Option 2 Map.

Alternative 4 Option 1

Alternative 4 Option 1 consists of a 240 kV single-circuit transmission line from Dover to McMillan, a new transmission line from McMillan to Lac La Biche 2, and a new transmission line from Lac La Biche 2 to Whitefish Lake. This Alternative would utilize the vacant side of existing double-circuit transmission line 9L990 (35 km) See Appendix 6 Alternative 4 Option 1 Map.

Alternative 4

Alternative 4 consists of a 240 kV single-circuit transmission line from Dover to McMillan and a 240 kV single-circuit from McMillan to Whitefish Lake. This option differs from Options 1 and 2 in that in that it would be necessary to construct a double circuit 240-kV line from Charron to the McMillan to Whitefish line. See Appendix 6 Alternative 4 Map.

DD-NW 1

Alternative DD-NW 1 consists of the Proposed Line as well as a 240 kV transmission line from Mitsue to Lubicon, Lubicon to Wesley Creek and Wesley Creek to Hotchkiss. See Appendix 6 DD-NW 1 Map.

DD-NW 2

Alternative DD-NW 2 consists of the Proposed Line as well as a 240 kV transmission line from Mitsue to Lubicon and Lubicon to Wesley Creek. See Appendix 6 DD NW 2 Map.

Critical Factors and Technical Details for North-South Alternatives

A summary of critical factors and technical details of the North-South alternatives is shown in the summary chart below. Details and analysis of the NW1 and NW2 options, line accessibility, land-use and environmental issues for the North-South alternatives follow the summary chart.

Source BR-TA-25	Proposed Proj	Alternative 4	Alternative 4 Options	DD/NW 1	DD/NW 2
Financial Considerations					
Capital Cost	120 million	126.6 million	101.3 million	209.4 million	178 million
Revenue Requirements including TMR (all projects)	156 million	162.9million	132.7 million (used 101.3 million in BR-TA-8 spreadsheet)	249.2 million	207.1 million
Technical Consideration					
Steady State	No overloads, voltages with-in limits	No overloads, voltages with-in limits	Voltage below acceptable limits, 788L overloaded*	No overloads, voltages with-in limits	No overloads, voltages with-in limits
N-1 Dynamic	Stable	Stable	Information N/A	Stable	Stable
Voltage Stability	Voltages within operating limits	Voltages within operating limits	Voltage below acceptable limits, 788L overloaded*	Voltages within operating limits	Voltages within operating limits
Transfer Capability (MW)	620	590	600	610	600
Limiting Factor on Transfer Capability	Minimum 240 kV at Leismer	Minimum 248 kV at Mitsue	Minimum 248 kV at Mitsue	Minimum 248 kV at Mitsue and 240 kV at Leismer	Minimum 240 kV at Leismer
Line Length (Total km)	422	351	Information N/A	791	643
System Losses (MW)	414.6	418.7	Information N/A	408.4	408.1
Supply Reliability	Meets criteria, better reliability to Crow Lake and Athabasca Loads	Meets criteria, better reliability to Crow Lake and Athabasca Loads	Information N/A	Meets criteria, better reliability to Crow Lake radial feeds	Meets criteria, better reliability to Crow Lake radial feeds
Double Circuit vs. Single Circuit transfer capability	200 MW increase	200 MW increase	Information N/A	200 MW increase	200 MW increase
Double Circuit vs. Single Circuit additional cost	206 million	207.4 million	Information N/A	299.3 million	267.9 million
Ability to Meet Supply Growth	25 MW capacity margin	Does not meet need	5 MW Capacity margin	15 MW capacity margin	5 MW capacity margin
Ability to Meet Load Growth in NE	Best option	2nd best option	Less that proposed (base case) for future load serving	Best option	Best option
Ability to Meet Load Growth in NW	N/A	N/A	N/A	NW additions enhance NW	NW additions enhance NW

*If the Forecast 70 MW of new pipeline Load is included and equally divided between the Flat Lake and Crown lake substations.

Line Accessibility/Operational and Maintenance Issues

AE noted that the proposed line had many good access points, as this route is generally close to Highway 63 or developed areas. Line accessibility for Alternative 4 south of McMillan to Whitefish veers from highway 63 and appears to have poor access, crossing a substantial area of wet/muskeg conditions.

With respect to Alternative 4 Options 1 and 2, AE noted that there appears to be suitable locations on Crown land for a 240/138 kV substation at either location.

Landowner Issues

AE noted that the proposed line is approximately 422 km in length, 180 km of which is located on wet/muskeg lands. AE indicated that there are approximately 225 landowners along this route.

With respect to Alternative 4, AE indicated that the route from Charron to a tap point on the McMillan – Whitefish line would traverse approximately 15 km of agricultural land beginning at the Charron end and then 45 km of Crown land for a total of 60 km.

With respect to Alternative 4 Option 1, AE noted that in order to locate the substation next to an all season road for operator access, the 240 kV line from McMillan would cross about 4 km of agricultural land used for grazing. AE noted that a substation at Point X of Alternative 4 Option 2 would be located on Crown Land.

Environmental Issues

AE noted that both the proposed line and Alternative 4would traverse approximately 180 km of wet/muskeg. AE also noted that there would be a high probability that the wet/muskeg portion could be constructed under frozen ground conditions in one winter, minimizing environmental impacts.

Timing Issues

AE stated that its estimated in-service date for the proposed line would be July/August, 2004.

With respect to Alternative 4, approvals would be required by August 1, 2003, in order to complete the project by July/August, 2004.

With respect to Alternative 4 Options 1 and 2, AE indicated that it could have the line in service by August 31, 2004 as long as the Dover to McMillan route is approved, and a new need statement and Phase 1 hearing are not required. As well approval to string the second circuit would be required in time to complete the work during the winter of 2003-2004.

AE noted, however, that if the above conditions were not met, the in-service date for Options 1 and 2 could be delayed until March 31, 2005.

Reasons for Including the NW1 and NW2 Options

The TA noted that the electric system in the Rainbow Lake and High Level areas is characterized by long 144 kV and 240 kV transmission lines connecting loads to generation. The system is generally radial with a low degree of redundancy of transmission paths. Some 144 kV transmission lines are heavily loaded and consequently have high transmission losses. The outage of a single transmission line or a local generator can result in voltage depressions outside of acceptable limits.

Because of the area's remoteness from any major source of generation and limited transmission capacity into the area, system security is maintained by ensuring certain local generation is running at all time, i.e. Transmission Must Run ("TMR").

Reducing the amount of TMR requires additional transmission capacity into the area. Extending the 240 kV network north towards Rainbow Lake would most efficiently do this. The need for TMR could be eliminated by the construction of a 240 kV double circuit line between Wesley Creek and Rainbow Lake, with an intermediate interconnection at Keg River.

Views of the Parties

ATCO Electric

AE submitted that the proposed Dover to Deerland line provided the best solution to satisfy the needs identified by the TA and meet the projected in-service date. AE acknowledged that routes such as the Alternative 4 options had a reasonable chance of being able to be constructed and available for operation within the same time frame.

Transmission Administrator

The TA submitted that none of the alternatives discussed during the hearing are superior to the proposed facility. All of the alternatives have a higher capital cost and a lower transfer capability than the proposed facility and all but one (Alternative 4) fail to meet the needs of future load growth. The other North-South alternatives that were discussed in Exhibit 2-23 (TA) are totally unsatisfactory from a system perspective. As noted in Table 2-23-TA-2 of Exhibit 2-23 (TA), none of the "Alternative 4A Type Options" would meet the load growth requirements in the Athabasca area.

The TA submitted that DD-NW1 and DD-NW2, although referred to as "alternatives" are not really alternatives at all and are better characterized as examples of how the proposed facilities could fit into the overall system development, including potential future augmentation in Northwest.

The Waskatenau Group

The Waskatenau Group submitted that it is apparent from the general routing of the proposed line by the TA and the Applicant, that the agriculture implications were given very little, if any priority.

The Waskatenau Group submitted that given the magnitudes of oil and gas production in conjunction with the planned co-generation, there should be a full environmental impact assessment completed in the approval process.

The Waskatenau Group further submitted that parties in the vicinity of the Charron substation have not been provided with clear information regarding the project's requirements and routing. The Waskatenau Group also contended that AE was not clear on the legislated safety requirements to ensure safety of agricultural and industrial operations under the proposed transmission line. The Landowners near the proposed Charron Substation took the position that the need analysis and public consultation were fundamentally deficient and therefore the TA and the Applicant should start from the beginning to demonstrate the integrity of the project.

The Waskatenau Group supported the Alternative 4A Options arising from Exhibit 2-23 (without the Charron Substation and its associated 240 kV loop), subject to the Applicant gaining the appropriate legislative and affected interest approvals. The Waskatenau Group submitted that the Alternative 4A Options meet the immediate and reasonable long term needs of the oil and gas producers and the co-generators, and compliment the AIES without undue impact to agriculture, the environment, and other public and private interests. The Waskatenau Group stated that these alternatives provide an opportunity for construction of a transmission line west from Ft. McMurray to compliment the electricity needs of northwestern Alberta in accordance with the AIES. Finally, the Alternative 4A Options allow for development of other transmission lines with the increased capacities expected to be required for delivery of co-generation produced electricity to markets.

