Monday, December 15, 2008

Dear Stakeholders:

Re: Southern Alberta Transmission Reinforcement Needs Identification Document

The AESO is pleased to post the attached Needs Identification Document detailing our assessment of the need, development and testing of transmission alternatives and our recommendation, for viewing. The AESO had identified the need to integrate 2,700 MW of wind interest over the next ten years in southern Alberta. Four major alternatives were considered for transmission development.

The AESO is recommending the 240 kV looped system for implementation in southern Alberta. It is estimated that the first stage of this plan will cost approximately $750 million. When required this plan will be expanded to the second and third stages with an estimated cost of $800 million and $280 million respectively.

The AESO will file this Needs Identification Document along with the Application for approval with the Alberta Utilities Commission (AUC) by December 31, 2008.

Thank you once again for your interest and cooperation during the preparation of this Southern Alberta Transmission Reinforcement plan. Your valuable feedback was crucial in helping us develop the recommendation that will best serve the needs of all stakeholders and I look forward to your continued support during the regulatory process.

The AESO is committed to participant involvement process based on fairness and transparency.

Yours truly,

Ata Rehman

Ata Rehman, P.Eng.
Manager, South System Planning

aeso

ALBERTA ELECTRIC SYSTEM OPERATOR

Southern Alberta

Transmission Reinforcement

Needs Identification Document

Application Number: ___________

Date: December 15, 2008

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APEGGA Permit to Practice P-08200

Executive Summary

As a part of its mandate, the Alberta Electric System Operator (AESO) is responsible for planning the transmission system within the province of Alberta as set out in the Electric Utilities Act, SA 2003 c E-5.1. As prescribed in the Transmission Regulation ("Regulation"), the AESO issued the 10-Year Transmission System Plan 2007-2016 in February 2007. In the context of the 10-Year Transmission System Plan, the AESO has engaged in the planning process to facilitate the preparation of this Needs Identification Document (NID) for the southern region of Alberta.

The need for transmission reinforcement in southern Alberta is driven predominantly by the forecast development of wind generation. The AESO's transmission planning activities have been based on the forecast that between 2,000 and 3,900 MW of wind generation will be operating within Alberta within the next 10 years, including the 500 MW currently in operation which is located in southern Alberta. Of that generation, given the relative interest in southern Alberta, it is anticipated that between 1,700 and 3,200 MW of the provincial totals will be located in southern Alberta; increases of 1,200 and 2,700 MW, respectively above the 500 MW.

The AESO has now received over 11,500 MW of wind interest of which approximately 7,500 MW is located in southern Alberta. However, the AESO recognizes that in the competitive electricity wholesale market, more wind projects may be pursued by developers than the market can absorb and that the competitive electricity wholesale market serves both to attract new generation when required, and also to send appropriate signals to limit excess supply.

The AESO's system studies have indicated that there is limited incremental capability in the southern Alberta transmission system to deliver additional generation output on a firm basis to Alberta Interconnected Electric System (AIES) load. A number of system constraints have been identified that reveal the requirement of substantial system improvements to accommodate the proposed wind generation regardless of the generation location within southern Alberta.

Accordingly, the AESO has developed its plan for transmission reinforcement, set out in the Need Identification Document, in a staged approach.

The first stage, upon which the AESO intends to act immediately upon approval of the NID by the Alberta Utilities Commission (AUC), will enable a minimum of the 1,700 MW forecast to be operating in southern Alberta over the next 10 years. That development is currently forecast to cost approximately $750 million.

Subsequent stages have also been developed, with the appropriate triggers identified that would lead to advancing the additional system reinforcement to accommodate up to the higher bound of the AESO's forecast over the next 10 years. In this way, the AESO transmission plan for Southern Alberta is ensuring that the necessary regulatory processes are being advanced so that future generation development is not impaired, and that transmission development is proceeding in a timely yet prudent fashion.

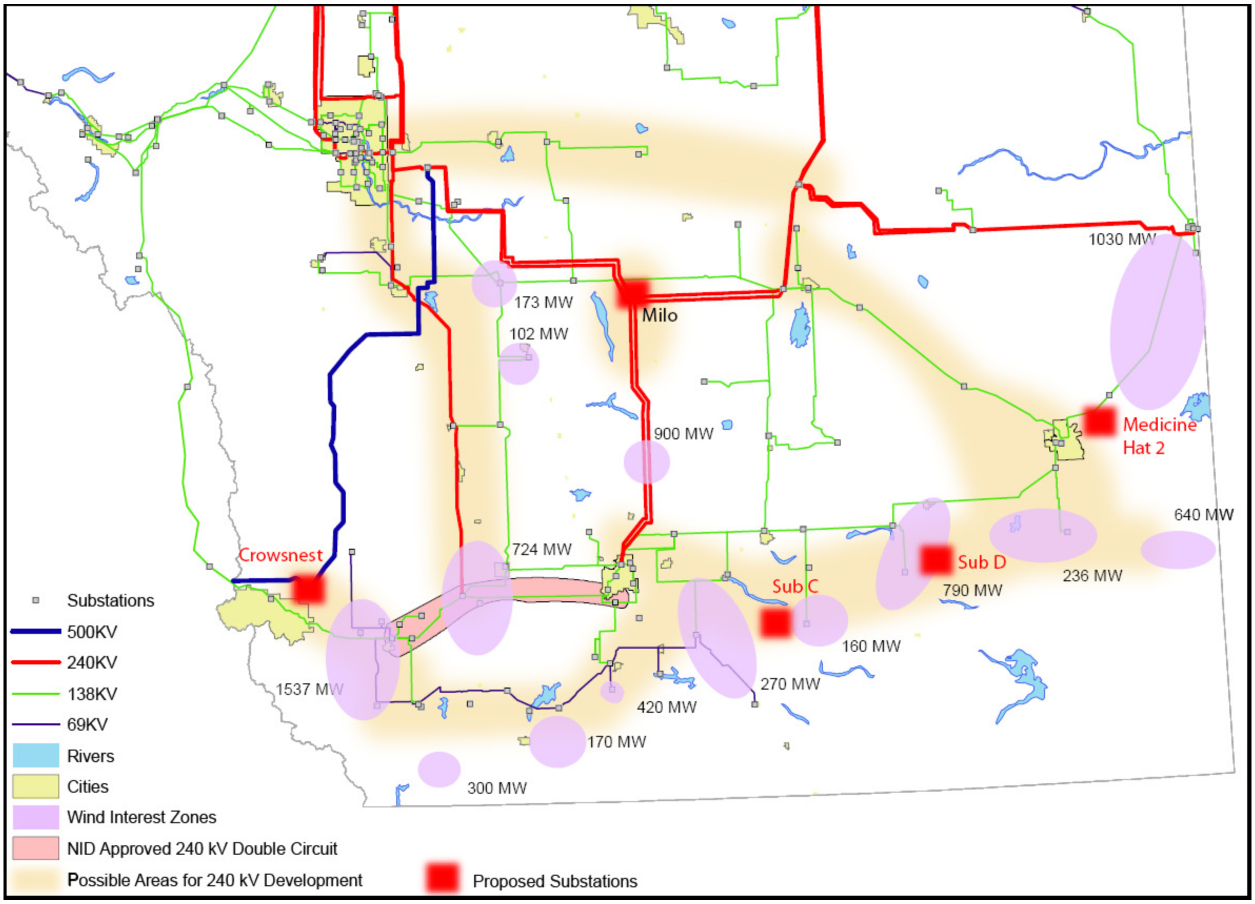
The staging of the various transmission reinforcements was developed by first considering the various transmission development concepts that could meet the needs of the higher bound of wind generation development, then assessing the relative merits, including flexibility for staging, of each alternative.

Four major transmission development alternatives were identified and studied to integrate the high forecast of 2,700 MW of additional wind interest for the southern region. These were:

- 240 kV AC Looped System
- 240 kV AC Radial System
- 500 kV AC Looped System
- HVDC Classic System

The AESO is recommending the 240 kV AC Looped System for implementation in the southern Alberta region. The recommended alternative along with the wind interest in southern Alberta region is shown in Figure EX-1.

Figure EX-1 Recommended Alternative for Southern Alberta



The looped system provides flexibility to integrate the wind generation in the south where the location and size of the actual generation coming on line is uncertain. Some parts of the recommended alternative would involve building single 240 kV circuits on double circuit towers so that capacity can be added at a later date by stringing the second 240 kV circuits when required.

The land impact assessment indicated that the 240 kV looped system has impacts comparable to the other alternatives.

The feedback received from the two rounds of open houses as well as from the meetings held with stakeholders clearly suggested the need to build capacity and expandability in the system for the future. The 240 kV looped system meets these objectives.

The total cost estimate for the recommended 240 kV looped alternative is $1.83 billion (+30% / -15%), 2008$). The economic analysis revealed that the recommended alternative was the most economical of all the alternatives considered. The relative net present value (NPV) of cost/benefit analyses for the four major alternatives is provided as follows:

Table EX-1: Relative Comparison of Major Alternatives

Alternative	NPV (M$)
240 kV AC Looped System (1A)	0
240 kV AC Radial System	647
500 kV AC Looped System	712
HVDC Classic System	1,165

As indicated earlier, the AESO is adopting a staged approach for implementation of the recommended plan. Stage I is recommended to proceed as soon as the regulatory approvals are received as most of the components in this stage are required for wind generation facilities that are ready to move forward. Stages II & III will have triggers that need to occur before these stages can move into the implementation phase. The details of each stage are as follows:

Stage I:

- 911L replaced by Calgary South – Peigan 240 kV double circuit transmission line with 50% seires compensation and a Static Var Compensator (SVC) at Peigan
- Sub D (south of Bow Island) with a SVC
- Sub D – Medicine Hat 2 – West Brooks 240 kV double circuit transmission line
- Milo Junction Switching Station
- Phase Shifting Transformer on 170L Coleman to Natal

The total cost for Stage I is approximately $750 million (+30%/-15%, 2008$)

Stage II:

- Medicine Hat 2 substation, Medicine Hat 138 kV changes/upgrades; (reflected in analysis as potentially being advanced in parallel with Stage I development)
- New Crowsnest 500/240 kV, Sub C (south of Taber)
- Crowsnest – Goose Lake 240 kV double circuit transmission line
- Goose Lake – Sub C 240 kV double circuit line with one side strung

- Sub C – Montana Alberta Tie Ltd. (MATL) 240 kV double circuit line with one side strung
- Sub C – Sub D 240 kV double circuit transmission line
- Salvage line 911L
- Peigan 179 MVA transformer replaced by 2 x 200 MVA transformers
- Blackie Area 138 kV upgrades/modifications
- Anderson – W. Brooks 240 kV in-and-out at Ware Junction
- SVCs at Crowsnest, Sub C, and Cypress

The total cost for Stage II is approximately $800 million (+30%/-15%, 2008$).

Stage III:

- Ware Junction – Langdon 240 kV double circuit transmission line with 50% series compensation

The total cost for Stage III is approximately $280 million (+30%/-15%, 2008$).

In the course of developing this NID, the AESO has identified the opportunity to significantly reduce the scope, cost and impact of other 138 kV reinforcement to the Medicine Hat area previously approved by the AUC, through the advancement of the Medicine Hat 138 kV changes and upgrades identified above in Stage II. The AESO intends at this time to pursue changes to the Southeast NID [Application No 1545328] and the technical and cost analysis supporting this application reflects the advancement of the work. Once the appropriate changes are confirmed by the AESO and filed with the AUC relating to the Application 1545328, the AESO intends to pursue advancing the Medicine Hat 138 kV upgrades and changes identified as part of Stage II in this NID in parallel with Stage I.

TABLE OF CONTENTS

List of Tables and Figures

List of Tables

List of Figures

1 Description of Southern Alberta

The Alberta Interconnected Electric System (AIES) is a vital component of the electric industry and provides a platform for a competitive wholesale electricity market. The AIES connects generators to load over a large and diverse geographic area and is designed to deliver electric energy to Alberta customers reliably and efficiently under a wide variety of system operating conditions and continuously changing customer demands.

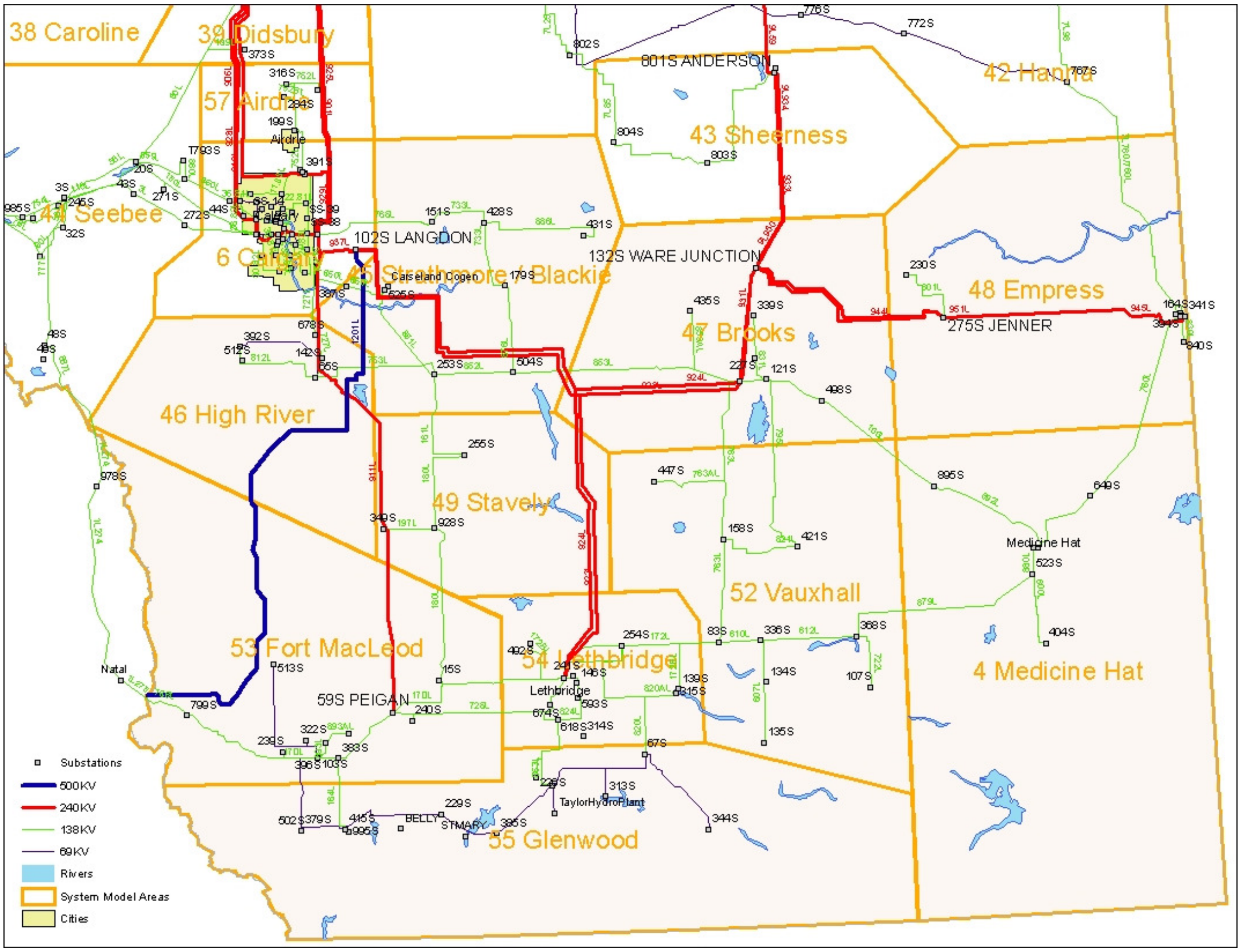
The southern region of Alberta is comprised of ten transmission planning areas which are Strathmore/Blackie (Planning Area No. 45), Brooks (47), Empress (48), High River (46), Stavely (49), Vauxhall (52), Medicine Hat (4), Fort MacLeod (53), Lethbridge (54) and Glenwood (55). The planning area borders Sheerness and Hanna to the north, Saskatchewan to the east, Montana to the south and British Columbia (BC) to the west. The existing transmission network in the Southern Alberta region is shown in Figure 1-1.

The southern Alberta region contains three major population centres; Lethbridge, Brooks and Medicine Hat. Most of the area is farmland with irrigation systems. The Empress area to the east is the major industrial area in southern Alberta and has the highest peak demand of the ten areas, followed by Medicine Hat and Lethbridge.

The region is mostly served by a 138 kV and 69 kV network with 240 kV transmission supply lines into the area. The 911L 240 kV line connects Janet 74S in Calgary to Peigan 59S substation in the southwest. A 240 kV double circuit 923L and 924L from Langdon 102S substation connects to North Lethbridge 370S through the Milo Junction. Another 240 kV double circuit is tapped off the Milo Junction to West Brooks 28S and onwards to Anderson 801S and Empress 163S substations.

The 500 kV Alberta-B.C. intertie traverses through the southern Alberta region and connects the Langdon Substation in the Calgary area to the Cranbrook Substation in B.C. In addition, there are two 138 kV tie lines to the British Columbia Transmission Corporation (BCTC) system, one of which connects Coleman 799S in Alberta to Natal in the BCTC system and the other connecting Pocaterra 48S (south of Kananaskis) to Fording Coal Brit Creek 978S (near Elkford B.C.). On the eastern side, the southern Alberta transmission system is connected to the Saskatchewan system through a HVDC back-to-back intertie.

Figure 1-1 Existing Southern Alberta Region Transmission System



2 Basis of the Southern Alberta Need

To identify the need to reinforce transmission in southern Alberta, the AESO tests the present and future adequacy of the existing transmission system by applying the AESO Reliability Criteria. The southern Alberta transmission system was tested under certain load forecast and future generation assumptions. The following sections describe the criteria and assumptions in further detail.

2.1 Reliability Criteria

The AESO Reliability Criteria was applied to test the regional system for acceptable performance for Category A (i.e. all elements in service) and Category B (i.e. an element out-of-service) contingencies. Category B requirements also cover single element outage events while the most critical generator is out-of-service for maintenance or for commercial reasons, and the remaining generators on the system are redispatched according to the generic stacking order. Relevant Category C events (i.e. two elements out-of-service) were also considered in the assessment of the Southern transmission development alternatives.

In addition, the capability of the regional transmission system to meet Category B requirements while accommodating planned outages was assessed at demand levels for which planned outages are performed. The end result of testing against the AESO Reliability Criteria is that all equipment must operate within its applicable thermal and voltage limits and the system must remain stable.

2.2 Input Assumptions

Primary assumptions that were considered in the southern Alberta planning study consist of the area load forecast, generation scenarios, bulk transmission scenarios and transfers on interconnections with other jurisdictions.

2.2.1 Load Forecast

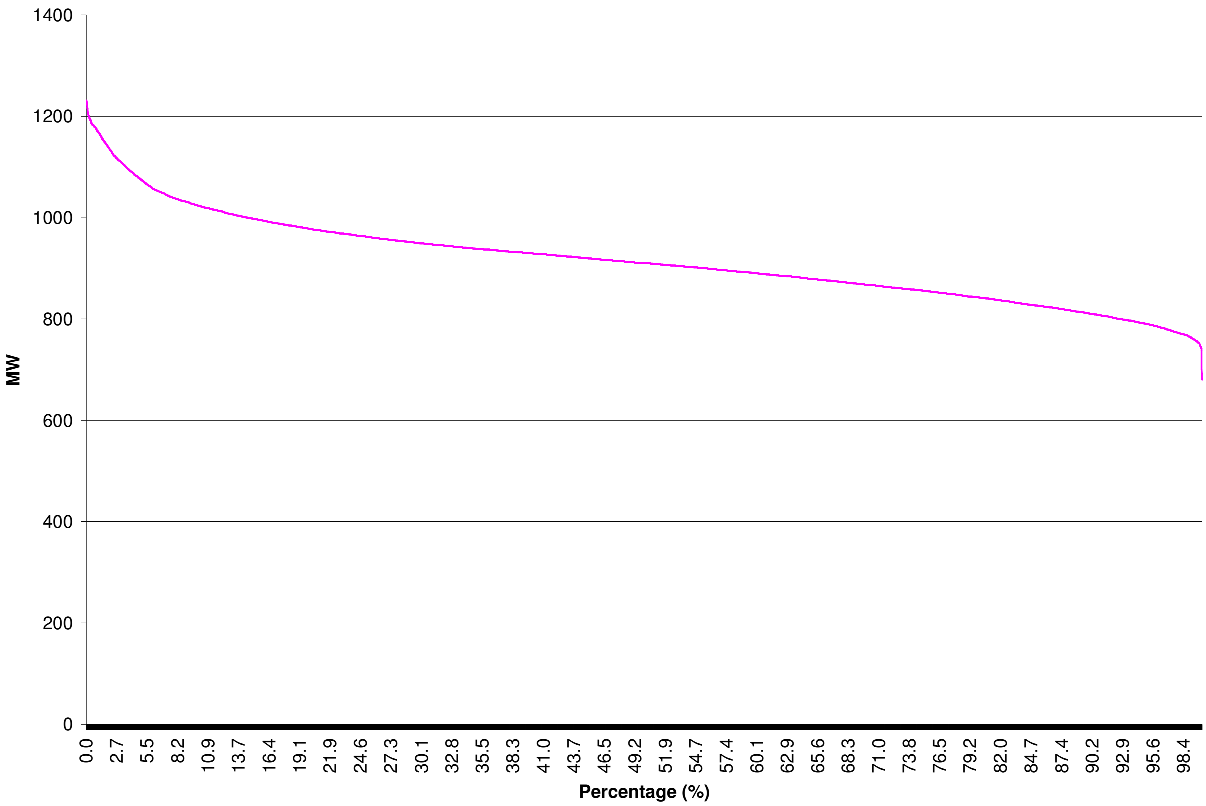
The coincident summer light, summer peak and winter peak load forecast for the southern Alberta region is provided in Table 2.2-1. The table shows that this area peaks in the summer and that the rate of load growth is approximately 2 percent annually for the period of 2007 – 2017.

Table 2.2-1 Southern Alberta Seasonal Historic and Forecast Coincident Load

Southern Alberta	Year	Season		
		Summer Light	Summer Peak	Winter Peak
Historical Load (MW)	2003	347	1,064	1,006
	2004	560	1,090	1,092
	2005	514	1,114	1,123
	2006	681	1,131	1,097
	2007	680	1,232	1,123
Forecast Load (MW)	2008	681	1,162	1,146
	2009	692	1,189	1,179
	2010	712	1,213	1,198
	2011	722	1,229	1,222
	2012	734	1,252	1,245
	2013	745	1,274	1,269
	2014	757	1,295	1,296
	2015	769	1,322	1,321
	2016	782	1,349	1,348
	2017	795	1,376	1,372

Figure 2.2-1 provides the load duration curve for the southern Alberta region for 2007. It presents the variation of the southern region load over a one year period. The peak load is slightly over 1200 MW and the minimum load is of the order of 700 MW. For most of the time, the load varies between 800 MW and 1000 MW.

