Central East Region

Transmission Development

Needs Identification Document

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Executive Summary

As 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 ("EUA"). As prescribed in the *Transmission Regulation* ("Regulation"), the AESO issued the Long-Term Transmission System Plan in June of 2009. In the context of the Transmission System Plan, the AESO has engaged in the planning process to facilitate the preparation of this Needs Identification Document ("NID") for the Central East region of Alberta.

The Central East region encompasses the eastern portion of the Alberta central planning region. The planning areas in this region include Cold Lake (Area 28), Vegreville (Area 56), Lloydminster (Area 13), Alliance/Battle River (Area 36), Wainwright (Area 32) and Provost (Area 37). With the exception of the Cold Lake planning area, most of the Central East transmission system was originally designed to supply farms and small towns. Recently, the region has experienced significant load growth. This growth is forecasted to continue due to industrial and pipeline loads.

The need for transmission reinforcement in the Central East region is driven predominantly by:

- Load growth – The winter peak load in the region is estimated to grow at an average rate of 6.4% per year from 2009 to 2018, which is approximately twice that of the average growth rate in Alberta. This is largely fueled by oilsands, pipeline development and associated infrastructure.
- *Generation development* – 255 MW of cogeneration facilities have applied for connection in the Cold Lake area and 280 MW of wind projects have applied for connection in the vicinity of the Provost area.

AESO system studies indicate that the Central East region transmission system is near its capacity and without any system upgrades, the present system will not be able to reliably supply projected load and connect proposed generation projects.

Several technology options were considered and a screening process was used to arrive at a final set of three regional alternatives for the Central East region. Moreover, in order to mitigate constraints that are pertinent to the individual planning areas of the region, a set of local reinforcements were selected and have been included in each of the regional alternatives. Since this set of local reinforcements will be part of the overall system development in all of the three alternatives, these are referred to as the "common set of local reinforcements". The methodology used for the identification and screening of alternatives is described in Section 5.

The proposed regional alternatives are:

- Alternative 1: Re-build the aging 138/144 kV 7L50 line from Battle River 757S to Buffalo Creek 526S;
- Alternative 2: Build a new 240 kV line from Nilrem to the new Vermillion area substation; and
- Alternative 3: Build a new 240 kV line from Hansman Lake 650S to the Lloydminster 716S via a new Provost wind collector substation.

Technical, social, and economic analysis was carried out for each one of the aforementioned three alternatives which include the common set of local reinforcements. The assumptions and methodology adopted for economic analysis, including a summary of estimated capital costs, evaluation of losses, revenue requirements and estimated net costs are presented in Section 6.6.

In order to provide adequate capacity and flexibility, technical and economic analysis of the proposed 240 kV lines were based on double circuit towers with one side strung (unless otherwise specified). Capacity of these lines can be increased at a later date by stringing the second 240 kV circuit when required, without the need for new rights-of-way. Also, technical and economic analyses of all proposed 240 kV lines were based on using 2x795 kcmil ACSR conductors per phase, while both single 477 kcmil and 795 kcmil conductors per phase were used for 138/144 kV lines.

Land Impact Assessment ("LIA") studies indicate that all of the alternatives are viable from a land impact perspective. Alternative 2 was found to have the largest overall impact while Alternative 3 had the least overall impact, in terms of the measurable indicators assessed. Alternative 1 ranks in between Alternatives 2 and 3.

The AESO conducted a Participant Involvement Program ("PIP") throughout the development of the NID and used a variety of methods for public consultation. The AESO did not receive any indication of a preference for any of the three regional alternatives from the public. One siting concern was referred to the AESO by St. Paul County. St. Paul County informed the AESO that they would like the existing 72 kV right-of-way located in their County to be utilized as much as feasible. The Transmission Facility Owner ("TFO") is made aware of this information. The AESO understands that the issue will be considered during the TFO Facilities Application stage.

The estimated capital costs in 2009 dollars are as follows:

Table EX- 1: Comparison of Costs (+/- 30%, 2009$, Million)

Regional Alternatives	Capital Costs
Alternative 1: Re-build the aging 138/144 kV 7L50 line from Battle River to Buffalo Creek	$370
Alternative 2: Build a new 240 kV line from Nilrem to Vermillion area substation	$521
Alternative 3: Build a new 240 kV line from Hansman Lake to Lloydminster	$417

The net cost of estimated revenue requirement and system energy loss, relative to Regional Alternative 1, is as follows:

Table EX- 2: Present Value Revenue Requirement and Losses, and Net Cost Relative to Alternative 1 (Million)

Regional Alternatives	Revenue Req't	Cost of Losses	Net Costs
Alternative 1: Re-build the aging 138/144 kV 7L50 line from Battle River to Buffalo Creek			
Alternative 2: Build a new 240 kV line from Nilrem to Vermillion area substation	$114	($5)	$109
Alternative 3: Build a new 240 kV line from Hansman Lake to Lloydminster	$35	($8)	$27

Regional Alternative 1 has the lowest relative net cost. This, coupled with its assessment of technical performance, LIA and feedback received from public consultation, leads the AESO to recommend Regional Alternative 1 as its preferred alternative.

The AESO's recommended plan thus consists of Regional Alternative 1 plus a set of local reinforcements that are common to all of the regional alternatives. The recommended transmission plan for the Central East region is shown in Figure EX-1.

The AESO proposes a staged approach for implementation of the recommended plan as follows:

Stage I – The target in-service date ("ISD") for all the proposed reinforcements in this stage is on or before Q4 2012.

1. Bonnyville and St. Paul Areas:
    a. Re-build the existing 72 kV Willingdon 711S substation to 144 kV and connect it via tapping nearby 144 kV line 7L92 line.
    b. Convert the existing 72 kV St. Paul 707S substation to 144 kV and connect it to 144 kV line 7L70 using an in and out configuration. Demobilize all 72 kV equipment at St. Paul 707S and install two 144/25 kV low noise transformers at this site.
    c. Demobilize (i.e. this equipment will be removed from this site for potential future use at other sites) all 72 kV equipment at Bonnyville 700S including the 144/72kV tie transformer and the two 72/25 kV load transformers. Install a new 144/25 kV load transformer at Bonnyville.
    d. Restore the capacity of 144 kV line 7L53 (from Bonnyville 700S to Vermilion 710S) to its full thermal conductor rating by mitigating line clearance issues.
2. Cold Lake Planning Area:
    a. Build a new 144 kV switching station (named as Bourque 970S), with associated set of breakers, near the existing Mahihkan 837S.
    b. Build a new double circuit 240 kV, one side strung, from Bourque 970S to Bonnyville 700S using 2x795 kcmil ACSR conductors per phase. This line will be initially operated at 144 kV.
    c. Build a new 144 kV double circuit line from Bourque 970S to Mahihkan 837S using 1x477 kcmil ACSR conductor per phase.
    d. Re-build 144 kV line 7L74 from Wolf Lake 822S and re-terminate it from Mahihkan 837S to Bourque 970S using 1x795 kcmil ACSR conductor per phase.
    e. Re-build 144 kV line 7L83 from Leming Lake 715S and re-terminate it from Mahihkan 837S to Bourque 970S using 1x477 kcmil ACSR conductor per phase.
    f. Re-build 144 kV line 7L87 from Marguerite Lake 826S to Wolf Lake 822S using 1x795 kcmil ACSR conductor per phase.
    g. Remove the existing thermal protection schemes in the Cold Lake area.
3. Provost Planning Area:
    a. Re-build 144 kV line 7L749 from Edgerton 899S to Lloydminster 716S using 1x477 kcmil ACSR conductor per phase.
    b. Build a new single circuit 138 kV line from Provost 545S to Hayter 277S using 1x795 kcmil ACSR conductor per phase.

   c. Re-build 138 kV line 748L from Hayter 277S to Killarney Lake 267S using 1x795 kcmil ACSR conductor per phase.
   d. Re-build 138 kV line 715L from Hansman Lake 650S to Provost 545S using 1x795 kcmil ACSR conductor per phase.
   e. Re-build 138 kV line 749L from Metiskow 648S to Edgerton 899S and build a double circuit 138 kV line from the existing Killarney Lake tap on 749L to Killarney Lake 267S as an in and out configuration. Use 1x795 kcmil ACSR conductor per phase for these lines.

4. Wainwright Planning Area:
   a. Build a new single circuit 138 kV line on the existing 69 kV right-of-way from Wainwright 51S to Edgerton 899S using 1x477 kcmil ACSR conductor per phase.
   b. Re-build 138 kV lines 704L and 704AL between Wainwright 51S, Tucuman 478S and Jarrow 252S using 1x477 kcmil ACSR conductor per phase. Wainwright 51S will thus be connected to Jarrow 252S via a double circuit line from the existing Wainwright tap point.

5. Lloydminster and Battle River Planning Areas:
   a. Restore the capacity of the 144 kV lines 7L14 (from Vermilion 710S to Hill 751S) and 7L701 (from Battle River 757S to Strome 223S) to their respective full thermal conductor rating by mitigating line clearance issues.
   b. Upgrade the existing 72 kV Heisler 764S and Kitscoty 705S substations to 144 kV by connecting them to nearby 7L701 and 7L14 lines, respectively.
   c. Salvage 72 kV line 6L06 from Kitscoty 705S to Vermilion 710S and demobilize all 72 kV equipment at Vermilion 710S.
   d. Install a new 144 kV 25 MVAr capacitor bank at Vermilion 710S.

Stage II – The target ISD for all the reinforcements proposed in this stage is Q4 2017:

1. Re-build the aging 138/144 kV 7L50 line from Battle River 757S to Buffalo Creek 526S using 1x477 kcmil ACSR conductor per phase.

2. Build a new double circuit 240 kV line with one side strung from Bourque 970S to Marguerite Lake 826S using 2x795 kcmil ACSR conductors per phase. This line will be initially operated at 144 kV.

The estimated capital cost for Stages I and II are approximately $310 million and $60 million (+/- 30%, 2009$), respectively, resulting in a total cost of $370 million (+/- 30%, 2009$).

Figure EX- 1: Central East Region Transmission Development Preferred Alternative

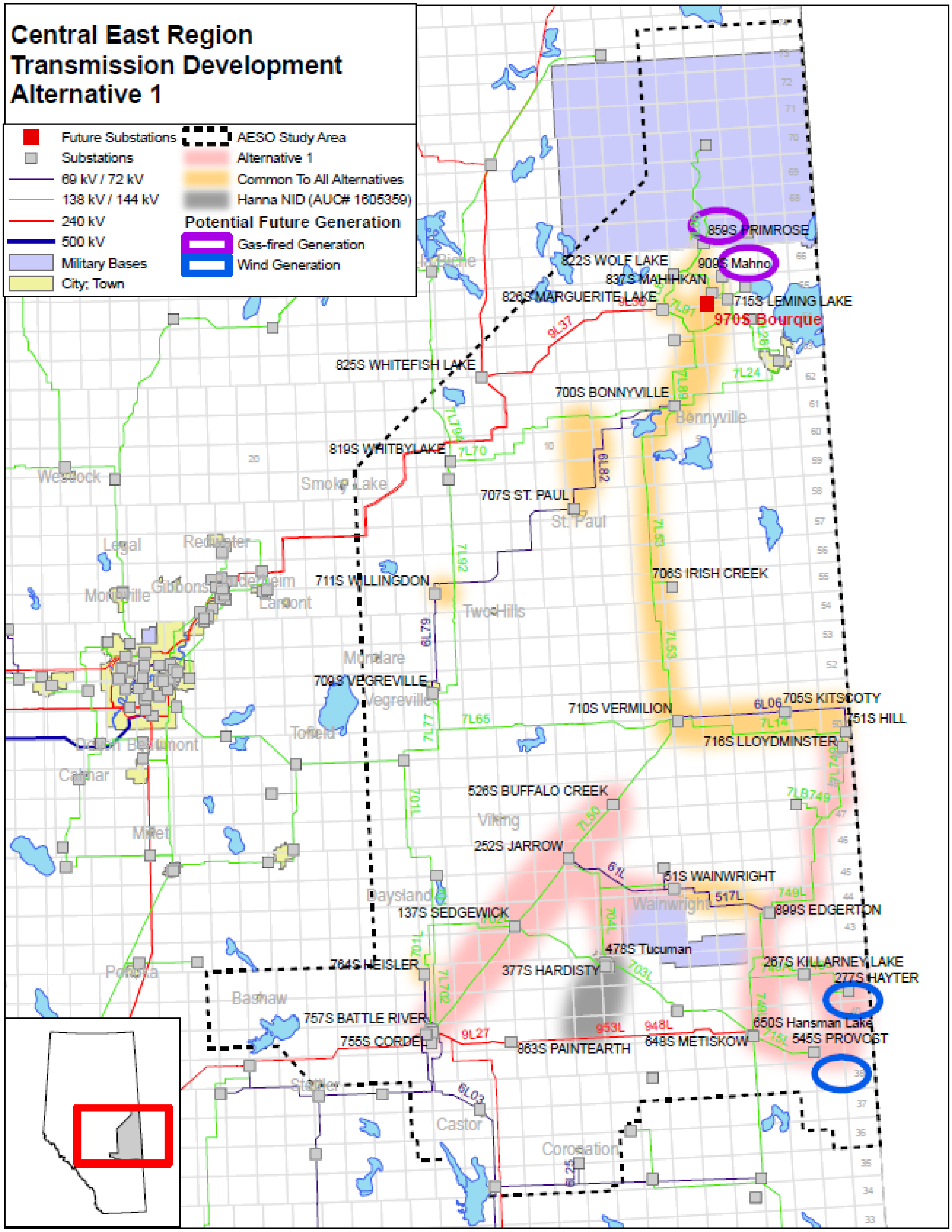


TABLE OF CONTENTS

List of Tables and Figures

List of Tables

List of Figures

1 Description of the Central East Region Transmission System

The Alberta Interconnected Electric System (AIES) is a vital component of the electric industry and provides a platform for the competitive wholesale electricity market in Alberta. 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.

The Central East region encompasses the east portion of the Alberta central planning region. The planning areas in this region include Cold Lake (Area 28), Vegreville (Area 56), Lloydminster (Area 13), Alliance/Battle River (Area 36), Wainwright (Area 32) and Provost (Area 37). The Central East region consists of the following larger rural communities: Cold Lake, Bonnyville, St. Paul, Vegreville, Vermilion, Lloydminster, Sedgewick, Hardisty, Wainwright and Provost. Figures 1-1 and 1-2 show the geographical map and schematic representation of the Central East region transmission system, respectively.

With the exception of the Cold Lake planning area, most of the Central East region transmission system was originally designed to supply primarily farms and small towns. Being mostly farming communities, the load growth in this region has been very steady to date. The recent significant regional growth is driven by oilsands and pipeline loads. As a result, the demand for electricity in the Cold Lake and Wainwright planning areas is expected to experience significant growth.

The study region is served by both 240 kV and 138/144 kV transmission networks. There are also some 69/72 kV system supplying town and mining loads in the region. A double circuit 240 kV line from Whitefish Lake 825S to Marguerite Lake 826S provides the 240 kV bulk system connection in the northern part of this region. The other regional 240kV source interconnections with the bulk system include 912L from Red Deer 63S to Nevis 766S, 9L59 from Anderson 801S to Cordel 755S and 9L79/9L80 from Battle River 757S to Cordel 755S. In the southern portion of this study region, 240 kV lines 9L953 and 9L948 carry energy from Battle River 757S eastward to Hansman Lake 650S via Cordel 755S and Paintearth Creek 863S.

The major source of power supply to this region is the coal-fired plant at Battle River, which is considered to be the critical generating plant in this study. In addition, three industrial generating sites exist in the Cold Lake planning area that supply power to both behind the fence loads and the AIES grid.

Figure 1-1: Geographical Map of Existing Central East Region Transmission System

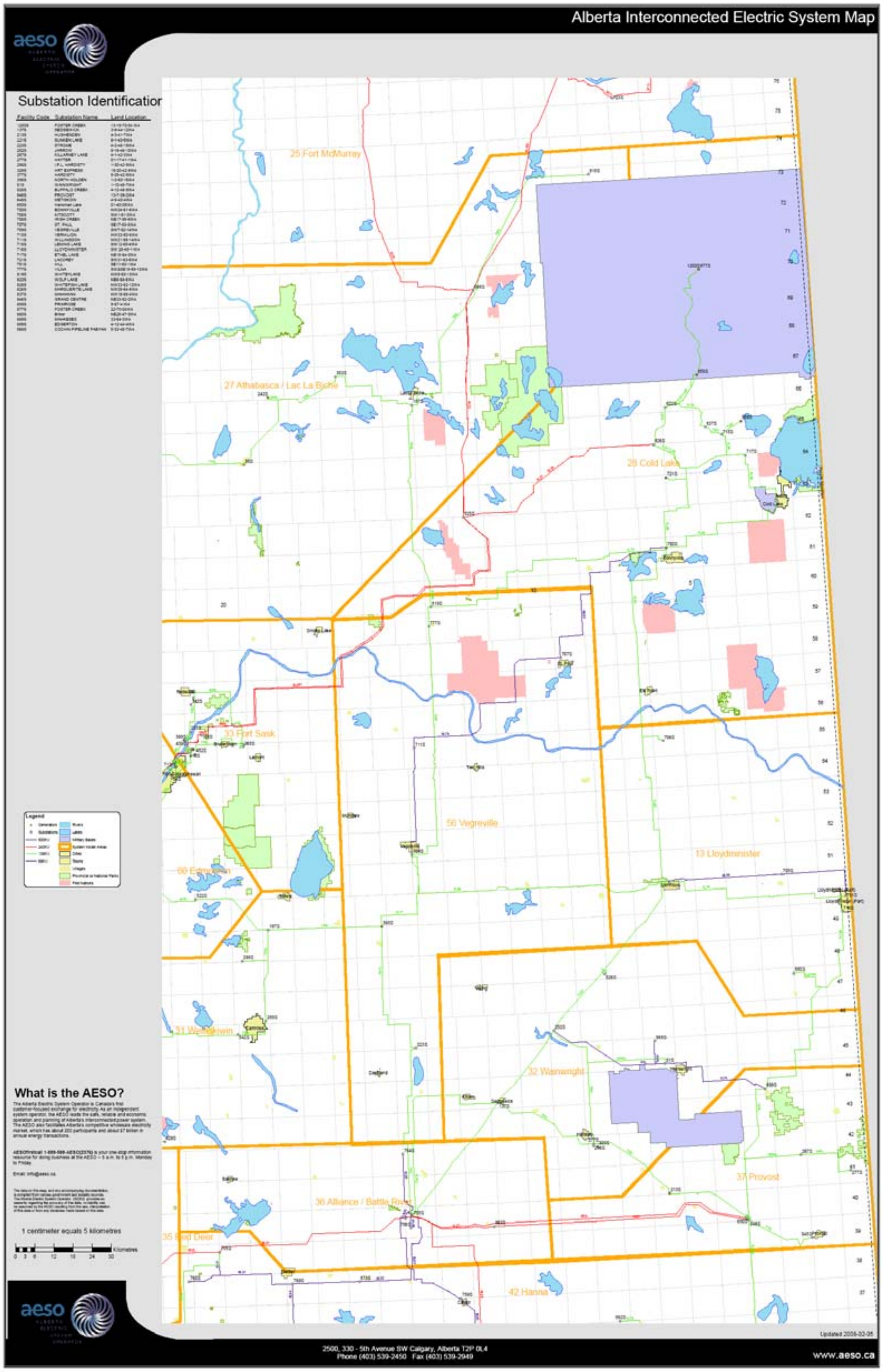
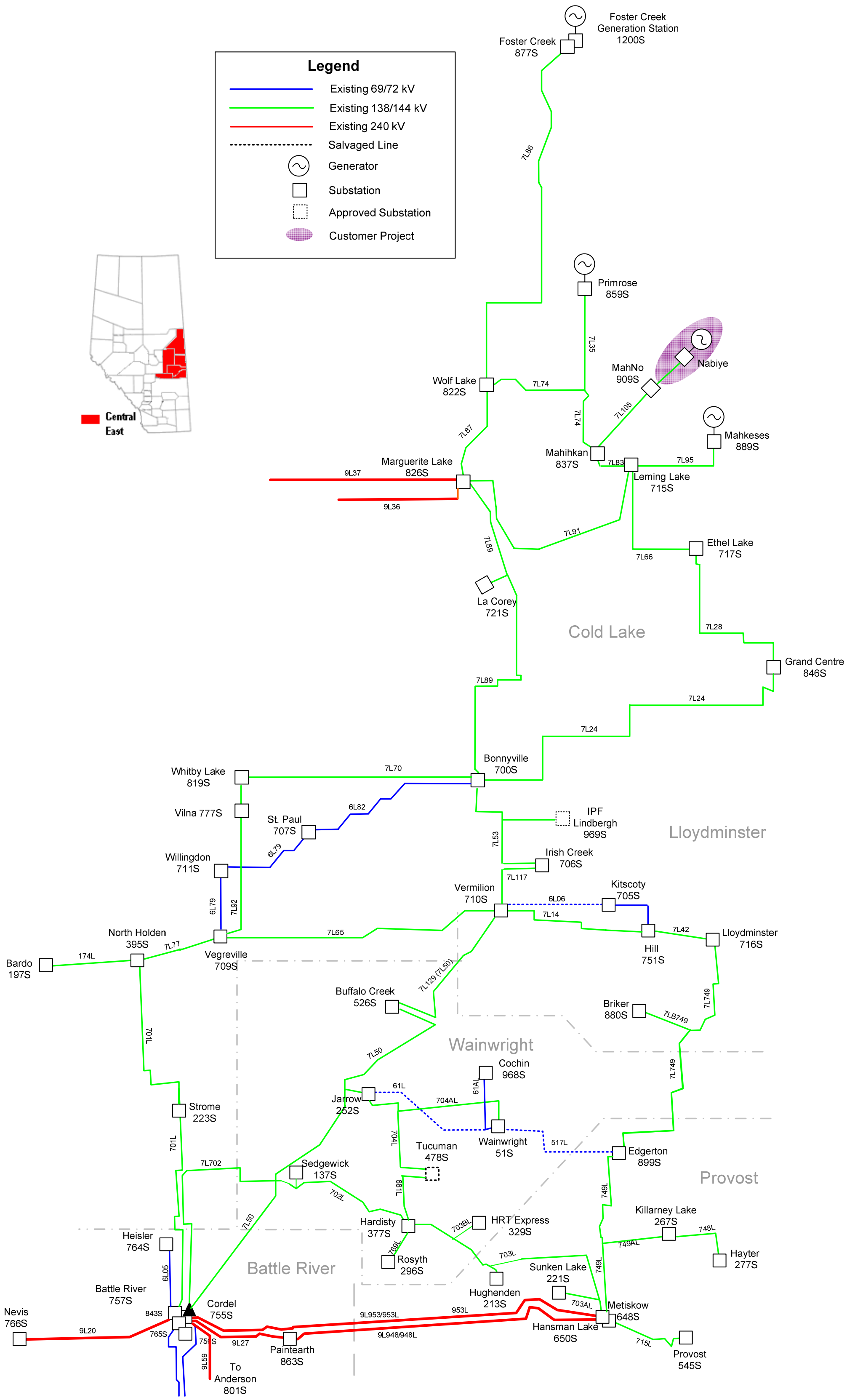