Saddle Lake First Nation and Buffalo Lake Metis Settlement

The Saddle Lake First Nation and Buffalo Lake Metis settlement indicated that they are opposed to the general route as it goes through their area of concern. They indicated that they would leave it to the Board to determine whether there may be a better route overall in the scheme of things, i.e. East-West.

The Saddle Lake First Nation and Buffalo Lake Metis settlement indicated that if the Board decided on a North-South route, then it would participate in the Phase II Part B hearing dealing specifically with configuration of the transmission line route.

Suncor and Syncrude

Suncor and Syncrude submitted that both a North-South and an East-West line are required to meet the TA’s service and reliability requirements in the Fort McMurray area.[20]

Suncor and Syncrude noted however that it did not have confidence in the timing projections that have been put forward with respect to various alternatives. However, Suncor and Syncrude noted that even ignoring timing issues, a single circuit east-west line would not solve transmission issues in the Fort McMurray area. Suncor and Syncrude therefore submitted that the Dover-Deerland line should be approved and built now.

[20] Exhibit 22-2, BR-Suncor-1

Views of the Co-generation / Oil Sands Developers

The Co-generation / Oil Sands Developers stated that the Board should approve the proposed line instead of the alternative options as it would be cheaper and would meet the required in-service date.

The Co-generation / Oil Sands Developers also noted that the TA has indicated that the alternative options would not provide adequate support to the Athabasca area if new pipeline load developed.

APPENDIX 5 – EAST-WEST EVALUATION FACTORS

General

The East-West Alternatives examined in this proceeding were referred to as follows:

Alternative 1

Alternative 1 consists of a 240 kV transmission line from Dover to Hotchkiss and a 240-kV transmission line from Hotchkiss to Wesley Creek. While these lines would provide additional transfer capability out of the Fort McMurray area, they would not address the load requirements in the Crow Lake and Athabasca areas. To resolve these issues, Alternative 1 includes a 240/144-kV substation at Crow Lake connected by a double circuit 240-kV transmission line to Leismer, and a 240/144-kV substation at Charron connected by a double circuit transmission line to 9L990. See Appendix 6 Alternative 1 Map.

Alternative 2

Alternative 2 consists of a 240-kV transmission line from Dover to Wesley Creek. This alternative would provide additional transfer capability out of the Fort McMurray area but would not address the load requirements in the Crow Lake and Athabasca areas. Alternative 2 includes a 240/144 kV substation at Crow Lake connected by a double circuit 240 kV transmission line to Leismer, and a 240/144 kV substation at Charron connected by a double circuit transmission line to 9L990. See Appendix 6 Alternative 2 Map.

Alternative 3

Alternative 3 is similar to Alternative 2 except it provides a lower capital cost alternative to the Crow Lake and Charron 240/144 kV step down substations. This alternative includes a 240/144 kV substation at Hanging Stone connected by a double circuit 240 kV transmission line to transmission line 9L990, and a 240/144 kV substation at the junction of transmission line 9L990 and transmission line 788L. For reference the proposed substation is referred to as East Lac La Biche. See Appendix 6 Alternative 3 Map.

Alternative 6

Alternative 6 was suggested in Board Information Request No.1 to the TA (BR-TA-8). It would include a 240 kV transmission line from Dover to Hotchkiss and from Hotchkiss to Wesley Creek. See Appendix 6 Alternative 6 Map.

Alternative 7

Alternative 7 was also suggested in Board Information Request No.1 to the TA (BR-TA-8). It would be similar to Alternative 6 except it would not include the portion from Hotchkiss to Wesley Creek. See Appendix 6 Alternative 7 Map.

Critical Factors and Technical Details for East-West Alternatives

A summary of critical factors and technical details of the East-West alternatives are shown in the summary chart below. Details and analysis of line accessibility, land-use and environmental issues for the East-West alternatives follow the summary chart.

Source BR-TA-25	Alternative 1	Alternative 2	Alternative 3	Alternative 6	Alternative 7
Financial Considerations					
Capital Cost	197.2 million	164.8 million	130 million	162.4 million	136.7 million
Revenue Requirements including TMR (all projects)	223.4 million	182.6 million	167.6 million	208.9 million	183.1 million
Technical Considerations					
Steady State	No overloads, voltages with-in limits	No overloads, voltages with-in limits	No overloads, voltages with-in limits	No overloads, voltages with-in limits	No overloads, voltages with-in limits
N-1 Dynamic	Stable	Stable	Stable	Stable	Stable
Voltage Stability	Voltages within operating limits	Voltages within operating limits	Voltages within operating limits	Voltages within operating limits	Voltages within operating limits
Transfer Capability (MW)	580	480	520	550	570
Limiting Factor on Transfer Capability	Minimum 248 kV at Mitsue	Minimum 248 kV at Mitsue	Minimum 248 kV at Mitsue	Minimum 248 kV at Mitsue	Minimum 240 kV at Leismer
Line Length (Total km)	644	498	362	508	360
System Losses (MW)	405.9	406.3	405	404.7	406.7
Supply Reliability	Meets criteria, better reliability to Crow Lake and Athabasca Loads	Meets criteria, better reliability to Crow Lake and Athabasca Loads	Meets criteria, poorer reliability to Crow Lake radial feeds	Meets criteria, poorer reliability to Crow Lake radial feeds	Meets criteria, poorer reliability to Crow Lake radial feeds
Double Circuit vs. Single Circuit transfer capability	200 MW increase	200 MW increase	200 MW increase	200MW increase	200 MW increase
Double Circuit vs. Single Circuit additional cost	251.6 million	219.8 million	185 million	214.4 million	192.5 million
Ability to Meet Supply Growth	Does not meet need	Does not meet need	Does not meet need	Does not meet need	Does not meet need
Ability to Meet Load Growth in NE	3rd best option	3rd best option	Poorest option	Poorest option	Poorest option
Ability to Meet Load Growth in NW	Best alternative	Alternative 1 is best option	Alternative 1 is best option	Alternative 1 is best option	Alternative 1 is best option

Line Accessibility/Operational and Maintenance Issues

AE stated, for the Dover to Hotchkiss segment of Alternatives 1, 6, 7, and for the Dover to Wesley Creek segment for Alternatives 2, and 3, that there are few access points, generally poor ground, and traveling conditions along most of the right of way.

For the Hotchkiss to Wesley Creek Segment in Alternatives 1 and 6, approximately 35% of the right of way is wet/muskeg conditions.

AE indicated that the Leismer to Crow lake segment of Alternatives 1, and 2 would have wet/muskeg conditions on most of the ROW. For segment 9L990 to Charron in Alternatives 1 and 2, AE indicated that there would be good access and right of way expected on any alignment south of Lac La Biche.

Landowner Issues

AE did not provide an estimate of the number of land interest holders and given the general characteristics of the route (less agriculture, more Crown land), for all East-West alternatives, AE estimated the number of landowners would be few. However, the potential for land related issues was difficult to assess without more detailed study.

Environmental Issues

AE stated that all the East-West alternatives had a large percentage of wet/muskeg conditions. AE noted that if the project could be constructed entirely under frozen ground conditions, the environmental impacts would be minimized.

AE stated that the potential for environmental impacts during emergency repairs in wet/muskeg areas under non-frozen ground conditions is proportional to the amount of wet/muskeg route length.

Views of Interested Parties

ATCO Electric

AE indicated the in-service date with two winter constructions, and no Phase II hearing would be March 31, 2005 for all East-West Alternatives. With one winter construction and no phase II hearing the in-service date would be July/August 2004.

Transmission Administrator

The TA indicated that there are four major points against the East-West alternatives:

- Timing
- Significant new supply would connect to minimal load growth
- Lack of sufficient transfer capability
- Higher capital costs

With respect to TMR requirements, the TA indicated that studies as to how this could be accomplished in the northwest of the province, particularly the Rainbow area, have not been optimized.

ATCO Power

ATCO Power indicated that the East-West alternatives are considerably more expensive than the proposed project.[21]

ATCO Power also indicated that the East-West alternatives would place a 2004 in service date in jeopardy, with these alternatives only remotely possible."[22] Furthermore ATCO Power submitted that the TA's evidence is clear that none of the East-West alternatives would meet the AIES Supply Growth.[23]

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21 BR-TA-25.

22 Transcript Volume 3, pages 513-515.

23 BR-TA-25, Attachment 1 North-South versus East-West Evaluation Factors

ATCO Power requested that the Board not overstate the benefit of reduced TMR payments and, at the same time, fail to take account of the costs of achieving the supposed TMR reduction. ATCO Power noted that the amount of forecast TMR expenses in the Rainbow Lake area might well be materially overstated.

AltaLink

AltaLink noted that a number of alternative transmission projects have been discussed in the course of the proceeding. AltaLink noted, however, that AE had not applied for any alternative projects, including an East-West line of any circuit design or voltage.