Figure 2.2-1 Southern Alberta 2007 Load Duration Curve



2.2.2 *Existing Generation*

The installed generation capacity in southern Alberta is a mix of wind, thermal and hydro as shown in Table 2.2-2. The total installed capacity is 1007 MW. In addition, there are a few small (under 10 MW) power plants connected to the distribution systems that are not shown in this table.

Table 2.2-2 Southern Alberta Existing Generation

#	Generating Plants	Fuel	Machine Continuous Rating (MW)	Type
1	Castle River	Wind	40	Wind
2	Cowley Ridge	Wind	41	Wind
3	McBride Lake	Wind	75	Wind
4	Summerview	Wind	68	Wind
5	Magrath	Wind	30	Wind
6	Taylor Wind	Wind	3	Wind
7	Soderglen	Wind	71	Wind
8	Chin Chute	Wind	30	Wind
9	Kettles Hill	Wind	63	Wind
10	ENMAX Taber Wind	Wind	80	Wind
11	Carseland 1	Gas	40	Cogen
12	Carseland 2	Gas	40	Cogen
13	Cavalier 1	Gas	40.8	Cogen
14	Cavalier 2	Gas	40.8	Cogen
15	Cavalier 3	Gas	25.5	Cogen
16	Old Man River	Hydro	32	Hydro
17	Chin Chute	Hydro	11	Hydro
18	Irrican	Hydro	7	Hydro
19	Taylor	Hydro	12.6	Hydro
20	Drywood	Hydro	6	Hydro
21	Raymond Reservoir	Hydro	18.5	Hydro
22	Medicine Hat	Gas	232	Simple Cycle
Total			**1,007.2**	

2.2.3 Future Generation Scenarios

Generation development in Alberta is driven by commercial business decisions within a competitive wholesale market, and it is not possible to definitively describe the timing and location of generation facilities in the future. Accordingly, the AESO creates a range of generation scenarios against which the transmission system can be tested to identify where future reinforcements are required. The generation scenarios are based on the transmission policy and market structure that is currently in place and the assumption that transmission is not a constraint in locating new generation. The generation scenarios do however anticipate future changes in the market related to environmental standards, technology development, increasing fuel costs and changing capital costs.

There are many factors that affect generation developers' decisions regarding when and where to build new power plants in Alberta. These include resource availability, the state of technology development, relative generation costs, environmental constraints, market structure, intertie capacity and the ability to finance projects in a competitive marketplace.

The amount of generation developed in the province is determined by market participants based on market signals and thus there is no pre-determined reserve margin requirement. For the purpose of developing reasonable generation scenarios a 10 per cent effective reserve margin is used as a proxy for the amount of generation that will be developed in the province. Effective reserve margin is calculated based on the ability to serve load on a continuous basis; the installed capacity of generation sources with intermittent availability are therefore derated in the calculation to reflect the availability of the resource. This 10 per cent effective reserve margin does not include intertie capacity and derates wind and hydro capacity recognizing that the two resources have significantly lower availability due to the variability in their energy sources. For the purpose of determining effective generation capacity on the system, wind and irrigation hydro were derated to 20 per cent of total capacity, legacy hydro was derated to 67 per cent of total capacity and new hydro is derated to 50 per cent of capacity. Wind is derated to a level that approximates the other capacity that will not be installed in the competitive market due to the addition of the intermittent generation. As an example, if 100 MW of wind capacity is added to the system it is known that this intermittent generation will not operate like other dispatchable generation and will therefore have a different impact on prices. The derated effective capacity attempts to capture the behavior of the market in making generation development decisions.

Based on this proxy reserve margin and forecasted Alberta internal load, effective generation capacity in Alberta will increase from 11,500 MW today to

15,500 MW by 2017 and 20,700 MW by 2027. Taking generation retirements into account, this translates into the expectation that 5,000 MW of effective capacity will be added to the Alberta system by 2017 and 11,500 MW by 2027.

Given this amount of expected additions, the information on potential generation resources and the relative costs of generation, five generation scenarios were created, as shown in Table 2.2-3. These scenarios represent a reasonable range of future expansion to comprehensively test the transmission system for planning purposes.

Table 2.2-3 Generation Scenarios for 2008-2017 (MW)

Scenario	A1	A2	A3	B4	B5
Coal	1,950	1,500	1,500	1,050	1,050
Cogeneration	1,760	2,260	1,760	1,760	1,760
Combined Cycle	90	90	720	1,230	1,230
Hydro (Installed)	100	100	100	100	100
(Effective)	50	50	50	50	50
Other Small Additions	100	100	100	100	100
Simple Cycle	800	800	620	620	430
Wind (Installed)	1,600	1,600	1,600	1,600	3,400
(Effective)	320	320	320	320	680
Total Effective Additions	**5,070**	**5,120**	**5,070**	**5,130**	**5,300**

As a basis for developing the scenarios, it was assumed that within the next 10 years, significant generation additions are expected to be comprised of super critical pulverized coal plants, combined cycle gas units, simple cycle gas units, cogeneration units and wind power. This assumption stems from the commercial availability of the technologies and the long lead time for other existing technologies such as nuclear and large hydro.

Two different electricity futures were considered in the creation of the generation scenarios, a business-as-usual case (scenarios A1 and A2) and an environmentally driven case (scenarios B4 and B5). Each case has unique characteristics which increase the likelihood of a particular generation scenario developing in Alberta. These characteristics include greenhouse gas

(GHG) emission constraints, technology development, future gas prices, oilsands development and other environmental constraints.

In the business-as-usual case, generation development over the next 10 years continues in a manner similar to what has occurred in the past in Alberta. Large coal plants are added to the system with gas-fired, wind and other generation added as required to fill the supply gaps between the large additions. This case could occur under three possibilities: 1) GHG costs remain relatively low, 2) natural gas costs are high enough to offset the GHG costs for coal, or 3) clean coal technologies make significant advancements. These possibilities allow for the continued development of Alberta's coal resource for power generation. Scenario A1 and A2 would both be developed in this type of situation. In the first 10 years scenarios A1 and A2 both include the addition of three large coal plants, cogeneration, simple cycle and wind. They differ in the fact that scenario A1 includes the addition of a fourth large coal unit, whereas scenario A2 includes the development of a petroleum coke gasification cogeneration plant near oilsands operations or in Fort Saskatchewan. The technology that will be applied in the development of the coal resources will depend on the maturity of the technologies and the associated costs at the time of construction.

In the environmentally driven cases, GHG costs are high enough that in the interim, as clean coal technologies continue to develop, minimal new coal-fired generation is developed in Alberta. Instead gas-fired combined cycle and more wind generation are developed. Either scenario B4 or B5 would be developed in this case. They both include additional combined cycle and wind in place of the additional coal plants included in scenarios A1 and A2.

The one additional scenario, A3, represents a blend of the two electricity futures, falling in between business-as-usual and environmentally driven.

Scenario B5 was used for the purpose of determining transmission reinforcement in southern Alberta to accommodate a high wind development scenario.

The coal additions in scenario B5 include the Keephills 3 project and a number of project upgrades, accounting for 600 MW of coal additions. One additional 450 MW unit located in the northern part of the province is also included in scenario B5

The cogeneration capacity included in scenario B5 is additions to support behind-the-fence load, with the bulk occurring within the oilsands industry in the northeast area of the province. The 1,760 MW of cogeneration capacity added exceeds growth in behind-the-fence load, by 500 MW.

Scenario B5 also includes the development of 1,230 MW of combined cycle generation prior to 2017. This combined cycle is assumed to be developed near Calgary based on project announcements made by ENMAX and TransCanada.

The hydro project included in the scenario represents the 100 MW Dunvegan project on the Peace River. The 100 MW of other small additions are included to capture the future development of biomass generation and other small projects, such as solar, microgeneration, or geothermal developments.

The characteristics of simple cycle generation allow it to provide peaking capability in Alberta's baseload heavy generation mix to manage the load and supply fluctuations. Scenario B5 includes 430 MW of additional simple cycle.

Large amounts of wind generation are planned for the province. Scenario B5 includes the addition of substantial wind capacity, with a total of 3,400 MW being added to the system by 2017. Including the existing capacity (of 497 MW), this will amount to 3,900 MW of wind generation in Alberta by 2017. The amount of wind added to the system over the next 10 years is assumed to be limited by market factors, and not transmission or market policy. Therefore the addition of wind generation is assumed to be limited by both the inability to construct the wind farms at the rate desired and the economic viability of the projects as the amount of wind on the system increases. The additions of wind generation were proportionally split throughout the province based on the wind applications in the AESO's interconnection queue as of February 2008, with 80 per cent being developed in southern Alberta and the remaining 20 per cent developing in central and northern Alberta.

It is recognized that there is the potential for additional generation resources to be developed in the south after 2017; these include additional wind generation, natural gas-fired generation and coal-fired generation.

3 The Need for Transmission in Southern Alberta

Studies of the transmission system in southern Alberta have identified necessary system improvements to accommodate load growth and proposed wind generation.

3.1 Approved System Upgrades for Southern Alberta

In March 2005, the Alberta Energy and Utilities Board (AEUB) approved need for the Southwest Alberta Transmission System Development NID [Application No 1340849]. The AESO's southwest NID sought approval for system upgrades and additions involving the following power system facilities:

- New 240/138 kV substation (Goose Lake) adjacent to the existing Pincher Creek Substation
- Two new double circuit 240 kV transmission lines (Pincher Creek – Peigan, Peigan - Lethbridge);
- Expansion of existing 240/138 kV substations (Pincher Creek, Peigan, Lethbridge);
- 138 kV substation upgrades (Pincher Creek, Drywood, Magrath and Stirling); and
- A 69 kV to138 kV transmission line upgrade (Tempest - Stirling).

The need for transmission in southwest Alberta was confirmed in the February 2006 need application amendment, informing the AEUB that the overall interest and activity in wind generation development had continued to climb. The total generation capacity of existing and proposed projects in the Southwest had increased to 1409 MW, representing an increase of 822 MW within a year. The AESO also reiterated in the need application amendment that the Southwest Alberta area plans will continue to be developed based on additional increases in requests for system access service. The 240 kV transmission facilities identified in the Southwest Need Application were the starting point for transmission system reinforcement in the Southwest Alberta. Pending the approval of the Facility Application by the AUC, the Southwest Alberta System Development project is expected to be in service by 2010.

In November 2007, the AESO submitted the Southeast Alberta Transmission Development NID Part A [Application No 1545328]. This application mainly focused on serving load growth in southeast Alberta, restoring the Alberta – Saskatchewan tie to its rated capacity and integrating 141 MW of wind. Part B of the Southeast Application was intended to focus on additional wind integration in the southeastern region pursuant to the new Market and Operational Framework. The concept of Part B is now being realized through this Southern Alberta Transmission Reinforcement NID.

The cost of the upgrades recommended in the Vauxhall/Medicine Hat area has increased since the Southeast Alberta NID was filed. This presented an opportunity to re-consider the transmission system options around Medicine Hat area to avoid the costs of the recommended upgrades. This is discussed in more detail in Section 7.1.4.

In April 2006, the AESO filed a NID [Application No 1458443] for the proposed interconnection of a 300-kilometre merchant transmission line from Lethbridge to Great Falls, Montana, which is currently scheduled for completion in 2010. The AESO is fulfilling its responsibilities by facilitating the project in accordance with the *Transmission Regulation*.

The facilities associated with MATL that will become a part of the AIES owned and operated by AltaLink will include the following:

- Construction of a new substation, designated as MATL 120S, located approximately 15 km north east of North Lethbridge 370S in proximity to transmission lines 923L and 924L.
- The bus configuration in MATL 120S will be a breaker and a half configuration with the installation of three (3) 240 kV breakers. The substation will allow for expansion to accommodate future potential system needs.
- Connection of circuit 923L in/out of MATL 120S.

A portion of costs for the new MATL 120S Substation were treated as a system cost providing for potential expansion of the substation and termination of additional circuits into the station in the future. The MATL 120S Substation and associated interconnection flows were considered as possible scenarios.

3.1.1 Possible Wind Generation in Southern Alberta

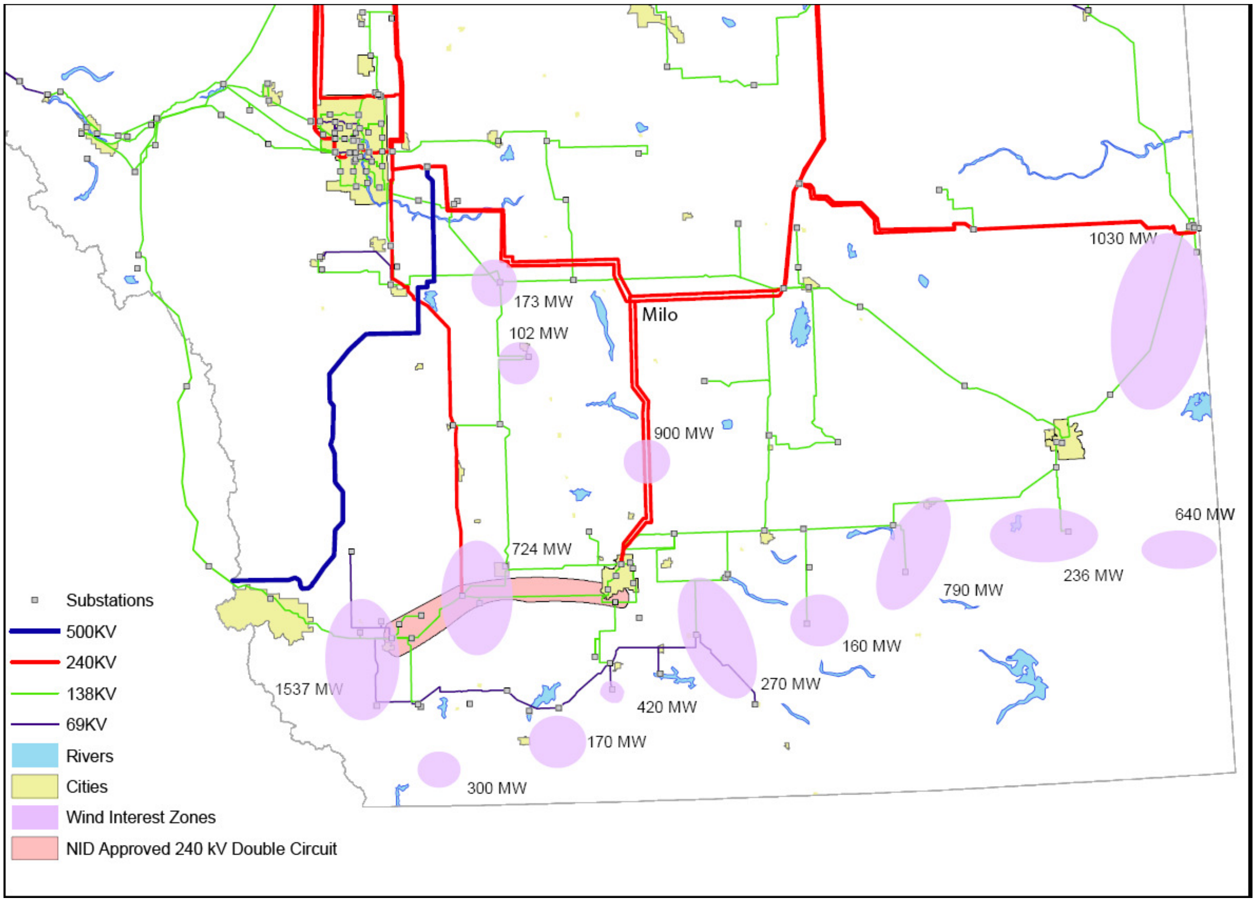
As discussed in Section 2, the AESO forecast for additional wind generation in Alberta is up to 3,400 MW by the year 2017, with up to approximately 2,700 MW (80 percent of 3,400 MW) anticipated in southern Alberta. Therefore, this transmission planning analysis considers 2,700 MW of possible new wind interconnections in southern Alberta by 2017.

The ten-year forecast of 2,700 MW of additional wind interconnections in southern Alberta is less than the total wind capacity requested in the AESO interconnection queue. As of November 2008, the AESO interconnection queue contained wind requests totaling approximately 11,500 MW in the province of which 7,500 MW was requested in the southern planning region. The latest AESO generation interconnection queue is shown in Appendix A.

The challenge for the AESO was to develop a ten-year transmission plan for Southern Alberta which could deliver 2,700 MW of additional wind interconnections and yet be flexible enough to accommodate the geographically dispersed 7,500 MW of interconnection requests.

The AESO began by identifying the geographic wind interest zones which contained wind interconnection requests. The wind interest zones, shown in Figure 3.1-1, may represent more than one proposed wind power facility. The size of the zone only reflects the general location of the proposed facilities and not the proposed capacity within the zone, which is shown by the labels. The wind interest zones are spread across southern Alberta and are even located in remote areas without any existing transmission network.

Figure 3.1-1 Southern Alberta Wind Interest Zones



3.2 Existing System Analysis

Two scenarios were simulated for the 2008 existing system analysis. These scenarios were:

- Summer light load
- Summer peak load

The summer season was selected as the line ratings are lower in summer. The summer light scenario included the 500 MW of existing wind dispatched at maximum where as the summer peak load scenario was analyzed without the existing wind generation to test the load carrying capability. Tables summarizing the results of this analysis as well as the power flow plots are shown in Appendix B. It is to be noted that during maximum wind generation, the Coleman – Natal 138 kV line was overloaded under Category A conditions. The contingency of

911L as well as some 138 kV lines caused overloading during summer peak as well as light load conditions.

Overloading as well as voltage problems were also observed on the 138 kV and 69 kV systems in High River and Glenwood/Drywood areas. These problems are the result of load growth in these areas. The system reinforcement plans for the High River and Glenwood/Drywood areas are discussed in Section 9.2.

3.3 Transfer Out Capability Assessment for 2010

The southwest Alberta transmission development is anticipated to be in service by 2010. For evaluating the system capability with these southwest improvements, a transfer out capability analysis was carried out on the 2010 system.

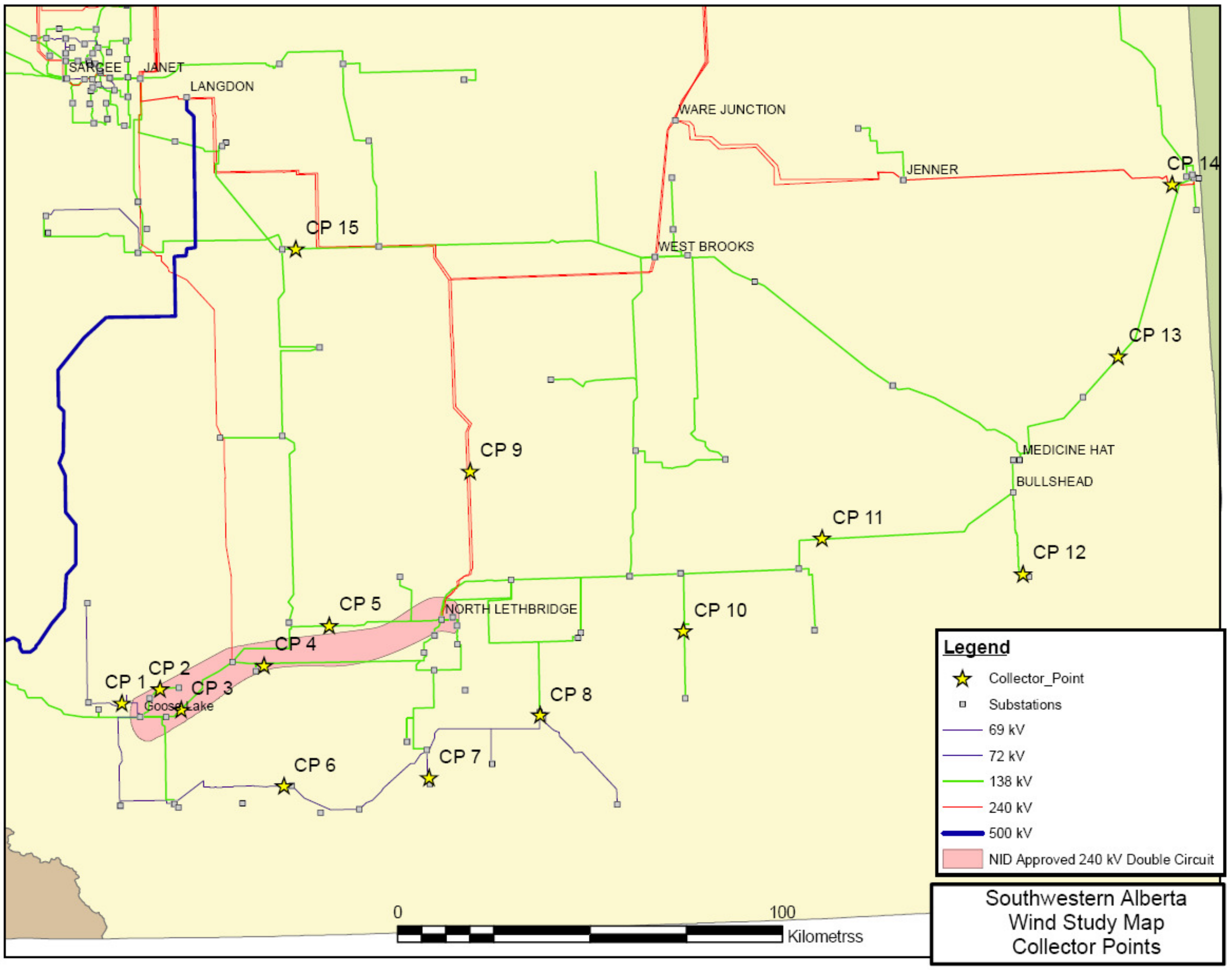
The overall purpose of the transfer out analysis was to identify the levels of wind generation capacity within a wind interest zone that create thermal overload conditions and also how those thermal loading impacts are similar or unique between different wind interest zones. The results of this approach provide an understanding of the transmission systems ability to deliver the proposed wind generation and how different interconnection locations influence the need for improvements. The SIEMENS MUST Version 8.3.2 software was used for the transfer out analysis. The MUST software is most commonly used to perform transfer out analysis in large interconnected networks due to its simulation automation techniques.

The transfer out analysis was based on the following assumptions:

- The 2010 summer light and peak cases were analyzed.
- The existing wind farms were fully dispatched at 497 MW prior to any additional transfer.
- The generation source was sixteen independent generation collection points, shown in Figure 3.3-1.
- The sink location was generation in the Wabamun area.
- The monitored facilities included the entire AIES.
- Category B contingencies for the entire AIES were examined.