Figure 1-2: Single Line Diagram of Existing Central East Region Transmission System



Of the six planning areas included in the Central East region study, the Cold Lake area located north of Bonnyville to the Saskatchewan border has the largest load with a winter peak of approximately 330 MW in 2009. A majority of this area load is located behind the fence at several industrial sites and is generally supplied by the customers' generation. However, due to the diversity of behind-the-fence generation and demand at the industrial sites, presently the Cold Lake area has a surplus of energy which can at times be supplied to neighbouring areas. This situation could change in the future depending upon load growth and the addition of new generation in the Cold Lake area.

The next major load area in the region is the Wainwright area having approximately 90 MW of winter peak load in 2009. This load is projected to grow at a rapid rate due to the expansion of pipelines and associated infrastructure.

The AESO has received applications to connect two cogeneration projects totalling 255 MW in the Cold Lake area and two wind farms totalling 280 MW in the vicinity of the Provost area.

Table 1.1 presents the ratings of the major transmission lines in the study region. The thermal overloads are assessed by comparing the line flows with these line and equipment ratings.

Table 1-1: Rating of Major Lines in Study Region

Line Designation	Lines Connectivity		Voltage	Summer (MVA)		Winter (MVA)		Limiting factor (If different than line conductor rating)
	From	To	(kV)	Base Case	Rating	Base Case	Rating	
61L	Jarrow 252S	Cochin tap	69	22	22	27	27	
61L	Wainwright 51S	Cochin tap	69	22	22	24	24	
61L	Cochin	Cochin tap	69	22	22	27	27	
6LA02	Mannix Mine 865S	tap	72	55	57	69	72	
6L02	Mannix Mine 865S	Battle River 757S	72	47	49	47	49	CT
6L03	Battle River 757S	Sullivan Lake 775S	72	47	49	47	49	CT
6L05	Battle River 757S	Heisler 764S	72	55	57	69	72	
6LA05	Bigknife Creek 543S	Mannix Mine 865S	72	31	32	38	40	
6L06	Vermillion 710S	Hill 751S	72	23	24	23	24	CT
6L08	Battle River 757S	Bigfoot 756S	72	55	57	69	72	
6L79	Willingdon 711S	Vegreville 709S	72	23	24	23	24	CT
6L79	Willingdon 711S	St. Paul 707S	72	23	24	23	24	CT
6L82	Bonnyville 700S	St. Paul 707S	72	23	24	23	24	CT
701L	North Holden 395S	Strome 223S	138	119	119	146	146	
703BL	HRT express	Express tap	138	123	123	150	150	
703L	Hardisty 377S	Express tap	138	83	83	83	83	
703L	Hughenden 213S	Express tap	138	121	121	145	145	
703L	Hughenden 213S	703AL tap	138	122	122	147	147	
703L	Sunken Lake	703AL tap	138	85	85	90	90	
703L	Metiskow 648S	703AL tap	138	122	122	143	143	
704L	Jarrow 252S	Jarrow tap	138	85	85	90	90	
704L	Jarrow 252S	Wainwright tap	138	75	75	79	79	
704L	Hardisty 377S	Tucuman 478S	138	149	149	190	190	
704L	Wainwright 51S	Wainwright tap	138	121	121	148	148	
704L	Tucuman 478S	Wainwright tap	138	75	75	79	79	
715L	Provost 545S	Hansman Lake 650S	138	98	98	132	132	
748L	Killarney Lake 267S	Hayter 277S	138	119	119	146	146	
749L	Metiskow 648S	Killarney Lake tap	138	121	121	149	149	
749L	Killarney Lake 267S	Killarney Lake tap	138	121	121	148	148	
749L	Edgerton 899S	Killarney Lake tap	138	85	85	90	90	
769L	Hardisty 377S	IPL Hardisty	138	86	86	115	115	
7L702	Hardisty 377S	Sedgewick 137S	138	87	87	135	135	
885L	Metiskow 648S	Hansman Lake 650S	138	287	287	287	287	
7L14	Vermillion 710S	Hill 751S	144	72	75	86	90	Clearance issues
7L224	Hansman Lake 650S	Monitor 774S	144	109	114	139	145	
7L24	Bonnyville 700S	Grande Centre 846S	144	109	114	139	145	
7L28	Ethel Lake 717S	Grande Centre 846S	144	109	114	139	145	
7L35	Primrose tap	Primrose 859S	144	140	146	143	149	
7L42	Hill 751S	Lloydminster 716S	144	95	99	95	99	CT
751L	Vermilion 710S	Buffalo Creek 526S	144	50	52	50	52	Clearance issues
7L50	Buffalo Creek 526S	Jarrow tap	144	64	67	64	67	Clearance issues
7L50	Jarrow tap	Battle River 757S	144	99	103	99	103	Clearance issues
7L53	Bonnyville 700S	Irish Creek 706S	144	72	75	86	90	Clearance issues
7L114	Irish Creek 706S	Vermilion 710S	144	72	75	86	90	Clearance issues
7L65	Vegreville 709S	Vermilion 710S	144	95	99	95	99	CT

Table 1-1: Rating of Major Lines in Study Region (Cont'd)

Line Designation	Lines Connectivity		Voltage	Summer (MVA)		Winter (MVA)		Limiting factor (If different than line conductor rating)
	From	To	(kV)	Base Case	Rating	Base Case	Rating	
7L66	Leming Lake 715S	Ethel Lake 717S	144	109	114	139	145	
7L70	Bonnyville 700S	Whitby Lake 819S	144	95	99	95	99	CT
7L701	Strome 223S	Battle River 757S	144	95	99	114	119	Clearance issues
7L702	Sedgewick 137S	Battle River 757S	144	95	99	110	115	Clearance issues
7L74	Wolf Lake 822S	Mahihkan 837S	144	109	114	139	145	
7L749	Edgerton 899S	PV tap	144	85	85	90	90	
7L749	PV tap	Briker 880S	144	109	114	139	145	
7L749	PV tap	Lloydminster 716S	144	109	114	139	145	
7L77	North Holden 395S	Vegreville 709S	144	109	114	139	145	
7L79	Ribstone 892S	Keystone Pump #1	138	115	115	145	145	
7L794	Lac La Biche 157S	Whitby Lake 819S	144	94	98	94	98	CT
7L83	Mahihkan 837S	Leming Lake 715S	144	109	114	139	145	
7L86	Wolf Lake 822S	Foster Creek 877S	144	139	145	143	149	CT
7L87	Wolf Lake 822S	Marguerite Lake 826S	144	109	114	139	145	
7L89	Marguerite Lake 826S	La Corey 721S	144	109	114	139	145	
7L89	La Corey 721S	Bonnyville 700S	144	109	114	139	145	
7L91	Leming Lake 715S	Marguerite Lake 826S	144	109	114	139	145	
7L92	Whitby Lake 819S	Vilna 777S	144	95	99	95	99	CT
7L92	Vilna 777S	Vegreville 709S	144	95	99	95	99	CT
7L95	Mahkeses 889S	Leming Lake 715S	144	190	198	190	198	CT
	Mahihkan 837S	New Generation 1	144	109	114	139	145	
948L/9L948	Hansman Lake 650S	Paintearth Creek 863S	240	207	207	207	207	CT
953L/9L953	Hansman Lake 650S	Cordel 755S	240	498	498	498	498	CT
954L	Metiskow 648S	Hansman Lake 650S	240	333	333	333	333	
9L20	Nevis 766S	Cordel 755S	240	488	488	498	498	L/CT
9L22	Heart Lake 898S	Whitefish Lake 825S	240	498	498	498	498	CT
9L27	Paintearth Creek 863S	Cordel 755S	240	207	207	207	207	CT
9L36	Whitefish Lake 825S	Marguerite Lake 826S	240	498	498	498	498	CT
9L37	Whitefish Lake 825S	Marguerite Lake 826S	240	498	498	498	498	CT
9L59	Cordel 755S	Anderson tap	240	488	488	498	498	L/CT
9L79	Battle River 757S	Cordel 755S	240	499	499	499	499	CT
9L80	Battle River 757S	Cordel 755S	240	415	415	415	415	CT
9L930	Leismer 72s	Whitefish Lake 825S	240	498	498	498	498	CT
9L960	Deerland 13S	Whitefish Lake 825S	240	498	498	498	498	CT
9L961	Deerland 13S	Whitefish Lake 825S	240	498	498	498	498	CT

NOTES:

1. CT means current transformer.

2. During the course of this study, ATCO completed clearance mitigation of 144 kV line 7L50 between Battle River, Buffalo Creek and Vermilion. The line ratings shown in this table were used in the need analysis as presented in Section 3 of this NID. However, the regional alternatives were evaluated using the recently restored ratings of 7L50 to 114 MVA and 146 MVA in the summer and winter seasons respectively.

3. The clearance issues on the section of 144 kV line 7L702 between Battle River and Sedgewick have been completed and the line capacity restored to its full conductor rating. However, CT limitations restrict the flow on this line to 125 MVA in the winter.

2 Criteria and Assumptions

To assess the need to reinforce the transmission system in the Central East region, the AESO tested present and future adequacy of the existing transmission system by applying the AESO Transmission Reliability Criteria ("Reliability Criteria"). The Central East region transmission system was tested for the load forecast and future generation assumptions given in Sections 2.2.1 and 2.2.3 respectively. The following sections describe a summary of the Reliability Criteria and the assumptions made in developing this NID.

2.1 Reliability Criteria

The AESO performs technical studies to assess the transmission supply and reliability needs in Alberta. These technical studies test the transmission system for adequacy, security, system operability and maintenance management.

The Reliability Criteria was applied to determine the load supply adequacy of the planned transmission system in the Central East region. The existing transmission system, along with the proposed alternatives, were tested to see if the proposed alternatives were capable of supplying the forecast peak demand under both Category A (i.e. all elements in service) and Category B (i.e. one element out of service, N-1 and N-G-1) contingencies[1]. Each of the alternatives considered was put through an iterative planning process to ensure that the performance of the planned transmission system conforms to the requirements of the Reliability Criteria.

Category B contingencies also cover single element outage events with the most critical generator assumed out of service (N-G-1), and the remaining generators in the system are dispatched according to the forecast merit order. All equipment must operate within its acceptable thermal and voltage limits.

Category C and D events are studied for the recommended alternative only. The system performance is evaluated to ensure that no system cascading occurs.

Category C events result in the loss of one or more system elements under specified fault conditions and include both normal and delayed fault clearing events. Examples of this category include loss of two circuits on a multiple circuit tower (N-2), loss of HVDC bipole (N-2), and loss of a generator/line/transformer followed by loss of another element (N-1-1).

Category D represents a wide variety of extreme, rare and unpredictable events which may result in loss of customer demand (firm load) and generation in wide spread areas. Examples of such events include loss of all transmission lines on a

[1] The terms "contingencies" and "events" are used interchangeably throughout this document

common right-of-way, loss of all generating units at a power plant, and loss of a substation.

Table 2-1 presents the acceptable steady state and contingency state voltage ranges for the AIES.

Table 2-1: Acceptable Range of Steady State Voltage (kV)[2]

Nominal Voltage	Extreme Minimum	Normal Minimum	Normal Maximum	Extreme Maximum
240	220	240	264	264
144	130	137	151	155
138	124	135	145	150
72	65	71	75	78
69	62	65	72	74

Voltage stability criteria used to test the system performance is provided in Table 2-2.

[2] For details, see Table 5.1-1 on Page 11 of "AESO Transmission Reliability Criteria – Part II System Planning."

Table 2-2: Voltage Stability Criteria[3]

Performance Level	Disturbance Initiated by: Fault or No fault DC Disturbance	MW Margin (P-V method)	MVAr Margin (V-Q method)
A	Any element such as: One generator One circuit One transformer	≥ 5%	Worst Case Scenario[4]
B	Bus section	≥ 2.5%	50% of margin requirement in Level A
C	Any combination of two elements such as: A line and a generator A line and a reactive power source Two generators Two circuits Two transformers	≥ 2.5%	50% of margin requirement in Level A
D	Any combination of three or more elements, such as: Three or more circuit on ROW Entire substation	> 0	> 0

[3] For details, see Table 5.2-1 Voltage Stability Criteria on Page 15 of the AESO Transmission Reliability Criteria – Part II System Planning

[4] The most reactive deficient bus must have adequate reactive power margin for the worst single contingency to satisfy either of the following conditions, whichever is worst: (i) a 5% increase beyond maximum forecasted loads or (ii) 5% increase beyond maximum allowable interface flows. The worst single contingency is the one that causes the largest decrease in the reactive power margin.

2.2 Input Assumptions

Primary assumptions that were considered in the Central East region planning study consist of regional forecast load, generation scenarios, and topology of the bulk system.

2.2.1 Load Forecast

The Central East region study is based on the AESO's *Future Demand and Energy Outlook (2007-2027)* (FC2007) which is updated for project information, generator standby load, and assumptions regarding potential future pipeline projects. Table 2-3 provides the historical and forecast area and regional summer and winter peak loads in MW for the Central East region. It is consistent with "Table 2.2-2 Region Historical and Forecast Area Peak Load" published in the Hanna Region Transmission Development Needs Identification Document Application[5].

The Central East region is a winter peaking region[6]. In 2009, the coincident recorded winter peak of this region was approximately 750 MW. The regional winter peak is forecasted to grow from 750 MW in 2009 to 1,160 MW in 2012 and 1,290 MW by 2017. Of the six planning areas, the Cold Lake and Wainwright areas contain the largest concentration of loads. Cold Lake has a number of oilsands projects and the power required to serve these as well as pipeline loads are expected to grow over the next decade. A number of pipeline storage tanks and pumping stations are located in the Wainwright area. These pipelines require a large amount of power for pumping bitumen or oil to the markets in the south.

As per Table 2-4, the Central East region peaks in the winter period with an overall average load growth rate of approximately 3.6% per year over the past six years. The regional winter peak load is projected to grow at an average of 6.4% per year over the next nine-year period.

[5] On April 29, 2010, the Alberta Utilities Commission granted the AESO approval of the Hanna Region Transmission System Development Needs Identification Document Application – AUC Approval No. 1606359.

[6] Winter period is defined as the period from November 01 to April 30; Summer period from May 01 to October 30. Winter peak is denoted as 'win'; summer peak is denoted as 'sum'.

Table 2-3: Central East Seasonal Historic and Forecast Peak Loads

	Year	Lloydminster (Area 13)		Cold Lake (Area 28)		Wainwright (Area 32)		Battle River (Area 36)		Provost (Area 37)		Vegreville (Area 56)		Regional Peak	
		WP	SP	WP	SP	WP	SP	WP	SP	WP	SP	WP	SP	WP	SP
Historical Peak Load (MW)	2002	97.3	91.2	216.5	187.5	81.3	77.0	40.1	39.3	113.4	108.2	64.4	55.5	584.6	531.3
	2003	105.2	97.6	232.8	209.1	87.2	80.0	40.8	38.6	117.1	108.9	62.7	52.8	637.9	573.9
	2004	109.2	94.6	241.4	217.3	89.1	85.2	38.5	40.2	114.6	105.4	70.3	56.4	643.2	574.4
	2005	111.0	91.6	258.2	219.5	92.6	82.7	37.4	37.9	120.1	106.2	62.1	55.2	651.9	566.7
	2006	111.2	99.5	273.7	253.2	92.5	87.5	45.0	39.7	118.9	112.8	67.5	59.3	678.3	639.5
	2007	105.4	94.8	297.0	263.4	92.2	84.8	34.7	33.3	123.0	112.2	67.4	54.7	695.5	626.4
	2008	115.8	99.8	322.7	281.3	94.4	84.6	34.6	32.4	125.5	108.6	68.8	52.6	740.7	628.3
	2009*	111.3	92.7	331.4	290.3	88.1	86.2	29.9	28.2	120.5	110.8	77.9	64.7	749.5	641.9
Forecast Peak Load (MW)	2009	131.1	123.6	418.7	376.3	162.4	154.0	51.6	37.9	150.0	112.7	79.3	71.8	980.5	836.0
	2010	133.7	125.9	442.5	398.7	186.8	178.4	51.6	38.0	151.5	113.4	80.3	72.7	1033.2	884.3
	2011	136.2	128.2	449.4	404.9	204.1	195.6	51.6	38.0	153.1	117.2	80.8	73.1	1061.6	913.0
	2012	138.6	130.5	459.1	413.9	266.1	257.4	51.6	38.0	178.0	141.3	81.7	73.9	1160.3	1006.4
	2013	141.1	132.8	464.4	418.5	268.4	259.5	51.6	38.0	179.4	141.4	81.9	74.1	1171.7	1015.4
	2014	143.6	135.1	475.7	429.1	270.7	261.7	51.6	38.0	181.1	139.5	82.4	74.6	1189.9	1028.3
	2015	146.1	137.5	482.7	435.3	273.2	264.0	51.6	38.0	183.1	140.2	83.0	75.0	1204.2	1039.9
	2016	148.7	139.8	487.2	439.3	275.6	266.2	51.6	38.1	185.2	144.4	83.5	75.5	1216.3	1052.6
	2017	151.2	142.2	494.9	446.3	314.1	304.5	51.6	38.1	210.5	168.6	84.6	76.5	1290.4	1122.1
	2018	153.8	144.6	502.6	453.2	316.7	306.8	51.7	38.1	212.3	169.4	85.2	77.0	1305.4	1134.4

* At the time of writing, historic peak load values are not yet available. As a result, Table 2-3 presents both 2009 historic peak load based on season-to-date information and 2009 forecast peak load.