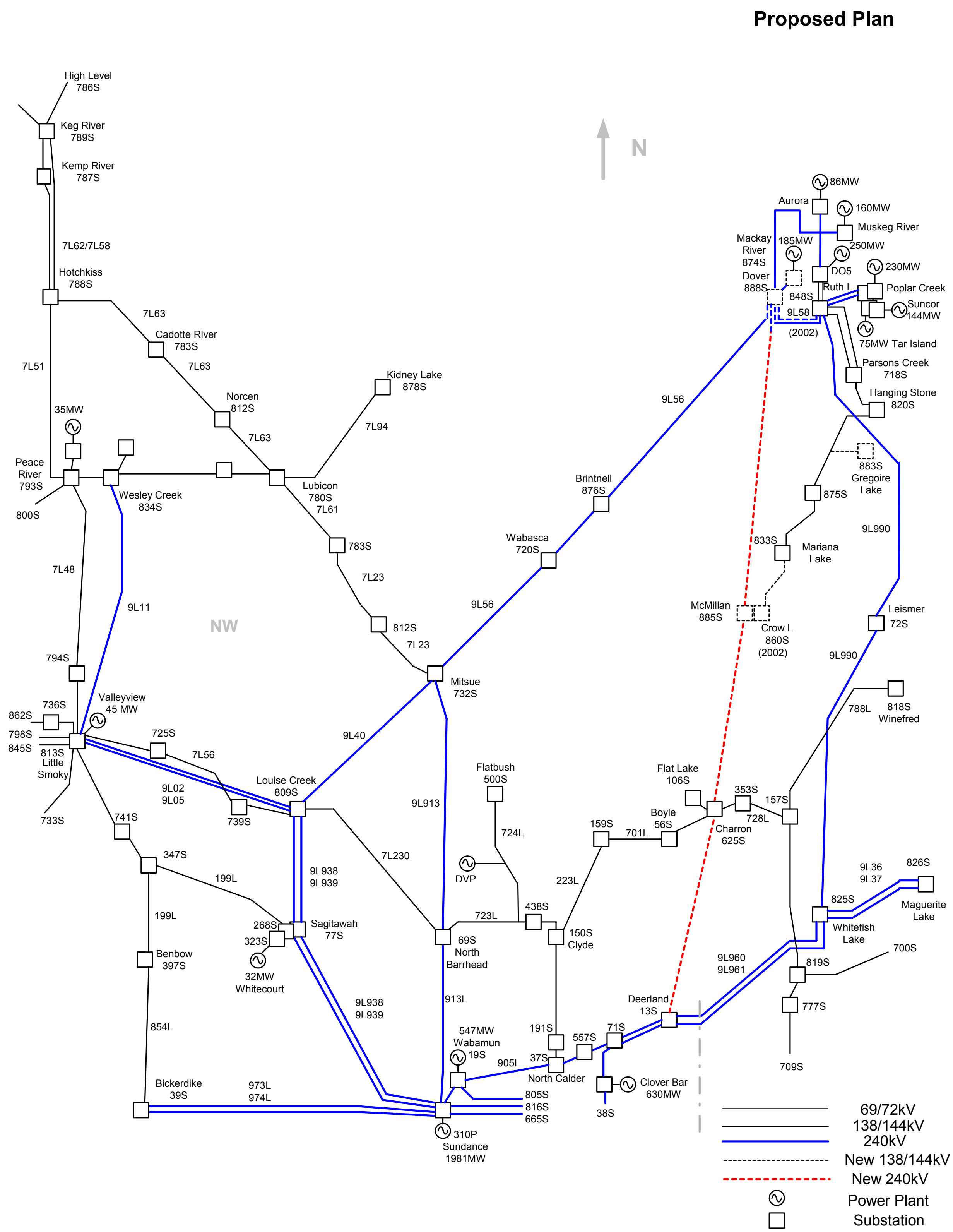
Views of Co-generation / Oil Sands Developers

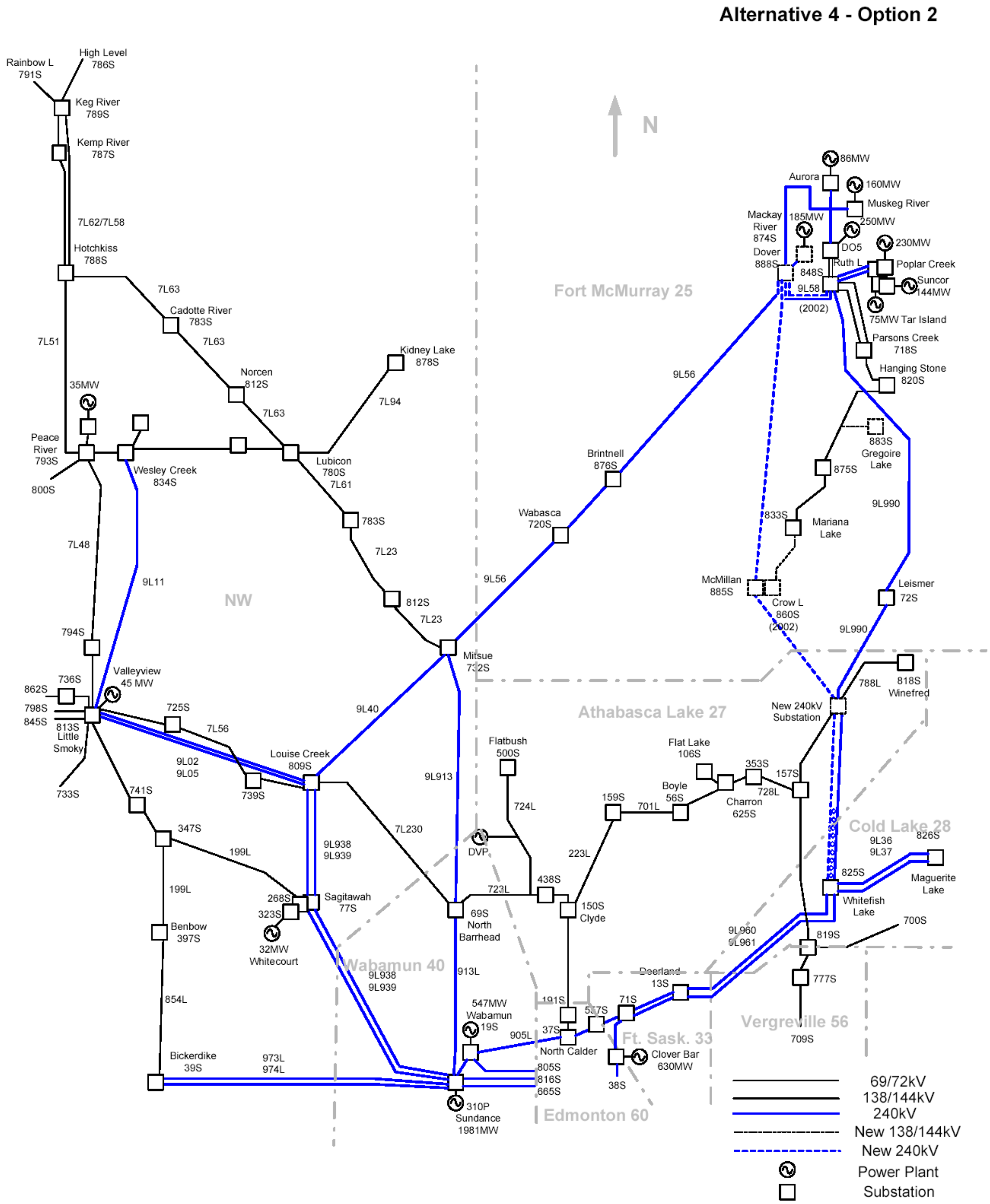
With respect to timing, the Co-generation / Oil Sands Developers noted that AE indicated it would be “highly risky” and unlikely that an East-West line would be in–service with a one year construction period and therefore submitted that little if any weight should be put on the possibility of AE achieving an East-West line in-service date prior to March 2005.

The Treaty Eight First Nations of Alberta (Treaty 8)

The Treaty eight considered that East-West alternatives provided transmission service in an area of the Province that currently did not receive. Treaty eight indicated that the alternatives connecting Fort McMurray to Hotchkiss had the potential for community development opportunities for Northern communities, could serve industrial load in the north, and were well positioned to serve industrial load in this area.