Sixteen different collection substations were identified based on the interconnection requestors' geographic proximity to the existing transmission system. The collection substations served the function of interconnecting a group of wind farms to the existing transmission network. In connecting the cluster area generation to the system, it was assumed that the nearest existing transmission facilities were utilized for the interconnection. Therefore, the collection substation for the cluster area was placed on the nearest existing 69 kV or higher transmission line. This approach was consistent with the purpose of the transfer out analysis which is to identify the transmission system's ability to deliver wind generation based on the requested locations.

Figure 3.3-1 Location of Collector Points for Transfer Out Analysis



The transfer out analysis studied the transfer of wind generation energy from a single wind farm cluster area from zero MW injected up to 1000 MW of wind generation capacity. The maximum transfer level of 1000 MW provided sufficient generation injection to identify transfer levels which impacted the system. The simulation was repeated for each of the sixteen wind farm cluster areas independently.

Existing thermal overload conditions were only reported if the transfer out simulations increased the overload by more than 3 per cent. In doing so, the relative responsibility of overloading system elements can be associated with different generator source locations.

The result of the transfer out analysis for the summer peak and summer light cases are summarized in Appendix B. All results shown are for the worst case single contingency conditions.

Most importantly, the results show that all collection point substations have a negative value or very small positive value for multiple limiting elements. This is summarized in Table 3.3-1 and Table 3.3-2 where the number of constraints for different levels of transfer out capacities is listed. This result demonstrates that the existing transmission system in southern Alberta has limited incremental transfer out capability regardless of the location of proposed generation interconnection and that the impacts are widespread across the network.

Table 3.3-1 2010 Summer Light Transfer Out Capability Results

Collection Point	Transfer Out Capability (MW)	Number of Constraints within Transfer Level				
		< 0 MW	0 - 100 MW	100 - 250 MW	250 - 500 MW	500 – 1,000 MW
CP #1	0	2	14	12	6	0
CP #2	9	0	3	5	8	20
CP #3	0	1	3	3	8	20
CP #4	0	1	7	10	5	9
CP #5	0	1	3	10	7	24
CP #6	0	2	13	6	17	2
CP #7	0	3	9	9	10	12
CP #8	0	1	9	14	11	5
CP #9	270	0	0	0	6	18
CP #10	0	1	6	8	11	9
CP #11	39	0	6	9	10	1
CP #12	27	0	5	9	6	5
CP #13	62	0	3	6	10	5
CP #14	343	0	0	0	6	24
CP #15	115	0	0	8	7	11
CP #16	0	1	3	8	14	21

Table 3.3-2 2010 Summer Peak Transfer Out Capability Results

Collection Point	Transfer Out Capability (MW)	Number of Constraints within Transfer Level				
		< 0 MW	0 - 100 MW	100 - 250 MW	250 - 500 MW	500 – 1,000 MW
CP #1	0	4	14	12	4	0
CP #2	0	2	1	4	8	15
CP #3	0	3	1	2	7	15
CP #4	0	5	5	9	6	8
CP #5	0	5	3	7	5	19
CP #6	0	5	9	15	10	2
CP #7	0	8	9	6	8	11
CP #8	0	8	9	14	5	13
CP #9	0	4	0	0	3	16
CP #10	0	8	5	7	7	12
CP #11	0	5	4	6	6	1
CP #12	0	5	1	10	4	6
CP #13	0	3	2	8	6	6
CP #14	0	4	0	0	5	22
CP #15	0	4	5	6	8	9
CP #16	0	8	3	4	10	21

Given the large numbers of existing system constraints, the southern Alberta transmission system will require substantial system improvements to accommodate the proposed wind generation regardless of the generation location.

3.4 Implications of Inadequate Transmission in Southern Alberta

The consequences of inadequate transmission in southern Alberta will be that the wind interest cannot be integrated into the AIES without violation of the AESO Reliability Criteria. For those proposed wind farms which proceed without system reinforcement, remedial action schemes will be required to prevent overloads on the transmission system and will result in curtailment of the output under different system conditions.

The existing system analysis shows that the reliability of the system to serve existing load in the High River and Glenwood areas is below the AESO Reliability Criteria.

4 Development of Southern Alberta Transmission Alternatives

For major transmission improvements such as will be needed in the southern region, the AESO formulates transmission development alternatives to address the identified transmission need. An alternative is comprised of a combination of transmission and substation facilities to meet the AESO Reliability Criteria and represents the transmission development proposed for the southern region to meet the need over a 10-year period. Alternatives may include staging of facilities to provide flexibility to be modified or delayed if the timing or the nature of the need changes. The details of alternative development went through a stakeholder process that is summarized in Section 7.

The following sections detail the development of the options considered for transmission alternatives in the southern region.

4.1 Transmission Technologies Considered

The range of transmission technologies considered for the system reinforcement in southern Alberta included:

- 240 kV AC
- 500 kV AC
- 765 kV AC
- High Voltage Direct Current (Classic) (HVDC)
- High Voltage Direct Current (Voltage Sourced Converter) (HVDC VSC)

The existing southern Alberta transmission system consists of a substantial amount of 138 kV network, which serves the rural load. However, the 138 kV system could not be considered, by itself, as a viable voltage to deliver the 2,700 MW of generation additions being proposed in southern Alberta.

Using 765 kV AC technology would have been suitable from the perspective of providing high capacity in the region; however this technology was excluded because:

- it provides less flexibility to adjust the staging of construction, and
- it would be a new voltage being introduced to Alberta which adds to the complexity and cost of integration into the system.

High-voltage underground AC transmission has significant technical limitations. While it may have benefits in specific applications, such as in urban areas, it was not considered a viable alternative over the long distances required to cross southern Alberta. HVDC VSC underground is favourable from a visual perspective; however the newer HVDC VSC underground technology has limited application at this time and has yet to be commercially or technically proven in applications similar to the requirements of this project (i.e. length and capacity).

The remaining technologies from which the alternatives for southern region transmission development have been formulated include 240 kV AC, 500 kV AC and HVDC Classic. The rationale for including these options in further detailed analysis is outlined in the sections below.

4.1.1 240 kV Transmission Technology

The existing southern region transmission system consists of a 240 kV transmission system with an underlying 138 kV system. This makes 240 kV a logical technology to be considered for new transmission lines in the region.

There are a number of advantages associated with 240 kV AC technology. It is suitable for interconnecting the approximate 2,700 MW of anticipated wind generation in the southern region as well as reinforcing the bulk system to transfer power to the Alberta load centres. It is an existing voltage in the system which minimizes the complexities associated with system integration. Also, 240 kV transmission lines typically require smaller right-of-way widths than higher voltage options creating a smaller construction footprint through new corridors.

The disadvantage of 240 kV AC technology is that it has less transfer capability per circuit compared to higher voltage technologies. Although 240 kV typically requires smaller right-of-way widths, more 240 kV lines may be required due to the fact that more circuits will be needed to provide a similar capability as that of a higher voltage.

4.1.2 500 kV AC Transmission Technology

System reinforcements for southern Alberta were also considered using 500 kV AC transmission technology. The planned backbone network voltage of the future system throughout Alberta is 500 kV, with new 500 kV lines currently at various stages of planning in Alberta. As such, 500 kV is another logical technology to consider for transmission development in the southern region.

One advantage of using 500 kV is that it could provide reserve capacity for system needs beyond the 10-year horizon. In addition, system losses would be lower for 500 kV transmission when compared to 240 kV transmission.

In contrast, the disadvantages include the requirement of larger right-of-way widths relative to 240 kV as well as a higher initial capital cost. Although some of the new 500 kV transmission lines could be initially operated at 240 kV until the higher capacity of 500 kV was required, it also represents higher risk of stranded costs if the voltage conversion is not implemented. Finally, Category C contingencies involving 500 kV lines could result in greater system impact than similar contingencies of 240 kV lines.

4.1.3 HVDC Classic Transmission Technology

HVDC lines are typically constructed when bulk power has to be transmitted over long distances. HVDC would be capable of transferring significant amounts of power out of the southern region to the Alberta load centres.

HVDC requires smaller right-of-way and smaller tower footprints relative to AC technologies. Although HVDC transmission lines have fewer losses than other options for transmitting energy over long distances, the distances across southern Alberta are shorter and would result in limited efficiency gains considering the additional energy losses consumed by the converter stations, and even with that, there is a practical limit as to the number of converter stations that can be added.

4.2 Formulation of Planning Alternatives

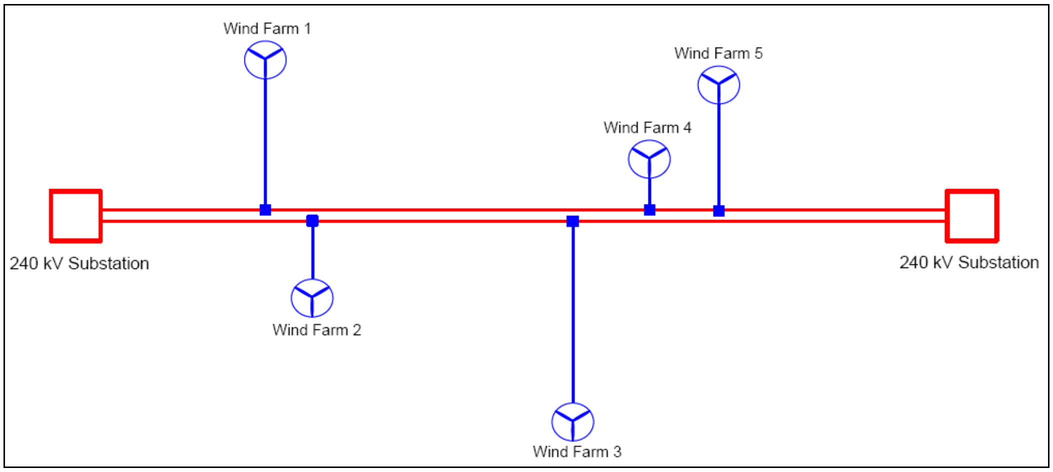
Planning alternatives are formed when one or more transmission technologies are combined to satisfy the AESO Reliability Criteria. The following sections describe the planning alternatives formulated to address the transmission need in southern Alberta.

4.2.1 Alternatives 1A, 1B & 1C – Looped 240 kV

Three different 240 kV looped alternatives were considered which would require new 240 kV transmission lines across southern Alberta. The new 240 kV lines would be looped into existing 240 kV substations which include Peigan, Lethbridge and West Brooks. New 240 kV switching stations would tie the 240 kV transmission lines together such that the 240 kV transmission lines would be fully looped. Some of the new 240 kV lines would be utilized to collect wind energy onto the bulk 240 kV system, where it can be delivered to Alberta load centres.

Figure 4.2-1 shows how the wind farms would be connected in Alternatives 1A, 1B and 1C. The wind farms will be required to build a 240 kV transmission line from their wind farm site to the closest transmission line and build a three-breaker substation at the point of interconnection.

Figure 4.2-1 Looped Wind Farm Connection Configuration

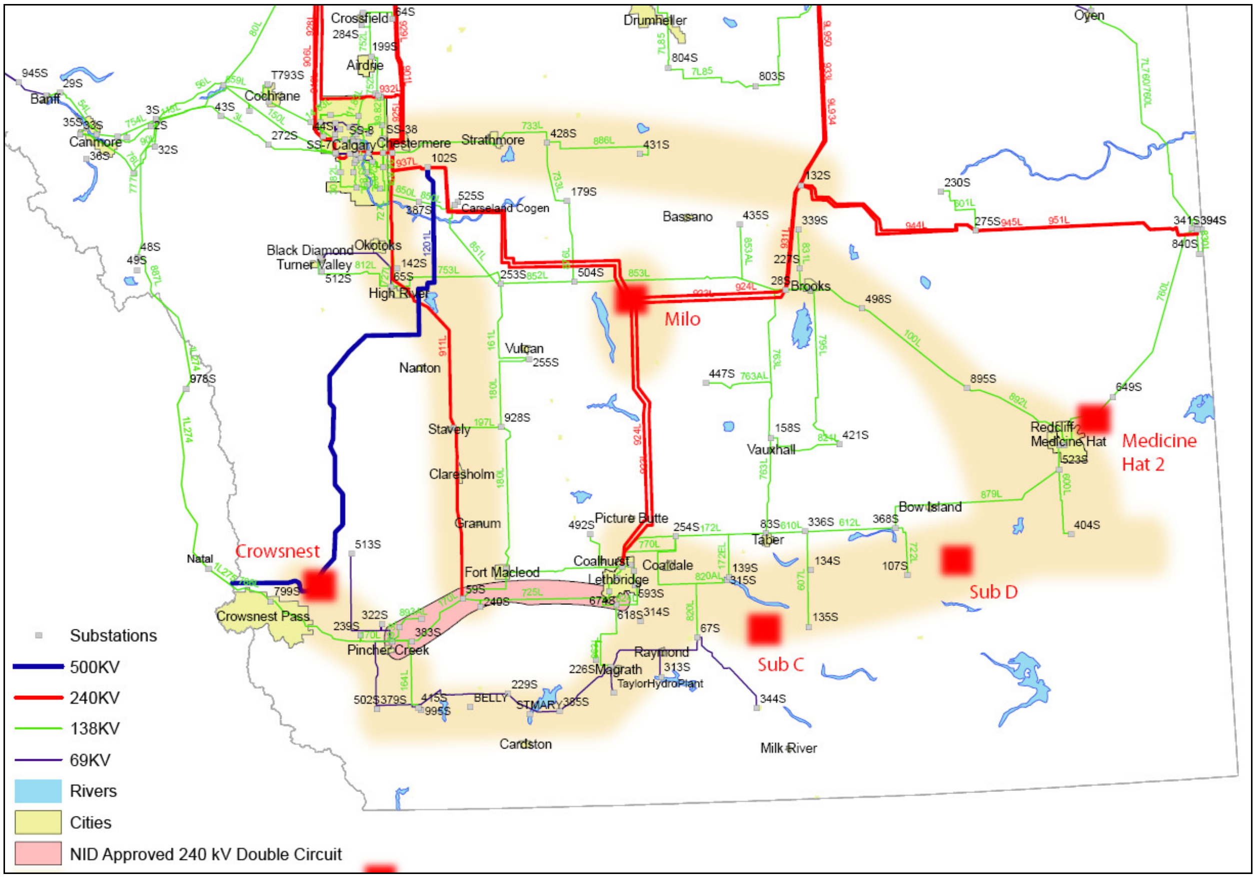


Some of the new 240 kV transmission lines would initially be built as double circuit lines with conductor initially strung on one side. The looping of the new 240 kV transmission lines will help to avoid the transfer limitations caused by longer lines.

Figure 4.2-2 illustrates the concept of the looped 240 kV Alternative 1A. The siting of proposed transmission lines and substations has not been considered in the NID stage but will be considered at the facilities application stage. Therefore, the possible locations of new 240 kV transmission facilities have been illustrated by the shaded areas.

The details of the 240 kV looped Alternatives 1A, 1B and 1C are included in Appendix C. Alternatives 1B and 1C were only slight variations to Alternative 1A as illustrated in Appendix C.

Figure 4.2-2 Alternative 1A – Looped 240 kV

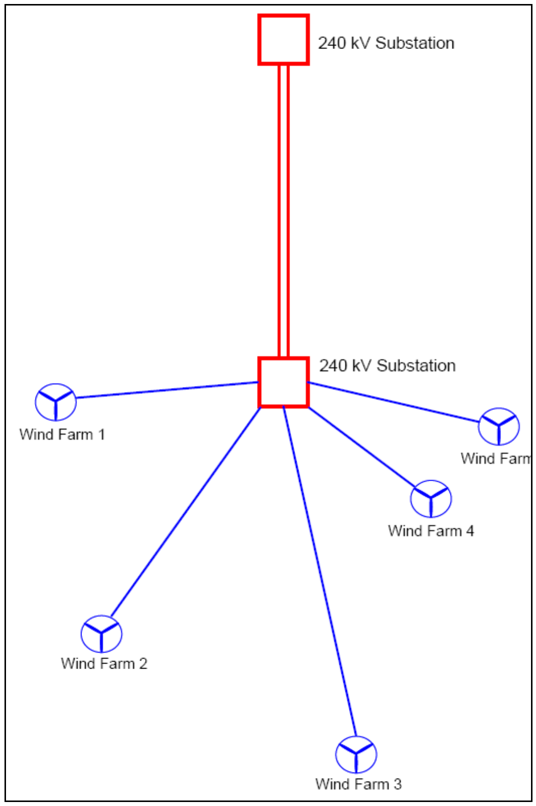


4.2.2 Alternative 2 – Radial 240 kV

A 240 kV radial alternative was considered which would also require new 240 kV transmission lines across southern Alberta. The objective for developing this alternative was to arrive at a lower capital cost alternative so that the impact on rate payers is lower compared to the other alternatives. The new 240 kV lines would extend as radial circuits from existing 240 kV substations such as Peigan, Lethbridge and West Brooks and would terminate at new 240 kV switching stations where future wind generators could connect. The radial 240 kV transmission lines would be constructed as double circuits to meet the AESO Reliability Criteria. Some of the new 240 kV lines would be utilized to collect wind energy onto the bulk 240 kV system, where it can be delivered to Alberta load centres.

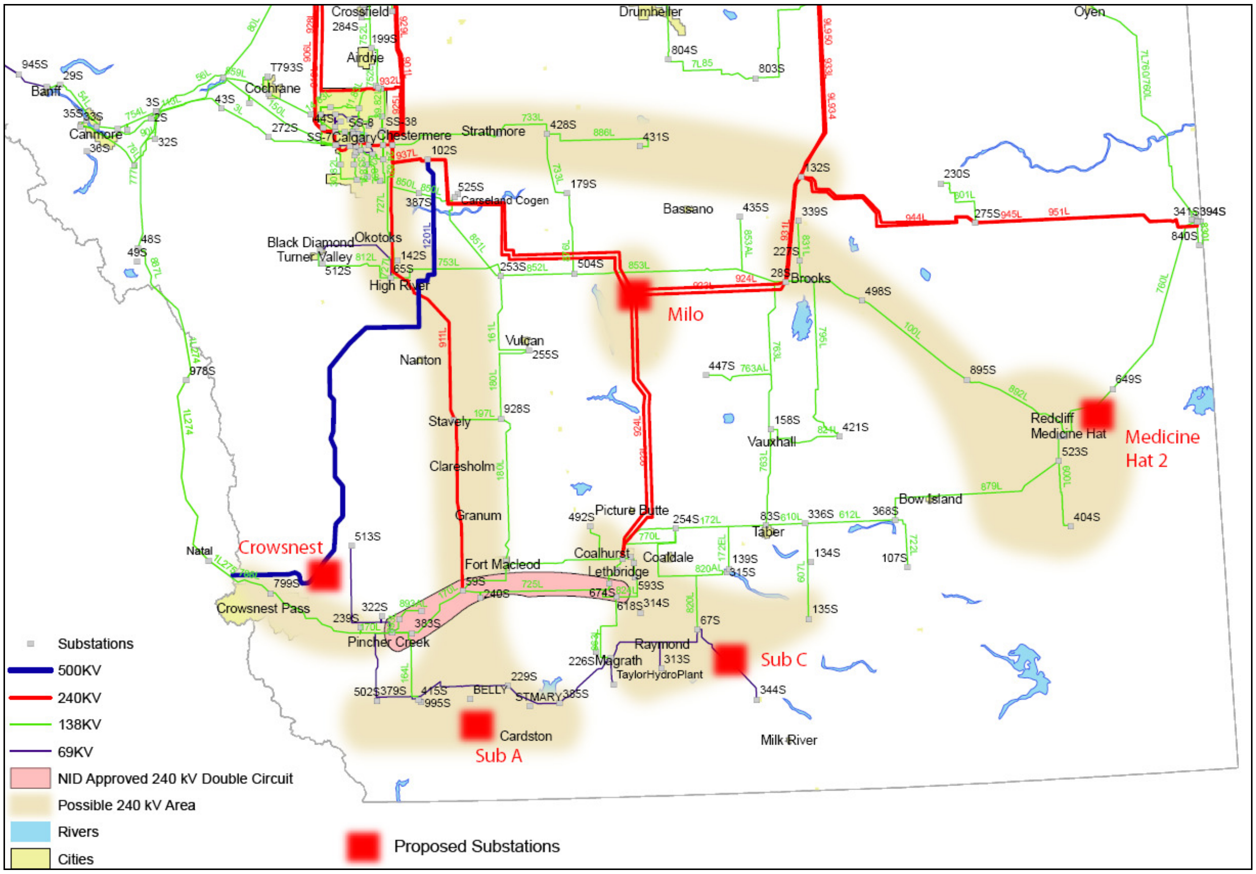
Figure 4.2-3 shows how the wind farms will be connected to Alternative 2. In Alternative 2, wind farms will connect directly to the system 240 kV substations.

Figure 4.2-3 Radial Wind Farm Connection Configuration



A significant disadvantage of the 240 kV radial alternative is that future expansion would require additional 240 kV lines resulting in proliferation of transmission lines to connect wind farms to hubs. The new 240 kV radial transmission lines will be of substantial length which would place limitations on the maximum amount of power that could be delivered from the remote southern Alberta region. Figure 4.2-4 illustrates the 240 kV radial alternative and the details are included in Appendix C. The 240 kV radial alternative is identified in subsequent analysis as Alternative 2. The siting of proposed transmission lines and substations has not been considered in the NID stage but will be considered at the facilities application stage. Therefore, the possible locations of new 240 kV transmission facilities have been illustrated by the shaded areas.