Table 2-4: Central East Planning Area Forecast Load Growth

Planning Area	Lloydminster (Area 13)		Cold Lake (Area 28)		Wainwright (Area 32)		Battle River (Area 36)		Provost (Area 37)		Vegreville (Area 56)		Regional	
	WP	SP	WP	SP	WP	SP	WP	SP	WP	SP	WP	SP	WP	SP
Historical (2002-2009)	1.9%	0.2%	6.3%	6.4%	1.2%	1.6%	-4.1%	-4.6%	0.9%	0.3%	2.8%	2.2%	3.6%	2.7%
Forecasted (2009* - 2018)	3.7%	5.1%	4.7%	5.1%	15.3%	15.2%	6.3%	3.4%	6.5%	4.8%	1.0%	1.9%	6.4%	6.5%

* Growth rate is calculated using 2009 historical figures

In February 2010, the AESO's most recent long-term load forecast, the *Future Demand and Energy Outlook (2009 – 2029)* (FC2009), was released. The FC2009 was updated to take into account generator standby load, recent project information and assumptions regarding potential future pipeline projects. The adjusted FC2009 for the Central East region and the differences between FC2009 and FC2007 are shown in Table 2-5:

Table 2-5: Central East Regional Peak – Updated FC2009

Year	Adjusted FC2009		Differences From FC2007	
	WP	SP	WP	SP
2010	876.2	766.4	-157.0	-117.9
2012	1063.5	933.4	-96.8	-73.0
2017	1257.8	1106.2	-32.6	-15.9

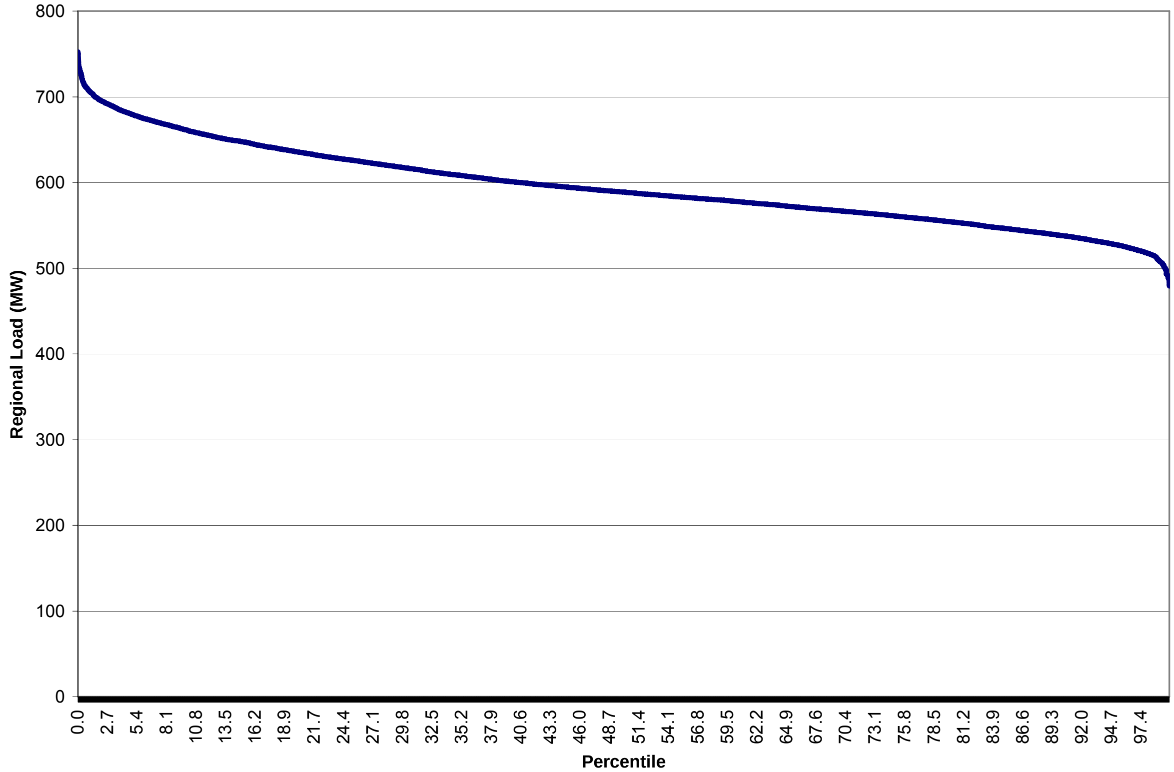
Due to the economic slowdown in 2008 and 2009, delays occurred in both the development of oilsands projects and pipeline projects' in-service dates. Consequently, the recorded load growth during this period was lower than projected in FC2007. However, by the 2017 study year, the difference between the regional load in Table 2-3 and the updated FC2009 is only 15 to 30 MW. Based on this information, the AESO considers the load forecast used for the study years as presented in Table 2-3 to be reasonable.

Table B-1 in Appendix B provides the historical summer and winter peak substation loads for the last five years.

Figure 2-1 presents the load duration curve for the Central East region for the year 2009. The peak load is approximately 750 MW and the minimum load is approximately 480 MW. For most of the time the load varies between 550 MW and 650 MW. The annual load factor for the study region is calculated at approximately 79% which indicates that the load in this region is predominantly industrial in nature. The minimum load of 480 MW is approximately 64% of the annual peak load.

The load factor for the Alberta system for 2009 was approximately 78%.

Figure 2-1: Central East Region 2009 Load Duration Curve



2.2.2 Existing and Proposed Generation in the Central East Region

The present generation capacity in the Central East Region is 1,009 MW, as listed in Table 2-6. In addition, the AESO has received applications for the connection of two wind power projects, totaling approximately 280 MW in the vicinity of the Provost area (130 MW near the Provost 545S substation and 150 MW near the Hayter 277S substation) as well as approximately 255 MW of cogeneration in the Cold Lake area. With the addition of these potential generation projects, the generation capacity in the Central East region would increase to 1,554 MW by 2017 as shown in Table 2-6.

Table 2-6: Central East Generation Summary

#	Generation Plant	Fuel Type	Existing Capacity	Capacity by 2017
1	Battle River #3	Coal	148	148
2	Battle River #4	Coal	148	148
3	Battle River #5	Coal	368	378
4	Mahkeses #1	Cogen	90	90
5	Mahkeses #2	Cogen	90	90
6	Foster Creek #1	Cogen	40	40
7	Foster Creek #2	Cogen	40	40
8	Primrose	Cogen	85	85
9	Primrose East	Cogen	-	85
10	Nabiye	Cogen	-	170
11	Bull Creek Wind Farm	Wind	-	130
12	Provost Wind Farm	Wind	-	150
Total			**1,009**	**1,554**

2.2.3 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.

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. There is no adequacy reserve margin requirement defined by an authoritative body in Alberta. For the purpose of developing reasonable generation scenarios a 10% effective reserve margin is used as a proxy for the amount of generation that will be developed in the province due to market signals. Based on this effective reserve margin and forecasted Alberta internal load, effective generation capacity in Alberta is expected to increase from 11,500 MW in November 2007 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 generation additions, information on potential generation resources, and the relative costs of generation, five generation scenarios were created, as shown in Table 2-7. These scenarios represent a reasonable range of future expansion to test the transmission system for planning purposes.

As a basis for developing the scenarios, it was assumed that prior to 2017 significant generation additions are expected to be comprised of coal-fired 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.

Table 2-7: Generation Additions for 2008-2017 (MW)

Scenario		A1	A2	B3	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**

For the Central East region study, Scenario B3 was used for the purpose of determining transmission reinforcement in the region as this scenario stresses the regional transmission system most appropriately.

The coal additions in Scenario B3 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 B3.

The cogeneration capacity included in Scenario B3 is additions to support behind-the-fence load, with the bulk occurring within the oilsands industry in the northeast area of the province. The two cogeneration projects planned for the Cold Lake area are included as additions in the study.

Scenario B3 also includes the development of 720 MW of combined cycle generation prior to 2017. This combined cycle generation is assumed to be developed near Calgary based on project plans from 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 waste heat, solar, micro generation, and geothermal developments.

The characteristics of simple cycle generation allow it to provide peaking capability in Alberta's base load heavy generation mix to manage load and supply fluctuations. Scenario B3 includes 620 MW of additional simple cycle generation.

Large amounts of wind generation are planned for the province. Scenario B3 includes the addition of 1,600 MW of wind capacity to the system by 2017. Including the existing capacity at the time the scenarios were developed, of 497 MW, wind capacity will amount to 2,100 MW in Alberta by 2017. The amount of wind added to the system over the next 10 years is assumed to be determined by market factors, and not transmission or market policy. The factors affecting wind generation additions are assumed to be the pace at which the wind farms can be constructed, the economic viability of the projects as the amount of wind on the system increases, and the ability of the system to integrate variable wind generation. For this regional study the two planned wind projects in Provost, amounting to 280 MW, were included in the estimate of future wind generation.

Additional information on the development of the generation scenarios is available in Appendices E, F and G of the 2009 AESO Long-Term Transmission System Plan[7].

[7] The 2009 AESO Long-Term Transmission System Plan can be found on the AESO website at: http://www.aeso.ca/downloads/AESO_LTTSP_Final_July_2009.pdf

2.2.4 Bulk System Assumptions

The system model used for this study included the following bulk system additions for the years indicated.

Bulk System by 2012

- 240 kV line from Brintnell to Wesley Creek;
- New 240 kV line to the Thickwood substation;
- New Cache Creek substation located between Ruth Lake and Kinosis substations;
- 240 kV line from the Thickwood substation to Cache Creek;
- 240 kV 600 MVA phase shifting transformer at Keephills;
- Reconfiguration of 946L/947L resulting in one 240 kV line from Ellerslie to Clover Bar and one 240 kV line from Ellerslie to East Edmonton;
- 240 kV double circuit line from Ellerslie to the new Eastwood substation; and
- De-bottlenecking project:
  - New 2x477 kcmil 240 kV lines from Keephills to new 904L – 908L – 909L confluence points;
  - 908L (Ellerslie – Sundance) re-termination from its existing location at Sundance to the new 904L – 908L – 909L confluence point;
  - Swap the connections of 904L (Jasper – Wabamun) and 908L at the confluence point so that the 904L termination at Wabamun can be moved to Sundance; and
  - New 240 kV 600 MVA phase shifting transformer located at the new Livock substation and on 9L57 (Livock – Dover) and the new 240 kV line to the Fort Murray 240 kV substation.

Bulk System by 2017

New HVDC Lines Developments:

- ± 500 kV, 2000 MW, HVDC Bipole line from Genesee to Langdon with associated static VAr compensators (SVC); and
- ± 500 kV, 2000 MW, HVDC Bipole line from the new Heartland 500 kV substation to the existing 240 kV West Brooks with associated SVCs.

New Substations:

- 500 kV Heartland substation; and
- 500 kV Thickwood substation.

New Transmission Lines:

- 500 kV AC from Ellerslie to Thickwood via Heartland;
- 500 kV AC from Ellerslie to Hartland; and
- 240 kV Southern Alberta Transmission Reinforcement – Looped System.

2.2.5 Hanna Region System Assumptions

The Hanna region and the Central East region share a number of key bulk system transmission substations and lines as well as the Battle River generation station. Hence, the system reinforcement in the Hanna region significantly impacts the operation of Central East region and has been modeled in the present study.

The following assumptions include upgrades and/or additions that are proposed to be in place by 2012 and 2017 in the Hanna region:

System Reinforcements by 2012:

- Single circuit 240 kV lines from Hansman Lake to Monitor and Oyen areas;
- First 240 kV line from Oakland to Lanfine;
- Double circuit 240 kV line from Anderson to Oakland switching station;
- Split 240 kV line 953L mid-way between Cordel and Hansman Lake and build a 240 kV line using in and out configuration at a new 240/138 kV substation Nilrem (Nilrem 138 kV bus will be tied to the newly added Tucuman substation);
- ± 200 MVAr SVC at Hansman Lake;
- ± 200 MVAr SVC at Pemukan; and
- ± 200 MVAr SVC at Lanfine.

System Reinforcements by 2017:

- Second 240 kV line from Oakland to Lanfine;
- Second 240/138 kV tie transformer at Hansman Lake;
- 2x27 MVAr 138 kV capacitor banks at new Nilrem substation;
- 2x36 MVAr 240 kV capacitor banks at Hansman Lake;
- 27 MVAr 138 kV capacitor bank at Hansman Lake; and
- 27 MVAr 138 kV capacitor bank at Metiskow.

2.2.6 Wind Integration in the Hanna Region

The following assumptions include upgrades and/or additions that are expected to be in place by 2012 and 2017 to integrate 175 MW and 700 MW of wind generation respectively:

2012 System Reinforcements:

- New 240 kV line between Ware Junction 132S and West Brooks 28S;
- New 240/144 kV collector substation Coyote Lake 963S in the Hand Hills area; and
- New 240 kV line (9L29) between Coyote Lake 963S and Oakland 946S on double circuit structures with single side strung.

2017 System Reinforcements:

- Second side strung on planned D/C towers (9L31 240 kV line) between Coyote Lake 963S and Oakland 946S; and
- New 240 kV line between Halkirk switching station 401S and Cordel 744S.

2.2.7 Southern Alberta Transmission Reinforcements (SATR) Assumptions

The following assumptions include upgrades and/or additions that are expected to be in place by 2012 and 2017 in southern Alberta:

Reinforcements by 2012:

- Replace the existing 240 kV 911L (Langdon 102S to Peigan 59S) by Calgary South – Peigan 240 kV double circuit transmission line with 50% series compensation;
- New 200 MVAr SVC at Peigan substation;
- Milo Junction upgrade to Switching Station to tie in 924L, 927L, 923L and 933L;
- New 120 MVA Phase Shifting Transformer on 170L Coleman to Natal;
- New 240 kV substation Sub D close to the Burdette substation;
- New 240/138 kV Medicine Hat 2 substation;
- Sub D – Medicine Hat 2 240 kV double circuit transmission line;
- New 240 kV double circuit line from West Brooks to the new Sub D substation;
- New 100 MVAr SVC at the new Sub D substation; and
- Medicine Hat 138 kV changes/upgrades.

Reinforcements by 2017:

- 500 kV Crowsnest substation located on the existing 500 kV 1201L with two 500/240 kV 1200 MVA transformers and one 240 kV 400 MVAr SVC;
- 240 kV double circuit transmission line from Crowsnest to Goose Lake;
- 240 kV single circuit transmission line from Goose Lake to Sub C;
- 240 kV single circuit transmission line from Sub C to MATL substation; and
- 240 kV single circuit transmission line from Sub C to Sub D.

3 Need Analysis for Transmission in the Central East Region

The AESO carried out power flow analysis for the existing system (i.e. without any system reinforcements in the region) to assess whether the system can supply projected demand in the years 2012 in accordance with Reliability Criteria requirements. Three load conditions, namely, summer light, summer peak and winter peak were studied to assess load supply adequacy in the years 2012 and 2017. Well over 200 Category B contingencies, including N-G-1, were investigated to assess load supply adequacy. Key contingencies are presented in Table A-1 of Appendix A. The AESO prepared and posted a Need Assessment document[8] in May 2009 which contains details of this assessment. The following sections provide a brief discussion of need assessment results. Moreover, representative power flow plots that show violations are included in Appendix A.

3.1 Existing System Analysis

Power flow analysis was carried out for the 2009 winter peak load conditions, as it stresses the system most. The existing system met the Reliability Criteria under normal conditions (i.e. Category A event) but failed to satisfy it for a number of contingencies. All five planning areas are subjected to either thermal overloads and/or voltage violations as shown in Appendix A (Figure A-2009-2a/b through Figure A-2009-65a/b).

3.2 2012 & 2017 System Analysis

Results of power flow analyses for the winter peak, summer peak and summer light load conditions show that the number of contingencies that would cause violations would significantly increase from the year 2009 to 2012 and 2017. This is to be expected since the same regional system currently in place would have to carry more load (about 50% higher than that in 2009) without any reinforcements to the system. Power flow plots that display the worst thermal overloads and/or voltage violations are included in Appendix A.

3.3 Summary of the Central East Need Assessment Results

Based on the power flow analysis of the existing transmission system within the Central East region for the years 2009, 2012 and 2017 under the winter peak, summer peak and summer light load conditions, the following conclusions can be drawn:

- The existing transmission system in the East Central region does not have enough capacity to serve the projected load growth in the very near term as

[8] Central East Region Transmission Development Need Assessment , May 11, 2009 , www.aeso.ca

well as over the next 5 to 10 years. Thus, the existing transmission network in this region does not meet the requirements of the Reliability Criteria;

- Virtually all of the planning areas in this region will experience thermal overloads and/or low voltages, even under N-0 system conditions in the years 2012 and 2017. The system performance further degrades under Category B (N-1 and N-G-1) events for all study years (2009, 2012 and 2017). Furthermore, the number of thermal overloads in the region as well their severity grew with time due to a lack of adequate transmission capacity. This is indicative of a region with insufficient load serving capability in the transmission system;

- Thermal overloads are foreseen on a number of lines that span the Central East region including a majority of 144 kV lines in the Cold Lake area, and 240 kV lines 9L27 and 9L948 in the Wainwright and Provost Areas; and

- It is not feasible to connect the proposed gas-fired generation and wind generation without system upgrades.

Thus, the existing transmission system in the Central East region is not adequate to serve the projected load growth or proposed generation development over the next 10 years. Hence, the transmission system must be reinforced in order to meet the Reliability Criteria. It is foreseen that a combination of system upgrades and new facilities would be required. The next sections describe the planning process for developing alternatives, screening and short listing of these alternatives and the studies carried out for selecting a preferred alternative.

4 Potential Options for Central East Region Transmission

The need for reinforcements in the Central East region has been established in the previous section. The next step was to formulate potential options, examine their applicability for the study region and determine an appropriate and manageable set of options which could be studied further. Figure 4-1 presents an overview of the planning process that was followed.

As laid out in Figure 4-1, the planning process consists of four phases, briefly described below:

1) Phase 1 deals with the reviewing of available potential technology options for transmission system planning and their applicability to the present study region. Assessments are made based on engineering judgment and experience to develop an appropriate set of options for use in the next phase.

2) Phase 2 involves the formulation of alternatives based on a selected set of technology options and the screening of these alternatives. Alternatives were formulated at a regional level and at a local area level. These two streams of alternative sets were screened using preliminary technical studies, high level cost estimates and information on the pre feasibility of routing. The end result of this phase is a short-list of alternatives for both the regional system and local areas. Section 5 presents a detailed description of the aforementioned process.

3) Phase 3 consists of detailed system studies (power flow, voltage stability, and system losses) for each of the alternatives short-listed in Phase 2. The results of these studies are analyzed to ensure that they meet the Reliability Criteria. Sections 6.1-6.4 discuss the technical performance of the three regional alternatives.

4) Phase 4 encompasses an evaluation of alternatives based on technical, economic, social, and land impact perspectives. The AESO conducts an economic comparison of alternatives taking into account capital costs (estimated by the TFOs), system losses and targeted ISDs. As directed by the AESO, TFOs perform a land impact assessment and present their findings with respect to the feasibility of proposed alternatives. The AESO carries out a participant involvement program and compiles feedback from stakeholders in the region and presents its conclusions.