APPENDIX 6 – ALTERNATIVE ROUTINGS EXAMINED IN PHASE 1 PROCEEDING

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High Level 786S
Keg River 789S
Kemp River 787S
7L62/7L58
Hotchkiss 788S
7L63
Cadotte River 783S
7L51
Norcen 812S
Kidney Lake 878S
7L94
35MW
Peace River 793S
800S
Wesley Creek 834S
Lubicon 780S
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783S
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Mitsue 732S
9L56
Brintnell 876S
Wabasca 720S
Valleyview 45 MW
736S
862S
798S
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813S Little Smoky
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725S
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9L02 9L05
739S
Louise Creek 809S
9L40
9L913
Flatbush 500S
724L
741S
347S
199L
7L230
9L938 9L939
DVP
Benbow 397S
268S
323S
32MW Whitecourt
Sagitawah 77S
69S North Barrhead
723L
438S
150S Clyde
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547MW Wabamun 19S
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North Calder
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Clover Bar 630MW
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Flat Lake 106S
Boyle 56S
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New 240kV Substation
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Crow L 860S (2002)
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883S Gregoire Lake
Hanging Stone 820S
Parsons Creek 718S
75MW Tar Island
Suncor 144MW
Poplar Creek
230MW
Ruth L
DO5
250MW
Muskeg River
160MW
Aurora
86MW
Mackay River 874S
185MW
Dover 888S
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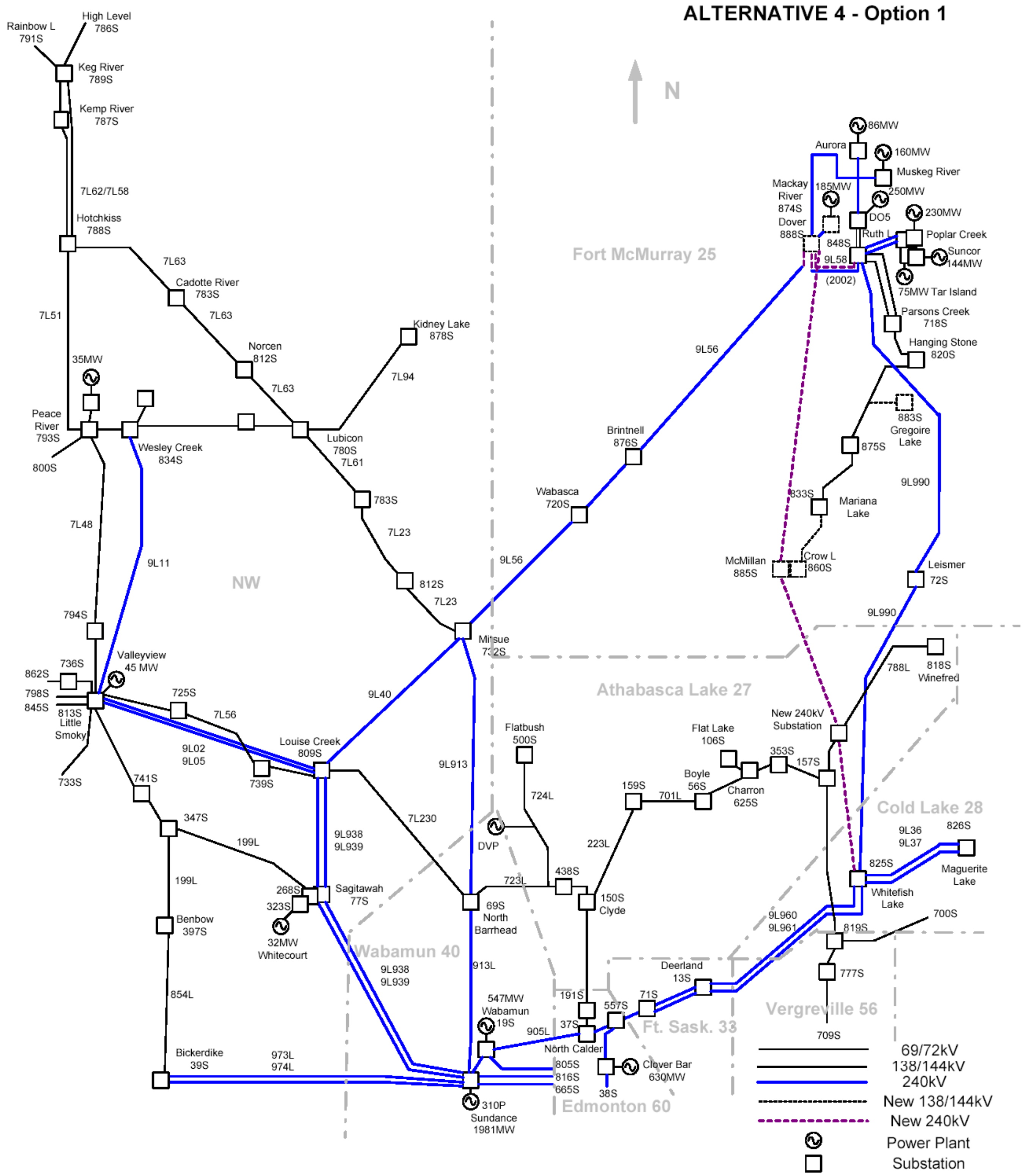
New 240kV
Power Plant
Substation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High Level 786S
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Kidney Lake 878S
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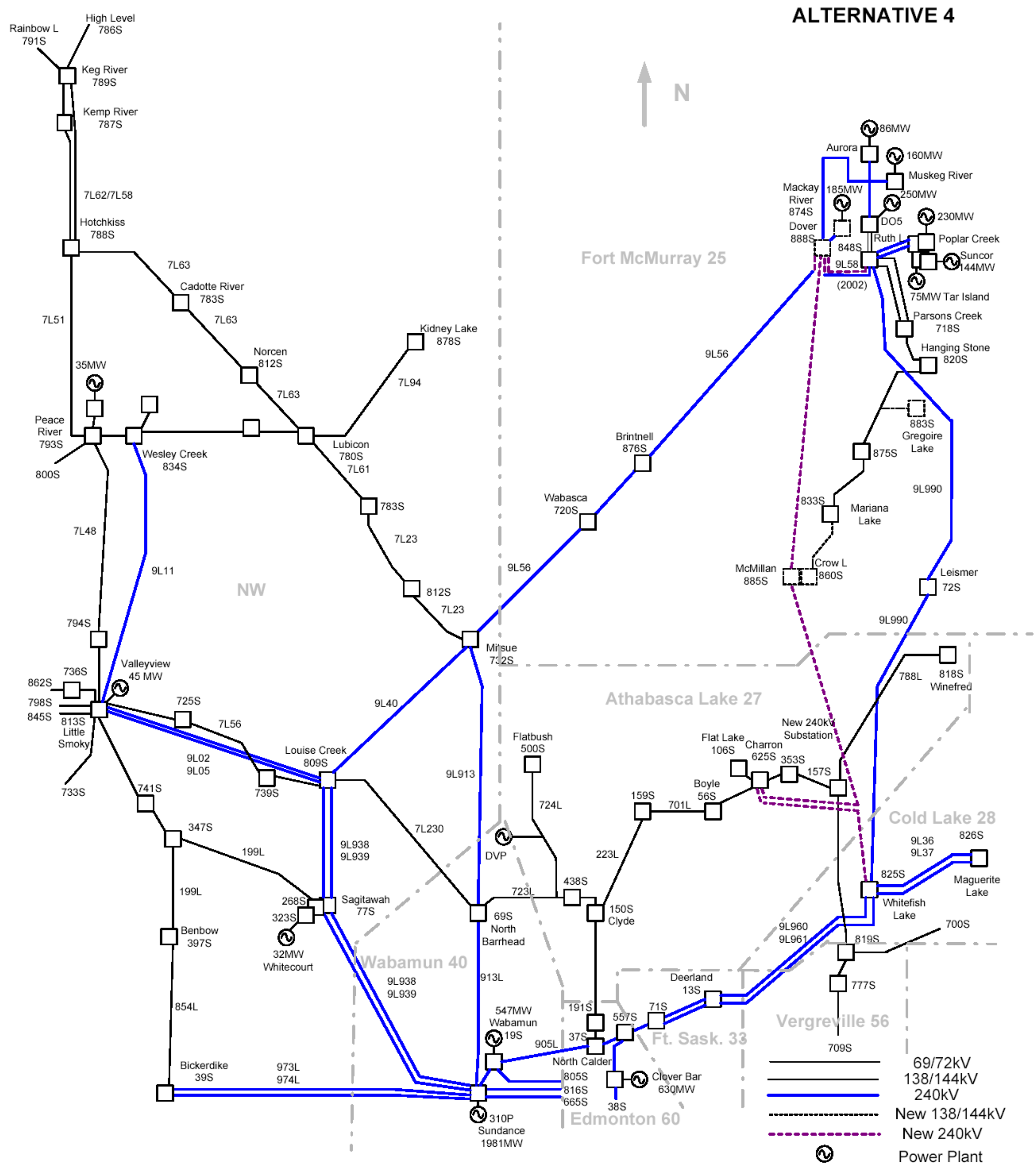
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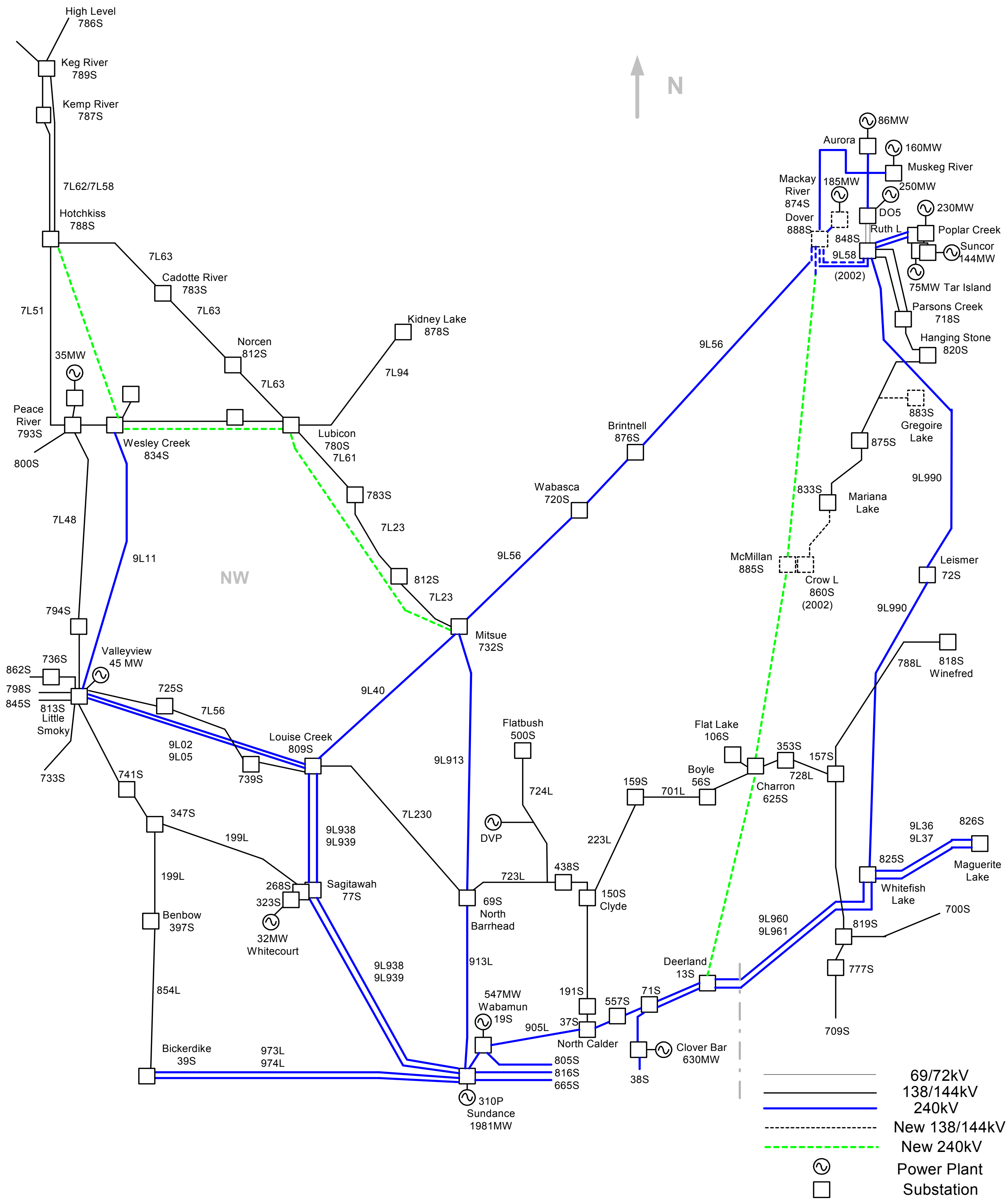
DD-NW1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Substation