Figure 4.2-4 Alternative 2 – Radial 240 kV

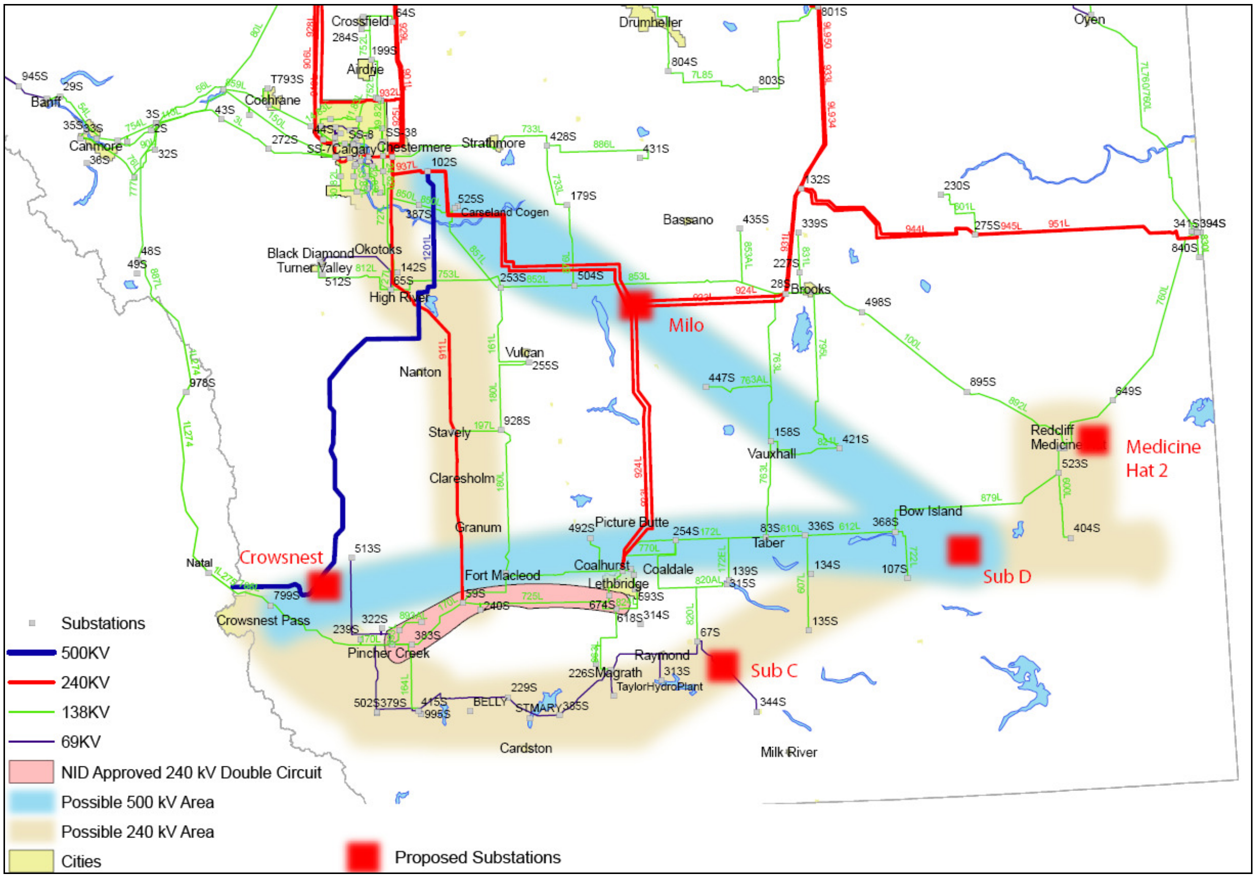


4.2.3 Alternative 3 – Looped 500 kV

The 500 kV looped alternative would require a new 500 kV AC transmission backbone loop in southern Alberta. The existing 500 kV line which connects Alberta to British Columbia would be utilized as part of the new 500 kV loop. Wind energy would be collected through existing and new 240 kV transmission lines and delivered to the 500 kV backbone loop by new 500/240 kV substations. The 240 kV transmission lines collecting the wind generation would be looped similar to the Figure 4.2-1 above.

The 500 kV looped alternative would have a higher capital cost than the 240 kV alternatives. This high initial cost poses the risk of stranded investment in the system if less than anticipated wind develops in the next ten years. Figure 4.2-5 illustrates the 500 kV looped alternative and the details are included in Appendix C. The 500 kV looped alternative is identified in subsequent analysis as Alternative 3. The siting of proposed transmission lines and substations has not been considered in the NID stage but will be considered at the facilities application stage. Therefore, the possible locations of new transmission facilities have been illustrated by the shaded areas.

Figure 4.2-5 Alternative 3 – Looped 500 kV



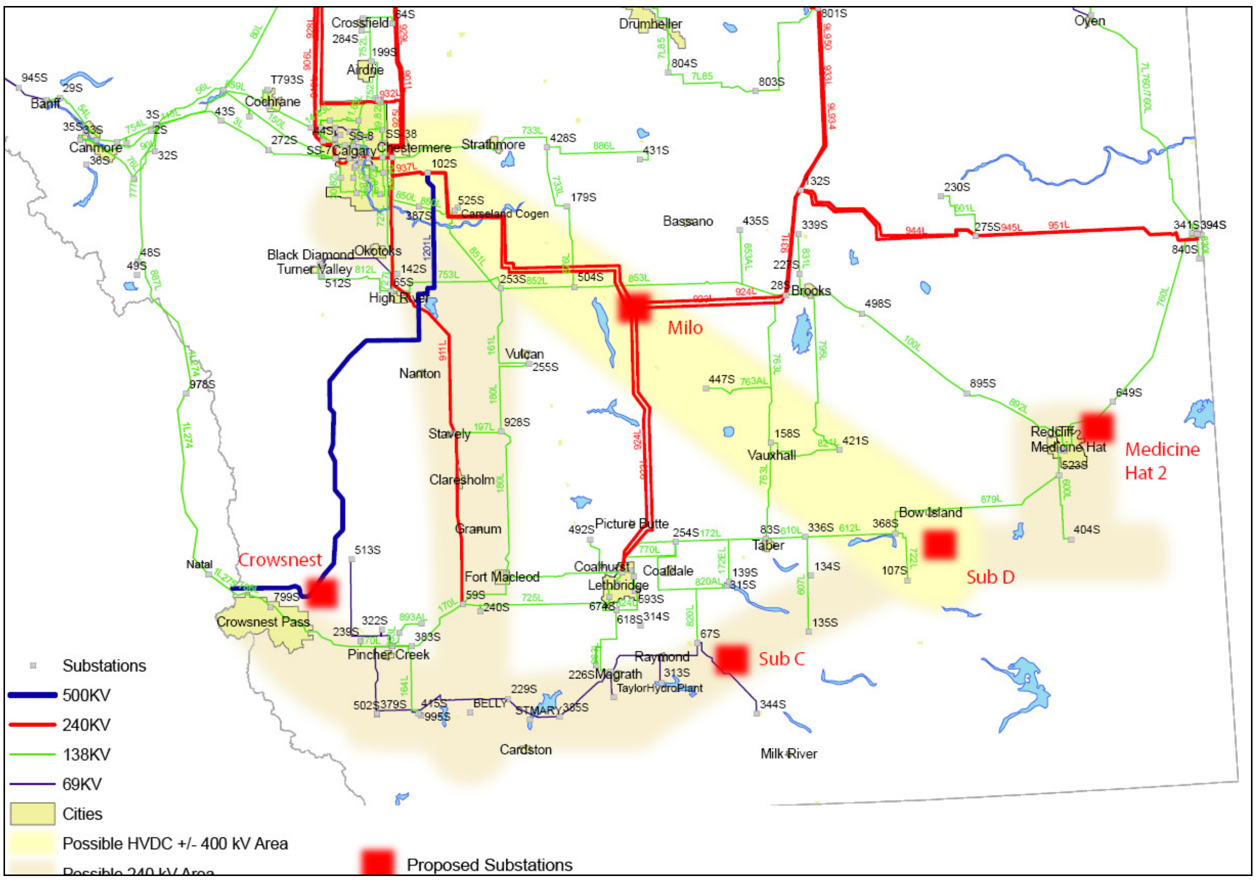
4.2.4 *Alternative 4 - HVDC Classic*

A HVDC alternative was considered which would require a new HVDC transmission line across southern Alberta. New converter/inverter substations would be needed at each end of the new HVDC line. The new converter/inverter substation at the north end of the new HVDC line would be connected to the existing Langdon substation. The new converter/inverter substation at the south end of the new HVDC line would likely be located near Bow Island.

Similar to the looped 500 kV Alternative 3, wind generators would be connected to the south converter station through new 240 kV transmission lines. The 240 kV transmission lines collecting the wind generation would be looped similar to the Figure 4.2-1 above. The new HVDC line would be utilized for transferring wind energy to central Alberta, where it would be delivered to the load centres by the existing transmission system.

The HVDC alternative would require high initial capital investment. This high initial cost poses the risk of stranded investment in the system if less than anticipated wind develops in the next ten years. Figure 4.2-6 illustrates the HVDC alternative and the details are included in Appendix C. The HVDC alternative is identified in subsequent analysis as Alternative 4. The siting of proposed transmission lines and substations has not been considered in the NID stage but will be considered at the facilities application stage. Therefore, the possible locations of new transmission facilities have been illustrated by the shaded areas.

Figure 4.2-6 Alternative 4 - HVDC Classic



5 Evaluation of Transmission Alternatives

Alternatives 1A, 1B, 1C, 2, 3 and 4 were evaluated based on technical, economic, land impact and social factors. Power flow analysis was completed for all alternatives to evaluate their ability to integrate 2,700 MW of wind generation in the southern region. Transient stability, reactive power margin, short circuit and subsynchronous resonance analyses were performed only for Alternative 1A to confirm its compliance with all AESO Reliability Criteria.

5.1 Power Flow Analysis

Power flow analysis for each alternative was completed for the 2013 (five-year) and 2017 (ten-year) scenarios. Southern Alberta is a summer peaking region, hence only summer load conditions were analyzed. The following scenarios were created for Alternatives 1A, 1B, 1C, 2, 3 and 4.

- 2013 Summer Peak
- 2013 Summer Light
- 2017 Summer Peak
- 2017 Summer Light

5.1.1 Model Development

The power flow cases were developed based on the various assumptions including load forecasts, generation scenarios, projected system topology upgrades, and wind farm injection points.

The summer light and summer peak load forecasts for 2013 and 2017 can be found in Table 2.2-1. Generation scenario B5 was used for generation dispatch, refer to section 2.2.3 for a detail discussion on the generation scenarios. Table 5.1-1 compares the Alberta interchange assumptions for the summer light and summer peak cases in both 2013 and 2017.

Table 5.1-1 AIES Interchange Assumptions for 2013 and 2017

Alberta Intertie	Summer Light	Summer Peak
MATL	0 MW	0 MW
AB - BC	1000 MW export	0 MW
AB - SK	0 MW	150 MW import

The network topology for the summer light and summer peak base cases were identical. The network topology was developed to reflect possible future system improvements as necessary for 2013 and 2017. The following is a list of system projects included in the 2013 and 2017 cases by planning region/area.

Calgary Area:

- [2013, 2017] - New Calgary South Substation with 2 x 400MVA; 240/138 kV Transformers
- [2017] - New 240 kV EnmaxPS Substation
- [2013, 2017] - New double circuit 240 kV transmission line from Calgary South to Sarcee
- [2013, 2017] - New double circuit 240 kV transmission line from Calgary South to EnmaxPS
- [2013, 2017] - New double circuit 240 kV transmission line from EnmaxPS to Janet
- [2013, 2017] - 917L Janet to East Calgary 240 kV line upgraded to 672 MVA rating
- [2017] - 936L and 937L Janet to Langdon 240 kV line upgraded to 1256 MVA

Bulk System:

- [2013, 2017] - Upgrade of 1202L 500 kV line from Keephills to Ellerslie
- [2013, 2017] - New 500 kV line from Langdon to Genesee
- [2013, 2017] - New 240 kV line from Ellerslie to Ft. Saskatchewan
- [2013, 2017] - New 500 kV line from Ellerslie to McMillan
- [2017] - New 240 kV line from McMillan to Brintnell

Central Region:

- [2013, 2017] - Monitor Substation upgrade with 240/144 kV 400 MVA transformer
- [2013, 2017] - Oyen Substation upgrade with 240/144 kV 400 MVA transformer
- [2013, 2017] - New 240 kV line from Monitor to Metiskow
- [2017] - New 240 kV line from Monitor to Oyen
- [2017] - New double circuit 240 kV line from Oyen to Anderson

- [2013, 2017] - 9L27 (Paintearth to Cordel 240 kV line) upgraded to 332 MVA
- [2013, 2017] - 760L/7L760 (Oyen – Dome Empress 138/144 kV line) upgraded to 114 MVA and 146 MVA (summer and winter rating respectively)
- [2013, 2017] - New 240 kV 100 MVAr SVC at Hansman Lake Substation
- [2013, 2017] - New 144 kV 20 MVAr SVC at Rowley Substation
- [2013, 2017] - New 2 x 10 MVAr capacitor banks at Metiskow Substation
- [2013, 2017] - New 5 MVAr capacitor bank at Rowley Substation

All the approved projects for southern Alberta except the Vauxhall area line clearance upgrades and proposed Hays to Burdett 138 kV line were incorporated in the 2013 and 2017 cases. The High River and Glenwood/Drywood area reinforcements were also included in the 2013 and 2017 cases. A discussion of the High River and Glenwood/Drywood areas is included in Section 8.2. In addition, the 240 kV line currently proposed by the Wild Rose developer was added to the 2013 and 2017 cases. This 240 kV line was connected radially to the Cypress Substation.

After the model topologies were updated with the changes described above, the 2013 and 2017 cases were inserted into Western Electricity Coordinating Council (WECC) cases. This was done to ensure that the cases contained an accurate representation of the Alberta to British Columbia and the Montana to Alberta (MATL) interchange flows during contingency simulations.

In developing the model data for each reinforcement alternative, different conductor types were compared to determine the optimal conductors for the transmission plans. The four conductor types considered for 240 kV alternatives were the 477 ACSS, 477 ACSR (Hawk), 795 ACSR (Drake) and the 1033 ACSR (Curlew). Table 5.1-2 below shows the rating for each conductor for a single circuit.

Table 5.1-2 Conductor Ratings

Conductor Type	Summer Rating (MVA)	Winter Rating (MVA)
240 kV Twin-Bundle 477 ACSS (200 deg C)	959	1,048
240 kV Twin-Bundle 477 ACSR (Hawk)	600	744
240 kV Twin-Bundle 795 ACSR (Drake)	874	1,103
240 kV Twin-Bundle 1033 ACSR (Curlew)	1,008	1,275

The rating of each conductor was evaluated in conjunction with the location and requested capacity (MW) of wind interest zones. It was observed that some of the more remote wind interest zones exceeded 700 MW of requested wind interconnections. Given the possibility that these wind farms could materialize, the 600 MVA rating of the 477 ACSR conductor was considered too limiting for future growth.

The 795 ACSR and 1033 ACSR conductors have much lower resistances than the 477 ACSS conductor and result in lower system losses. A loss analysis of the alternatives was completed as part of the Economic Evaluation in Section 5.7. Table 5.1-3 below shows the conductor impedances in per unit per kilometer values.

Table 5.1-3 Conductor Impedances

Conductor Type	Impedance (pu/km)		Admittance (pu/km)
	R	X	B
240 kV Twin-Bundle 477 ACSS (Hawk) - Single Circuit	0.000349	0.000883	0.002691
240 kV Twin-Bundle 795 ACSR (Drake) - Single Circuit	0.000082	0.000611	0.002724
240 kV Twin-Bundle 1033 ACSR (Curlew) - Single Circuit	0.000066	0.000134	0.012448

Based on the system loss implications, the 477 ACSS (Hawk) conductor was only used for one of the proposed 240 kV transmission alternatives (Alternative 2) to evaluate the possible savings in capital cost. For the remaining alternatives, a combination of twin bundle 795 ACSR and twin bundle 1033 ACSR conductors was used.

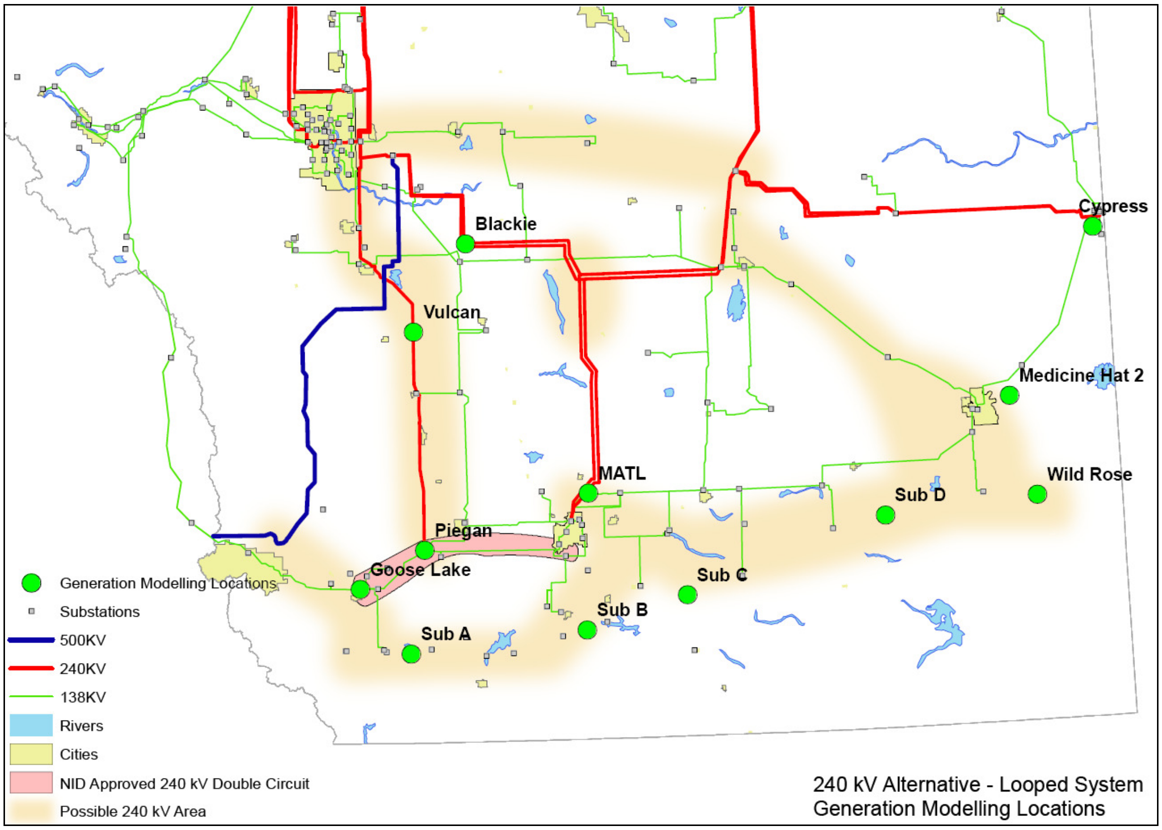
5.1.1.1 Wind Interconnection Assumptions

By 2017, approximately 2,700 MW of wind is forecasted to be interconnected in the southern region. Section 3.1.1 discusses Alberta wind development expectations in more detail. The exact location of the wind generation that will come on line in the next ten years cannot be predicted at this time. For power flow analysis, it was assumed that the wind capacity would develop in each zone in proportion to the actual wind interest. Therefore, wind dispatches for 2013 and 2017 were created by proportionally scaling down the actual wind interest in the southern region to match the AESO forecasted values for those years. The magnitude and location of the proportional wind dispatch was modeled at collector substations near the wind interest zones for testing the alternatives as shown in Table 5.1-4. The collector substation locations are shown in Figure 5.1-1. This wind generation is in addition to the 497 MW of wind generation currently connected to the system. The wind dispatch for 2013 was based on the first stage of transmission development for each of the alternatives. Transmission facilities for collector Subs A, B and C are part of stage II development and therefore, no additional wind was dispatched at those locations for 2013.

Table 5.1-4 Wind Dispatch for Proportional Representation of Wind Interest

Collector Substation	Actual Wind Interest (MW)	2013 Wind Dispatch (MW)	2017 Wind Dispatch (MW)
Goose Lake	1,537	282	556
Peigan	724	133	262
MATL	900	165	326
Blackie	173	32	63
Vulcan	102	19	37
Sub A	300	0	109
Sub B	590	0	213
Sub C	440	0	159
Sub D	1,026	189	371
Med Hat2	515	95	186
Cypress	515	95	186
Wild Rose	640	118	232
Total	**7,462**	**1,128**	**2,700**

Figure 5.1-1 Location of Wind Generation Collector Substations



5.1.2 Power Flow Results for 2013

For the 2013 power flow analysis, the first stage of the transmission development as well as Medicine Hat area reinforcements were modeled for Alternatives 1A, 1B, 1C, 2, 3 and 4. Details about the staging of the alternatives are included in Appendix C.

Both Category A and B contingency events were simulated for each alternative for the 2013 summer peak and summer light load conditions. The detailed results of the power flow studies for 2013 are provided in Appendix D and are summarized in Table 5.1-5.

The results indicate that the first stage of transmission development meets the AESO Reliability Criteria for the forecasted 2013 wind dispatch with the exception of the overload identified in the table. The first stage of development does not include reinforcements in the Blackie area which will alleviate the West Brooks to Queenstown overload for the Alternative 1A, 1B, 1C and 2.

Table 5.1-5 2013 Power Flow Analysis - Summary of Results

Alternative	Overloaded System Elements
1A, 1B, 1C and 2	853L West Brooks to Queenstown 108% overload

5.1.3 Power Flow Results for 2017

The power flow analysis for 2017 was completed for each alternative including all three stages of development. Both Category A and B events were studied for all the alternatives. The power flow plots for the Category A and B events are also included in Appendix D. A summary of results is included as Table 5.1-6. The power flow results for 2017 demonstrate that once all three stages of development are implemented, the alternatives meet the AESO Reliability Criteria for thermal loading and steady state voltage.

Table 5.1-6 Power Flow Analysis - Summary of Results

Alternative	Thermal Loading Violations	Voltage Criteria Violations
Alt 1A	None	None
Alt 1B	None	None
Alt 1C	None	None
Alt 2	None	None
Alt 3	None	None
Alt 4	None	None

5.1.4 Power Flow Sensitivity Analysis for 2017

As previously discussed, the actual wind dispatch which occurs in 2017 will be a function of the location in which wind develops. Therefore, it was prudent to consider different possible wind dispatch scenarios in 2017. In addition to the proportional wind dispatch scenario discussed above, power flow sensitivity analysis was completed for Alternative 1A under the following scenarios;

- East Wind Dispatch
- West Wind Dispatch
- Proportional Wind Dispatch with 300 MW of Imports on MATL
- Proportional Wind Dispatch with 1000 MW Bow City Generation

The east and west wind scenarios assume that the future wind generation interconnects primarily in the eastern or western regions of southern Alberta respectively. The assumptions for the generation dispatch locations in the east and west wind scenarios are provided in Table 5.1-7. The west and east wind dispatches were created by allocating the forecasted 2,700 MW to the west and east collector substations in proportion to the actual wind interest. The dividing line between east and west was roughly taken as a north-south line through Lethbridge.