Figure 4-1: Planning Process Overview

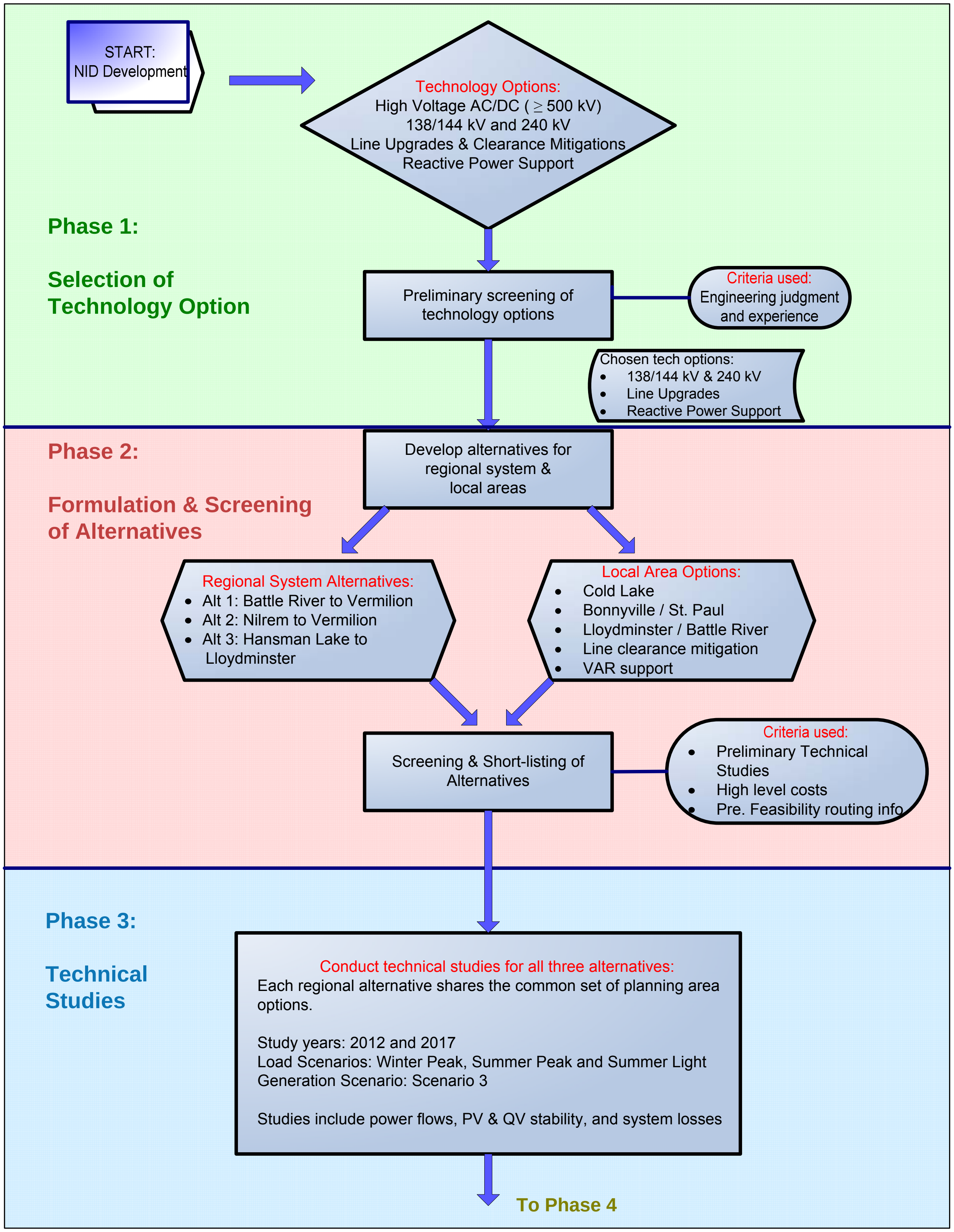
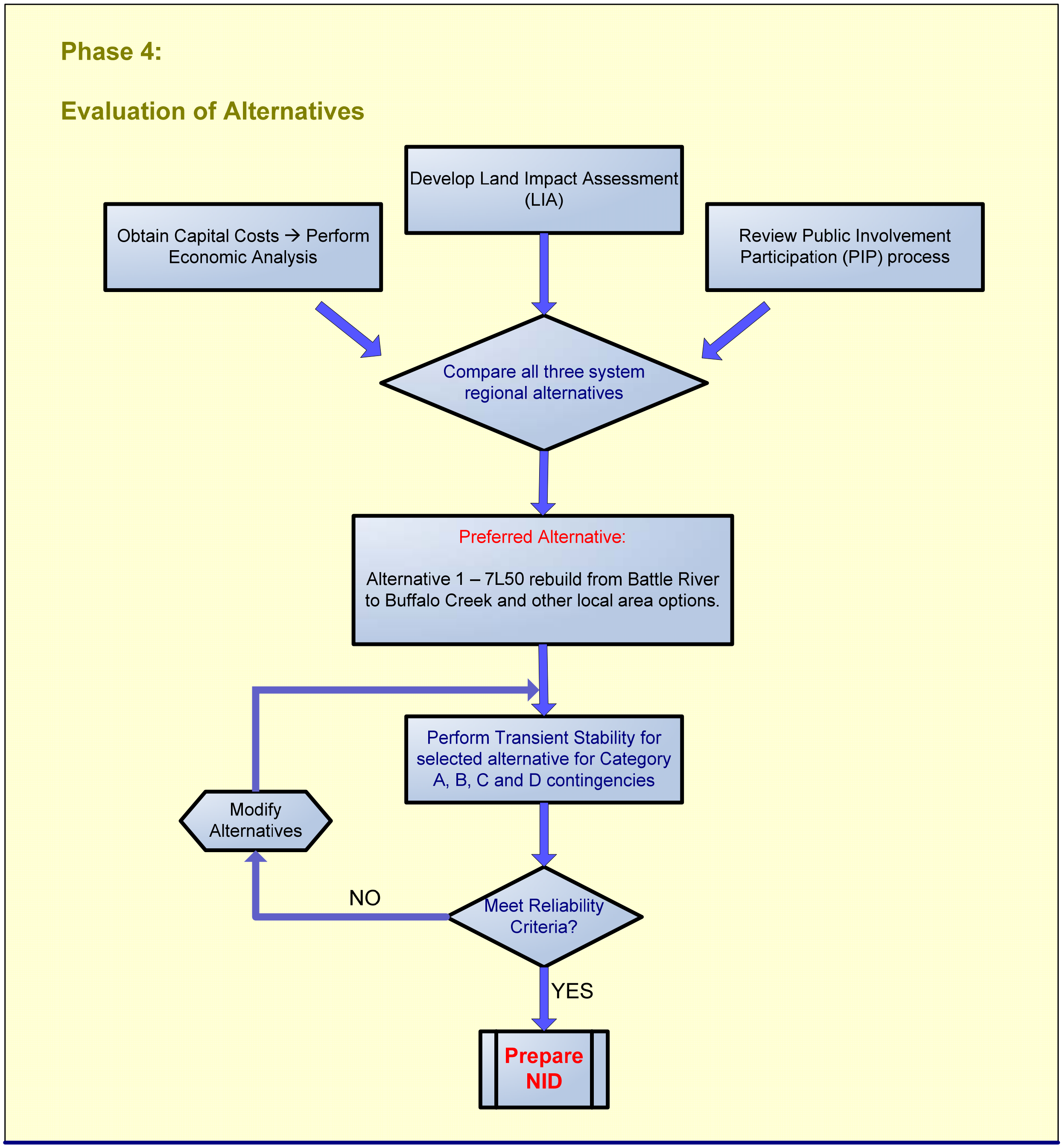


Figure 4-1: Planning Process Overview (Cont'd)



The remainder of Section 4 describes the outcome of the analysis performed during Phase 1 of the planning process. Combinations of the aforementioned potential options are considered to fully address the transmission development requirements in the Central East region. The broad categories of options include:

- Transmission system facility upgrades and re-builds;
- New transmission lines (including pre-builds);

- Conversion of existing 69/72 kV facilities to 138/144 kV;
- Provide reactive power support:
  - Fixed or switched capacitors and reactors; and
  - Static VAr compensators.

The following sections discuss the potential applicability of the above options for the Central East region transmission development.

4.1 Transmission Line Upgrades and Re-builds

The following three options offer solutions for mitigating the thermal overloads in the region, which were identified in the Need Assessment.

i) Uprating of existing lines – this option is available for those transmission lines which are presently derated significantly below their thermal rating of the conductor due to clearance or substation's terminal equipment limitations. In investigating this option, mitigation techniques requiring increasing phase-to-phase and/or phase-to-ground clearances or increasing the circuit-to-circuit clearances from the low voltage under-build to increase the power carrying capability of the line were examined.

The following 144 kV lines are candidates for the uprating option, as they are currently limited by clearance issues:

- 7L14 from Hill 751S to Vermilion 710S
- 7L53 from Vermilion 710S to Bonnyville 700S
- 7L701 from Battle River 757S to Strome 223S
- 7L702 from Battle River 757S to Hardisty 377S

The 240 kV derated line from Paintearth Creek 863S to Cordel 755S and Hansman Lake 650S can be increased from 207 MVA to 399 MVA by increasing the existing current transformer ratios at Paintearth Creek.

ii) Re-building of lines along the existing rights-of-way – this means a complete re-building of existing aging transmission lines along the existing rights-of-way. This option may be economical compared to building new transmission lines on new rights-of-way but presents higher risk to the system since such lines need to be out of service for unduly long durations of time during construction.

The candidate lines for this option are two 144 kV lines: 7L50 from Battle River 757S to Buffalo Creek 526S and 7L129 from Buffalo Creek 526S to Vermilion 710S.

iii) Re-conductoring of existing 138/144kV transmission lines to a larger conductor size – the feasibility of this option depends upon a number of factors such as: any physical structural limitations of the existing structures to carry the heavier conductor, clearance requirements, age of line and new line design code requirements. Hence, detailed engineering analysis on potential candidate lines would be required prior to selecting this option.

4.2 New Transmission Lines

Electric utilities around the globe employ a wide range of extra high voltage (EHV) class (345 kV and above) transmission lines to meet their present and future needs. In Alberta, the EHV transmission technology used so far is 500 kV AC lines. Plans are underway to develop ± 500 kV HVDC lines in Alberta by 2014.

The EHV technologies are most suited to situations involving the transfer of large amounts of power between regions. As this is not the case in the Central East region these EHV technologies were not pursued for application in the Central East region.

The Central East region consists primarily of transmission lines and substations operating at 138/144 kV and also includes some operating at 240 kV. Both of these voltage class lines and facilities were considered in this NID application.

In order to efficiently serve the long-term needs of the region in terms of providing access to generation and supplying anticipated load growth, regional development based on 240 kV is a suitable choice for the reasons cited below:

- Load Carrying Capability: Based on Surge Impedance Loading (SIL), the load carrying capability of 240 kV lines is about 200 MW. The lines could carry more power than SIL for distances up to 300 km subject to thermal capability of conductors. The peak loads in the Central East region are projected to increase from 750 MW (2008) to 1,290 MW (2017) – an increase of approximately 540 MW. In addition, there are four generation projects (individual sizes range between 75 MW and 150 MW) to be connected to the grid in the region for a total of approximately 550 MW. The transmission distances (i.e. point to point) involved in the study region are about 200 km. A 240 kV system would have capacity to meet the projected loads over the present 10-year planning period and beyond, i.e., for the next 20 to 30 years.
- Voltage Support: Under normal and heavy load conditions, the reactive power demand of 240 kV lines are lower than 144 kV lines and hence do not require significant amount of capacitor banks and/or Static VAr Compensators to maintain voltages in the normal operating range.
- Transmission Efficiency: Transmission losses on 240 kV lines are lower than 144 KV lines resulting in higher transmission efficiency and lower operating costs.
- Lastly, the AESO’s mandate is to plan a robust and flexible transmission system to serve the long-term load and generation needs of Alberta.

Where appropriate, building the lines to a 240 kV standard in advance of the need and operating them initially at 138 kV or 144 kV will be considered to defer transformation costs and maximize the use of rights-of-way. In addition, both 138 kV and 144 kV lines are considered where appropriate to meet local needs.

The addition of new transmission lines to alleviate overloads and eliminate existing thermal protection schemes has been assessed as part of the alternative analysis. For new transmission lines, both single circuit and double circuit designs have been considered. For all new 138/144kV transmission lines, the minimum and maximum size of conductors considered are 477 kcmil and 795 kcmil ACSR type, respectively, which will provide capacity for future load growth.

In addition, consideration for all new 240 kV proposed developments in the Central East region includes development of double circuit line construction with single side strung using 2x795 kcmil ACSR conductor per phase, unless both circuits are required initially. The benefits of proceeding with double circuit line construction in anticipation of future need are:

- Double circuit infrastructure will provide flexibility and extra capacity to meet potential growth by providing the opportunity of stringing a second circuit on the same structure at the appropriate time;
- The land will be effectively used since no new rights-of-way will be required for new line(s); and
- It is in line with the Alberta Provincial Energy Strategy principal related to sizing of new transmission lines to accommodate long-term growth.

The above benefits outweigh the incremental investment required for the proposed double circuit construction over a single circuit tower construction. Hence the strategy of developing new 240 kV lines in the Central East region at double circuit tower construction with single side strung initially where applicable is recommended.

4.3 Conversion of Existing 69/72 kV Facilities to 138/144 kV

System simulations revealed that thermal overloads, voltage collapse, and voltage violations on the existing 72 kV network between Bonnyville 700S and Vegreville 709S will occur under a number of contingencies in 2009, 2012 and 2017. This 72 kV system is beyond its capability to serve the connected load. The migration of this system to 144 kV in whole or in part was investigated in the alternative development.

The existing 69 kV line right-of-way between the Wainwright and Edgerton substations may be re-used for new line additions to mitigate thermal overloads in the Provost and Lloydminster areas.

4.4 New Transmission Substations and Associated Facilities

Large area voltage collapse, as noted in the Need Assessment phase, occurs when any one of the critical tie transformers in the Wainwright and Battle River areas is forced out of service. Additional substation elements to mitigate these area contingencies were investigated.

In addition, where area support is required and expansion of existing simple buses is not appropriate, a new breaker and one third 138/144 kV switchyard layouts were considered to increase area reliability.

4.4.1 Potential 240 kV wind generation collector station

Forecast Central East region wind generation is concentrated around the Provost and Hayter substations. Even though, the total planned wind generation in these locations is presently 280 MW, all indications are the wind potential could reach as high as 500 MW, which is beyond the capacity of the 138 kV network.

A centrally located 240 kV collector substation would provide required transmission access while facilitating an eastern connection path up towards Lloydminster from this substation.

4.4.2 Generator interconnections

Table 4-1 presents assumptions regarding the Point of Connection of proposed generators.

Table 4-1 New generation Additions for System Consideration

Generator	Point of Connection
Bull Creek Wind Farm	Provost Area Collector substation or Hayter substation
Provost Wind Farm	Provost Area Collector substation or Provost substation
Cold Lake generation	Near existing Primrose and Mahno substations

4.5 Reactive Power Support

The Need Assessment has identified reactive power support requirements under Category B conditions. The option of reactive power support was considered to select appropriate VAr supply device(s) for maintaining voltages in the required operating range.

The status of the existing Bonneville SVC was reviewed to determine its ability to contribute VAr requirements in the region.

4.6 Application of Aforementioned Options for Planning Areas

All of the options discussed and their possible application in each of the six planning areas in the Central East region are shown in Table 4-2. The suitability of an option for a particular area depends on a number of factors including the nature of the need in the area, strength of the transmission system and forecasted load and generation in the region. These will be investigated in the next section.

Table 4-2 Broad Category Options Considered

	Options Considered				
Planning Area	**Transmission Line Upgrades and Rebuilds**	**New Transmission Lines**	**New Transmission Substation Elements**	**Conversion of 69/72 kV elements to 138/144 kV**	**Reactive Power Support**
Cold Lake	Yes	Yes	Yes	Yes	Yes
Vegreville				Yes	
Lloydminster	Yes	Yes	Yes	Yes	Yes
Wainwright	Yes	Yes	Yes	Yes	
Alliance/ Battle River	Yes	Yes	Yes	Yes	
Provost	Yes	Yes	Yes		

5 Development & Screening of Transmission Alternatives

This section presents the analysis conducted during Phase 2 of the planning process (as illustrated in Figure 4-1) which involves development and screening of alternatives for further evaluation based on technical, economic and social impacts considerations.

The Central East region is too large to conceive alternatives that will simultaneously solve both local and regional constraints identified in the Need Assessment. As such, a two-step approach is used for developing alternatives to effectively address issues related to local areas and the overall region as follows.

Step 1: Develop reinforcements for local areas in the region to mitigate local thermal overloads and voltage violations within those areas. This will be discussed in Section 5.1.

Step 2: Develop alternatives for solving regional issues by taking into account local area reinforcements recommended in Step 1 above. These regional alternatives are comprehensive since they include local area reinforcements and together help solve regional issues. This will be discussed in Sections 5.2-5.4.

Throughout the course of development of these alternatives, both ATCO and AltaLink played an active role and provided their comments and suggestions. In addition, the Hanna region developments have been fully integrated into this region to maximize their combined effect on the overall system.

The following sections present the formulation and screening of alternatives for the planning areas and their integration into the respective regional alternatives.

5.1 Development of Reinforcements for Local Areas

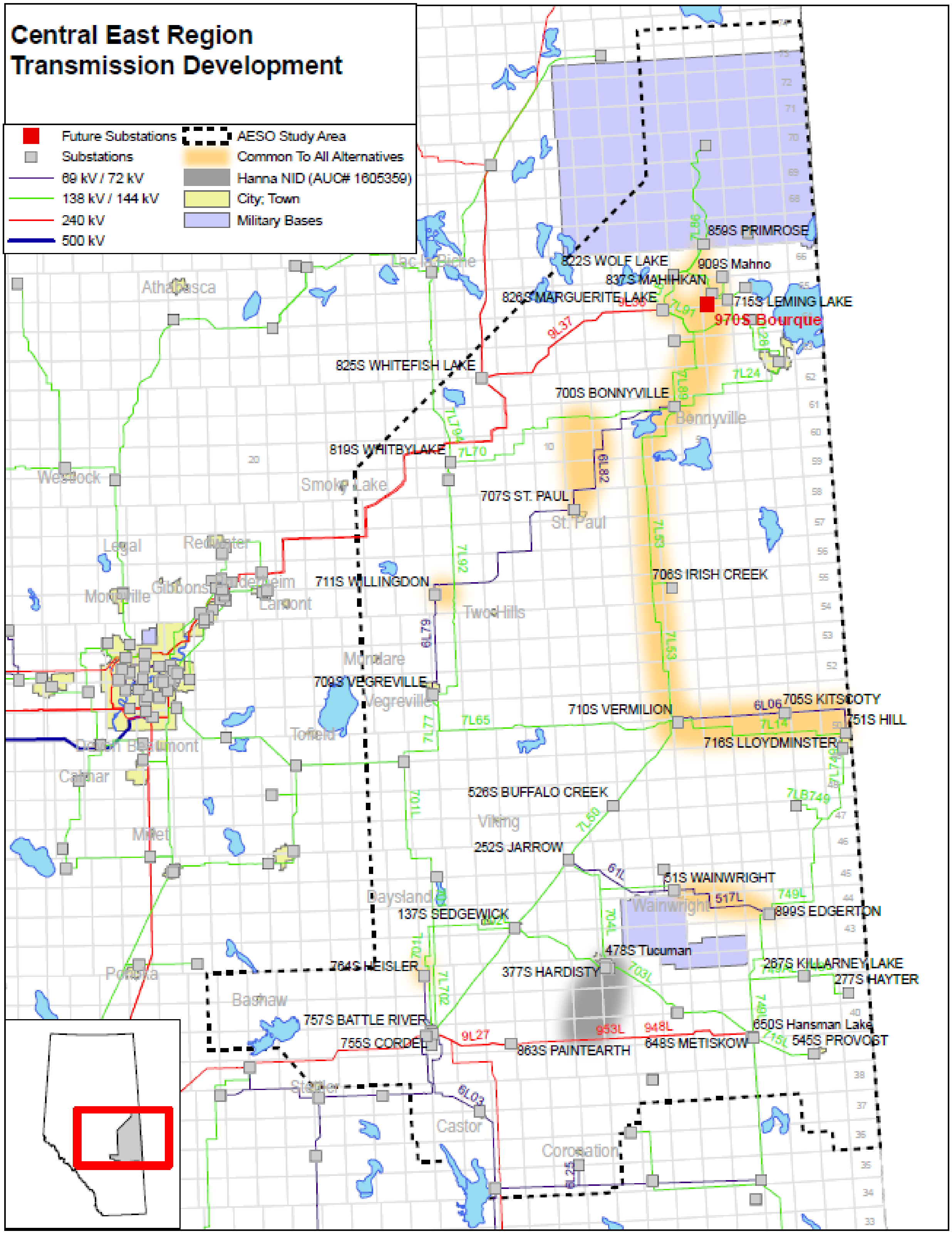
In order to mitigate Reliability Criteria violations and provide adequate transmission facilities for load growth and generation additions on a local area level, the following were studied:

- Cold Lake Area
- Bonnyville and St. Paul Areas
- Lloydminster and Battle River Areas
- Line clearance mitigation - across the region
- Voltage support in the Vermilion Area

The selected alternative for each of the above areas will be grouped and referred to as the “common set of local reinforcements” throughout this NID. They will be common to all of the regional alternatives to be studied.

Figure 5-1 shows a high level presentation of the selected common set of local reinforcements. The remainder of this section presents how these were selected from the numerous alternatives investigated.