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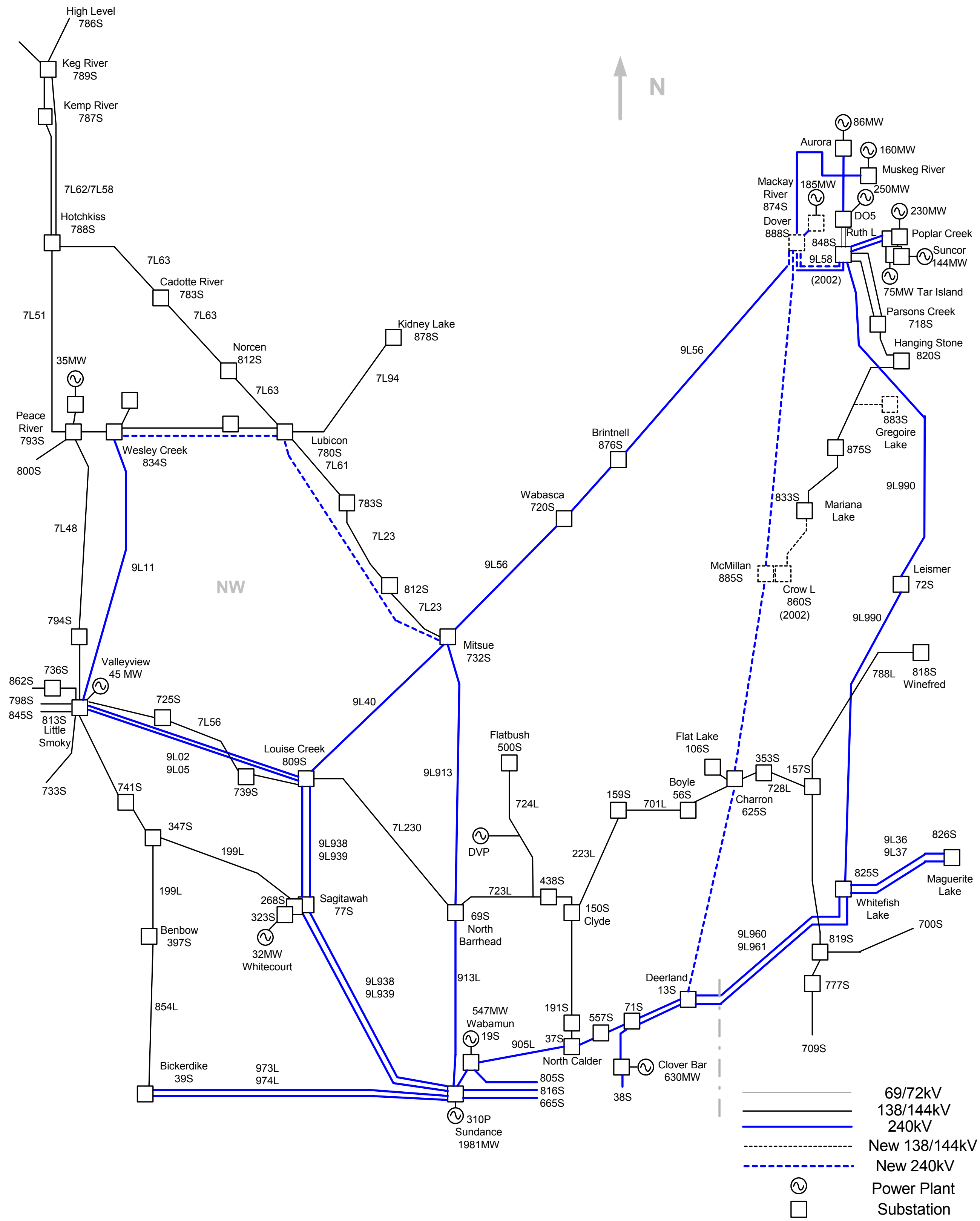
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Poplar Creek
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Muskeg River
160MW
Aurora
86MW
Mackay River 874S
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Dover 888S
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(2002)
9L56
Brintnell 876S
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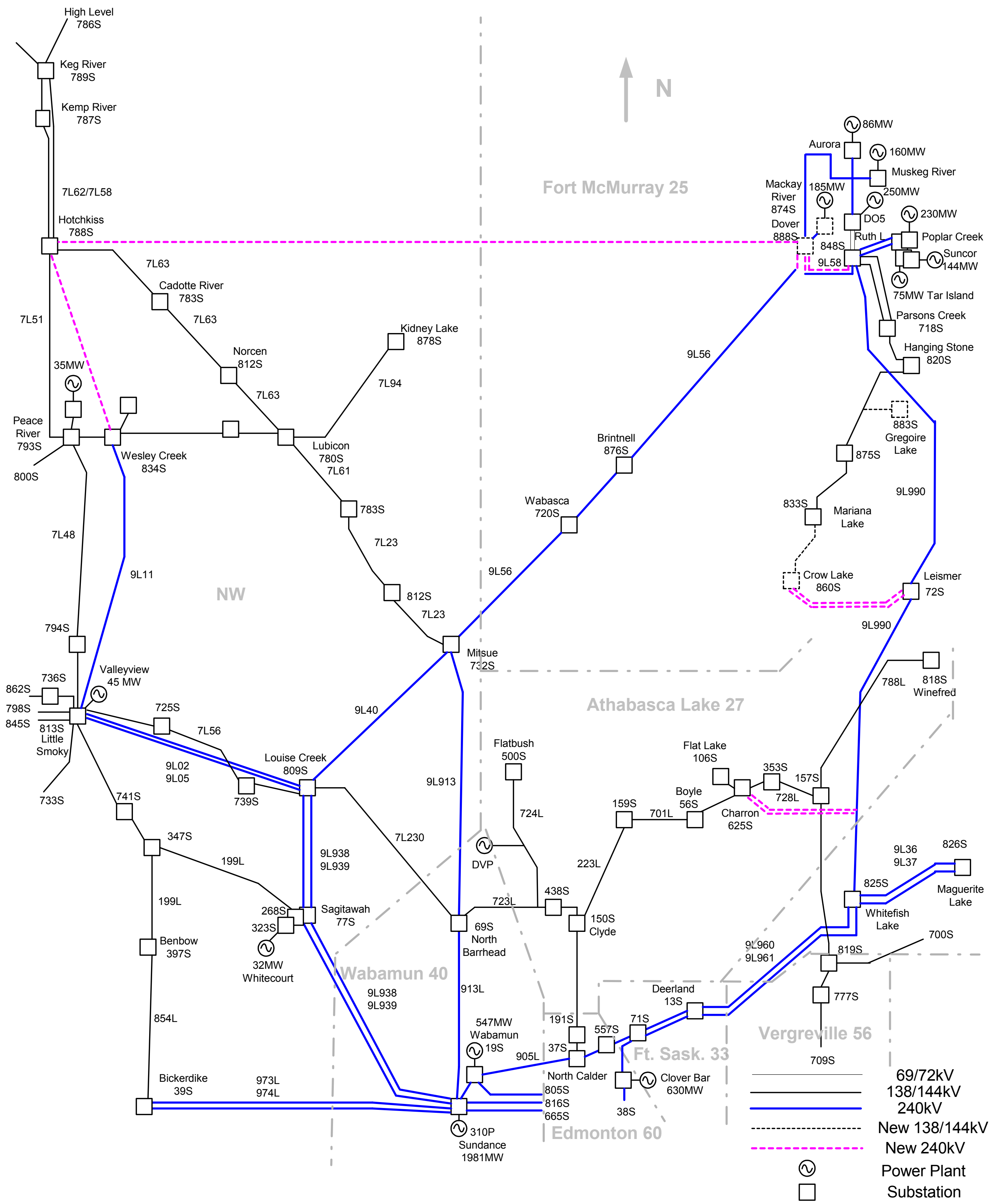
Power Plant
Substation