Table 5.1-7 Wind Dispatch for Sensitivity Analysis

Collector Substation	Actual Wind Interest (MW)	West Wind Dispatch (MW)	East Wind Dispatch (MW)
Goose Lake	1,537	959	0
Peigan	724	452	0
MATL	900	562	0
Blackie	173	108	0
Vulcan	102	64	0
Sub A	300	187	0
Sub B	590	368	0
Sub C	440	0	379
Sub D	1026	0	883
Med Hat2	515	0	643
Cypress	515	0	243
Wild Rose	640	0	551
Total	**7,462**	**2,700**	**2,700**

Sensitivity analyses were also carried out for the proportional wind distribution scenario with imports of 300 MW from Montana to Alberta on the MATL line and the 1000 MW Bow City generation scenario. The MATL line was modeled with a phase shifter at the MATL substation to control the Montana to Alberta interchange. Based on the initial information available on the approximate location of the proposed Bow City power plant, the scenario was modeled with a total of 1000 MW of generation injected into the Westbrooks substation.

The power flow plots for Category A and B events for the Alternative 1A sensitivity studies are also included in Appendix D. Table 5.1-8 lists the system reinforcements that would resolve AESO Reliability Criteria violations identified by the sensitivity analyses results. These system reinforcements are not considered required in this NID because they are unlikely scenarios. The AESO will be closely monitoring actual wind interconnections to continually plan for the future. If one of the scenarios materializes, the AESO will take appropriate action with a separate application.

Table 5.1-8 Power Flow Sensitivity Analysis for Alternative 1A

Sensitivity Scenario	Required Reinforcements
West Wind Scenario	Upgrade 172L 138 kV line from Coaldale to Taber to a twin-bundled 477 ACSR conductor
East Wind Scenario	Tie in the 240 kV line from North Lethbridge to Milo at MATL
	Install a second circuit on the Sub C to MATL 240 kV double circuit tower
	Upgrade 760L, 138 kV line from Cypress to Empress to Dome Empress to a twin-bundled 477 ACSR conductor
MATL 300 MW Import Scenario	Tie in the 240 kV line from North Lethbridge to Milo at MATL
Bow City 1,000 MW Generation Scenario	No additional reinforcements required in the southern region

5.2 Reactive Power Margin Analysis

P-V and Q-V analysis was also carried out for Alternative 1A in order to calculate the reactive power margins available under Category B conditions as well as to ensure that the reactive power compensation recommended is adequate under normal and contingency conditions. The results of the analysis are also included in Appendix D and reveal that Alternative 1A meets the AESO Voltage Stability Criteria.

5.3 Transient Stability Analysis

A transient stability analysis was performed to assess the proposed new wind generation and network upgrades on system stability. Transient stability analysis is also commonly referred to as dynamic stability analysis. The analysis was performed for the Alternative 1A with full wind dispatched to ensure the system remains stable under dynamic conditions. This analysis presents the stability response of the AESO system with the Alternative 1A configuration to Category B and C contingencies as specified in the AESO Transmission Reliability Criteria.

5.3.1 Modeling Assumptions

The specific wind turbine manufacturers for the potential wind farms in southern Alberta will not be known until later in their individual interconnection processes. Therefore, in order to model large scale wind generation interconnected to the southern Alberta grid, standard wind farm dynamic models were developed. The WECC Wind Generator Modeling Group (WGMG) has identified the following four basic model types for commercial, utility-scale wind turbine technologies.

- Type 1 – Conventional induction generator
- Type 2 – Wound rotor induction generator with variable rotor resistance
- Type 3 – Doubly fed induction generator
- Type 4 – Full converter interface

The WGMG classified some of the available commercial wind turbines into the basic modeling types as shown in Table 5.3-1. The table is not an exhaustive list of available turbines, but is an illustration of the wide variety of available turbine types.

Table 5.3-1 Wind Turbine Model Types

Type 1 Turbines	Type 2 Turbines	Type 3 Turbines	Type 4 Turbines
Vestas V82/72	Vestas V80/47	GE 1.5MW Series	Enercon E70
Bonus 1.3/2.3 MW	Suzlon 2.0 MW	Gamesa G80/90	Clipper 2.5 MW
MPS MWT1000A		Vestas V90	GE 2.x Series

The transient stability analysis was performed using both type 1 and type 3 turbine models to compare possible differences in wind turbine stability response. The Vestas V82 1.65 MW wind turbine model (V82) was selected to represent a type 1 turbine response and the General Electric 1.5 MW wind turbine model (GE1.5) was selected to represent a type 3 turbine response.

The V82 and GE1.5 turbine dynamic models were used to develop standard wind farm models to meet the AESO's Low Voltage Ride Through (LVRT) criteria and reactive power requirements. The standard wind farm models were developed for generation capacity blocks of approximately 25, 50, 150 and 250 MVA for both the V82 and GE1.5 turbines. The total wind generation dispatch at a collector substation was then modeled by combining the standard model capacity blocks on the 240 kV collector bus.

For example, 556 MW of new wind generation was modeled at the Goose Lake Substation by combining two 250 MVA model blocks, one 50 MVA model block and one 25 MVA model block. This example is illustrated for the type 1 (V82) machine and type 3 (GE1.5) machine in Figures 5.3-1 and 5.3-2, respectively.

The SVC and capacitor shown in the V82 wind farm model figure are devices that are part of the V82 simulation program made available by Vestas. The capacitor serves to correct the power factor at the wind machine terminals to unity. Therefore, the V82 capacitor does not contribute to the AESO steady state capacitive requirement for interconnection. Note that for the V82 model, an additional DVAR device was utilized to meet the AESO dynamic and steady state reactive power requirements.

Figure 5.3-1 Goose Lake Collector Substation Type 1 (V82) Wind Farm Model

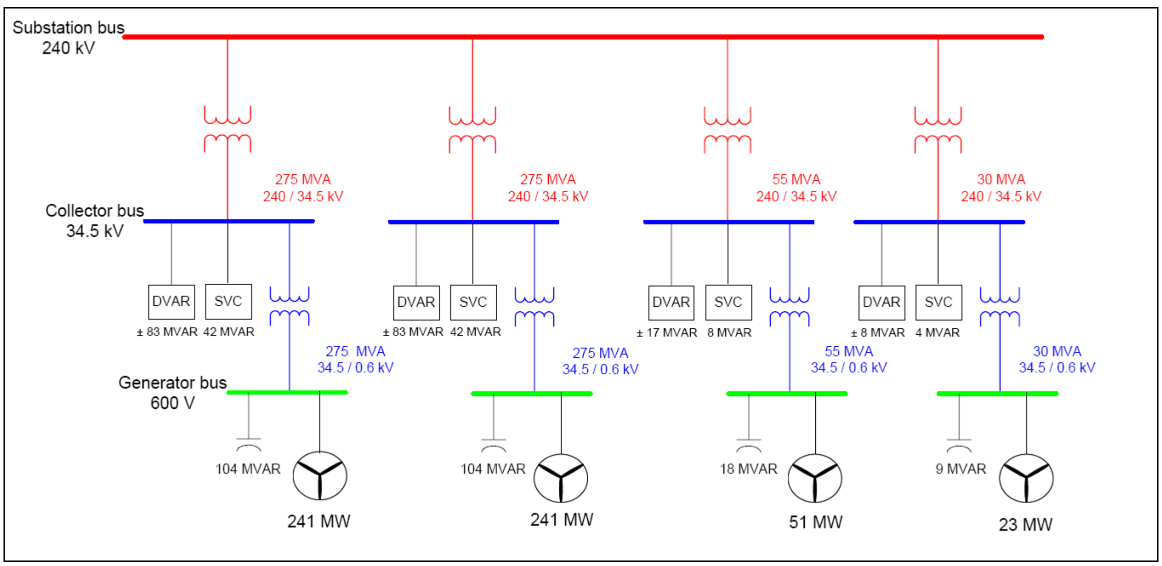
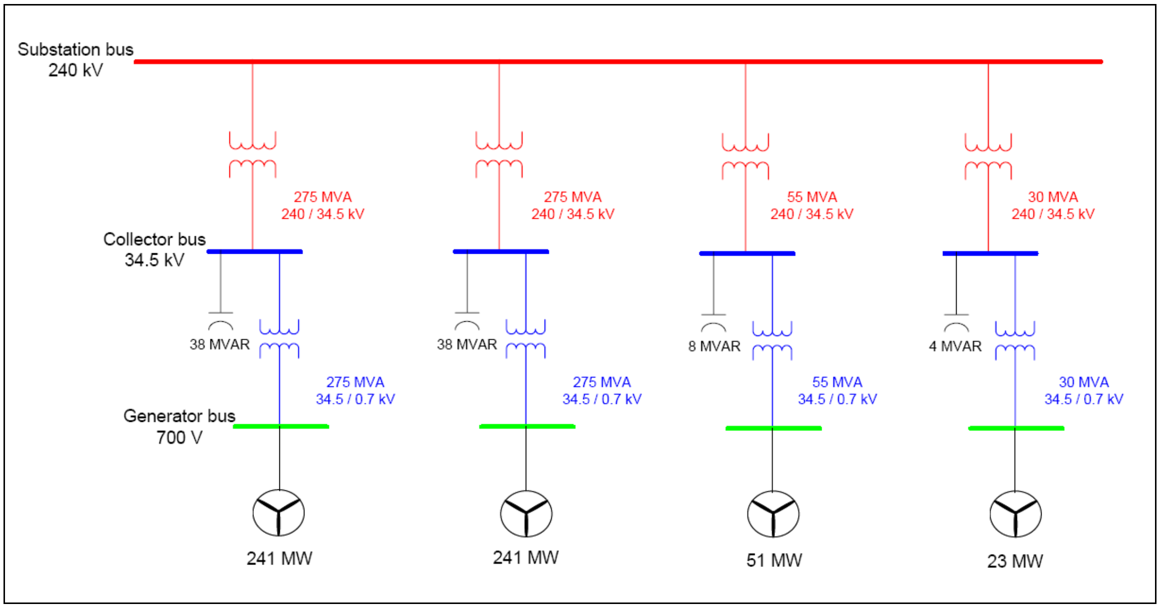


Figure 5.3-2 Goose Lake Collector Substation Type 3 (GE1.5) Wind Farm Model



The dynamics model data for a 250 MVA block wind farm, including associated reactive power devices, are provided for the V82 and GE1.5 machines in Appendix E.

The stability analysis was performed using six different scenarios of load flow and associated dynamics databases shown in Table 5.3-2. Note that in all six scenarios, 2,700 MW of new wind generation was modeled on-line at collection substations throughout Southern Alberta as was previously defined for the proportional wind scenario (see Table 5.1-4 above).

Table 5.3-2 Scenarios for Transient Stability Analysis

Scenario Number	Season	AB-BC Interchange	Expansion Alternative	Wind Turbine Model	Additional Wind Generation in South
1	2017 Summer Light	1,000 MW export	Alt 1A	V82	2,700 MW
2	2017 Summer Shoulder	Neutral	Alt 1A	V82	2,700 MW
3	2017 Summer Shoulder	800 MW export	Alt 1A	V82	2,700 MW
4	2017 Summer Light	1,000 MW export	Alt 1A	GE1.5	2,700 MW
5	2017 Summer Shoulder	Neutral	Alt 1A	GE1.5	2,700 MW
6	2017 Summer Shoulder	800 MW export	Alt 1A	GE1.5	2,700 MW

The following fault clearing times were used in the transient stability analyses:

- 240 kV Normal Total Clearing Time = 5/6 (near end/far end) cycles
- 500 kV Total Clearing Time = 4/5 (near end/far end) cycles
- Delayed Clearing Time = 18 cycles

The AESO Reliability Criteria requires modeling 20% of the total load as motor load. The remaining load was assumed to be constant current and impedance for real and reactive power, respectively.

5.3.2 Transient Stability Analysis Results

The southern Alberta region was tested extensively with Alternative 1A in place. Three phase to ground faults were simulated for Category B events throughout the south system and the response of the system was observed. The AESO Reliability Criteria also requires Category C contingencies to be studied. This is to ensure that under Category C conditions, there are no uncontrolled or cascading outages in the system. Several Category C events were simulated in the southern region.

Category B fault analysis was performed for Alternative 1A. Category B faults are defined as three-phase faults of a transmission line or transformer with normal clearing time. Figures 5.3-3, 5.3-4 and 5.3-5 show the locations where the Category B faults were applied to the system. Table 5.3-3 summarizes the fault descriptions and results for the Category B fault analysis for all six scenarios. Specific transient simulation plots for Category B contingencies can be found in Appendix E.

Figure 5.3-3 Category B Fault Locations - Southwestern Area of Southern Region

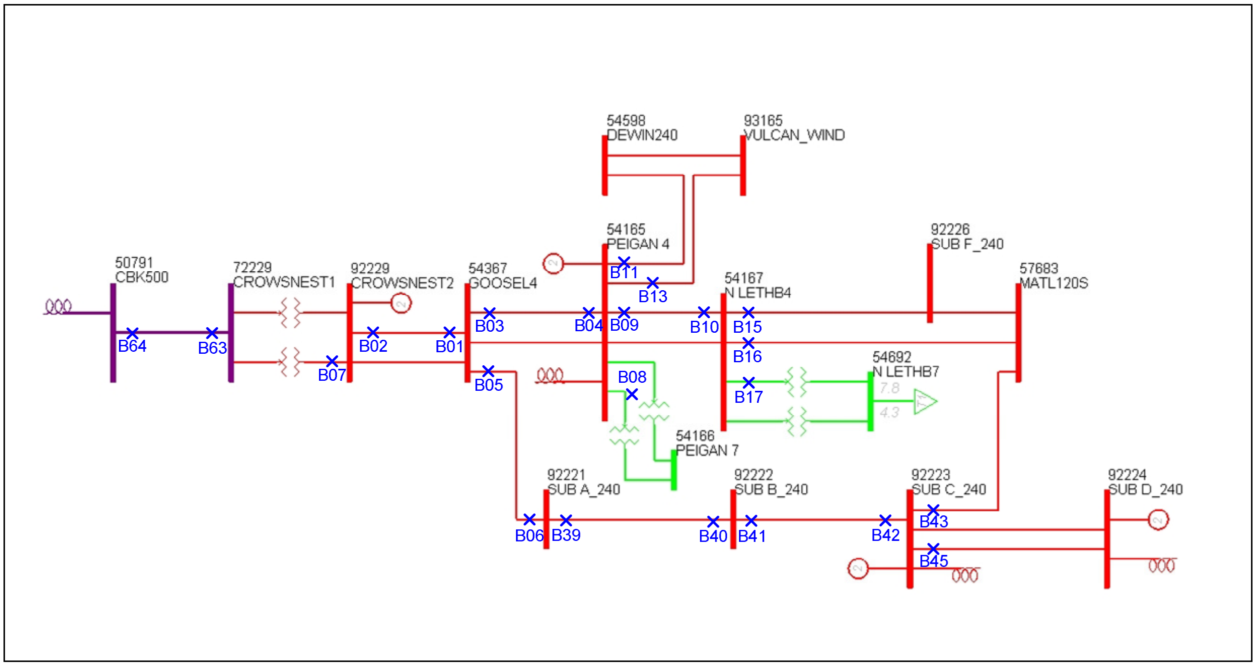


Figure 5.3-4 Category B Fault Locations – Northwestern Area of Southern Region

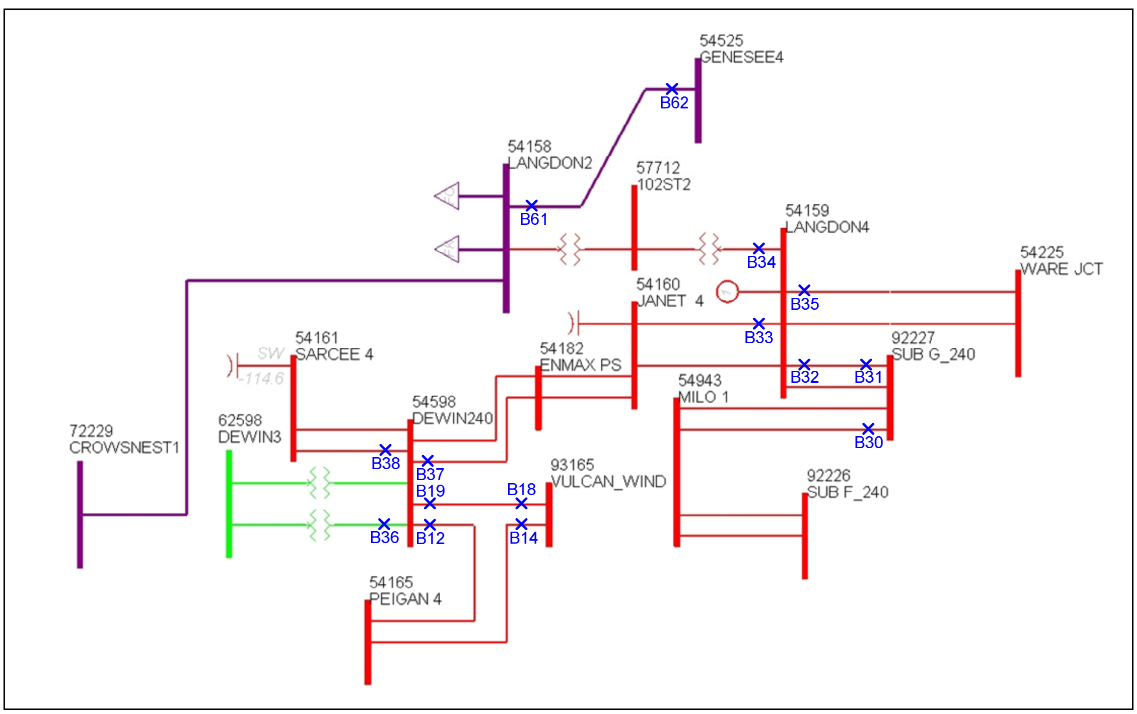


Figure 5.3-5 Category B Fault Locations - Eastern Area of Southern Region

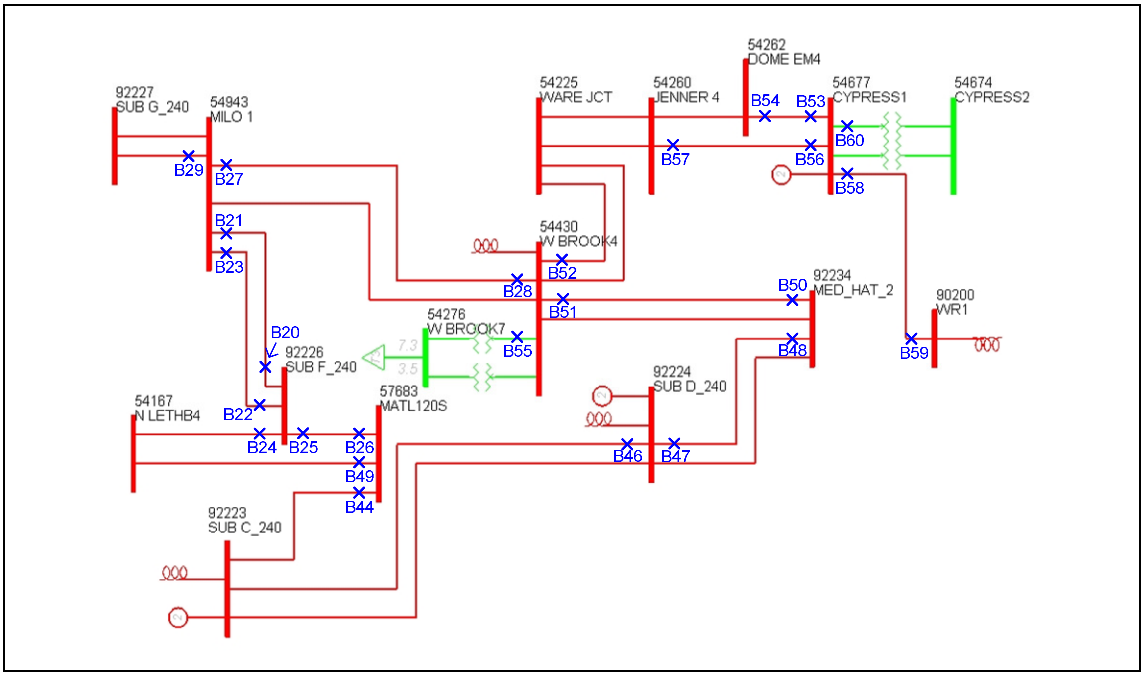


Table 5.3-3 Stability Results for Category B Events

Case ID	Description	Observations
B01**	3ph fault at Gooselake 240kV line to Crowsnest 5 cycles: trip Gooselake CB on Gooselake - Crowsnest line 6 cycles: trip Crowsnest CB on Gooselake - Crowsnest line	System stable Good voltage recovery No load shedding
B02	3ph fault at Crowsnest 240kV line to Gooselake 5 cycles: trip Crowsnest CB on Crowsnest - Gooselake line 6 cycles: trip Gooselake CB on Crowsnest - Gooselake line	System stable Good voltage recovery No load shedding
B03	3ph fault at Gooselake 240kV line to Peigan 5 cycles: trip Gooselake CB on Gooselake - Peigan line 6 cycles: trip Peigan CB on Gooselake - Peigan line	System stable Good voltage recovery No load shedding
B04*	3ph fault at Peigan 240kV line to Gooselake 5 cycles: trip Peigan CB on Peigan - Gooselake line 6 cycles: trip Gooselake CB on Peigan - Gooselake line	System stable Good voltage recovery No load shedding
B05	3ph fault at Gooselake 240kV line to SubA 5 cycles: trip Gooselake CB on Gooselake - SubA line 6 cycles: trip SubA CB on Gooselake - SubA line	System stable Good voltage recovery No load shedding
B06	3ph fault at SubA 240kV line to Gooselake 5 cycles: trip SubA CB on SubA - Gooselake line 6 cycles: trip Gooselake CB on SubA - Gooselake line	System stable Good voltage recovery No load shedding
B07	3ph fault at Crowsnest transformer 5 cycles: trip Crowsnest CB on transformer	System stable Good voltage recovery No load shedding
B08	3ph fault at Peigan transformer 5 cycles: trip Peigan CB on transformer	System stable Good voltage recovery No load shedding
B09	3ph fault at Peigan 240kV line to N_Leth 5 cycles: trip Peigan CB on Peigan - N_Leth line 6 cycles: trip N_Leth CB on Peigan - N_Leth line	System stable Good voltage recovery No load shedding
B10*	3ph fault at N_Leth 240kV line to Peigan 5 cycles: trip N_Leth CB on N_Leth - Peigan line 6 cycles: trip Peigan CB on N_Leth - Peigan line	System stable Good voltage recovery No load shedding
B11	3ph fault at Peigan 240kV line to Dewin 5 cycles: trip Peigan CB on Peigan - Dewin line 6 cycles: trip Dewin CB on Peigan - Dewin line	System stable Good voltage recovery No load shedding
B12*	3ph fault at Dewin 240kV line to Peigan 5 cycles: trip Dewin CB on Dewin - Peigan line 6 cycles: trip Peigan CB on Dewin - Peigan line	System stable Good voltage recovery No load shedding

* Stability simulation plots for V82 machine are included in Appendix E.