Figure 5-1: Central East Region Development – Common Set of Local Reinforcements



5.1.1 Cold Lake Planning Area

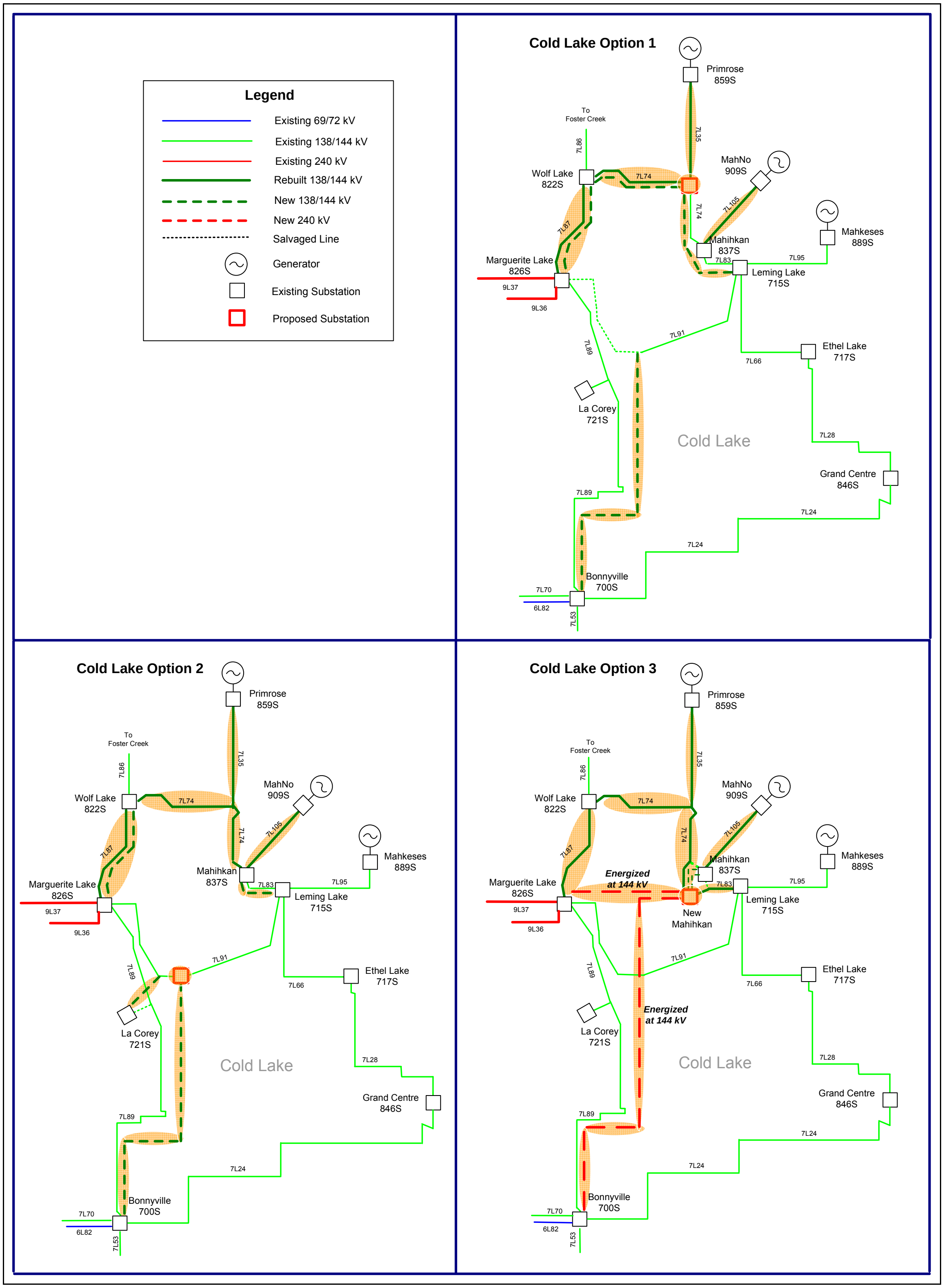
Presently, all the lines in the Cold Lake area are 144 kV except for a double circuit 240 kV line from Whitefish Lake to Marguerite Lake. The key issues as identified in the Need Assessment are:

- A number of 144 kV lines become overloaded under certain contingencies;
- In order to mitigate overloads under contingency conditions, ATCO installed thermal protection schemes on 7L89 from Marguerite Lake to Bonnyville and 7L66 from Leming Lake to Ethel Lake. These lines are being operated under the AESO Operations Planning and Procedures (OPP) 508. This OPP calls for generation curtailments at Mahkeses and/or EnCana Foster Creek plants as required. Thus, the generation in this area is constrained under contingencies and this issue needs to be mitigated;
- The existing system in the area does not have transmission capacity to connect the proposed cogeneration;
- The Cold Lake area cannot supply the forecasted load which is projected to grow at an average rate of approximately 4.7 % per year.

Formulation and Screening of Cold Lake Options:

Three options were considered for the Cold Lake area as shown in Figure 5-2. Recognizing that the existing generators are connected to the grid via radial lines, a new switching station would be required to integrate new generation facilities and manage the existing generation under contingencies.

Figure 5-2: Cold Lake Area Options



Cold Lake Option 1 was eliminated as it is not cost effective compared to the other two options, as it requires longer transmission lines.

Cold Lake Option 2 proposes a switching station mid-way between Marguerite Lake and Leming Lake. This is also not cost effective because of the additional costs involved in moving the La Corey tap from 7L87 to 7L91.

For the reasons outlined below (i.e. cost and flexibility), Cold Lake Option 3 is selected.

Cold Lake Option 3 consists of a new switching station (Bourque) close to the existing Mahikhan substation. Building a new switching station is preferred over expanding the existing Mahihkan substation for the following reasons:

- It is not cost effective to expand the existing Mahikhan substation as any new 144 kV bay would require a new control building and both transmission lines and distribution lines would need to be re-routed.

- It would be extremely difficult thereafter to route any future transmission lines out of the existing Mahikhan substation.

In order to facilitate the long-term vision of connecting the Cold Lake area to the bulk system (240 kV), the new Bourque switching station and the lines from the Bourque substation to Bonnyville and Marguerite Lake will be built to 240 kV standards and initially energized at 144 kV. These lines are required to alleviate voltage collapse and thermal overloads in the area. The second circuit would be strung in the future to provide flexibility for meeting long-term requirements without the need for new rights-of-way.

Recommended Cold Lake Option:

The preferred Cold Lake Option 3 consists of the following facilities:

- New Bourque switching station built to 240 kV standards;
- New lines from Bourque switching station to Bonnyville and Marguerite Lake built to 240 kV standards and operated at 144 kV; and
- Double circuit 144 kV lines to connect the new Bourque switching station to the existing Mahihkan substation.

Cold Lake Option 3 will be part of the common set of local reinforcements and will be studied in detail in the final selection of the preferred regional system alternatives.

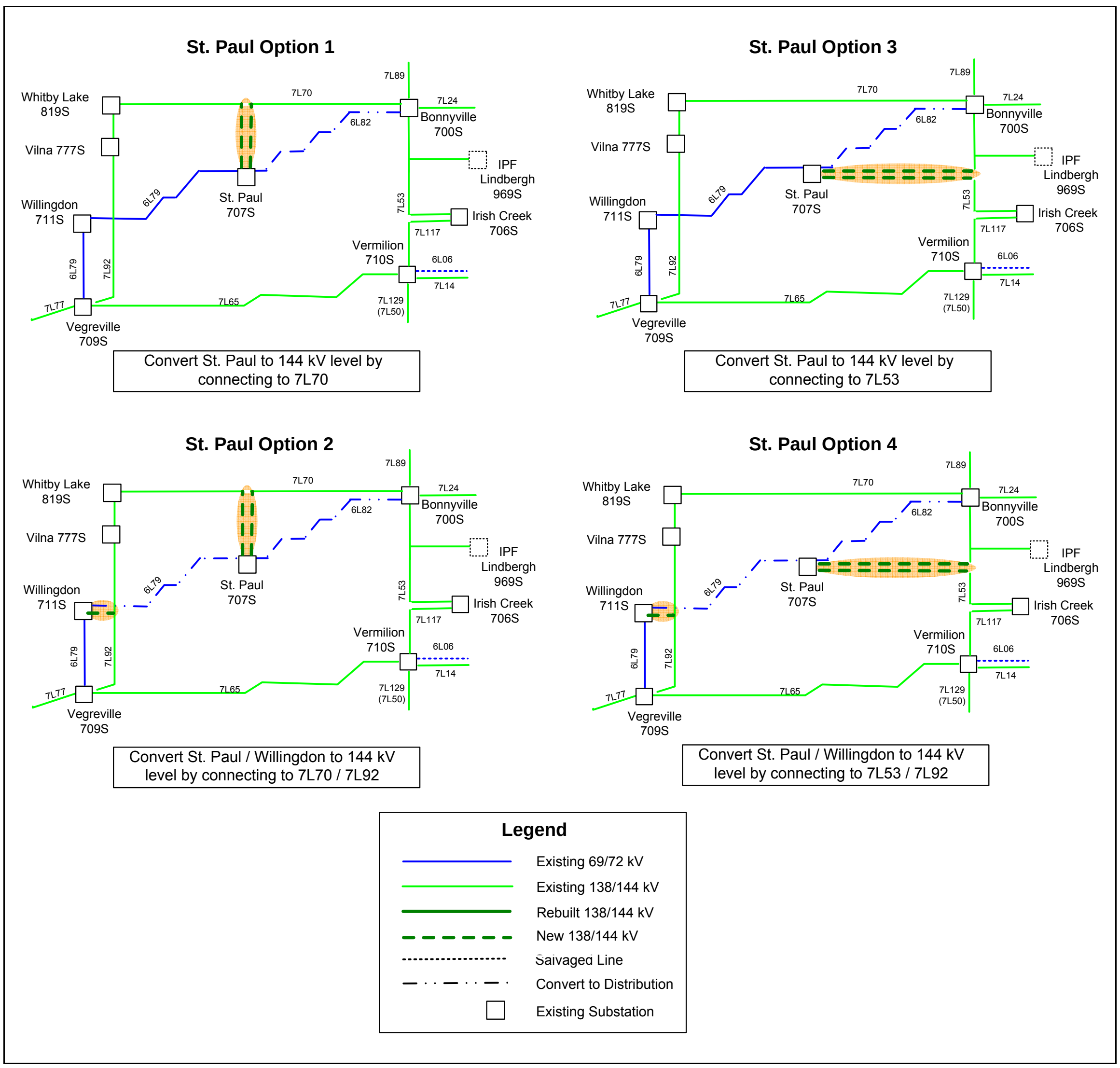
5.1.2 Bonnyville and St. Paul Planning Areas

The existing 72 kV transmission supply network is at capacity and does not meet the Reliability Criteria in the Bonnyville, St. Paul, and Willingdon areas during Category B contingencies.

Formulation and Screening of Bonnyville/St. Paul Options:

Four alternatives were identified that involve upgrades to the existing 72 kV network between Bonnyville 700S and Vegreville 709S that affect the supply to the town loads at Bonnyville, St. Paul and Willingdon. Primarily, these include upgrading the existing 72 kV St. Paul substation to 144 kV by feeding it either from 7L70 to the north or 7L53 to the east. The viability of converting the 72 kV Willingdon substation to 144 kV was also investigated. These upgrades will help address the overloading and voltage violations for Category B events. Figure 5-3 presents these four options.

Figure 5-3: St. Paul Area Options



Recommended Bonnyville/St. Paul Option:

All of the above options appear to be feasible. Preliminary studies indicate that St. Paul Option 2 is preferred for the reasons given below:

- Operational flexibility: Under certain N-1-1 events, this option does not result in voltage violation and offers operational flexibility compared to others. The N-1-1 events referred to include the loss of supply from Bonnyville or Battle River, combined with loss of any one of 749L, 7L749, 7L14 and 7L42 lines.

- It is necessary to convert the existing 72 kV Willingdon substation to 144 kV because it is reaching the end of its service life, has existing safety concerns and there is no space to expand because of its proximity to a highway. Without upgrades, it is not feasible to supply all load at St. Paul and Willingdon via 6L79 by 2012 because the 144/72 kV tie transformer at Vegreville is not large enough to supply all these loads.

- The aging 72/25 kV transformer at St. Paul substation is noisy even with the current transformer sound barrier and must be replaced to meet noise standards.

5.1.3 Lloydminster and Battle River Planning Areas

The issues identified in the Lloydminster and Battle River planning areas include:

- Battle River area: With the loss of the 144/72 kV tie transformer at Battle River 757S, the 72 kV Heisler 764S as well as mining loads at Bigfoot 756S and Bigknife Creek 843S experience voltage collapse.
- Lloydminster area: Loss of the 144 kV line 7L14 between Vermilion 710S and Hill 751S causes overloads on the 144/72/25 kV tie transformer at Vermilion 701S and on the 72 kV 6L06 line between Vermilion 710S and Hill 751S. (Several other contingencies cause overloading of this tie transformer as shown in the Need Assessment document and summarized in section 3 and Appendix A.)

A cost effective alternative is proposed that will help solve voltage collapse in the Heisler area as well as thermal overloads identified in the Lloydminster area.

The proposed Heisler & Kitscoty Option consists of the following:

- Upgrade the existing 72 kV Heisler 764S substation to 144 kV and connect it to nearby 7L701 via a 144 kV single circuit tap.
- Re-locate the existing 144/72/25 kV tie transformer at Vermilion 710S to Heisler 764S to strengthen its supply and avoid 72 kV voltage collapse when the Battle River 144/72 kV transformer is out of service.

- Upgrade the existing 72 kV Kitscoty 705S substation to 144 kV and connect it to nearby 7L14 through a short double circuit 144 kV line with auto-sectionalizing switches.
- Re-locate the re-connectable primary transformer at Heisler 764S to Kitscoty 705S.
- Salvage the existing 72 kV 6L06 line from Vermilion 710S to Kitscoty 705S.
- At Vermilion, install a second 144/25 kV transformer and salvage all 72 kV equipment.

5.1.4 Line Clearance Mitigation

There are currently a number of transmission lines in the Central East region whose ratings are limited either by terminal equipment such as current transformers or clearance requirements. The option of restoring the ratings of these lines to their rated values by removing the limiting constraints was considered. Table 5-1 provides a list of the candidate lines for this option.

Table 5-1 Derated Transmission Lines

Line	From	To	Voltage (kV)	Limiting line conductor	Line Winter (MVA)	Line Summer (MVA)	Present Winter (MVA)	Present Summer (MVA)	Limit Cause
9L27	Cordel 755S	Paintearth Creek 863S	240	2x397.5	624	489	207	207	CT
9L948	Hansman Lake 650S	Paintearth Creek 863S	240	2x397.5	624	489	207	207	CT
7L53	Bonnyville 700S	Vermilion 710S	144	266.8	146	114	90	75	Clearance
7L14	Vermilion 710S	Hill 751S	144	266.8	146	114	90	75	Clearance
7L701	Battle River 757S	Strome 223S	144	397.5	187	147	120	100	Clearance
7L702*	Battle River 757S	Sedgewick 137S	144	266.8	146	114	115	100	Clearance
7L702	Hardisty 377S	Sedgewick 137S	138	266.8	146	114	135	87	Clearance

NOTE: All above MVA ratings are based on using either 240kV or 138/144kV base as appropriate.

*ATCO updated information indicates that the rating on 7L702 has already been restored to its full conductor rating.

5.1.5 Local Voltage Support

The existing SVC at Bonnyville has not been in operation for several years and is in disrepair. It is not economical to return it to service since it is very difficult to find replacement parts for this old technology. The AESO's assessment is that there is not a continued need for the functionality of this SVC and therefore it is recommended to salvage it and replace it with a capacitor bank in the Vermilion area for voltage support.

5.1.6 Summary of Local Area Reinforcements

Table 5-2 summarizes the developments outlined in the preceding sections.

Table 5-2 Summary of Local Area Reinforcements

Planning Area	Alternative ID	Description of Local Area Reinforcements
Cold Lake	Cold Lake Option 3	Build a new Bourque 144 kV switching station near the existing Mahihkan 837S substation. Rebuild the existing 144 kV 7L74, and 7L87 lines using 795 kcmil ACSR conductor and 7L83 using 477 kcmil ACSR conductor.
		Build a new 240 kV line from the proposed Bourque switching station to Bonnyville 700S and initially energize at 144 kV. Salvage SVC at Bonnyville substation.
		Build a new 240 kV line from Marguerite Lake to new Bourque switching station and initially energize it at 144 kV.
St. Paul / Bonnyville	St. Paul Option 2	Convert the existing 72 kV substations at St. Paul and Willingdon to 144 kV. Connect these to 7L70 and 7L92 lines respectively. Remove all 72/25 kV transformers from Bonnyville 700S and install a new 144/25 kV load transformer.
Lloydminster / Battle River	Heisler & Kitscoty Option	Convert the existing 72 kV substations at Heisler and Kitscoty to 144 kV and connect them to nearby 144 kV 7L701 and 7L14 lines respectively. Remove 72/25 kV transformers from Vermilion 710S and install a 144/25 kV transformer. Salvage 6L06 line from Vermilion to Kitscoty.
Various	Clearance Mitigation	Restore the derated capacities of 144 kV lines 7L14 (Vermilion 710S to Hill), 7L53 (Bonnyville to Vermilion) and 7L701 (Battle River 757S to Strome 223S) to their full conductor rating by mitigating line clearance issues. Eliminate CT restrictions on 9L27 and 9L948 to increase line ratings to 399 MVA.
Vermilion	VAr Support	Install a new 25 MVAr 144 kV capacitor bank at Vermilion 710S

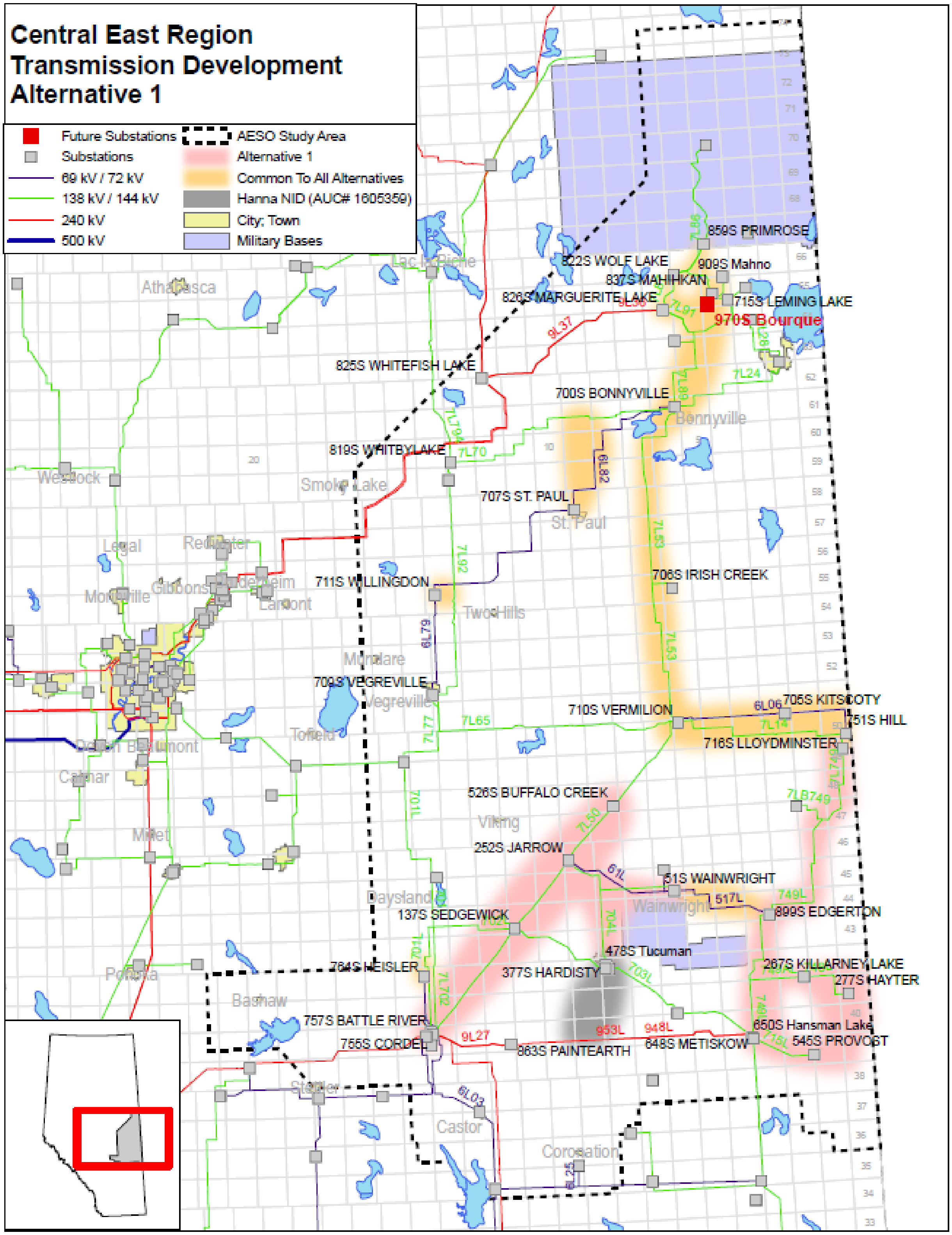
5.2 Regional Alternative 1

Three key issues which need to be addressed, including the common set of planning area reinforcements, are the following:

i. 144 kV infrastructures between Battle River, Buffalo Creek, and Vermilion: Assess whether the aging 7L50/7L129 lines should be rebuilt in whole or in part;
ii. Reinforcement of the Wainwright and Edgerton areas: Address the need to re-enforce the eastern side of the region; and
iii. Reinforcement in the Provost area: Provide access to wind generation in the Provost area and enhance the reliability of supply to the town of Provost.