ALTERNATIVE 1



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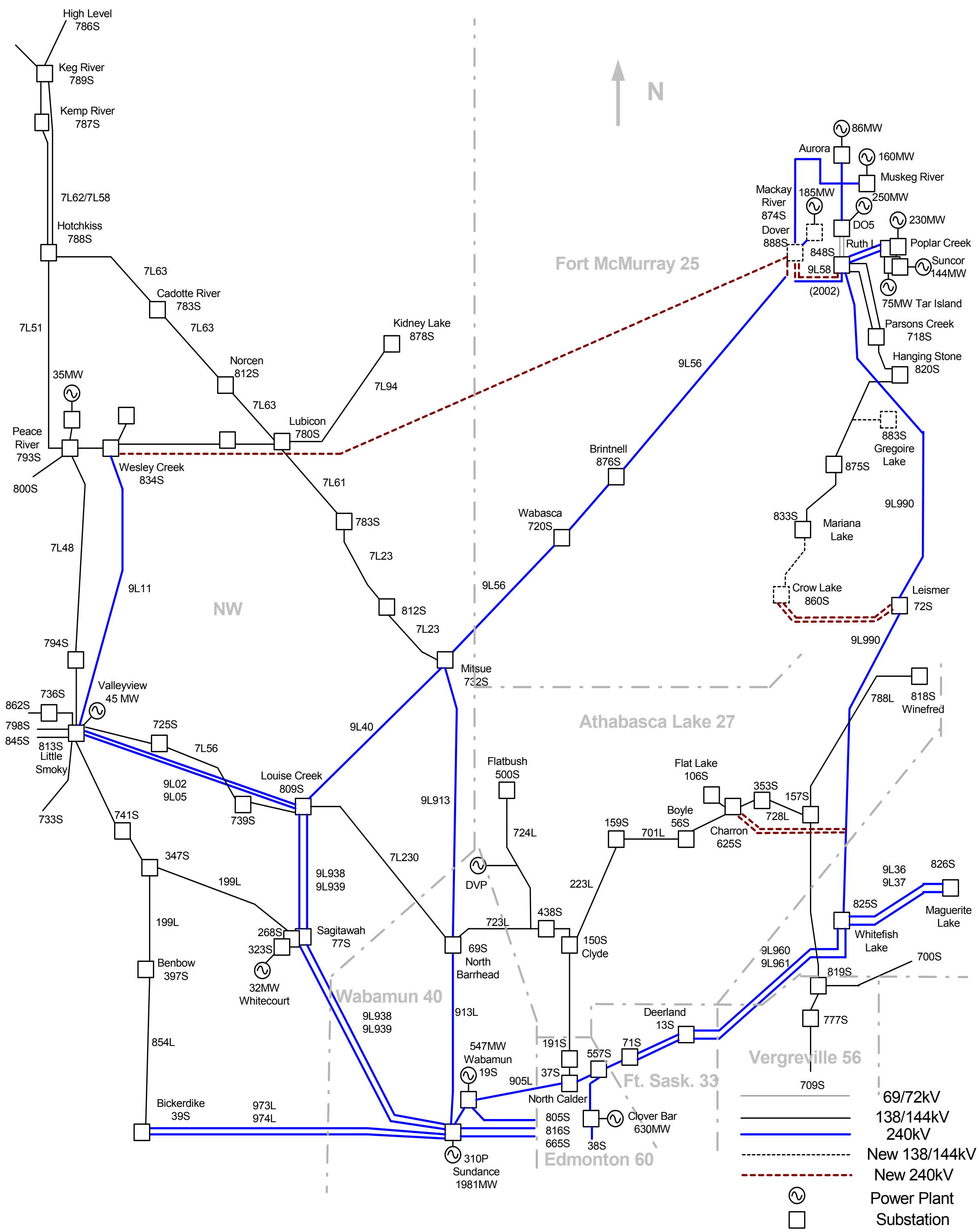