** Stability simulation plots for V82 and GE machines are included in Appendix E.

Table 5.3-3 Stability Results for Category B Events (continued)

Case ID	Description	Observations
B13*	3ph fault at Peigan 240kV line to Vulcan 5 cycles: trip Peigan CB on Peigan - Vulcan line 6 cycles: trip Vulcan CB on Peigan - Vulcan line	System stable Good voltage recovery No load shedding
B14	3ph fault at Vulcan 240kV line to Peigan 5 cycles: trip Vulcan CB on Vulcan - Peigan line 6 cycles: trip Peigan CB on Vulcan - Peigan line	System stable Good voltage recovery No load shedding
B15	3ph fault at N_Leth 240kV line to SubF 5 cycles: trip N_Leth CB on N_Leth - SubF line 6 cycles: trip SubF CB on N_Leth - SubF line	System stable Good voltage recovery No load shedding
B16	3ph fault at N_Leth 240kV line to Matl 5 cycles: trip N_Leth CB on N_Leth - Matl line 6 cycles: trip Matl CB on N_Leth - Matl line	System stable Good voltage recovery No load shedding
B17	3ph fault at N_Leth transformer 5 cycles: trip N_Leth CB on transformer	System stable Good voltage recovery No load shedding
B18*	3ph fault at Vulcan 240kV line to Dewin 5 cycles: trip Vulcan CB on Vulcan - Dewin line 6 cycles: trip Dewin CB on Vulcan - Dewin line	System stable Good voltage recovery No load shedding
B19	3ph fault at Dewin 240kV line to Vulcan 5 cycles: trip Dewin CB on Dewin - Vulcan line 6 cycles: trip Vulcan CB on Dewin - Vulcan line	System stable Good voltage recovery No load shedding
B20	3ph fault at SubF 240kV line to Milo 5 cycles: trip SubF CB on SubF - Milo line 6 cycles: trip Milo CB on SubF - Milo line	System stable Good voltage recovery No load shedding
B21*	3ph fault at Milo 240kV line to SubF 5 cycles: trip Milo CB on Milo - SubF line 6 cycles: trip SubF CB on Milo - SubF line	System stable Good voltage recovery No load shedding
B22	3ph fault at SubF 240kV line to Milo 5 cycles: trip SubF CB on SubF - Milo line 6 cycles: trip Milo CB on SubF - Milo line	System stable Good voltage recovery No load shedding
B23	3ph fault at Milo 240kV line to SubF 5 cycles: trip Milo CB on Milo - SubF line 6 cycles: trip SubF CB on Milo - SubF line	System stable Good voltage recovery No load shedding
B24*	3ph fault at SubF 240kV line to N_Leth 5 cycles: trip SubF CB on SubF - N_Leth line 6 cycles: trip N_Leth CB on SubF - N_Leth line	System stable Good voltage recovery No load shedding

* Stability simulation plots for V82 machine are included in Appendix E.

** Stability simulation plots for V82 and GE machines are included in Appendix E.

Table 5.3-3 Stability Results for Category B Events (continued)

Case ID	Description	Observations
B25	3ph fault at SubF 240kV line to Matl 5 cycles: trip SubF CB on SubF - Matl line 6 cycles: trip Matl CB on SubF - Matl line	System stable Good voltage recovery No load shedding
B26	3ph fault at Matl 240kV line to SubF 5 cycles: trip Matl CB on Matl - SubF line 6 cycles: trip SubF CB on Matl - SubF line	System stable Good voltage recovery No load shedding
B27**	3ph fault at Milo 240kV line to WBrook 5 cycles: trip Milo CB on Milo - WBrook line 6 cycles: trip WBrook CB on Milo - WBrook line	System stable Good voltage recovery No load shedding
B28	3ph fault at WBrook 240kV line to Milo 5 cycles: trip WBrook CB on WBrook - Milo line 6 cycles: trip Milo CB on WBrook - Milo line	System stable Good voltage recovery No load shedding
B29	3ph fault at Milo 240kV line to SubG 5 cycles: trip Milo CB on Milo - SubG line 6 cycles: trip SubG CB on Milo - SubG line	System stable Good voltage recovery No load shedding
B30*	3ph fault at SubG 240kV line to Milo 5 cycles: trip SubG CB on SubG - Milo line 6 cycles: trip Milo CB on SubG - Milo line	System stable Good voltage recovery No load shedding
B31	3ph fault at SubG 240kV line to Langdon 5 cycles: trip SubG CB on SubG - Langdon line 6 cycles: trip Langdon CB on SubG - Langdon line	System stable Good voltage recovery No load shedding
B32	3ph fault at Langdon 240kV line to SubG 5 cycles: trip Langdon CB on Langdon - SubG line 6 cycles: trip SubG CB on Langdon - SubG line	System stable Good voltage recovery No load shedding
B33	3ph fault at Langdon 240kV line to Jannet 5 cycles: trip Langdon CB on Langdon - Jannet line 6 cycles: trip Jannet CB on Langdon - Jannet line	System stable Good voltage recovery No load shedding
B34	3ph fault at Langdon transformer 5 cycles: trip Langdon CB on transformer	System stable Good voltage recovery No load shedding
B35*	3ph fault at Langdon 240kV line to Ware_Junction 5 cycles: trip Langdon CB on Langdon - Ware_Junction line 6 cycles: trip Ware_Junction CB on Langdon - Ware_Junction	System stable Good voltage recovery No load shedding
B36	3ph fault at Dewin transformer 5 cycles: trip Dewin CB on transformer	System stable Good voltage recovery No load shedding

* Stability simulation plots for V82 machine are included in Appendix E.

** Stability simulation plots for V82 and GE machines are included in Appendix E.

Table 5.3-3 Stability Results for Category B Events (continued)

Case ID	Description	Observations
B37	3ph fault at Dewin 240kV line to Enmax 5 cycles: trip Dewin CB on Dewin - Enmax line 6 cycles: trip Enmax CB on Dewin - Enmax line	System stable Good voltage recovery No load shedding
B38	3ph fault at Dewin 240kV line to Sarcee 5 cycles: trip Dewin CB on Dewin - Sarcee line 6 cycles: trip Sarcee CB on Dewin - Sarcee line	System stable Good voltage recovery No load shedding
B39	3ph fault at SubA 240kV line to SubB 5 cycles: trip SubA CB on SubA - SubB line 6 cycles: trip SubB CB on SubA - SubB line	System stable Good voltage recovery No load shedding
B40	3ph fault at SubB 240kV line to SubA 5 cycles: trip SubB CB on SubB - SubA line 6 cycles: trip SubA CB on SubB - SubA line	System stable Good voltage recovery No load shedding
B41	3ph fault at SubB 240kV line to SubC 5 cycles: trip SubB CB on SubB - SubC line 6 cycles: trip SubC CB on SubB - SubC line	System stable Good voltage recovery No load shedding
B42*	3ph fault at SubC 240kV line to SubB 5 cycles: trip SubC CB on SubC - SubB line 6 cycles: trip SubB CB on SubC - SubB line	System stable Good voltage recovery No load shedding
B43	3ph fault at SubC 240kV line to Matl 5 cycles: trip SubC CB on SubC - Matl line 6 cycles: trip Matl CB on SubC - Matl line	System stable Good voltage recovery No load shedding
B44*	3ph fault at Matl 240kV line to SubC 5 cycles: trip Matl CB on Matl - SubC line 6 cycles: trip SubC CB on Matl - SubC line	System stable Good voltage recovery No load shedding
B45*	3ph fault at SubC 240kV line to SubD 5 cycles: trip SubC CB on SubC - SubD line 6 cycles: trip SubD CB on SubC - SubD line	System stable Good voltage recovery No load shedding
B46	3ph fault at SubD 240kV line to SubC 5 cycles: trip SubD CB on SubD - SubC line 6 cycles: trip SubC CB on SubD - SubC line	System stable Good voltage recovery No load shedding
B47*	3ph fault at SubD 240kV line to Med_Hat 5 cycles: trip SubD CB on SubD - Med_Hat line 6 cycles: trip Med_Hat CB on SubD - Med_Hat line	System stable Good voltage recovery No load shedding
B48	3ph fault at Med_Hat 240kV line to SubD 5 cycles: trip Med_Hat CB on Med_Hat - SubD line 6 cycles: trip SubD CB on Med_Hat - SubD line	System stable Good voltage recovery No load shedding

* Stability simulation plots for V82 machine are included in Appendix E.

** Stability simulation plots for V82 and GE machines are included in Appendix E.

Table 5.3-3 Stability Results for Category B Events (continued)

Case ID	Description	Observations
B49	3ph fault at Matl 240kV line to N_Leth 5 cycles: trip Matl CB on Matl - N_Leth line 6 cycles: trip N_Leth CB on Matl - N_Leth line	System stable Good voltage recovery No load shedding
B50*	3ph fault at Med_Hat 240kV line to WBrook 5 cycles: trip Med_Hat CB on Med_Hat - WBrook line 6 cycles: trip WBrook CB on Med_Hat - WBrook line	System stable Good voltage recovery No load shedding
B51*	3ph fault at WBrook 240kV line to Med_Hat 5 cycles: trip WBrook CB on WBrook - Med_Hat line 6 cycles: trip Med_Hat CB on WBrook - Med_Hat line	System stable Good voltage recovery No load shedding
B52	3ph fault at WBrook 240kV line to Ware_Junction 5 cycles: trip WBrook CB on WBrook - Ware_Junction line 6 cycles: trip Ware_Junction CB on WBrook - Ware_Junction	System stable Good voltage recovery No load shedding
B53	3ph fault at Cypress 240kV line to Dome_Empress 5 cycles: trip Cypress CB on Cypress - Dome_Empress line 6 cycles: trip Dome_Empress CB on Cypress -	System stable Good voltage recovery No load shedding
B54	3ph fault at Dome_Empress 240kV line to Cypress 5 cycles: trip Dome_Empress CB on Dome_Empress - 6 cycles: trip Cypress CB on Dome_Empress - Cypress line	System stable Good voltage recovery No load shedding
B55	3ph fault at WBrook transformer 5 cycles: trip WBrook CB on transformer	System stable Good voltage recovery No load shedding
B56*	3ph fault at Cypress 240kV line to Jenner 5 cycles: trip Cypress CB on Cypress - Jenner line 6 cycles: trip Jenner CB on Cypress - Jenner line	System stable Good voltage recovery No load shedding
B57	3ph fault at Jenner 240kV line to Cypress 5 cycles: trip Jenner CB on Jenner - Cypress line 6 cycles: trip Cypress CB on Jenner - Cypress line	System stable Good voltage recovery No load shedding
B58	3ph fault at Cypress 240kV line to WR 5 cycles: trip Cypress CB on Cypress - WR line; trip WR 6 cycles: trip WR CB on Cypress - WR line	System stable Good voltage recovery No load shedding
B59	3ph fault at WR 240kV line to Cypress 5 cycles: trip WR CB on WR - Cypress line; trip WR 6 cycles: trip Cypress CB on WR - Cypress line	System stable Good voltage recovery No load shedding
B60	3ph fault at Cypress transformer 5 cycles: trip Cypress CB on transformer	System stable Good voltage recovery No load shedding

* Stability simulation plots for V82 machine are included in Appendix E.

** Stability simulation plots for V82 and GE machines are included in Appendix E.

Table 5.3-3 Stability Results for Category B Events (continued)

Case ID	Description	Observations
B61**	3ph fault at Langdon 500kV line to Genesee 4 cycles: trip Langdon CB on Langdon - Genesee line 5 cycles: trip Genesee CB on Langdon - Genesee line	System stable Good voltage recovery No load shedding
B62	3ph fault at Genesee 500kV line to Langdon 4 cycles: trip Genesee CB on Genesee - Langdon line 5 cycles: trip Langdon CB on Genesee - Langdon line	System stable Good voltage recovery No load shedding
B63**	3ph fault at Crowsnest 500kV line to Cranbook 4 cycles: trip Crowsnest CB on Crowsnest - Cranbook line 5 cycles: trip Cranbook CB on Crowsnest - Cranbook line	System stable Good voltage recovery No load shedding
B64	3ph fault at Cranbook 500kV line to Crowsnest 4 cycles: trip Cranbook CB on Cranbook - Crowsnest line 5 cycles: trip Crowsnest CB on Cranbook - Crowsnest line	System stable Good voltage recovery No load shedding

* Stability simulation plots for V82 machine are included in Appendix E.

** Stability simulation plots for V82 and GE machines are included in Appendix E.

Category C5 fault analysis was performed for the 2017 Summer Light scenario with the V82 and GE1.5 machine (scenarios 1 and 4 in Table 5.3-2). Category C5 faults are defined as double line-to-ground faults of a double circuited transmission tower with normal clearing time. Figures E-4, E-5, and E-6 in Appendix E show the locations where the Category C5 faults were applied to the system. The impedances of the double line to ground faults were calculated at the faulted locations on the system. Table E-2 in Appendix E summarizes the fault descriptions and results for the Category C5 fault analysis. The stability observations reported in Table E-2 are applicable to both V82 and GE1.5 wind turbine results. Specific transient simulation plots for Category C5 contingencies can also be found in Appendix E.

Category C7 fault analysis was performed for the 2017 Summer Light scenario with the V82 and GE1.5 machine (scenarios 1 and 4 in Table 5.3-2). Category C7 faults are defined as single line-to-ground faults of transmission lines with delayed clearing time (stuck breaker condition). For each substation in the south system, the fault location was assumed to be on the 240 kV line with the largest power flow. This fault was then simulated for a stuck breaker at the near end substation as a worst case condition. For breaker and a half or ring-bus substation configurations, the breakers on either side of the faulted line were considered in separate stuck breaker simulations. The impedances of the single line to ground faults were calculated at the faulted locations on the system.

Figures in Appendix E show the locations where the Category C7 faults were applied at each substation. The stuck breaker conditions simulated are identified by breaker number labels in the figure. Breakers without labels were not simulated for stuck breaker conditions. Tables in Appendix E summarize the fault descriptions and results for the Category C7 faults at each substation. All simulation observations reported are applicable to both V82 and GE1.5 wind turbine results. Specific transient simulation plots for Category C7 contingencies can also be found in Appendix E.

The results of the transient stability analysis revealed that the system remained stable during all the Category B and C events simulated in the analysis. The angular damping performance of the generators was monitored using a user model which calculates the damping factor based on successful positive peak ratios (SPPR) from the rotor angle response. The simulation results showed that the damping factors of the generators monitored were in acceptable range.

Single pole tripping and reclosing (SPTR) is a capability that can be employed to enhance the reliability of the transmission system. It is expected that all the new 240 kV breakers proposed as part of the southern Alberta system reinforcement plan will have SPTR capability. The decision to implement the SPTR capability will however be made by the operations group in consultation with the transmission facility owner.

5.4 Sub-synchronous Resonance Analysis

Series compensation is proposed in all alternatives for some of the new 240 kV lines in the southern region. Sub-synchronous resonance (SSR) is a concern in series compensated networks – the series capacitor can result in an electrical resonance in the sub-synchronous frequency range (0-60 Hz). The shaft system of a gas turbine or thermal unit can contain numerous turbines, generators, and mechanical exciters masses on the turbine shaft. This results in a fixed set of mechanical frequencies of oscillation, often in the sub-synchronous range. SSR is a direct concern if the frequencies of the electrical resonances correlate with the mechanical modes of oscillation. The worst cases usually result when there is a direct radial path between the generator and the series capacitor, in which case a higher degree of torsional interaction would occur, resulting in possible shaft damage due to undamped oscillations.

Harmonic impedance scans were performed to compute the electrical impedance as seen from the generator. A resonance in the sub-synchronous frequency region will result in an “impedance dip” – i.e. a variation in the impedance at the resonant frequency. The size of the impedance dip is an approximate indicator of the likelihood for SSR or torsional interactions.

5.4.1 Thermal Power Plant Concerns

Three existing power plants (Sheerness, Carseland and Cavalier) were considered for potential SSR interactions with the series capacitor banks proposed in the southern region. Frequency scans of the electrical network were performed as seen from behind each generator impedance to determine the resonant frequencies of the electrical network under base case and contingency conditions. Contingencies were selected up to Category C which place the generator more radially connected to the nearby series capacitor banks.

The harmonic impedance studies indicate that the new series capacitor will not have an adverse impact on the SSR performance at these generators, at up to Category C contingency/outage conditions. Torsional stress relays, which detect undamped or growing sub-synchronous oscillations and trip units if the oscillations get too large, could be utilized at nearby units as a precaution for SSR impacts.

5.4.2 Wind Farm Concerns

Wind farms can also be affected by nearby series capacitors. According to SSR experts consulted by the AESO, some studies have indicated that doubly fed wind turbines demonstrated low frequency control instabilities and control interactions, whereas a full converter model appeared to function well in these conditions.

Frequency scans of the electrical network were performed for the wind farms at collector substations Peigan, Goose Lake and Vulcan, as seen from behind an equivalent inductance approximating the wind farm generator impedance and transformer reactances, to determine the resonant frequencies of the electrical network under base case and contingency conditions. Again, contingencies were selected up to Category C which place the generator more radially connected to the nearby series capacitor banks.

The studies at the wind farm collector substation sites indicate that control interactions due to the series capacitors are possible at:

- Peigan in 2013 (before the Goose Lake system is tied into the 500 kV system at Crowsnest)
- Goose Lake in 2013 (before the Goose Lake system is tied into the 500 kV system at Crowsnest)
- Vulcan in 2013 and 2017

The Vulcan location is most at risk, as it is connected directly at the series capacitor site – a single Category B contingency of the line to Calgary South Substation will result in a pure radial configuration with the series capacitor.

Possible mitigation to avoid the SSR impacts on wind farms associated with series capacitors may include modifications to wind controls, if accommodated by the manufacturer. The AESO will not be directly involved in manufacturer negotiations for wind turbine control modifications. Other mitigation options could include the use of SSR bypass filters across each series capacitor bank or power electronic alternatives such as thyristor controlled series capacitors.

5.5 Short Circuit Analysis

A short circuit analysis was performed for the southern Alberta region to determine the impact of Alternative 1A improvements on the south system short circuit levels. Short circuit current levels were calculated for two cases; the existing system and the Alternative 1A system. The Alternative 1A case included 2700 MW of south wind generation. Three phase faults were applied at the existing and proposed Alternative 1A 500 kV and 240 kV substations. The three phase fault currents observed at each substation for both scenarios are compared in Table 5.5-1. The fault current levels at the existing substations are higher in the Alternative 1A case than in the existing system since the Alternative 1A improvements include major 500 kV and 240 kV transmission system additions.

Table 5.5-1 Three Phase Fault Currents Levels

Substation (Fault Location)	Bus Voltage	Existing System	Alternative 1A with 2,700 MW South Wind Generation
		3 Phase Fault Current (kA)	3 Phase Fault Current (kA)
Goose Lake	240 kV	4.0	19.0
Peigan	240 kV	4.6	18.0
N. Lethbridge	240 kV	5.8	13.8
MATL	240 kV	5.4	12.4
Milo Junction	240 kV	7.0	14.4
West Brooks	240 kV	9.7	15.6
Ware Junction	240 kV	9.3	18.7
Jenner	240 kV	6.4	9.7
Empress	240 kV	5.5	8.6
Cypress	240 kV	5.5	8.7
Langdon	500 kV	7.1	9.2
Langdon	240 kV	16.1	22.6
Calgary South	240 kV	13.6	18.3
Crowsnest	500 kV	-	8.0
Crowsnest	240 kV	-	15.5
Sub A	240 kV	-	10.6
Sub B	240 kV	-	8.1
Sub C	240 kV	-	10.2
Sub D	240 kV	-	8.4
Medicine Hat	240 kV	-	8.3
WR	240 kV	-	3.8
Sub F	240 kV	-	13.3
Sub G	240 kV	-	12.9
Vulcan	240 kV	-	10.1

5.6 Land Impact Assessment

A land impact assessment was completed for all the alternatives to evaluate the impact of each alternative. The detailed land impact assessment is provided in Appendix F, which includes maps of the areas impacted. All of the alternatives start with the Peigan-Calgary and Goose Lake-Crowsnest components, referred to as phase 1. The potential impacts for phase 1 will occur for all alternatives. Only phases 2 through 4 were used in a comparison of the alternatives.

All of the alternatives are viable from a land impact perspective, and none have potential impacts that would cause any to be rejected.

Comparisons between metrics were done in relation to Alternative 1B, which was about the middle of the three 240kV looped Alternatives (1A, 1B & 1C). Metrics that were at least 20% lower potential impact are colored green, and metrics that are at least 20% higher potential impact are colored red.

When comparing the alternatives considered, the length of the line is the largest driver for most of the impacts. The HVDC Alternative 4 has the shortest overall length. Alternative 4 has the most number of metrics that are 20% lower potential impact. Similarly, Alternative 3 has the longest line length, and the most number of metrics that are 20% higher potential impact, except notably for some of the more significant metrics, such as residences within 150 m, potential to parallel transmission lines, and amount of irrigated parcels crossed.

The potential to construct paralleling lines next to existing right-of-way provides the opportunity to reduce the impacts. The incremental difference can not be estimated until more detailed routing and consultation is completed. For example the environmental impacts within 800 m of two lines together would be lower than the impacts within 800 m of lines that are separated. This report does not incorporate any reductions that could be realized due to paralleling.

The 240kV Alternatives 1A, 1B, 1C and 2 are relatively similar. The relative comparison of the land impact assessment results are summarized below and are provided in Table 5.6-1.

Agricultural

- Alternative 2 has the least potential impact
- Alternative 3 has the highest potential impact

Residential

- Alternatives 3, and 4 have the least potential impact to residences within 150 m
- Alternative 4 has the least potential impact to residences within 800 m
- Alternative 1C has the highest potential impact to residences within 800 m

Environment

- Alternative 1C and 4 have the least potential impact
- Alternative 3 has the highest potential impact

Electrical Considerations

- Alternative 3 has the highest potential for paralleling new facilities

Visual Impacts

- Alternatives 3, and 4 have the least potential impact to residences within 150 m
- Alternative 3 potentially impacts the most Protected or Designated Areas.