Figure 5-4 shows a high level presentation of the selected common set of local alternatives and the proposed Alternative 1 regional system reinforcements.

Figure 5-4: Central East Region Development – Regional Alternative 1



5.2.1 7L50 Options

One of the key 138/144kV transmission lines in the Central East region is the aging 7L50 line that runs from Battle River 757S to Vermilion 710S. This 144 kV line was built in 1955 on a true cross country corridor using H-frame structures. The wooden poles were tested in 2002 for rot and shown to be in satisfactory condition although their overall strength due to age is in doubt. The conductor has failed several times and is not in good shape. It has no shielding for approximately one-half of the distance and is exposed to lightning strikes. As part of the Buffalo Creek capacity upgrade project, this line was split into two sections at Buffalo Creek, with the line from Buffalo Creek to Vermilion re-labeled as 7L129. In addition, ATCO has restored the 7L129 line rating to its rated value by mitigating line clearance issues.

The purpose of this alternative is to examine if it is feasible to re-build the 7L50 line along with any other reinforcements needed in the eastern corridor (i.e. along the path from Metiskow to Lloydminster).

Four options for mitigating the concerns regarding the condition of 7L50 and 7L129 were identified:

- 7L50 Option 1: Salvage existing 7L50 and build a new 240 kV line operated at 144 kV initially.
- 7L50 Option 2: Re-configuration of the tapped off loads on 7L50 line.
- 7L50 Option 3:
  a) Open the 7L50 line from Battle River to Buffalo Creek; or
  b) Open the 7L129 line Buffalo Creek to Vermilion.
- 7L50 Option 4:
  a) Salvage existing 7L50 and build a new 144 kV line along the existing right-of-way or on a new right-of-way or
  b) Re-build sections of 7L50/7L129, i.e. from Battle River to Buffalo Creek or Buffalo Creek to Vermilion.

7L50 Option 1:

This alternative was found not to be practical and was eliminated for the following reasons:

It is not feasible to connect additional 240 kV lines to either Battle River or Cordel substations due to substation site congestion, restricted access and line clearance issues. As well, significant outages at the Battle River plant would be required, adding significantly to the cost. This option would require new 240 kV substations on both ends of this line in the future – again adding to the overall cost making it more expensive.

7L50 Option 2:

Jarrow 252S is presently tapped off of 7L50 line and it is further connected to the Wainwright area. Its disconnection from 7L50 causes widespread area voltage collapse under a set of contingencies and is not a viable option for this regional alternative.

7L50 Option 3:

Even though these sub-options (a) and (b) are feasible, they are not cost effective because they require more line and substation additions compared to a re-build option.

7L50 Option 4:

7L50 and 7L129 from the Battle River generation station are necessary to supply power to the Vermilion area loads and provide system support to the surrounding areas. Re-building individual sections of 7L50/7L129 (i.e. 7L50 from Battle River to Buffalo Creek or 7L129 from Buffalo Creek to Vermilion) as well as re-building the entire line were considered.

The recent upgrades to 7L129 have provided sufficient load carrying capacity under contingencies and hence there is no need to for further upgrades. However, given that the line is well over 50 years old, ATCO plans to re-evaluate its condition by conducting further tests in 2012. A final decision regarding its future development would be made only after ATCO completes its testing and assessment of its condition. However, ATCO indicated that it can maintain the line without major capital expenditures until 2017.

By 2017, 7L50 from Battle River to Buffalo Creek will be overloaded under Category B contingencies even with its full thermal capacity restored. Therefore, re-building of 7L50 is a prudent choice as it provides critical support to maintain continuity of supply from the Battle River generation plant to the Vermilion area. As stated earlier, given the cross country nature of its right-of-way and the outage constraints on this key line, both options to build on the existing or a new right-of-way will be considered. The actual line route will, however, be determined at the facilities application stage.

Due to low voltage conditions in the Vermilion area for certain area contingencies like the loss of 7L50 line, voltage support in the area will be required by 2012. It is proposed that a capacitor bank at the Vermilion substation be installed.

The existing thermal protection scheme will be turned off by 2012 and removed prior to 2017. It is designed to trip either Battle River Unit #3 or Unit #4 when overloading on 7L50 is sustained.

Recommended 7L50 Option:

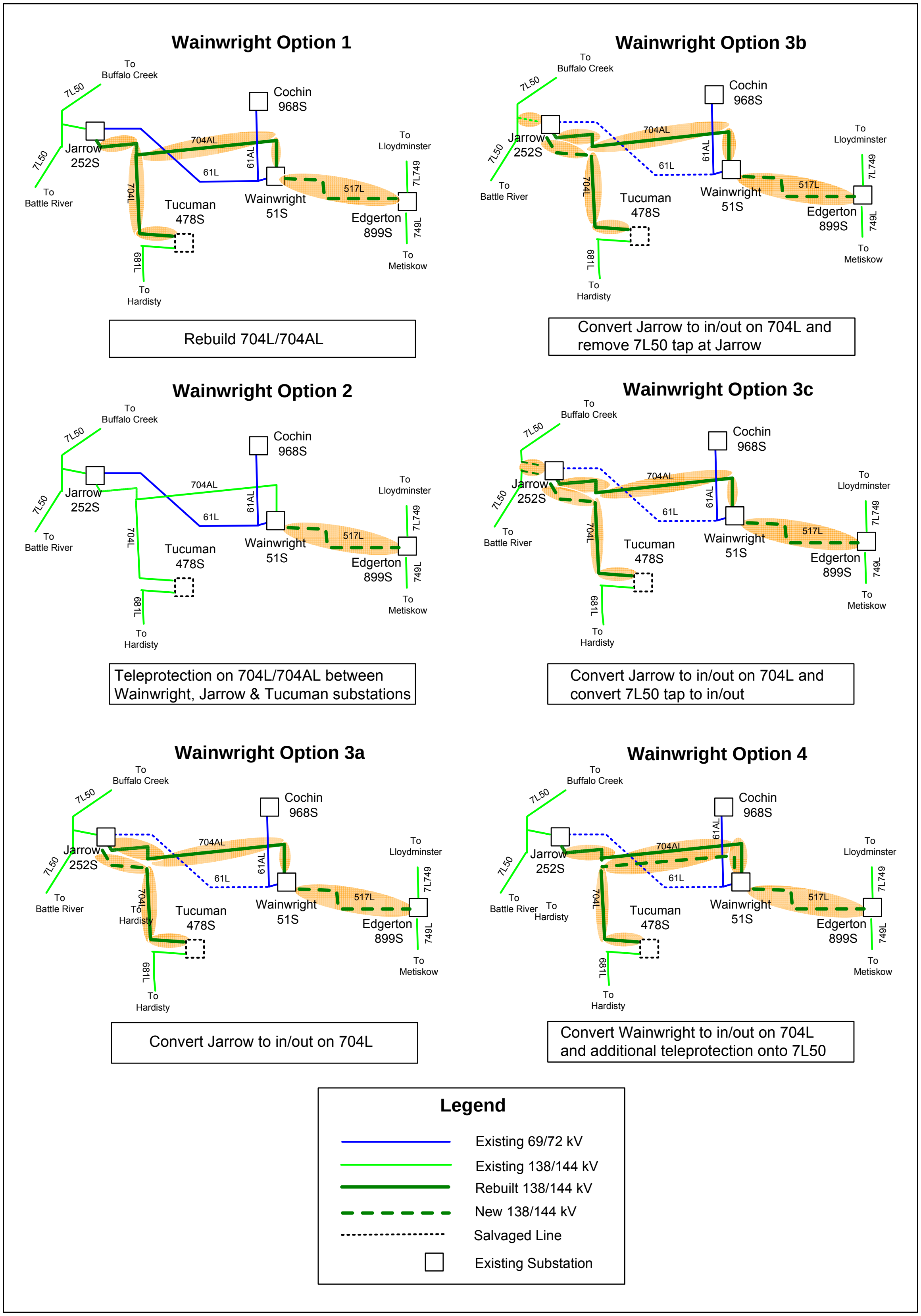
7L50 Option 4 (b) (with 7L50 re-built from Battle River to Buffalo Creek) was chosen to be part of Alternative 1 as it is a cost effective solution to mitigate system constraints in the Battle River and Vermilion areas.

5.2.2 Reinforcement of Wainwright and Edgerton Areas

Presently thermal overloads occur in the Wainwright area when the supply from Metiskow to Lloydminster area is out of service. There is no transmission line from Edgerton 899S to Wainwright 51S to support Wainwright under contingencies. Also there is no teleprotection scheme on the 7L50 line covering three terminal connection of the Jarrow 252S bus to clear the faults on the line in order to avoid potential damage to equipment.

A new 138 kV line from Edgerton 899S to Wainwright 51S is required to strengthen supply to the Wainwright area. A potential route available is the existing 69 kV right-of-way due to the military base to the north. Additional reinforcement in the Wainwright area is also required. Figure 5-5 shows six options for the Wainwright and Edgerton areas reinforcement.

Figure 5-5: Wainwright Area Options



The preliminary technical studies indicate that Wainwright Option 4 meets the requirements for Regional Alternative 1. In order to maintain voltage stability, it was found that Jarrow 252S must remain connected to 7L50 for outages of 715L and 749L. Hence, Wainwright Option 4 was chosen to be part of Alternative 1.

5.2.3 Reinforcements of Provost Area

The main issues in the Provost area are:

- Provost 545S is supplied via a radial 138 kV line 715L. This substation feeds the Town of Provost as well as many other industrial, residential, commercial and farming loads; and

- The AESO has received two applications for connecting wind farms with a combined capacity of 280 MW near the Provost area.

In order to address reliability of supply and provide access to wind generation projects, a number of reinforcements were examined. These include upgrading of 715L and 749L and re-configuration of the Killarney Lake substation.

Provost Option 1:

The preferred option consists of the following:

- A new 138 kV line from Hayter 277S to Provost 545S using 1x795 kcmil ACSR conductor per phase;
- Re-build 138 kV lines 748L, 749L and 715L using 1x795 kcmil ACSR conductor per phase;
- Re-build 144 kV line 7L749 using 1x477 kcmil ACSR conductor per phase; and
- Connect Killarney Lake substation in and out on 749AL.

5.2.4 Summary of Regional Alternative 1

The above completes discussion of the Regional Alternative 1. Table 5-3 summarizes the developments for this alternative.

Table 5-3 Summary of Regional Alternative 1 Developments

Areas	Alternative ID	Description of Alternative 1 Developments
Battle River / Wainwright	7L50 Option 4	Re-build 7L50 from Battle River 757S to Buffalo Creek 526S using 1x477 kcmil ACSR conductor per phase. Remove existing thermal protection scheme.
Wainwright	Wainwright Option 4*	Build a new 138 kV line from Wainwright 51S to Edgerton 899S. Re-build 704AL & 704L lines and connect Wainwright as in/out on 704L. Jarrow 252S remains tapped off of 7L50.
Provost	Provost Option 1	Build a new 138 kV line from Provost 545S to Hayter 277S using 1x795 kcmil ACSR conductor per phase. Build a new 138 kV line from Killarney Lake 267S to the existing tap point to convert the supply to this substation to an in/out configuration. Re-build 7L749, 749L, 748L and 715L using 1x795 kcmil ACSR conductor per phase

* Sequential Clearing on 7L50 must be mitigated with additional teleprotection.

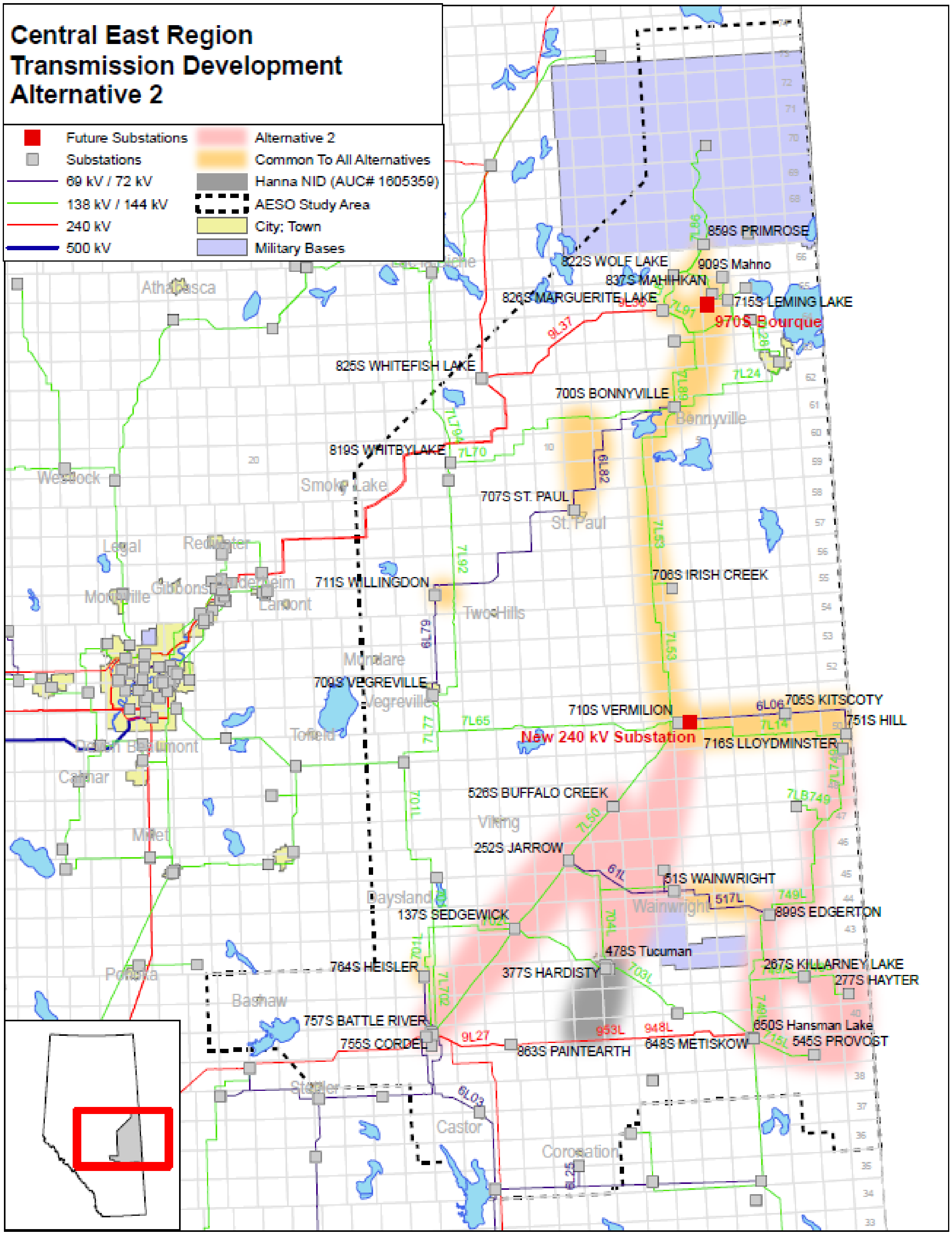
5.3 Regional Alternative 2

This is one of two 240 kV regional system alternatives considered in this NID. One feature of this 240 kV alternative is that it aligns with the long-term strategic objective of providing a 240 kV source into the Vermilion area (i.e. the geographic centre of the study region). Also it offers the flexibility to connect southern generation (Battle River and Sheerness plants) via Nilrem substation and to further extend an additional 240 kV supply to the Cold Lake area as and when required in the long-term. As outlined in Section 5.1.1, a 240 kV line (energized at 144 kV) from Bourque substation to Bonnyville substation is proposed. Subject to future load and generation developments in the Cold Lake area, this 240 kV development can be extended beyond Bonnyville substation.

With the above long-term strategy in view, two options were considered to determine whether there exists potential to defer or eliminate the re-building of 7L50 and 7L129 lines altogether.

Figure 5-6 shows a high level presentation of the selected common set of local alternatives and the proposed Regional Alternative 2 system reinforcements.

Figure 5-6: Central East Region Development – Regional Alternative 2



5.3.1 240 kV Vermilion Options

The two proposed options are:

- 240 kV Vermilion Option 1: New 240 kV line from Nilrem substation to new Vermilion substation with 7L50 opened; and

- 240 kV Vermilion Option 2: New 240 kV line from Nilrem substation to new Vermilion substation with 7L50 remaining closed.

240 kV Vermilion Option 1:

This option consists of the following changes to the existing system:

- Build a new Vermilion 240/144 kV substation complete with a 180/240/300 MVA 240/144 kV transformer and associated set of breakers;
- Build a new 100 km long 240 kV transmission line from the new Nilrem to the new Vermilion substations;
- Re-terminate all existing 144 kV lines from existing Vermilion 710S into the new Vermilion area substation;
- Build a new 45 km long 138 kV line between Jarrow 252S and Strome 223S;
- Salvage 7L129 between the Vermilion tap location and Buffalo Creek 526S (thus supplying the Buffalo Creek load radially out of Jarrow 252S)
- Salvage 7L50 between Battle River 757S and the Jarrow tap point; and
- Salvage 701L between Strome 223S and North Holden 395S to prevent thermal overloads under Category B contingencies.

Even though this option eliminates the need to re-build 7L50, it leaves the Buffalo Creek load on a radial supply hence deteriorating its reliability. Therefore, this option is not recommended.

240 kV Vermilion Option 2:

This option was developed to investigate whether it is feasible to defer re-building all or parts of the 7L50/7L129 lines. This option involves the following:

- Build a new Vermilion 240/144 kV substation complete with a 180/240/300 MVA 240/144 kV transformer and associated set of breakers;
- Build a new 100 km long 240kV transmission line from the new Nilrem to the new Vermilion substations; and
- Re-terminate all existing 144kV lines from existing Vermilion 710S into the new Vermilion area substation.

Preliminary technical studies indicated that the existing Jarrow tap to 7L50 must be maintained to prevent voltage collapse under Category C contingencies (N-1-1). With this configuration, a re-build of 7L50 from Battle River 757S to Buffalo Creek 526S is required to mitigate thermal overload issues. One advantage of this option compared to 240 kV Vermilion Option 1 is that the Buffalo Creek load can be supported from both Battle River and Vermilion thereby maintaining its reliability of supply.

Recommended 240 kV Vermilion Option:

Based on the above discussion and high level cost comparisons, the AESO's recommended option is 240 kV Vermilion Option 2. However, a 240 kV line from Nilrem to a new Vermilion substation does not solve all the regional issues and will need to be complemented by reinforcements discussed in Sections 5.3.2 and 5.3.3.

5.3.2 Reinforcement of Wainwright and Edgerton Areas

Similar to Alternative 1, reinforcement in the Wainwright and Edgerton areas is required. For Regional Alternative 2, Wainwright Option 1 is selected as it meets the reliability requirements at low cost. See Figure 5-5 for details.

5.3.3 Reinforcements of Provost Area

Identical to Regional Alternative 1, reinforcement in the Provost area includes:

- Build a new 138 kV line from Hayter 277S to Provost 545S using 1x795 kcmil ACSR conductor per phase;
- Re-build 138 kV lines 748L, 749L and 715L using 1x795 kcmil ACSR conductor per phase;
- Re-build 144 kV line 7L749 using 1x477 kcmil ACSR conductor per phase; and
- Connect Killarney Lake 267S in and out on 749AL.

5.3.4 Summary of Regional Alternative 2

The above completes discussion of Regional Alternative 2. Table 5-4 summarizes the developments for this alternative.

Table 5-4 Summary of Regional Alternative 2 Developments

Planning Area	Alternative ID	Description of Alternative 2 Developments
Wainwright	Wainwright Option 1*	Build a new 138 kV line from Wainwright 51S to Edgerton 899S using 1x477 kcmil ACSR conductor per phase. Re-build 704AL & 704L lines and add teleprotection. Jarrow 252S remains tapped off 7L50.
Provost	Provost Option 1	Build a new 138 kV line from Provost 545S to Hayter 277S using 1x795 kcmil ACSR conductor per phase. Build a new 138 kV line from Killarney Lake 267S to the existing tap to convert the supply to this substation to an in/out configuration. Re-build lines 7L749, 749L, 748L and 715L using 1x795 kcmil ACSR conductor per phase.
Vermilion / Wainwright	240 kV Vermilion Option 2	Build a new Vermilion 240 kV substation. Build a new 100 km long 240 kV line from the new Vermilion substation to Nilrem 574S. Move all 144 kV lines from existing Vermilion 710S to the new Vermilion substation. Re-build 7L50 line using 1x 477 kcmil ACSR conductor per phase.

* Sequential Clearing on 7L50 must be mitigated with additional teleprotection.