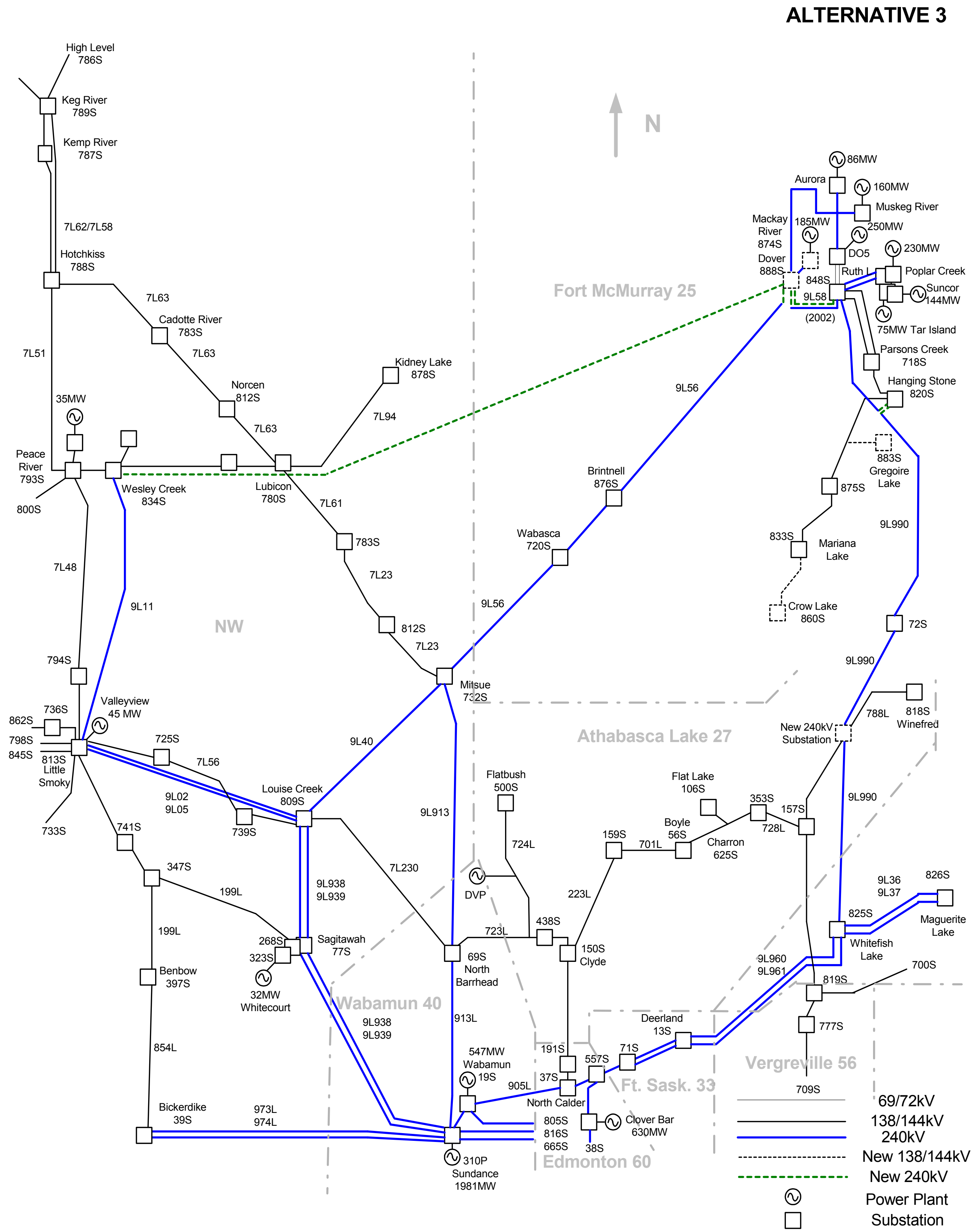
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Norcen 812S
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Kidney Lake 878S
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35MW
Peace River 793S
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Wesley Creek 834S
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Valleyview 45 MW
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Louise Creek 809S
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Mitsue 732S
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7L230
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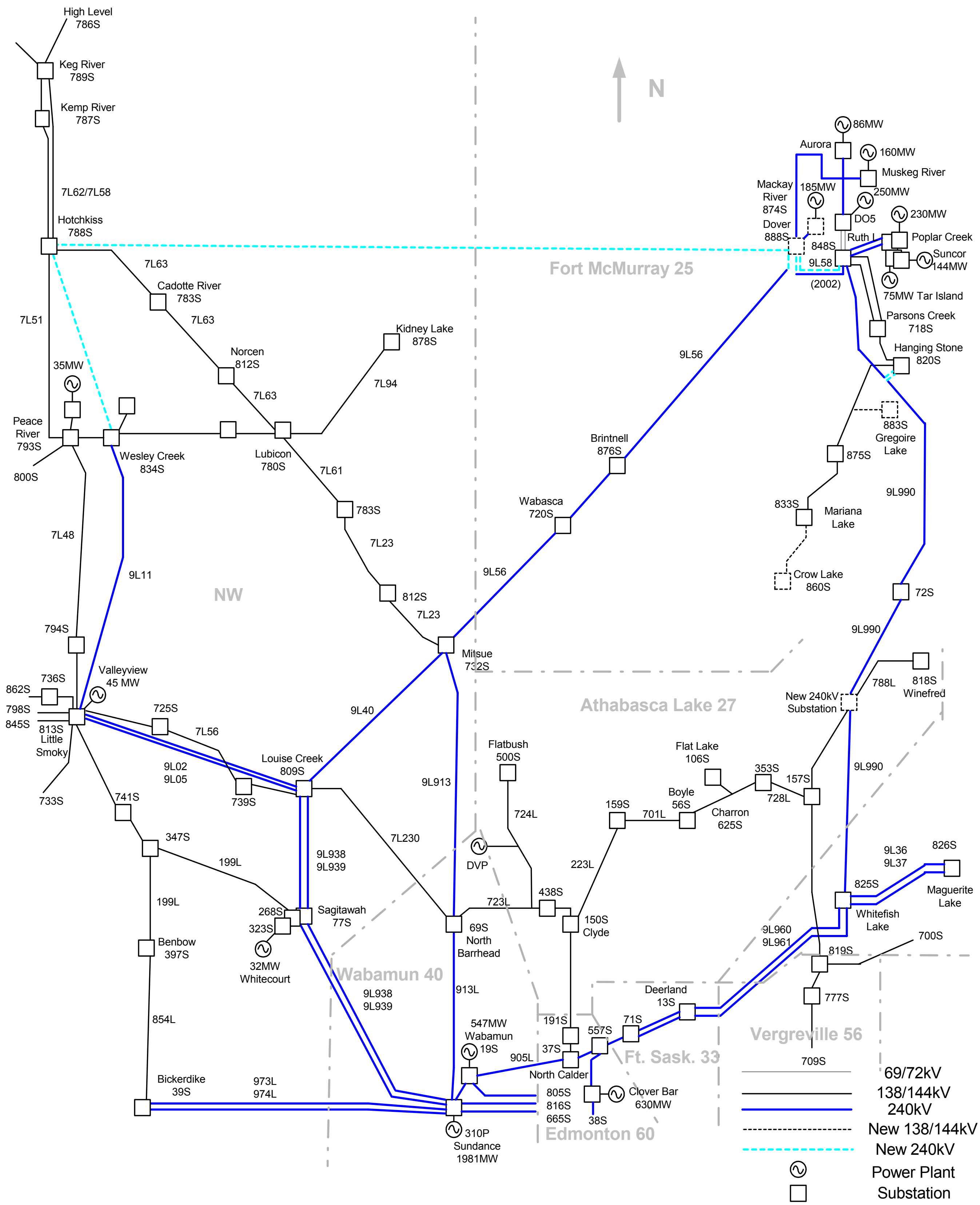
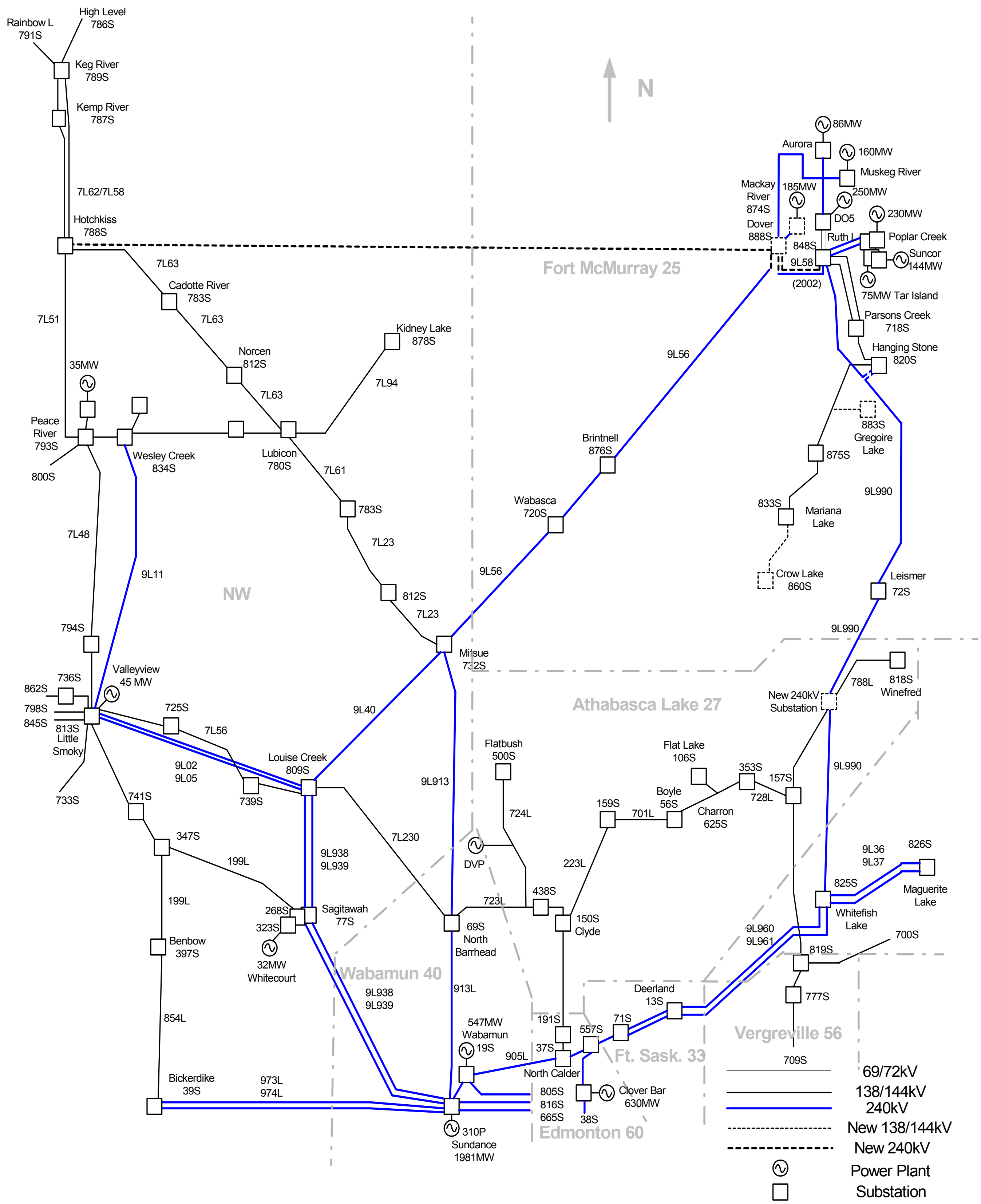
Sagitawah 77S
268S
323S
32MW Whitecourt
Benbow 397S
854L
Wabamun 40
9L938 9L939
913L
69S North Barrhead
Bickerdike 39S
973L 974L
547MW Wabamun 19S
905L
310P Sundance 1981MW
Fort McMurray 25
9L56
Brintnell 876S
Wabasca 720S
9L56
Flatbush 500S
724L
DVP
723L
438S
223L
150S Clyde
159S
701L
Boyle 56S
Flat Lake 106S
Charron 625S
353S
728L
157S
Athabasca Lake 27
191S
37S
North Calder
805S 816S 665S
557S
71S
Deerland 13S
38S
Clover Bar 630MW
Edmonton 60
Ft. Sask. 33
Vergreville 56
709S
777S
819S
700S
9L960 9L961
Whitefish Lake
825S
9L36 9L37
826S
Maguerite Lake
9L990
New 240kV Substation
788L
818S Winefred
9L990
72S
9L990
Crow Lake 860S
833S
Mariana Lake
875S
883S Gregoire Lake
Hanging Stone 820S
Parsons Creek 718S
75MW Tar Island
Suncor 144MW
Poplar Creek
230MW
Ruth L
DO5
250MW
Muskeg River
160MW
Aurora
86MW
185MW
Mackay River 874S
Dover 888S
848S
9L58
(2002)
69/72kV
138/144kV
240kV
New 138/144kV
New 240kV
Power Plant
Substation

ALTERNATIVE 6



ALTERNATIVE 7



APPENDIX 7 – DEFINITION AND CALCULATION OF TRANSFER-OUT CAPABILITY

The Board notes that the TA did not provide any information on the record setting out the method used to determine the transfer-out capability of various alternatives or the supporting load flow figures to support the transfer-out capabilities. The Board considers it important that the transfer-out capability of the various alternatives be calculated on the same basis in order to ensure an “apples” to “apples” comparison. Further the Board considers it important to define what is meant by the transfer-out capability.

The Board considers that Exhibit 3-19 properly sets out the method of calculating transfer-out need being:

- The available generating capacity less onsite load, to a maximum of contracted STS capacity,
- Less the load forecast for the City of Fort McMurray and surrounding area.