Special Constraints

- Alternative 4 has the least potential impact
- Alternatives 3 and 4 have the least potential impact to irrigated parcels
- Alternative 3 has the highest potential impact on historical resources

Table 5.6-1 Major Aspects of Land Impact Assessment

Major Aspects and Considerations November 19, 2008 — South Alberta Transmission Development SATD LIA		Alternatives						
		Common	240 kV Looped			240kV Radial	500kV	HVDC
			IA	1B	1C	II	III	IV
		Phase 1	Phase 2 - 4	Phase 2 - 4	Phase 2 - 4	Phase 2 - 4	Phase 2 - 4	Phase 2 - 4
		A,J	G,F,C1,E,D,H	G,F,C2,E,D,H	G,F,C1,E,D,K	G,B,D,H	Y,F,C1,E,X,Z	F,C1,E,HVDC
		Min. - Max.						
Line Parameters								
R-O-W Length (km)		190 - 291	768-795	793-841	808-852	774-819	1113-1206	748-778
Agricultural Impact								
Amount of Agricultural Land Crossed (km)	Cultivated	39 - 98	258 - 319	265 - 330	294 - 369	142 - 176	443 - 571	279 - 366
	Forage land	7 - 14	40 - 89	40 - 89	25 - 71	34 - 65	30 - 104	16 - 65
	Total	51 - 110	322 - 382	334 - 389	344 - 415	182 - 235	529 - 619	327 - 399
Dominant Land Suitability Class Distribution - Distance Crossed (km)	1	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
	2	11 - 52	33 - 40	51 - 59	46 - 69	46 - 53	39 - 60	31 - 56
Classes 1 - 3 are good agricultural land	3	79 - 115	243 - 289	253 - 316	265 - 316	154 - 214	421 - 489	229 - 285
Classes 4 - 7 require more and more work to be productive	4	31 - 89	249 - 300	248 - 300	257 - 300	238 - 285	384 - 520	257 - 349
	5	9 - 56	86 - 118	84 - 118	93 - 122	127 - 166	114 - 148	78 - 106
	6	0 - 0	30 - 37	30 - 37	37 - 39	48 - 54	30 - 34	28 - 35
	7	0 - 0	66 - 70	66 - 70	52 - 56	104 - 104	35 - 42	31 - 40
Residential Impacts								
Total Residences within 150 m of centreline (#)		20 - 40	40-90	40-90	40-80	40-90	30-70	20 - 50
Total Residences within 0 - 800 m of R-O-W edge (#)		180 - 400	270 - 420	290-430	370-550	280- 400	310-450	200-330
Environmental Impacts								
Surface Water (ha) in or within 800m of R-O-W edge		214 - 468	1543 - 2091	1597 - 2147	1522 - 2344	1690 - 2353	2102 - 2838	1186 - 2000
Native Grassland Crossed (km)		24 - 85	258 - 280	272 - 303	257 - 277	402 - 434	323 - 378	231 - 265
Sensitive Wetland Areas (ha) in or within 800 m of R-O-W		36 - 1081	1597 - 1986	1607 - 1996	455 - 797	1637 - 2051	693 - 1973	317 - 1723
Proximity to Protected or Designated Areas in or within 800 m of R-O-W edge (ha)		8 - 20	14 - 15	14 - 15	16 - 18	16 - 16	25 - 33	14 - 16
Cost – Cost information and comparisons are provided in other sections of the Need application								
Electrical Considerations								
Paralleling Existing Transmission Lines greater than or equal to 240 kv (km)		76 - 148	7 - 7	7 - 7	4 - 13	7 - 7	59 - 78	7 - 82
Crossing Existing Transmission Lines greater than or equal to 240 kv (#)		0 - 1	1 - 2	1 - 2	3 - 6	1 - 2	1 - 2	1 - 5
Potential to Parallel Future Transmission Lines greater than or equal to 240 kv (Km)		0 - 59	3 - 3	0 - 0	8 - 31	251 - 256	368 - 397	3 - 3
Visual Impacts								
Total Residences within 150 m of centreline (#)		20 - 40	40 - 90	40 - 90	40 - 80	40 - 90	30 - 70	20 - 50
Proximity to Protected or Designated Areas in or within 800 m of R-O-W edge (#)		8 - 20	14 - 15	14 - 15	16 - 18	16 - 16	25 - 33	14 - 16
Special Constraints								
Proximity to Historical Resources in or within 800 m of R-O-W (#)		113 - 335	365 - 473	408 - 522	388 - 507	434 - 559	650 - 837	379 - 458
Major River Crossings (#)		7 - 11	7 - 12	7 - 12	11 - 22	8 - 12	16 - 27	10 - 22
Minor Airports in or within 1.6/3.2 km of R-O-W (#)		0 - 3	0 - 0	0 - 0	1 - 1	0 - 0	0 - 1	0 - 0
Irrigated Parcels Crossed (km)		0 - 12	74 - 127	74 - 127	60 - 110	69 - 98	43 - 123	29 - 85

Notes: Phase 1 is common to all alternatives, and not included in the metrics used for comparison
Colored comparisons in relation of Alternative 1B, which was about the middle of the looped 240kV alternatives
Green represents at least 20% LESS potential impact
Red represents at least 20% MORE potential impact
Agricultural suitability class 4 through 7 were not compared because they are poor soils
Treed areas not on table as they were all zero
No major airports within 6km of any of the representative routes

5.7 Economic Evaluation

The AESO calculates the present value (PV) of each alternative and ranks options based on net cost/benefit. The economic evaluation methodology involves estimation of the revenue requirement (using costs with an accuracy of +/- 30 percent) and estimation of the loss savings that would likely result from improved system efficiency. The results of the economic evaluation are evaluated together with other factors, such as technical feasibility, social and land use issues, environmental issues, project flexibility, planning horizon and applicable legislation.

5.7.1 Revenue Requirement

The revenue requirement calculation estimates the amount a TFO would recover each year in return for constructing and operating a proposed transmission facility. The calculation includes operating expenses, depreciation, income taxes, debt costs and a return on equity. In its evaluation of Southern Alberta transmission development alternatives, the AESO has applied currently approved input assumptions related to the TFO business.

5.7.1.1 Capital Costs

Capital cost estimations include costs related to design, construction, land, regulatory, Allowance for Funds Used During Construction (AFUDC), Engineering & Supervision (E&S), contingencies and inflation.

For the south system planning study, four major alternatives were considered and evaluated. Capital cost estimates are provided in Table 5.7-1.

Table 5.7-1 Capital Costs Estimates (2008, $Million)

	Alt 1A	Alt 1B	Alt 1C	Alt 2	Alt 3	Alt 4
Without AFUDC	1,827	1,863	1,820	1,724	2,307	2,462
With AFUDC	1,953	1,992	1,946	1,844	2,466	2,632

Capital cost estimates have been split into three stages, with assumed completion dates of 2013, 2016 and 2017. Assumed capital costs for the in-service dates are provided in Table 5.7-2.

Table 5.7-2 Capital Cost Estimates (ISD Years, $M)

ISD Year	Alt 1A	Alt 1B	Alt 1C	Alt 2	Alt 3	Alt 4
2013	1,464	1,464	1,464	1,237	1,673	2,990
2016	1,391	1,464	1,934	1,520	2,662	1,447
2017	584	584	0	510	0	0
Total	3,439	3,512	3,398	3,267	4,336	4,437

Other cost and economic assumptions included in the revenue requirement calculation are included in Appendix G.

5.7.1.2 Revenue Requirement Results

Results from the revenue requirement PV calculation are summarized in Table 5.7-3 below.

Table 5.7-3 PV Revenue Requirement (2013 $M)

	Alt 1A	Alt 1B	Alt 1C	Alt 2	Alt 3	Alt 4
PV Revenue Requirement	2,903	2,957	2,914	2,724	3,672	4,068

Given that input assumptions are consistent among the various alternatives, results reflect the relative capital costs of each alternative.

5.7.2 Total System Losses

Average system losses for each alternative were calculated using production simulation techniques. For each of the three simulated years, 2008, 2013 and 2017, 25 points were identified on the load duration curve and a power flow case was run for each of the 25 points in order to calculate system losses. Losses for the years 2008 to 2012, and 2014 to 2016 were interpolated using data from the simulated years. Losses beyond 2017 were estimated by assuming on the average growth rate between 2008 and 2017 for each alternative. Total system losses volumes for each of the alternatives were then compared to Alternative 1A, the reference case.

To put a dollar value to losses, the AESO multiplied the loss volume of each alternative (relative to the reference case), by a pool price forecast provided by independent consultant EDC Associates Ltd. For each alternative, the PV of losses relative to Alternative 1A (discounted to 2013) is provided in Table 5.7-4.

Table 5.7-4 PV Relative Cost of Losses ($M)

	Alt 1A	Alt 1B	Alt 1C	Alt 2	Alt 3	Alt 4
PV Losses Savings	0	8	74	825	(56)	0

Results indicate that the cost of losses of Alternatives 1B, 1C and 2 are greater than Alternative 1A, that the estimated cost of losses of Alternative 3 is less than Alternative 1A and that Alternative 4 losses are roughly equivalent to Alternative 1A losses. Alternative 2 is a radial 240 kV alternative with a small conductor. Intuitively, losses should be higher with the radial alternative as compared to a looped high capacity 240 kV alternative.

5.7.3 Relative Net Comparison

A discount rate of 6.83% was applied when calculating the present value of each alternative. The discount rate represents the before tax, weighted average cost of capital (WACC) of Alberta TFOs and is calculated as follows;

WACC (before tax) = (Equity % x ROE) + (Debt % x Debt Rate)/(1-Tax Rate)

In order to compare the South alternatives on a relative net basis, Alternative 1A has again been used as the reference case. Comparative results, on a net basis, are provided in Table 5.7-5.

Table 5.7-5 PV of Net Relative Results ($M)

	Alt 1A	Alt 1B	Alt 1C	Alt 2	Alt 3	Alt 4
PV Revenue Requirement	0	54	11	(179)	768	1,165
PV Losses Savings	0	8	74	825	(56)	0
Net Results	0	62	86	647	712	1,165

Below are observations and conclusions about the results:

- The 240 kV looped transmission alternatives are the lowest NPV's, with Alternative 1A being the most preferred.
- The capital cost impact of Alternative 2 is lower in comparison to other alternatives; and
- The estimated cost of losses for Alternatives 2 is much greater than the cost of losses of the other alternatives.

5.7.4 Sensitivity Analysis

Sensitivity analysis has been performed in order to determine the impact that a change in variables may have on the comparability of transmission alternatives. Single variable sensitivity analysis was undertaken for the capital cost, discount rate, depreciation rate and pool price assumptions. Changes to these input assumptions did not result in a change to the relative ranking of transmission alternatives.

5.8 Description of Participant Involvement Program

The AESO conducted a Participant Involvement Program (PIP) throughout the development of its Needs Identification Document (NID) for major transmission reinforcement to integrate wind energy in southern Alberta. A variety of methods were used to notify, consult with and engage residents, occupants, landowners, businesses, industry, First Nations, advocacy groups as well as elected and administrative municipal and provincial officials with interests in southern Alberta.

Throughout the PIP, the AESO:

- Delivered presentations at meetings with various stakeholders
- Hosted public information sessions (open houses);
- Mailed information by postal code (unaddressed mail through Canada Post) and directly (addressed mail);
- Posted information on the AESO web site;
- Advertised in newspapers and on radio;
- Corresponded with stakeholders by mail, email and telephone; and
- Published information in the AESO's weekly stakeholder newsletter.

The AESO's PIP provided the opportunity for all stakeholders with interests in southern Alberta transmission development:

- To be fully informed about the AESO NID process for reinforcing the transmission system in southern Alberta; and
- To share their feedback about the need for reinforcement and about alternatives the AESO proposed to meet this need.

The PIP also allowed the AESO to identify stakeholders (and their concerns) and to take measures to address these concerns where reasonable.

The AESO has responded to all concerns about potential reinforcements in southern Alberta received as a result of the PIP in a reasonable and appropriate manner. The AESO knows of no outstanding issues or concerns related to this PIP.

A detailed outline of the PIP has been provided in Appendix H.

6 Alternative Comparison

The following section compares the southern Alberta transmission alternatives based on technical, economic and societal factors. Table 6-1 provides a summary of the comparison.

Based on the results of the technical analyses (see Section 5), all the alternatives meet the AESO's Transmission Reliability Criteria. The ranking of the alternatives based on potential for future expandability was contingent on using existing rights-of-way. All the 240 kV transmission lines included in the Alternatives 1A, 1B, 1C, 3 and 4 are double circuit towers and some of the lines have only one circuit strung. Therefore, the system capacity can be easily increased with Alternatives 1A, 1B, 1C, 3 and 4 by stringing a second circuit on to the towers that have only one circuit strung. However, Alternative 2 can only be expanded by the acquisition of additional right-of-way. This makes Alternative 2 less expandable than the other alternatives. Alternative 4 also has 240 kV circuits that can be modified to increase the system capacity, but the HVDC line has a fixed capacity and this makes Alternative 4 relatively less expandable than Alternatives 1A, 1B, 1C and 3.

Table 6-1 Comparison of Alternatives

	Alt 1A	Alt 1B	Alt 1C	Alt 2	Alt 3	Alt 4
Technical Factors						
Meets Reliability Criteria	Green	Green	Green	Green	Green	Green
Future Expandability (Using Existing ROW)	Green	Green	Green	Red	Green	Yellow
Economic Factors						
System Losses	Green	Green	Yellow	Red	Green	Green
Capital Cost	Yellow	Yellow	Yellow	Green	Red	Red
Risk for Stranded Cost	Green	Green	Green	Green	Yellow	Red
Societal Factors						
Land Impact Assessment	Green	Yellow	Yellow	Yellow	Red	Green
Stakeholder/Public Feedback	Green	Green	Green	Red	Yellow	Green

Green: High Relative Benefit
Yellow: Medium Relative Benefit
Red: Low Relative Benefit

The economic benefits of the alternatives were also compared in Table 5.7-5. Refer to section 5.7.2 for the evaluation of the alternative system losses. Alternative 2 has higher system losses than the other alternatives. On the other hand, Alternative 2 has a lower capital cost than all the other alternatives. The risk for stranded cost is a consideration of how easily an alternative can be staged as the wind generation develops in the south and how much transmission is built upfront in anticipation of wind generation growth. Appendix C shows the staging of each alternative. In Alternative 4, the HVDC line will be built in the first stage of the plan. If wind generation does not develop in that region to the capacity anticipated, there is a risk that the system will be overbuilt and the cost per MW will be relatively higher. Alternative 1A is staged such that the system expands as the wind generation develops in the southern region. The same argument applies to Alternatives 1B, 1C and 2 and lowers their risk for stranded system costs.

Societal factors such as land impact, including environment, and stakeholder/pubic feedback were also considered in the comparison of the alternatives. Table 5.6-1 shows the results of the land impact assessment of all the alternatives. For land impact, Alternative 3 will have a greater impact than other alternatives on the environment because of the additional right-of-way needed for the 500 kV line. Within the 240 kV looped alternatives, no relative benefits were observed in Alternatives 1B or 1C over 1A, as these were similar alternatives and they had greater land impact.

Based on the feedback from the public obtained during open houses and also from other stakeholders, Alternatives 1A, 1B, 1C and 4 were favored over Alternatives 2 and 3. Section 5.8 discusses the details of the participant involvement program.

Based on the overall results of the alternative comparison, Alternative 1A is preferred compared to the other alternatives studied.

7 Recommended Plan

Based on the results shown in the alternative comparison table in Section 6, the 240 kV looped system (Alternative 1A) is recommended for the southern region system development to integrate the wind interest. Alternative 1A, also referred to as the Recommended Plan, is shown in Figure 7-1 along with the wind interest zones. The total cost estimate for the recommended 240 kV looped system is $1.83 billion (+20% / -15%, 2008$, no escalation, no AFUDC). Once the recommended alternative is approved the AESO will be adopting a staged approach for implementation of this plan as shown in. Stage I is recommended to proceed immediately as some of the components are needed to address existing reliability concerns as demonstrated in the existing system analysis. Stages II and III will have triggers that need to occur before these stages move into the implementation phase. Triggers for components of Stages II and III are discussed in Section 7.2 below.

Figure 7-1 Recommended Plan with Wind Interest Zones

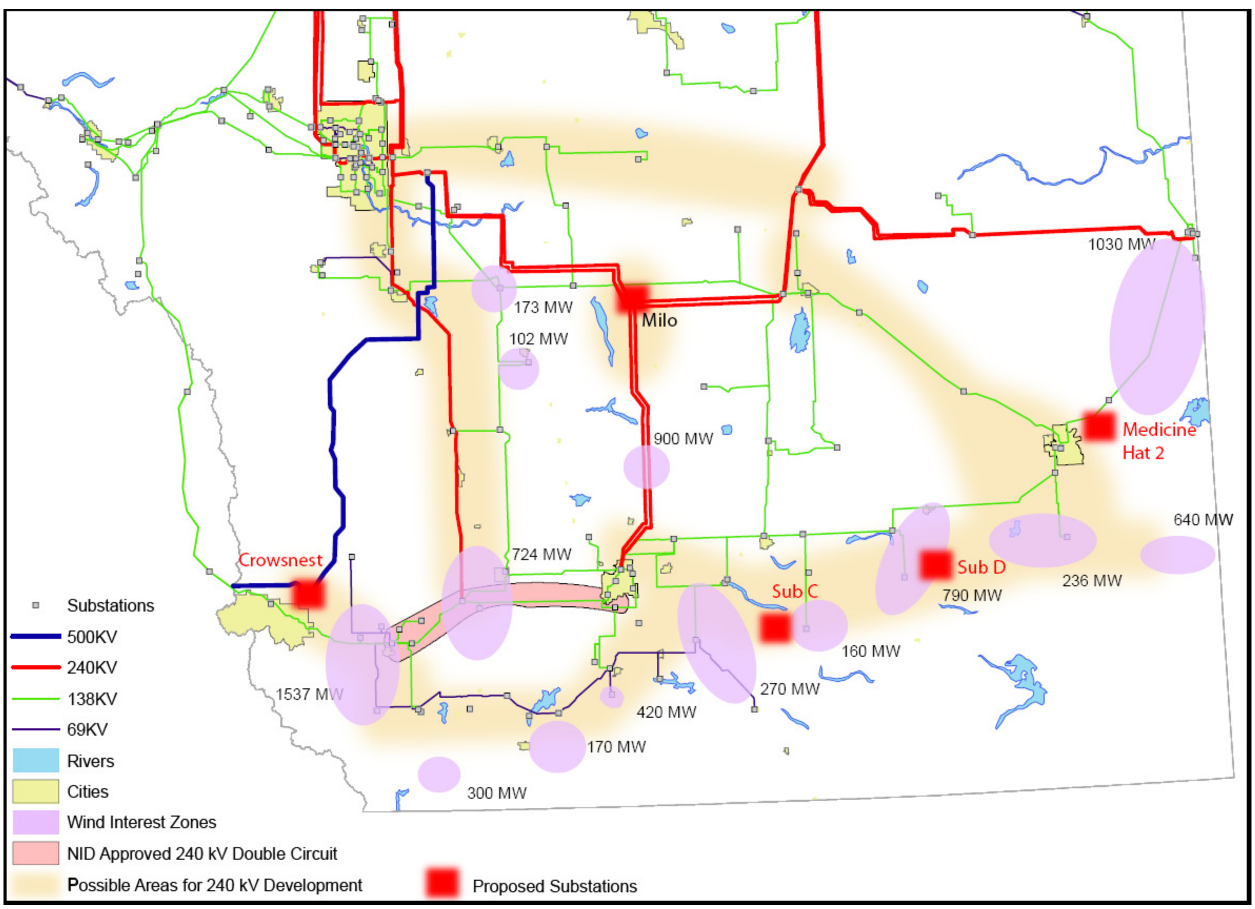


Table 7-1 Stage I Components of the Recommended Plan (Alternative 1A)

Item #	Description	Capacity Specs	Cost 2008$
STAGE I			
I-1	Rebuild 911L Calgary South to Peigan 240kV transmission line	2X1033 kcmil ACSR D/C line (150km) 50 per cent series compensation	$265,600,000
I-2	Calgary South Substation line terminals	N/A	$4,600,000
I-3	Peigan Substation	Includes SVC 0 - -200 MVAR	$74,900,000
I-4	Milo Junction Switching Station	N/A	$24,700,000
I-5	Coleman 138 kV Phase Shifter	120MVA, +/- 60 Degree transformer	$13,300,000
I-6	West Brooks Substation line terminals	N/A	$21,900,000
I-7	Sub D to West Brooks 240kV transmission line	2X1033 kcmil ACSR D/C line (219km)	$299,800,000
I-8	Sub D	Includes SVC 0 - -100 MVAR	$54,700,000
		Stage I Total	**$759,500,000**

Table 7-2 Stage II Components of the Recommended Plan (Alternative 1A)

Item #	Description	Capacity Specs	Cost 2008$
STAGE II			
II-1	Med Hat 2 Substation	2X120/160/200MVA, 240/138kV transformers	$40,400,000
II-2	Med Hat 138kV changes: Med Hat 2 to Med Hat 138 kV transmission line Med Hat 2 to Chappice Lake 138 kV transmission line reroute Med Hat to Suffield extension 138 kV transmission line Med Hat 2 to Bullshead 138 kV transmission line Burdett to Med Hat 2 138 kV transmission line Peace Butte to Bullshead to Med Hat 138 kV line modifications	 2X477 kcmil ACSR D/C line with one side strung (20km) 1X477 kcmil ACSR D/C line with one side strung (2.5km) 1X477 kcmil ACSR D/C line with one side strung (17.5km) 2X477 kcmil ACSR D/C line with one side strung (34.5km) 1X477 kcmil ACSR stringing second circuit on D/C line 1SS (33.5km) and 1X477 kcmil ACSR 1SS (1km) 1X477 kcmil ACSR D/C line with one side strung (1km)	$50,300,000
II-3	Replace Peigan 240/138 kV transformers	2X200MVA,240/138kV transformers	$6,800,000
II-4	Salvage line 911L	N/A	$18,900,000
II-5	Goose Lake substation line terminals	N/A	$16,600,000
II-6	New Crowsnest 500/240kV Substation	2X720/960/1200 MVA, 500/240kV transformers, SVC 0 - 400 MVAR	$132,700,000
II-7	Crowsnest – Goose Lake 240kV transmission line	2X1033 kcmil ACSR D/C line (47.2km)	$68,100,000
II-8	Sub C	Includes SVC 0 - -100 MVAR	$59,400,000
II-9	Goose Lake – Sub C 240 kV transmission line	2X795 kcmil ACSR D/C line with one side strung (220km)	$186,600,000
II-10	Sub C – MATL 240kV transmission line	2X795 kcmil ACSR D/C line with one side strung (64km)	$61,700,000

II-11	MATL substation line terminals	N/A	$7,300,000
II-12	Sub C – Sub D 240kV transmission line	2X795 kcmil ACSR D/C line (73km)	$75,600,000
II-13	Sub D line terminals	N/A	$3,700,000
II-14	Blackie Area 138kV upgrades/modifications	1X477 kcmil ACSR D/C line with one side strung (24km)	$18,100,000
II-15	Cypress SVC	+25 - -50 MVAr SVC	$31,100,000
II-16	West Brooks to Anderson in and out at Ware Junction	N/A	$10,300,000
		Stage II Total	**$787,600,000**

Table 7-3 Stage III Components of the Recommended Plan (Alternative 1A)

Item #	Description	Capacity Specs	Cost 2008$
STAGE III			
III-1	Ware Junction – Langdon 240kV transmission line	2X1033 kcmil ACSR D/C line (137km)	$246,600,000
III-2	Ware Junction substation line terminals	N/A	$14,300,000
III-3	Langdon substation line terminals	N/A	$18,200,000
		Stage III Total	**$279,100,000**

7.1 Rationale for Components of the Recommended Plan

The rationale for each component of the recommended plan is discussed in following sections. The rationale briefly reviews why each major component was needed in terms of staging.