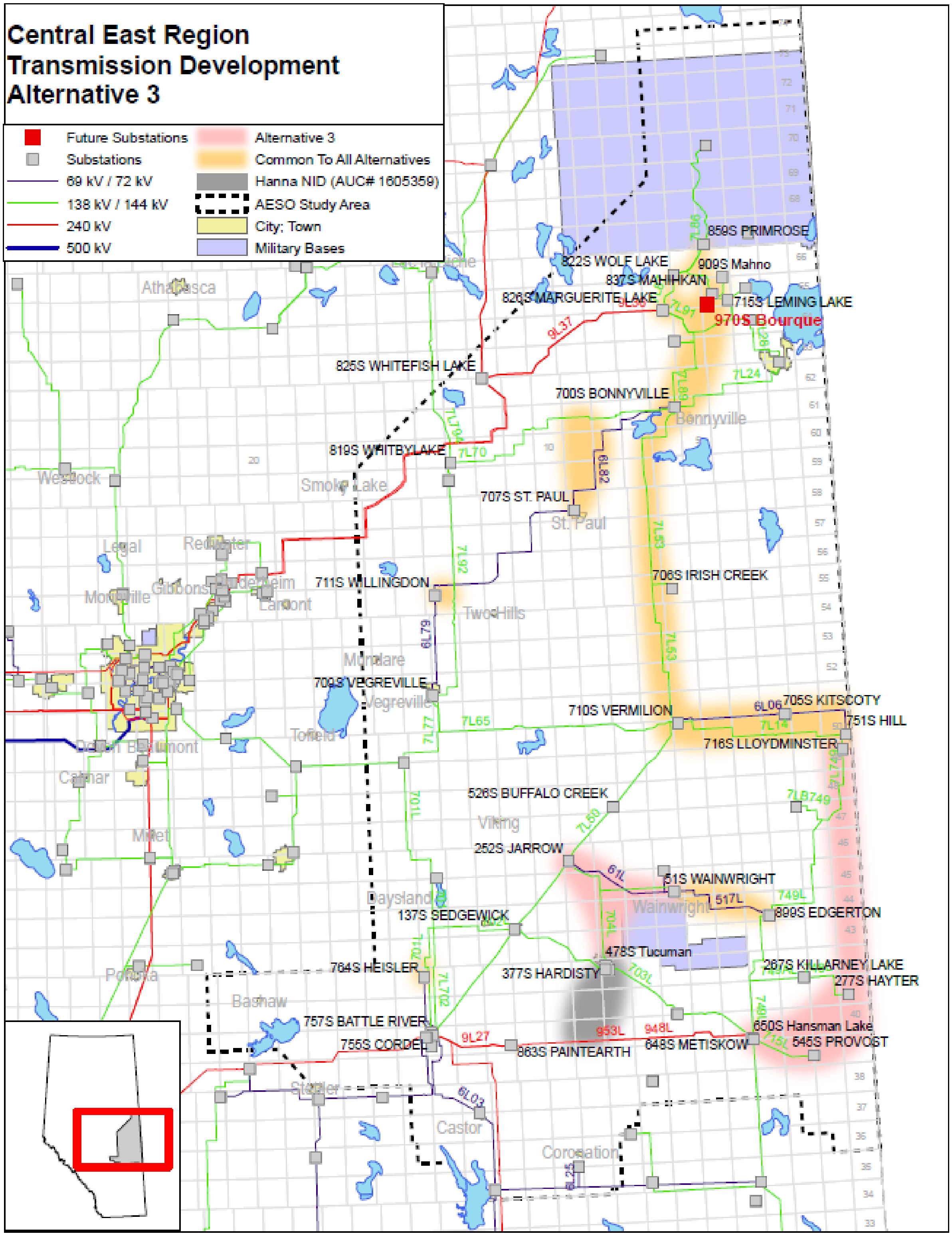
5.4 Regional Alternative 3

This alternative is designed in keeping with the long-term strategy of providing a 240 kV path from the bulk system in the south (Sheerness area) all the way to Lloydminster along the eastern edge of the province and eventually into the Cold Lake area. As part of the recently approved Hanna Region Transmission System Development NID (Application #1605359, Proceeding ID 278, Decision Report Number 2010-188) (“Hanna NID”), the AESO received AUC approval for the development of a 240 kV system from Anderson to Hansman Lake. Regional Alternative 3 fits into this long-term strategy. Some advantages of this strategy are: this line provides access to any potential generation in the Lloydminster and Provost areas and could also supply future load growth. Also it is only one hop away to the Cold Lake area. Thus it links the bulk system in the south to the northeastern part of the province.

An investigation was completed to determine what proposed infrastructure in Alternative 1 could be reduced or eliminated with this 240kV reinforcement along the eastern edge of the region. Additionally, the investigation considered if a 240 kV wind collector station as part of this development would avoid any re-builds of the 138/144 kV lines from Metiskow through to Lloydminster.

Figure 5-7 shows a high level presentation of the selected common set of local alternatives and the proposed Regional Alternative 3 system reinforcements.

Figure 5-7: Central East Region Development – Regional Alternative 3



5.4.1 240 kV Lloydminster Options

Two options for the Lloydminster area 240 kV developments were considered as follows:

- 240 kV Lloydminster Option 1: 240 kV system development in 2017; and
- 240 kV Lloydminster Option 2: Build facilities to 240 kV standards and operate them initially at 144 kV.

240 kV Lloydminster Option 1:

This option was conceived to be developed in two stages:

Stage 1 (2012):

- Build a new 138 kV switching station near existing Hayter 277S for wind generator and area transmission connections;
- Build a new 30 km long 138 kV line from Provost 545S to the new Hayter switching station (to eliminate the radial supply to Provost 545S);
- Re-terminate 748L from Killarney Lake 267S into the new Hayter switching station; and
- Connect existing Hayter 277S to the new Hayter switching station.

Stage 2 (2017):

- Expand the new Hayter switching station to install 240 kV facilities. Add a 240/320/400 MVA 240/138 kV transformer at the new Hayter substation;
- Build a 50 km long 240 kV line between Hansman Lake 650S and the new Hayter substation;
- Build a 88 km long 240 kV line between the new Hayter substation and Lloydminster 716S;
- Add a 240/144 kV 240/320/400 MVA transformer and 240 kV line termination bay at Lloydminster 716S; and
- Address the CT restriction on 7L42 from Hill to Lloydminster and bring the line up to full conductor rating. Replace the auto-sectionalizing scheme at Lloydminster by adding a 144 kV breaker bay for this line.

240 kV Lloydminster Option 1 avoids the re-building of 7L50, thus eliminating the need to build up to 160 km of new 144 kV line (and additional new right-of-way if the existing right-of-way is insufficient).

240 kV Lloydminster Option 2:

The intent of this option is to assess the potential benefits of building a dedicated wind collector substation along with pre-building some facilities to 240 kV standards and initially operating them at 138 kV; thereby providing a lower cost alternative for interconnecting the proposed 280 MW of wind generation. These facilities would be converted to their designed voltage level of 240 kV by 2017 to facilitate building a 240 kV line from Hansman Lake 650S to Lloydminster substation, via a wind collector substation.

240 kV Lloydminster Option 2 requires the following infrastructure to accommodate the 280 MW of wind applications received by AESO:

Stage 1 (2012):

- Build a new Provost area138 kV wind collector substation (for wind farm connections only);
- Pre-build a 50 km long 240 kV line between Hansman Lake 650S and the new Provost area wind collector station, energized at 138 kV;
- Clearance mitigation on 7L749 from Edgerton 899S to the Briker 880S tap; and
- Build a new 30 km long 138 kV line using 1x477 kcmil ACSR conductor per phase from Provost 545S to Hayter 277S (to eliminate the radial supply to Provost 545S).

Stage 2 (2017; identical to 240 kV Lloydminster Option 1):

- Add a 240/320/400 MVA 240/144 kV transformer at the wind collector substation in the Provost area;
- Conversion of the pre-built line from Hansman Lake 650S to 240 kV operation with a 240 kV line termination bay addition at Hansman Lake 650S;
- Build a new 90 km long 240 kV line between the Provost wind collector substation and Lloydminster 716S;
- Add a 240/320/400 MVA 240/144 kV transformer and 240 kV line termination bay addition at Lloydminster 716S; and
- Address the CT restriction on 7L42 from Hill to Lloydminster 716S and bring the line up to full conductor rating. Replace the auto-sectionalizing scheme at Lloydminster 716S by adding a 144 kV breaker bay for this line.

This option has the potential to accommodate additional wind capacity in the Provost area.

Recommended 240 kV Lloydminster Option:

240 kV Lloydminster Option 2 was chosen based on preliminary technical studies done during the screening phase and high level cost estimates. Potential benefits of this chosen alternative option are:

- Jarrow 252S could be removed from 7L50 without any negative impacts on the system which prevents the thermal overloading previously described in Section 5.2 and, therefore, the need to re-build 7L50; and

- Eliminates the need to re-build of the eastern 138/144 kV lines from Metiskow through Lloydminster (715L, 748L, 749L, and 7L749, with a total length of about 205 km).

5.4.2 Reinforcement of Wainwright and Edgerton Areas

Similar to Regional Alternatives 1 and 2, reinforcements in the Wainwright and Edgerton areas are required. For Regional Alternative 3, Wainwright Option 3b is selected as it best meets the system requirements. See Figure 5-5 for details.

5.4.3 Reinforcements in the Provost Area

Similar to Regional Alternatives 1 and 2, reinforcements in the Provost area are required. However, the specifics of the reinforcements are different than those described for Regional Alternatives 1 and 2 and are therefore referred to as Provost Option 2, and include:

- A new 138 kV line from Hayter 277S to Provost 545S using 1x477 kcmil ACSR conductor per phase; and
- Clearance mitigations on 144 kV lines 749L/7L749 and 7L42.

5.4.4 Summary of Regional Alternative 3

The above completes discussion of the Regional Alternative 3 and Table 5-5 below summarizes these developments.

Table 5-5 Summary of Regional Alternative 3 Developments

Areas	Alternative ID	Description of Alternative 3 Developments
Lloydminster / Provost	240 kV Lloydminster Option 2	Build a new 240 kV wind collector substation in the Provost area close to the wind projects. Build a new 240 kV line from Hansman Lake 650S to the wind collector substation and energize it at 138 kV (2012 ISD). Build another 240 kV line from the wind collector substation to Lloydminster 716S (2017 ISD). All facilities will be operated at 240 kV by 2017.
Lloydminster / Provost	Provost Option 2	Build a new 138 kV line from Provost 545S to Hayter 277S using 1x477 kcmil ACSR conductor per phase. Restore capacities of 144 kV lines 7L42 and 7L749 (Edgerton 899S to Briker 880S tap only) to their respective full conductor rating
Wainwright	Wainwright Option 3b	Build a new 138 kV line from Wainwright 51S to Edgerton 899S. Re-build 138 kV line 704L and connect Wainwright 51S with an in/out configuration on 704L. Disconnect Jarrow 252S from 7L50 to form a local loop with Wainwright and Tucuman substations.

6 Evaluation of Proposed Transmission Alternatives

This section presents a summary of the results of detailed technical studies carried out to evaluate the relative performance of each regional alternative. The studies were conducted in two phases to assess the capability of proposed alternatives to meet load adequacy and generation integration requirements while satisfying the AESO's Reliability Criteria.

- Phase 1: Investigate whether the performance of the proposed alternatives meets the projected load growth over the study period (2009-2017) i.e. load supply adequacy; and

- Phase 2: Investigate whether additional facilities are required to integrate proposed wind and gas-fired generation in the Central East region.

Power flow analyses were completed for all regional alternatives to evaluate their ability to serve projected load growth and connect new generation in the Central East region. Transient stability, voltage stability and short circuit analyses were performed only for the preferred Regional Alternative 1.

6.1 Power Flow Analysis

Power flow analysis for each regional alternative was carried out for 2012 and 2017 under winter peak, summer peak, and summer light load conditions. Generation Scenario B3 (see Table 2-6) along with the existing generation was modeled in these power flow analyses. The results are presented in the subsections that follow.

6.1.1 Power Flow Results for 2012

Power Flow Analysis: 2012 Load Supply Adequacy

Both Category A and B contingencies were simulated for each regional alternative for the 2012 winter peak, summer peak and summer light load conditions based on Generation Scenario B3. Approximately 20 Category B contingencies were studied.

Battle River Unit #5 was identified as the critical generating unit in the area for the purposes of the load supply adequacy study as it is the largest generator within the Central East region. When Battle River Unit #5 is out of service and with the Hanna 240kV re-enforcement in-service by 2012, this loss of generation to supply the loads in the Central East region is made up by supplies from Sheerness via 9L59 (95 MW), Wabamun area generation via 912L (Red Deer to Nevis) and Cold Lake area generation.

Simulation results reveal that all three regional alternatives satisfy voltage range requirements without any thermal overloads for both Category A and B contingencies. Thus, the proposed alternatives meet the Reliability Criteria for 2012 forecasted load as shown in Table 6-1.

Table 6-1: Power Flow Analysis Results – Load Supply Adequacy

Regional Alternatives	Thermal Loading Violations	Voltage Range Violations
Alternative 1	None	None
Alternative 2	None	None
Alternative 3	None	None

Power Flow Analysis: 2012 Integration of Central East Wind Generation

The power flow analysis was repeated with the addition of approximately 280 MW of wind capacity in the Central East region in 2012. Both Category A and B events were simulated for each regional alternative for the 2012 winter peak, summer peak and summer light load conditions.

The simulation results indicate the proposed transmission system is free of both voltage range violations and facility thermal overloads under both Category A and B events for all the load scenarios as summarized in Table 6-2.

Table 6-2: Power Flow Analysis Results – Integration of Central East Wind Generation

Regional Alternatives	Thermal Loading Violations	Voltage Range Violations
Alternative 1	None	None
Alternative 2	None	None
Alternative 3	None	None

6.1.2 Power Flow Results for 2017

Power Flow Analysis: 2017 Load Supply Adequacy

The base cases were updated to reflect the additional reinforcements identified for the year 2017. Both Category A and B contingencies were simulated for each alternative for the 2017 winter peak and summer peak load conditions using Generation Scenario B3. As in 2012, for purposes of the load supply adequacy study, Battle River Unit # 5 is the critical unit and was assumed out of service.

The proposed system in 2017 was found to be free of both voltage violations and thermal overloads for both Category A and B contingency events. The results indicate that these proposed regional alternatives meet the Reliability Criteria to supply the forecast load in 2017 as shown in Table 6.1-3 below.

Table 6-3: Power Flow Analysis Results – Load Supply Adequacy

Regional Alternatives	Thermal Loading Violations	Voltage Range Violations
Alternative 1	None	None
Alternative 2	None	None
Alternative 3	None	None

Power Flow Analysis: 2017 Integration of Central East Wind Generation

There is no increase in the amount of wind modeled in the region in 2017. The simulations were repeated for the three load conditions with the same 280 MW of wind in the Provost area. There were no negative impacts on the system and all three regional alternatives meet the Reliability Criteria as shown in Table 6.4.

Table 6-4: Power Flow Analysis Results – Integration of Central East Wind Generation

Regional Alternatives	Thermal Loading Violations	Voltage Range Violations
Alternative 1	None	None
Alternative 2	None	None
Alternative 3	None	None

Appendix D presents power flow plots for the above load flow studies carried out for Category A and B contingencies in 2012 and 2017. These power flow plots have been identified by the study year and contingency. A summary table outlining the power flow plots is also included in the Appendix.

6.1.3 System Performance under Category C and D Events

The system performance for the recommended plan was tested using power flow analysis for a number of Category C and D contingencies.

The power flow plots for the worst Category C and D events for years 2012 and 2017 are presented in Appendix D. System performance under Category C and D contingencies are summarized in Table 3 of Appendix D. Tables C-2012, C-2017 of Appendix D list figure numbers of power flow plots for the selected contingencies.

The overall performance for Regional Alternative 1 was found to be satisfactory and met the Reliability Criteria for all 2012 and 2017 load conditions. It should be noted that the worst case N-1-1 contingencies involve loss of 7L50 combined with the subsequent loss of either 7L53 (loss of Cold Lake generation support) or 7L749 (loss of Metiskow/Edgerton support into Lloydminster).

6.2 Voltage Stability (P-V and Q-V) Analysis Summary

Voltage stability (P-V and V-Q) analyses were also carried out to determine the ability of the proposed system based on Regional Alternative 1 to be voltage stable under normal and abnormal system conditions. Also, these studies were used to calculate the reactive power margins available under Category B events. This information was used to ensure that the reactive power compensation recommended is adequate under normal and contingency conditions. The results of this P-V and Q-V study are presented in Appendix D.

These studies reveal the following:

- The system is voltage stable and meets the AESO Voltage Stability Criteria;

- Approximately 15 MVA of load will have to be shed under one Category C contingency (i.e. loss of both 7L50 from Battle River to Buffalo Creek and 7L749 from Edgerton to Lloydminster). An under voltage load shedding scheme and special protection scheme will be developed to alleviate the risk of wide spread voltage criteria violations in the unlikely event of this occurrence; and

- Based on the results of the Q-V analysis, a 25 MVAr capacitor bank was recommended to be installed at the Vermilion substation to maintain the area voltage under contingencies. The analysis was repeated to ensure the choice of location is appropriate and indeed the capacitor bank at the Vermilion substation helps maintain voltage profile in and around Vermilion area.

6.3 Transient Stability Analysis Results

The performance of the Central East regional system was tested extensively with the preferred Regional Alternative 1 in place. The study assumed GE 1.5 MW wind turbine generator models for purposes of the dynamic analysis. The motor models used in the Hanna NID are adopted here.

Dynamic system events, including three-phase and phase-to-ground faults, were simulated for selected Category B, C, and D events throughout the Central East region. Critical Category C and D events were simulated in the Central East region. Results of the Category C and D events were analyzed to ensure that under these events there are no uncontrolled or cascading outages in the system.

Three-phase faults were simulated for Category B events on select critical lines throughout the study area and the system response was recorded.

In 2012, no stability concerns arose, and no system changes or additions were needed to the planned system. By the 2017 time frame however, a few faults in the Cordel area on the 240 kV system have the potential to cause system instability.

To address this issue, an Under-Voltage Load Shedding (UVLS) scheme needs to be implemented on a number of motors in the Wainwright area. This UVLS scheme was previously identified in the Hanna area NID study, and work here independently confirms it. In some cases, the faults studied herein require faster trip times than those identified in the Hanna NID, but the specific relay time settings will be determined by the results of operational studies conducted closer to the in-service date of the facilities. Once the UVLS scheme is implemented, the recommended Regional Alternative 1 Central East Transmission Plan will result in a stable system with good voltage recovery and no additional load shedding for all Category B faults in the region.

In addition to Category B contingencies, Category C contingencies were also simulated with Regional Alternative 1 in place to test its performance against the AESO Reliability Criteria.

C-3 contingencies involving the prior loss of a line and a three-phase fault on a critical second line were simulated on critical pairs of facilities throughout the East Central East region. No uncontrolled or cascading outages in the system were observed. An UVLS scheme for motor loads in the Wainwright area is again required for certain double contingencies on the southern portion of the system.

C-5 contingencies, which simulate simultaneous faults on both circuits of a double circuit transmission line, are not an issue for the Central East region. Four double faults on existing or proposed double circuit lines in the study area resulted in acceptable voltage responses and no uncontrolled or cascading outages to the system.

C-7 contingencies simulate “stuck breaker” or breaker failure fault scenarios at substations. These types of faults can be among the most difficult for a transmission system to survive due to the length of time the fault is present on the system. C-7 contingencies were simulated on critical lines and substations throughout the Central East region and the proposed system performed very well. All faults resulted in a stable system and no uncontrolled or cascading outages were observed.

Category D contingencies are extreme events involving the loss of both transmission towers in a right-of-way, the loss of entire substations, or all units at a generating plant. Using AESO Reliability Criteria, Category D contingencies were simulated on the system with the preferred Regional Alternative 1 in place.

Again, the proposed Central East system performed well. No unstable system conditions were observed and the Category D faults resulted in no uncontrolled or cascading outages.

The simulation results for Category B, C and D events are summarized in the tables in Appendix E. For each simulated fault, the plots of transient response of key system parameters are also included in Appendix E.

A brief summary of the aforementioned detailed transient stability results are:

- The preferred Regional Alternative 1 was subjected to rigorous testing of its performance under a wide range of system disturbances. These ranged from three phase faults, line to ground faults and Category C and D events.

- The system was found to be stable in 2012. In 2017, a UVLS is required to maintain system stability under a few fault conditions in the Cordel area. The need for this scheme was previously identified in the Hanna NID.