The transfer-out capability must be sufficient to meet the above transfer-out need under the most severe N-1 post contingency. The TA has identified the loss of the transmission line 9L57 as the most severe contingency in BR-TA-8, BR-TA-17 and Exhibit 2-23 for all alternatives and the Proposed Project.

Accordingly it follows that the proper method of determining the transfer-out capability for each alternative is to examine the corresponding load flows on the remaining two 240 kV lines following an N-1 9L57 contingency, as well as considering whether there is an additional transfer-out or transfer-in from/to the 144 kV distribution system lines serving the load in the City of Fort McMurray and surrounding area.

Accordingly, the Board has obtained the transfer-out capability for each alternative directly from the Winter 2005 load flow analysis for each alternative and set these out in the chart below. The Board has used the post contingency 9L57 load flows and summed the transfer-out on the two remaining lines as well as adding or subtracting the transfer-out or transfer-in from/to the 144kV system serving Fort McMurray city and surrounding load area.

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		Transfer-Out Capability Calculations Per Board						**Transfer-Out Capability Per-TA**	
North/South Alternatives	Reference	New NS	9L990	Crow Lake	Hanging Stone	Total	Rounded		
Proposed Project	Figure BR-TA-17-3	294	306	7.9	0.0	607.9	**610**	BR-TA-17	**610**
Alternative 4	Figure 2-23-TA-44	252	332	0.5	0.0	584.5	**580**	BR-TA-25	**590**
Alternative 4 Option 1	Figure 2-23-TA-45	277	306	5.4	0.0	588.4	**590**	Figure 2-23-TA-45	**600**
Alternative 4 Option 2	Figure 2-23-TA-46	285	318	5.1	0.0	608.1	**610**	Figure 2-23-TA-46	**600**
DD-NW-1	Figure BR-TA-8-3	301	317	9.4	0.0	627.4	**630**	BR-TA-8	**610**
DD-NW-2	Figure BR-TA-6	294	306	7.9	0.0	607.9	**610**	BR-TA-8	**600**
East/West Alternatives									
		New EW							
Alternative 1	Figure BR-TA-8-9	258	313	6.9	0.0	577.9	**580**	BR-TA-8	**580**
Alternative 2	Figure BR-TA-8-12	231	243	-3.6	0.0	470.4	**470**	BR-TA-8	**480**
Alternative 3	Figure BR-TA-8-15	236	272	0.0	-37.6	470.4	**470**	BR-TA-8	**520**
Alternative 6	Figure BR-TA-8-18	240	305	0.0	-33.5	511.5	**510**	BR-TA-8	**550**
Alternative 7	Figure BR-TA-8-21	196	362	0.0	-27.4	530.6	**530**	BR-TA-8	**570**

APPENDIX 8 – PLANNING FOR TRANSMISSION FACILTIES

Views of the TA

The TA submitted that the circumstances in Fort McMurray present the transmission planner with considerable difficulty. Volatility of the generation forecast in particular, and to a lesser extent of the load forecast, creates uncertainty as to how much transmission will be required and when.

The TA noted that most of the discussion of the proposed facility focused on the transfer capability out of Fort McMurray. From the perspective of existing and potential STS customers, transfer capability is a critical factor supporting the need for the proposed facility, but it is not the only factor. The proposed facility is a response to a number of transmission planning issues. It is important to ensure that the focus on transfer capability does not divert attention from the other factors supporting the need for the proposed facility, particularly the requirement to reliably serve load and consistency with overall planning of the transmission system.

The TA submitted that it does not construct transmission facilities to meet the total STS and DTS contracts on the system. Rather, the TA takes into account diversity, particularly in the deep system. The TA plans the system in order to meet its contractual commitments, but recognizes that all customers will not require their full contract demands at the same time. However, while diversity can be relied upon to average flows for purposes of planning the deep system, it is a lesser factor the closer one gets to the points of supply and delivery.

Views of ATCO Electric

AE submitted that the legislative responsibilities of the TA to plan the transmission system should be given considerable deference. It is the TA that identifies the requirement for additional transmission facilities and takes reasonable and prudent steps to ensure that these facilities are put in place in a timely fashion so that all eligible persons may indeed have a reasonable opportunity to exchange electric energy through the AIES. While the Board retains a residual jurisdiction to approve any specific facilities application brought before it (in order to ensure that such facilities are in the economic, orderly and efficient development and operation, in the public interest, of transmission facilities in the province of Alberta) AE submitted that the Board should approach any situation where it would engage in detailed system planning, in a manner that is inconsistent with the position of the TA, very carefully.

Views of the Board

The AIES is a transmission network designed to transmit energy from multiple generators (or supply customers) to multiple loads (or demand customers).

The TA's responsibilities have been thoroughly canvassed in Board Decision 2002-099. For purposes of clarity, the Board has included, in this Decision, relevant findings and elaborations.

Under the *Electric Utilities Act*, the Government of Alberta appoints a company to act as the TA.[24] The TA is required to provide system access service on the AIES in a manner that gives all eligible persons wishing to exchange electric energy through the Power Pool a reasonable opportunity to do so.[25] Eligible persons include both generators and loads.[26]

The Board considers that the TA has discharged its obligation to provide a reasonable opportunity to exchange energy through the Power Pool when the transmission system is planned to accommodate the forecast in-merit transactions of generators and loads. The Board does not consider that the TA's responsibilities are different for generators, in this regard, than they are for loads.[27]

The Board in previous Decisions has determined that "reasonable opportunity" does not mean that the AIES must be planned to provide a transmission system that will allow firm customers to complete their transactions 100% of the time. The AIES will inevitably experience congestion from time to time since generator offers to the pool and the resulting actual dispatch are beyond the control of the TA. Further, congestion may arise as a result of differences between forecast and actual generation, load and losses.

The Board notes that in the deregulated generation market, when considering an application for construction and operation of a new generating plant, the Board must not have regard to whether the generating unit is an economic source of electric energy in Alberta or whether there is a need for the electric energy in meeting the needs for electric energy in Alberta or outside Alberta.[28] Consequently, the Board considers that adequate and reliable transmission facilities must be made available for all new supply (generating) customers regardless of the business opportunities seen by the supply customer.

The Board notes the following comment from the TA:

> In all fairness, we would like to have a long-term robust transmission development plan that we would see this transmission line in context with, and at this point in time, we don't have that to the level that we might like to have, so that is one area, again, where we do deal with some uncertainty. Those are just observations on where we are in terms of meeting those objectives, the three objectives, again, of transfer capability out of the Fort McMurray area and reinforcement of load carrying capability between Fort McMurray and Deerland. We do have pretty good information.[29]

The Board agrees that the TA should have a long-term transmission plan such that specific need documents can be seen and analyzed in the context of the long-term transmission plan. The Board considers this to be particularly important in deciding whether it is economic and orderly to pre-build the basic infrastructure for transmission facilities (e.g. double circuit 240 kV towers and/or 500kV lines initially operated at 240 kV).

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24 Electric Utilities Act, section 21
25 Electric Utilities Act, section 24
26 Electric Utilities Act, section 1(1)(h)
27 Decision 2002-099, pages 22-23
28 Bill 3, section 164
29 Tr Pg 293

The Board considers that the TA should plan for, and initiate, transmission enhancements to ensure reliable service is available to serve forecast in-merit generation, forecast firm Alberta loads and contracted firm exports. Recognizing that transmission enhancements may have a much longer lead-time than the construction of new generation, the Board expects the TA to initiate transmission enhancements on a timely basis even in the absence of contractual commitments from the new generators.[30]

In the Board's view, a forecast of in-merit generation must consider the forecast generator offer at peak load (normally the Supply Transmission Service (STS) capacity times the generator availability factor) and the forecast offer price.[31] The Board considers that it would not be appropriate to plan for the sum of all of the STS contracts for generators in an area, without any regard for diversity between the generators in the area or the impact of local load patterns on the net transfers out from the area. The Board also notes that under the TA's current STS tariff structure, there is little incentive for generators to minimize their STS contract levels, other than for the initial sizing of the dedicated interconnection facilities.

The Board considers a "trigger participant" to be any new generation or load for which the TA needs to upgrade the transmission system. Trigger participants, both new generators and new loads, are curtailed before existing customers until all new facilities, as defined by the TA, required to provide firm service to the trigger participant are in place.[32] The TA can ensure that trigger participants are curtailed before existing customers by installing a Remedial Action Scheme (RAS) at the site of the trigger participant.

The TA is expected to plan for and ensure the timely development of the AIES using accepted reliability criteria.[33] Generally, the TA is expected to plan the development of the AIES so that the transmission system can withstand the unexpected loss of any single element of the non-radial transmission system.

The TA publishes an annual ten-year transmission development plan (TDP) that sets out forecasts of the transmission upgrades required to provide all of the TA's firm customers a reasonable opportunity to exchange electric energy for each of the ten years in the TDP.

When preparing its annual TDP, the TA is expected to consider all reasonable alternatives that would accommodate the forecast in-merit transactions of generators and loads. The Board expects the TA to develop transmission plans that provide for the economic, orderly and efficient development of the AIES over the long-term planning horizon, including a high level consideration of general routing on landowners.

30 Decision 2002-099, pages 184-185
31 Decision 2002-099, page 184
32 Decision 2002-099, page 133
33 Decision 2002-099, page 175