7.1.1 Peigan to Calgary – Items I-1, I-2, I-3, II-3 and II-4

The existing 911L Peigan – Janet 240 kV transmission line, which is rated at 337 MVA (summer), limits the transfer of wind generation from the Pincher Creek area. The proposed Peigan to South Calgary 240 kV double circuit transmission line will replace 911L and will provide a high capacity corridor between Peigan and Calgary. The series compensation on this line will help off load the 923L/924L 240 kV circuits out of Lethbridge Substation by providing a shorter electrical distance from Peigan to Calgary. The larger 2 x 1033 kcmil conductors will not only provide higher capacity (approx. 1000 MVA/cct summer) but will also result in lower losses. The existing 911L Peigan to Janet 240 kV transmission line will be salvaged once the proposed Peigan to South Calgary 240 kV line is in service. The proposed Peigan to South Calgary 240 kV line will also require line terminal upgrades at Calgary South and Peigan Substations.

In order to control system voltages during varying wind generation conditions, static var compensators are recommended at Peigan Substation. The single 179 MVA transformer at Peigan 59S substation will be replaced with 2 x 200 MVA transformers.

7.1.2 Milo Junction – Item I-4

The Milo Junction at present is a simple T-tap resulting in a three terminal line between Langdon, West Brooks and North Lethbridge. Therefore, a fault on any one of the sections between Langdon, Milo Junction, West Brooks or North Lethbridge will take out the three line sections. Due to the central location of Milo Junction, a switching station will reduce the exposure of the line and will provide enhanced reliability on these lines.

7.1.3 Coleman Substation – Item I-5

A phase shifting transformer on 170L Pincher Creek to Coleman 138 kV line will serve to block the power flow and prevent overloading especially on the Coleman to Natal 138 kV section which is rated at 99 MVA. This is an existing problem and results in curtailment of wind generation even under Category A (N-0) conditions.

7.1.4 Medicine Hat – Items I-6, II-1 & II-2

The recommended plan proposes a new 240/138 kV substation near Medicine Hat, referred to as Medicine Hat 2. The system reinforcements being proposed in the Medicine Hat area will connect the Medicine Hat and Bullshead loads currently supplied by the existing 138 kV network to the new Medicine Hat 2 Substation. New 138 kV lines will be required to reconfigure the Medicine Hat and Bullshead supply connections to the Medicine Hat 2 Substation. The new 240/138 kV substation provides dual benefits to the Medicine Hat area in that it be a collection point for area wind farms as well as a new supply source for southeast region. The new 240/138 kV substation will also increase the ability to serve future load growth in the southeast region.

These reinforcements eliminate the need for the 138 kV line upgrades throughout the southeast region as well as the proposed Hays – Burdett 138 kV line, which were approved in the Southeast Alberta Transmission Development NID Part A [Application No 1545328]. The AESO intends to submit an amendment to the Southeast NID Part A which will provide revised cost estimates for the originally proposed 138 kV line upgrades. These costs can be avoided by completing the reinforcements now being proposed around the Medicine Hat area. In order to fulfill the needs identified in the Southeast NID, the proposed Medicine Hat area reinforcements (Items II-1 & II-2 in Table 7-2) may need to be expedited to advance in parallel with Stage I even though they appear as part of Stage II. The conceptual diagrams of the proposed Medicine Hat area changes are included in Appendix C.

7.1.5 West Brooks to Sub D – Items I-7 and I-8

As wind interest develops in the southeast region, the 240 kV double circuit from West Brooks to a new 240 kV Substation, referred to as Sub D. This double circuit line is being proposed with 2 x 1033 kcmil conductors in view of the significant amount of wind interest in southeast Alberta. The new West Brooks to Sub D line is needed immediately for integration of wind interest in the southeast region and will provide a high capacity path from the Burdett and Peace Butte areas onto the bulk 240 kV network. Line terminals will be needed at the West Brooks Substation for the new 240 kV line. The West Brooks to Sub D will also be a source for future supply to the Medicine Hat area load as discussed in Section 7.1.4.

In order to control system voltages during varying wind generation conditions, static var compensators are recommended at Sub D.

7.1.6 Goose Lake to Crowsnest – Items II-5, II-6 and II-7

The proposed Crowsnest 500/240 kV substation along with the Goose Lake to Crowsnest 240 kV double circuit transmission line will provide an additional path for the generation in the Pincher Creek area as well as that located in southern Alberta. Two 500/240 kV 1,200 MVA transformers and the 240 kV double circuit with 2 x 1033 kcmil conductor are needed. In order to connect some of the wind farms in the Pincher Creek area, a section of the Goose Lake – Crowsnest 240 kV line may be advanced. Section 8.1 discusses the

Pincher Creek area planning concept which is proposed to connect the various area wind farms.

The Crowsnest Substation is proposed to tap the existing 1201L Langdon to Cranbrook 500 kV transmission line, which is part of the WECC Path #1. A WECC path rating study has been initiated to determine any impacts of the proposed Crowsnest Substation. In order to control system voltages during varying wind generation conditions, static var compensators are recommended at Crowsnest Substation.

7.1.7 Goose Lake to Sub C – Items II-8 and II-9

A new 240 kV transmission line is recommended from Goose Lake Substation to a new 240 kV substation located southeast of Lethbridge, referred to as Sub C. This new 240 kV line and substation will provide a high capacity connection to the bulk 240 kV network for the wind interest in the remote southwestern Alberta areas. In order to control system voltages during varying wind generation conditions, static var compensators are recommended at Sub C.

7.1.8 Sub C to MATL – Items II-10 and II-11

A new 240 kV transmission line is recommended from MATL Substation to a new 240 kV substation located southeast of Lethbridge, referred to as Sub C. The line is recommended to be constructed double circuit with one side initially strung. This new 240 kV line and substation will provide a high capacity connection to the bulk 240 kV network for the wind interest in the areas south of Lethbridge. Line terminals will be needed at MATL substation for the new 240 kV line connection. In order to control system voltages during varying wind generation conditions, static var compensators are recommended at Sub C.

7.1.9 Sub C to Sub D – Items II-12 and II-13

A new double circuit 240 kV transmission line is recommended from the new Sub C Substation to the new Sub D Substation. This line will complete a 240 kV loop in southeastern Alberta and provide more system capacity for wind interest development throughout that region. Additional line terminals will be needed at the new Sub D Substation for the new 240 kV line connections.

7.1.10 Blackie Area – Item II-14

System reinforcements on the Blackie 138 kV network are being proposed to separate the Carseland to Blackie and High River to Blackie 138 kV lines from the existing Blackie substation. A new 138 kV line from Blackie to

Queenstown and changes at Queenstown will result in a direct connection between Blackie and Gleichen Substations. This is being proposed to eliminate loops flows through the 138 kV network to prevent 138 kV overloads during contingency conditions.

7.1.11 Cypress Substation – Item II-15

In order to control system voltages during varying wind generation conditions, a static var compensator is recommended at Cypress.

7.1.12 Ware Junction to Langdon – Items II-16, III-1, III-2 and III-3

A new double circuit 240 kV transmission line is proposed from Ware Junction Substation to Langdon Substation. The Ware Junction – Langdon 240 kV high capacity lines will serve to transmit power generated in the southeast Alberta as well as in south-central Alberta towards the load center of Calgary.

The in-and-out arrangement of 933L West Brooks to Anderson 240 kV line serves to strengthen the Ware Junction to West Brooks section and is required in case of heavy flows on Medicine Hat2 to West Brooks or Cypress to Ware Junction 240 kV lines.

7.2 Triggers for Staged Implementation

The staged implementation of the Recommended Plan will be based on triggers, shown in Table 7.2-1. The triggers will allow for coordination of transmission development with actual future wind generation development. If the identified trigger for a component of the transmission development fails to occur by 2017, the need for that component will be revisited.

Table 7.2-1 Triggers for Staged Implementation

Stage I			
South West		**South East**	
Item	**Off Ramp**	**Item**	**Off Ramp**
Peigan – S. Calgary 240 kV D/C with 50% series compensation	Less than 500 MW of gen interconnection Need Applications in the Pincher Creek and Peigan areas combined, filed with AUC	New Sub D Substation Sub D – W. Brooks 240 kV double circuit line	1st Cct – No gen interconnection Need Application from Burdett/Medicine Hat area filed with AUC 2nd Cct – Less than 500 MW of gen interconnection Need Applications in Burdett/Medicine Hat area filed with AUC
Coleman 138 kV Phase Shifting Transformer	None – Required at present	Milo Switching Station	No new Need Application filed in the southeast
Stage II			
South West		**South East**	
Item	**Trigger**	**Item**	**Trigger**
500/240 kV Crowsnest Substation Crowsnest – Goose Lake 240 kV double circuit line	> 600 MW of gen interconnection Need Applications in the Pincher Creek area filed with AUC	New Medicine Hat 2 Sub Medicine Hat area 138 kV modifications	Southeast NID [App No 1545328] is amended and approved by AUC
Sub C Substation Goose Lake – Sub C 240 kV double cct line with one side strung	At least one gen interconnection Need Application in the area between Goose Lake and Sub C filed with AUC	Sub C – Sub D 240 kV double circuit line	1st Cct – At least one gen interconnection Need Application in the area between Sub C & Sub D filed with AUC 2nd Cct – > 874 MW of gen interconnection Need Applications between Sub C and Sub D area filed with AUC
Sub C – MATL 240 kV double cct line with one side strung	At least one gen interconnection Need Application in the area between Sub C and MATL filed with AUC or > 500 MW of gen int Need Applications between Sub C and Sub D area filed with AUC	Separate Carseland – Blackie and High River – Blackie 138 kV lines at Blackie substation. Blackie – Queenstown 138 kV single circuit line	> 400 MW of gen interconnection Need Applications in Burdett, Medicine Hat and Cypress areas combined, filed with AUC
Salvage existing 911L line	New Peigan – S. Calgary 240 kV D/C is in-service	W. Brooks – Anderson 240 kV in-and-out at Ware Junction	> 750 MW of gen interconnection Need Application in the Burdett, Medicine Hat and Cypress areas combined, filed with AUC
New Peigan 240/138 kV transformers	> 180 MW of combined existing and new gen Need App on 138 kV system near Peigan	Cypress SVC	Contingent on wind farm Need Applications connecting to Cypress that cause voltage criteria violations
Stage III			
South West		**South East**	
Item	**Trigger**	**Item**	**Trigger**
		Ware Jn – Langdon 240 kV line with 50% series compensation	Contingent on gen interconnection Need Applications in southeast Alberta that cause overloadings on the 240 kV network

7.3 Advancement of Expenses

In order to advance Stage 1 project development to meet projected in-service dates and enable the interconnection of a number of wind power projects, and with the expectation the Medicine Hat 138 kV reinforcements will be done in parallel, the AESO intends to direct AltaLink to proceed with certain activities as preparatory activities in advance of approval of the NID and in advance of approval of the subsequent AltaLink application for permit and license. .

Stage 1 of the development is estimated at $759.5 million (+30 % / -15 %, 2008$, no escalation, no AFUDC). It is assumed that NID will be approved by the end of June 2009. .

With the above assumptions and in order to maintain project schedule, it is estimated that about $52 million will be incurred by the TFO prior to the need being approved. Similarly, $370 million is expected to be incurred in advance for supporting labour and material prior to receipt of permit and license. The $52 million is made up of $11 million in labour costs and $41 million in long-lead material costs. The $370 million is made up of $138 million in labour costs and $232 million material committed costs. Costs include the $3 million of presently authorized funds.

These cost estimates are based on order-of-magnitude estimates and actual cost flows and will be refined later.

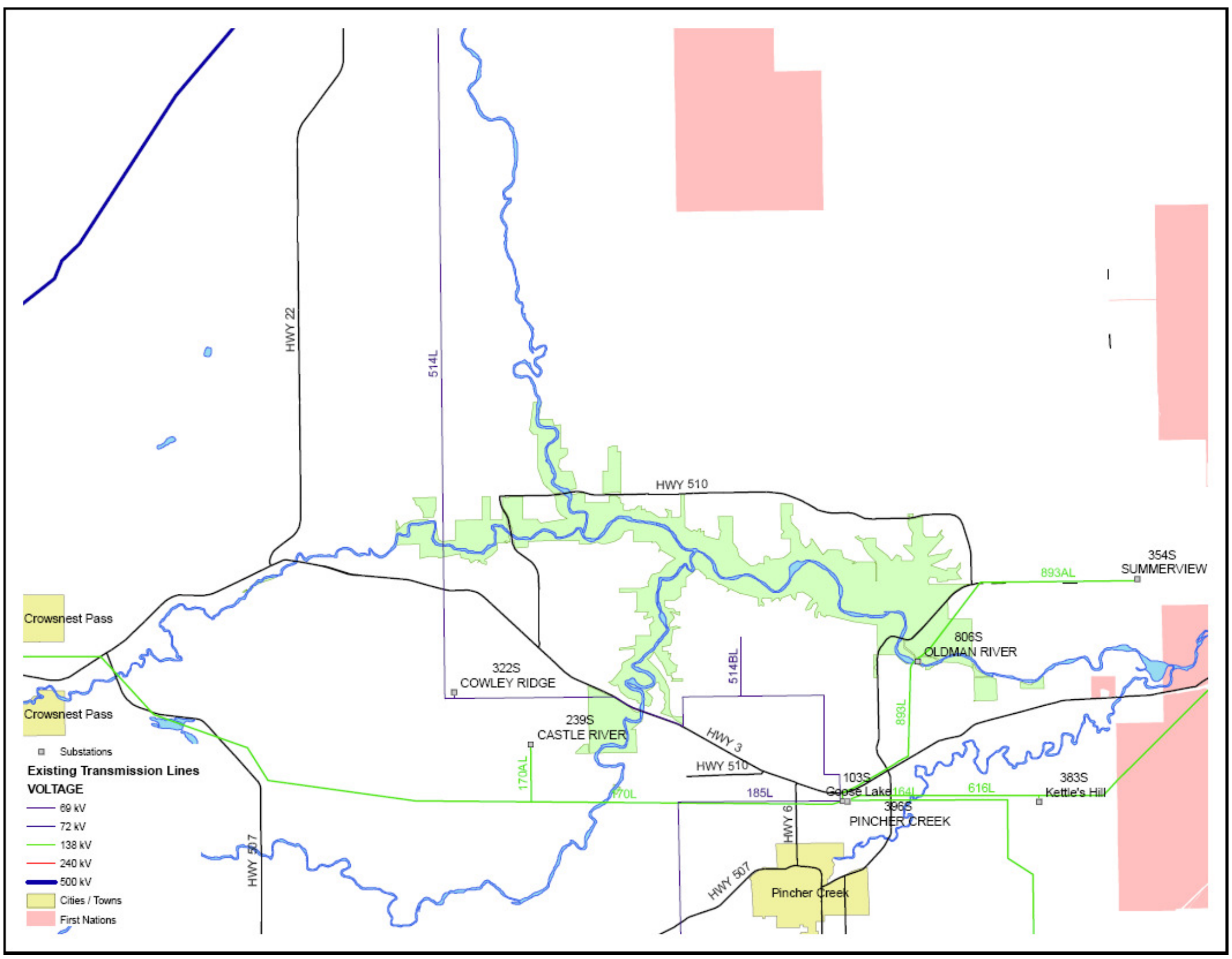
8 Additional Plans for Southern Region

The staging of the Recommended Plan discussed in Section 7 above allows for flexibility to accommodate future events as they occur and should be coordinated with on-going planning activities in the southern region as future load growth and wind generation materialize. The Pincher Creek and High River/Glenwood areas will require reinforcements which were not included in the Recommended Plan but were considered in the overall planning concepts. The sections below discuss the planning concepts for these areas to demonstrate how they fit with the Recommended Plan.

8.1 Pincher Creek Area Planning Concept

The Pincher Creek area is at the forefront of wind development in Alberta. Figure 8.1-1 shows the Pincher Creek area with the existing transmission system and wind farms locations.

Figure 8.1-1 Pincher Creek Area Existing Transmission System



The following four wind farms are currently in operation in this area.

- Cowley Ridge (41 MW)
- Castle River (40 MW)
- Kettles Hill (63 MW)
- Summerview (68 MW)

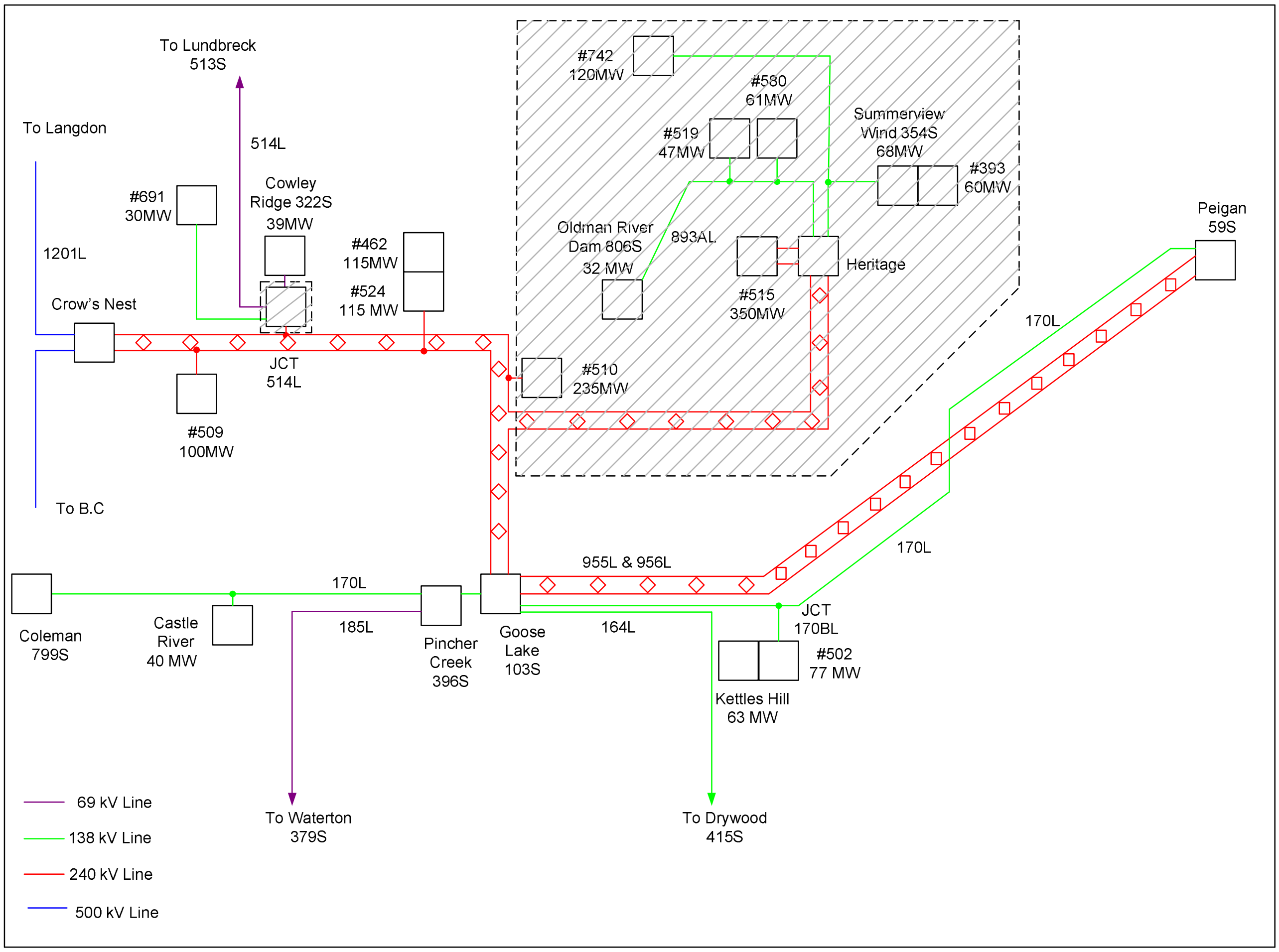
Besides these existing wind farms, the Old Man River hydro plant (32 MW) is also located in the Pincher Creek area. There are four 138 kV lines terminating at the Pincher Creek Substation. One of the 138 kV lines connects the Pincher Creek Substation to Coleman Substation and then to Natal Substation. The Coleman to Natal 138 kV line is part of the intertie between Alberta and British Columbia and is frequently a limitation for existing wind generation in the Pincher Creek area.

At present, there is about 1,300 MW of existing and proposed wind generation in the Pincher Creek area. The AESO has developed a transmission reinforcement concept, shown in Figure 8.1-2, for this area so that all the wind interest can be connected. The concept is to loop the new Goose Lake to Crowsnest 240 kV line in-and-out of a new Heritage Substation. The Heritage Substation will act as a collector station to connect proposed wind farms in the Heritage/Summerview area. The existing Summerview to Old Man River 138 kV line will be re-terminated at the new Heritage Substation which will allow salvaging the existing Old Man River to Pincher Creek 138 kV line.

The 69 kV line between Pincher Creek and Cowley Ridge could be salvaged by installing a 240/138/69 kV transformer near Cowley Ridge to connect the wind farms and serve load in the Cowley Ridge area.

The facilities identified by shaded areas in Figure 8.1-2 are Pincher Creek area concepts which have not been included in the Recommended Plan and are provided for information only. As illustrated, the Pincher Creek area concepts are well coordinated with the Recommended Plan. The system reinforcements shown in the shaded areas will be applied for in the individual need applications for specific wind farm interconnections.

Figure 8.1-2 Pincher Creek Area Development Concept



8.2 High River Area and Glenwood/Drywood Area Planning Concepts

In the analysis of need for transmission (Section 3.2), voltage and thermal loading problems were identified in the High River and Glenwood/Drywood areas. These problems are a result of the projected area load growth. In the power flow analysis for 2013 and 2017 scenarios, the 69 kV line from Drywood 415S to Stirling 67S was replaced with a 138 kV transmission line. Similarly a 138 kV line was modeled from Calgary South to Black Diamond 392S substation. These system reinforcements will be applied for in separate need applications for the High River and Glenwood/Drywood areas.