- Even under extreme Category C and D events, the system exhibited stable performance with good voltage recovery, no additional load shedding and no uncontrolled or cascading outages.

Thus it is concluded that the proposed Regional Alternative 1 meets the requirements of AESO Reliability Criteria.

6.4 Short Circuit Analysis

A short circuit analysis was carried out by applying thee-phase and single phase-to-ground faults at the existing and proposed 240 kV and 138/144 kV substations to determine the impact of Regional Alternative 1 reinforcements on the short circuit levels in the Central East region. Short circuit levels were calculated for both the existing system and for the planned system in 2017 and are presented in Table 6.4-1.

The fault current levels at the existing substations are higher in 2017 than for the existing system since Regional Alternative 1 proposes major system reinforcements as well as the addition of about 550 MW of gas-fired and wind generation. The results indicate that there is no need to change any existing breakers in the study region.

Table 6-5 Existing and Future (2017) Fault Current Levels

Substation Name (Fault Location)	Voltage (kV)	Existing System [1]		Alternative 1 2017 Winter Peak [2]	
		3 Phase Fault Current (kA)	1 Phase Fault Current (kA)	3 Phase Fault Current (kA)	1 Phase Fault Current (kA)
Briker 880S	144	1.89	1.26	2.36	1.64
Irish Creek 706S	144	2.66	1.68	2.92	1.8
Vermilion 710S	144	3.66	2.48	3.92	2.61
Vermilion 710S (To be salvaged)	72	3.29	2.66		
Vermilion tap sub (New)	144			3.48	2.21
Kitscoty 705S (New)	144			2.88	2.23
Kitscoty 705S	72	1.99	1.43	1.22	1
Hill 751S	144	2.35	2	2.64	2.58
Hill 751S	72	2.66	2.34	2.49	3.32
Lloydminster 716S	144	2.29	1.86	2.64	2.4
Mahkeses 889S	144	6.65	7.27	8.19	8.54
Wolf Lake 822S	144	7.69	7.19	9.53	7.97
Foster Creek 877S	144	3.58	4.05	3.76	4.24
Primrose 859S	144	5.73	5.91	7.66	6.7
Bourque 970S (New)	144			10.88	9.25
Mahihkan 837S	144	6.81	6.06	10.46	8.54
Leming Lake 715S	144	7.15	7.04	9.42	8.81
Marguerite Lake 826S	240			6.77	6.31
Marguerite Lake 826S	144	8.8	10.22	11.2	12.36
La Corey 1315	144	5.01	3.86	5.61	4.09
Ethel Lake 717S	144	5.18	4.55	6.03	5.03
Ethel Lake 717S	72	3.14	3.65	3.28	3.79
Grande Centre 846S	144	4	2.97	4.44	3.14
Enb_Bonn (New)	144			3.22	2.1
Bonnyville 700S	144	4.67	3.98	6.46	5.05
Bonnyville 700S (To be salvaged)	72	3.24	3.35		
IPF Lindberg	144	1.79	1.11	2.2	1.33
HRT Exp7	138	3.62	1.95	7.87	7.84
Jarrow 252S	138	34	2.32	4.31	2.62
Hardisty 377S	138	3.81	2.03	9.28	11.03
Wainwright 51S	138	2.23	1.21	5.04	3.2
Wainwright 51S	69	0.87	0.61	2.65	2.3
Sedgwick 137S	138	2.65	1.51	3.68	2.31
Buffalo Creek 526S	138	3.29	2.02	3.5	2.16
Cochin	69	0.83	0.57	1.89	1.42
IPL Har7	138	3.71	1.98	8.74	10.1
Nilrem (New)	240			6.2	6.76
Nilrem (New)	138			9.55	12
Tucuman 478S	138	3.57	1.89	9.21	10.74
Heisler 764S (New)	144			4.96	3.2
Heisler 764S	72	2.06	1.46	3.69	3.02

Table 6-5 Existing and Future (2017) Fault Current Levels (Cont'd)

Substation Name (Fault Location)	Voltage (kV)	Existing System [1]		Regional Alternative 1 2017 Winter Peak [2]	
		3 Phase Fault Current (kA)	1 Phase Fault Current (kA)	3 Phase Fault Current (kA)	1 Phase Fault Current (kA)
Bigknife Creek 843S	72	5.08	4.66	6.13	5.42
Mannix Mine 765S	72	5.01	4.53	5.72	4.76
Battle River 757S	240	9.73	9.19	11.49	11.61
Battle River 757S	240	9.72	9.09	11.48	11.54
Battle River 757S	144	11.96	9.64	12.33	10.47
Battle River 757S	72	5.38	5.03	6.41	5.92
Bigfoot 756S	72	3.46	2.87	4.31	3.15
Metiskow 648S	240	4.67	3	7.6	6.06
Metiskow 648S	138	6.57	4.23	11.3	9.82
Sunken Lake 221S	138	6.47	4.43	11	9.39
Hughenden 213S	138	4.14	2.42	6.07	4.33
Provost 545S	138	3.51	2.18	7.43	4.1
Killarney Lake 267S	138	2.78	1.58	6.45	3.7
Hayter 277S	138	2.04	1.14	6.34	3.22
Edgerton 899S	138	2.84	1.76	4.58	2.9
Hansman Lake 650S	240	4.69	3.01	7.67	6.13
Hansman Lake 650S	138	6.56	4.53	11.38	9.82
North Holden 395S	138	4.49	2.81	4.51	2.88
Strome 223S	138	3.49	2.07	3.59	2.16
Whitby Lake 819S	144	3.31	2.14	2.78	1.7
Vilna 777S	144	3.16	2.03	2.73	1.68
Willingdon 711S (New)	144			2.54	1.63
Willingdon 711S	72	1.78	1.48	1.37	0.9
Vegreville 709S	144	3.83	2.82	3.74	2.76
Vegreville 709S	72	3.2	3.07	2.92	2.8
St. Paul 707S (New)	144			2.68	1.64
St. Paul 707S (To be salvaged)	72	1.49	1.51		
Paintearth Creek 863S	240	6.16	4.55	7.63	5.83
Cordel 755S	240	9.76	9.18	11.55	11.65

Notes:

1. Generation Scenario 3 used.
2. Generation Scenario 3 used plus new cogeneration and wind generation in the Central East region.

6.5 Land Impact Assessment

A Land Impact Assessment (LIA) was completed for the proposed three Regional Alternatives, including the common set of local reinforcements. The LIA is presented in two separate documents in Appendix F, one each for the transmission facilities to be provided by the Transmission Facility Owners (TFO) that have assets in the area, namely, AltaLink Management Ltd. (AltaLink) and ATCO Electric (ATCO).

Each TFO undertook the preparation of an LIA for the components of each Regional Alternative that are contained within their own respective service territories. The first document included in Appendix F was prepared by AltaLink and the second document was prepared by ATCO. AltaLink used a qualitative approach as the level of effort required to quantitatively assess relative routes for each of the developments was deemed unnecessary due to the area being rural and sparsely populated. ATCO followed a quantitative approach to allow for a better comparison of potential impacts since the majority of the proposed developments were located within its service territory.

The main conclusions of both LIAs are:

- The proposed three Regional Alternatives, including the local developments common to all the alternatives, are viable from a land impact perspective. None have potential impacts that would cause any alternative to be rejected.
- Regional Alternative 3 has the least overall potential impact for the majority of the measurable indicators assessed, while Regional Alternative 2 has the highest potential impact. Regional Alternative 1 has relatively modest impacts as almost all of the values for the measurable indicators are between those of Regional Alternatives 2 and 3.

For comparative purposes, ATCO's "metrics" for measurable indicators for all three Regional alternatives were examined as significant numbers of reinforcements are in ATCO's service territory. The following describes the individual categories of impacts assessed. A detailed comparison of "metrics" is given in Table 6-6.

Agricultural

- Regional Alternative 3 has the least potential impact on the amount of agricultural land crossed.
- Regional Alternative 2 has the highest potential impact.
- Regional Alternative 1 has moderate impact.
- All three alternatives pass primarily through CLI Capability Classes 2 through 5 soil capability for agriculture.

Forestry

- Only the common developments cross through forested land.
- All three Regional alternatives equally impact forested lands.

Residential

- Regional Alternative 3 has the least potential impact on residences within 150 m of the centerline and 800 m of the edges of the potential right-of-way.
- Regional Alternative 2 has the highest potential impact.
- Regional Alternative 1 impacts fewer residences within 150 m of the centerline and 800 m of the potential right-of-way than Alternative 2.

Environment

- Regional Alternative 3 has the least potential impact on Environmentally Significant Areas (ESA's) and Protected or Designated Areas.

- Regional Alternative 2 has the highest potential impact for ESA's and Protected or Designated Areas.
- Regional Alternative 1, again, has less potential impact than Regional Alternative 2 for ESA's and Protected or Designated Areas.
- Regional Alternative 3 has the least potential impact on Surface Water.
- Regional Alternatives 1 and 3 have the least number of major river crossings.
- All three Regional alternatives have similar impacts on Grazing Reserves and Community Pastures.

Electrical Considerations

- Regional Alternative 3 has the least potential to parallel existing linear disturbances and impact telecommunications towers, gas facilities, and wells, while Regional Alternative 2 has the highest potential. The impacts of Regional Alternative 1 are between the results of Regional Alternatives 2 and 3.

Visual Impacts

- Regional Alternative 3 has the least potential impact on residences within 150 m of the centerline and 800 m of the potential right-of-way
- Regional Alternative 2 has the highest potential.
- Regional Alternative 2 has the highest potential impact on Protected or Designated Areas and crosses through the most ESA's.

Special Constraints

- Regional Alternative 3 has the least potential impact on the following special constraints: Historical Resources, Urban Areas, and Private Lands.

- Regional Alternative 2 has the highest potential impact on the following special constraints: Historical Resources, Urban Areas, and Private Lands.
- Regional Alternative 1 has the least potential impact on Crown Lands.
- Regional Alternative 1 is equivalent to Regional Alternative 3 for Cemeteries within 800 m.
- None of the Regional Alternatives impact municipal lands or airfields.

Table 6-6 Summary of Comparison of Metrics for Three Alternatives (ATCO components only)

Major Aspects and Considerations		Technical Components		
		Alternative 1*	Alternative 2*	Alternative 3*
		Total	Total	Total
ROW Length (km)		434	632	273
Land Impact				
Amount Agricultural Land Crossed (km)	Crop land	159	193	64
	Forage Land	5	5	0
	Total	164	198	64
Land Capability for Forestry (km)	Forestry Capability Class 1	0	0	0
	Forestry Capability Class 2	0	0	0
	Forestry Capability Class 3	17	17	17
	Forestry Capability Class 4	122	122	122
	Forestry Capability Class 5	7	7	7
	Forestry Capability Class 6	4	4	4
	Forestry Capability Class 7	12	12	12
	Forestry Capability Class 8	0	0	0
Land Capability for Agriculture (km)	Agricultural Capability Class 1	14	14	2
	Agricultural Capability Class 2	80	138	16
	Agricultural Capability Class 3	177	268	98
	Agricultural Capability Class 4	109	128	43
	Agricultural Capability Class 5	86	17	87
	Agricultural Capability Class 6	18	37	19
	Agricultural Capability Class 7	0	0	0
	Agricultural Capability Class 8	0	0	0
	Agricultural Capability Class O	11	11	11
Residential Impacts				
Residences (#)	Within 150 m of centreline	20	24	7
	Within 800 m of R-O-W	131	218	84
Environmental Impacts				
Amount of Environmentally Significant Areas Crossed (km)		12	18	2
Number of Protected or Designated Areas in or within 800m of R-O-W edge (#) includes: Parks (Municipal, Provincial)		1	6	0

Table 6-6 Summary of Comparison of Metrics for Three Alternatives (Cont'd)

Major Aspects and Considerations		Technical Components		
		Alternative 1	Alternative 2	Alternative 3
		Total	Total	Total
Environmental Impacts				
Number or Grazing Reserves, Community Pastures within 800m of R-O-W edge (#)		3	3	3
Major River Crossings (#)		2	3	2
Surface Water (ha) in or within 800m of R-O-W edge		2693	3667	1347
Electrical Considerations				
Amount of Existing Linear Disturbances Paralleled (km)	Existing Transmission Lines >= 240 kV	0	0	0
	Existing Transmission Lines = 144 kV	152	153	25
	Primary / Secondary Highways	11	11	3
	Railways	0	0	0
	Pipelines	13	22	14
Total Amount of Existing Disturbances (km)		*176*	*186*	*42*
Number of Telecommunications Towers (>25m) within 800m of R-O-W (#)		87	93	79
Number of Gas Facilities Within 800m of R-O-W (#)		1	1	0
Number of Wells within 40m of Centreline (#)		74	87	62
Visual Impacts				
see "*Residences (#)*" *in Residential Impacts*				
see "*Proximity to Protected or Designated Areas in or within 800 m of R-O-W edge (#)*" *in Environmental Impacts*				
Special Constraints				
Proximity to Historical Resources in or within 800 m of R-O-W (#)		17	37	6
Urban Areas within 800m of R-O-W (#) (Cities, Towns, Villages, Hamlets, Rural Subdivisions)		4	6	2
Cemeteries within 800m of R-O-W (#)		3	4	3
Airfields within 800m of R-O-W (#)		0	0	0
Municipal Lands Crossed (km)		0	0	0
Crown Lands Crossed (km)		78	81	80
Private Lands Crossed (km)		350	537	189

* Alternative 1 include studies of these lines: 7L163, 7L146, 7L157/7L160, 7L74, 7L83, 7L87, 7LA14, 7LA701, 7L70/7L139, 7L749, 7LA92, 7L50

Alternative 2 include studies of these lines: 7L163, 7L146, 7L157/7L160, 7L74, 7L83, 7L87, 7LA14, 7LA701, 7L70/7L139, 7L749, 7LA92, 7L50, 9LXXX (line designation to be determined), 7L53, 7L14, 7L65, 7LXXX (line designation to be determined), 7L129

Alternative 3 include studies of these lines: 7L163, 7L146, 7L157/7L160, 7L74, 7L83, 7L87, 7LA14, 7LA701, 7L70/7L139, 7LA92, 9L928

6.6 Economic Evaluation

The selection of a preferred alternative by the AESO includes economics as one of the key factors considered together with technical and social factors. In terms of economic assessment, all things being equal, the alternative with the lowest relative capital cost and system energy loss is preferred.

The AESO has performed an economic comparison of alternatives using a net present value approach. The analysis considers capital costs and the cost of losses and in turn the total net cost of proposed alternatives. Net present value calculations were performed to derive a single number that was used to compare alternatives. A before-tax weighted average cost of capital discount rate (before-tax WACC) was used as the discount rate in net present value calculations since it represents the TFO approved cost of capital. Before-tax WACC is calculated as follows:

$$\text{Before Tax WACC} = [\text{Debt }\% \times \text{Debt Cost}] + [\text{Equity }\% \times (\text{After Tax ROE} \div (1 - \text{Tax Rate}))]$$

where:

a) Equity %: 36%, based on AUC Decision 2009-216;

b) Debt %: 64%, calculated as (1 – Equity(%) presented in a) above);

c) Debt Cost: 5.07%, calculated as 1% + March 2010 Long-term Bank of Canada benchmark bond yields;

d) After-tax ROE: 9%, based on AUC Decision 2009-216;

e) Federal corporate tax rate: 18%, based on rates listed on the Canadian Revenue Agency website; and

f) Provincial corporate tax rate: 10%, based on the Alberta Corporate Tax Act, section 21 (o).

The economic model used for the economic assessment is included in Appendix G of this NID.

6.6.1 Capital Costs

Appendix G contains capital cost estimates for facilities included in each Regional Alternative, including the common set of local reinforcements. Cost estimates provided by the TFOs have an accuracy of +/- 30%. Capital cost estimates include costs related to design, construction, land, regulatory activities, Allowance for Funds Used During Construction (AFUDC), Engineering and Supervision (E&S) and contingency.

Table 6-7 summarizes capital cost estimates for the assumed project stages, 2012 and 2017 (+/- 30%, 2009$, Million).

Table 6-7: Capital Cost Estimates for Regional Alternatives in Stages (+/-30%, 2009$, Million)

	Alternative 1	Alternative 2	Alternative 3
Stage 1 (2012)	$310	$302	$302
Stage 2 (2017)	$60	$218	$115
Total	**$370**	**$520**	**$417**

Capital cost estimates were escalated to targeted in-service dates using annual escalation rates provided by the incumbent TFOs. Table 6-8 summarizes capital cost estimates in dollars of the year in which costs are planned to be incurred.

Table 6-8: Capital Cost Estimates for Regional Alternatives (+/-30%, In-service Date$, Million)

	Alternative 1	Alternative 2	Alternative 3
Stage 1 (2012$)	$349	$340	$340
Stage 2 (2017$)	$82	$299	$157

6.6.2 Revenue Requirement

The AESO has performed revenue requirement calculations that approximate the amount TFOs would likely seek to recover in return for constructing, owning, operating and maintaining transmission facilities. Revenue requirement calculations consider operating expenses, depreciation, income taxes, debt costs and return on equity. The economic model contains as “Assumptions” worksheet referencing the source of each variable.

Table 6-9 summarizes the net present value of annual revenue requirement calculations for each Regional Alternative, including the common set of local reinforcements.

Table 6-9: Net Present Value of Annual Revenue Requirement Discounted over a 20 year period to 2010 (Million)

Alternative 1	Alternative 2	Alternative 3
$369	$483	$404

Table 6-10 summarizes the present value of the annual revenue requirement for each Regional Alternative relative to Regional Alternative 1.

Table 6-10: Present Value of Annual Revenue Requirement Relative to Regional Alternative 1 Discounted over a 20 year period to 2010 ($Million)

Alternative 1	Alternative 2	Alternative 3
$0	$114	$35

The depreciation rate of 2.88% used in the revenue requirement calculation is based on depreciation rates from the AltaLink 2007-2008 General Tariff Application (Appendix K-1 - Depreciation Study, p. III-11) and ATCO's 2009-2010 General Tariff Application (Schedule 6-3).

The Operating expense factor of 1.5% used to approximate Operating and Maintenance cost is an approximation based on discussions with the TFOs.

6.6.3 Cost of System Losses

The AESO has estimated system energy loss for each regional alternative as an input into the economic comparison of alternatives. For each regional alternative, hourly system losses for the years 2009, 2012 and 2017 were calculated using the PSS/E software. The ‘UPLAN’ software was used to produce the hourly generation dispatches used in the PSS/E software for estimating the losses. For each of the aforementioned three simulated years, a power flow case was run for each hour in the year to determine the amount of system losses. These 8,760 hourly system losses for each regional alternative were averaged over one year to obtain an average hourly loss for that year. Table 6-11 summarizes average hourly losses for the three simulated years.

Table 6-11: Average Hourly Losses (MW) for Simulated Years (2009, 2012 and 2017)

Year	Alternative 1	Alternative 2	Alternative 3
2009	303	303	303
2012	337	337	336
2017	389	388	388

Average annual hourly losses for each year of the study period were estimated using a linear regression model.

Table 6-12 summarizes the estimated hourly losses for years 2010 to 2029. As a result of the regression analysis, estimated losses may differ from the original data points shown in Table 6-11.

Table 6-12: Estimated Hourly Losses (MW)

Year	Alternative 1	Alternative 2	Alternative 3
2010	315	314	314
2011	325	325	325
2012	336	336	336
2013	347	346	346
2014	357	357	357
2015	368	368	367
2016	379	378	378
2017	389	389	388
2018	400	399	399
2019	411	410	410
2020	421	421	420
2021	432	431	431
2022	443	442	441
2023	453	452	452
2024	464	463	462
2025	475	474	473
2026	485	484	484
2027	496	495	494
2028	507	505	505
2029	517	516	515

The losses were estimated using the following coefficients of a linear equation: (y=mx+b), where:

Y = loss value;
M = year;
x = x-variable; and
b = intercept

Values for the ‘m’ and ‘b’ coefficients were derived using the linear regression analysis function in Excel. The following inputs were used when prompted:

Input X Range = Loss for the simulated years (2009, 2012 and 2017); and

Input Y Range = Years “2009”, “2012” and “2017”.

In order to compare differences in losses for each regional alternative, the AESO has calculated the amount of incremental losses of each alternative relative to Regional Alternative 1. The AESO then multiplied the incremental loss volume of each alternative relative to Regional Alternative 1 by forecasted annual Alberta power pool prices provided to the AESO by EDC Associates Ltd.

Table 6-13 summarizes the present value of annual loss values for each alternative relative to Regional Alternative 1.

Table 6-13: Present Value of Annual Loss Values Relative to Regional Alternative 1 Discounted over a 20 year period to 2010 ($Million)

Alternative 1	Alternative 2	Alternative 3
$0	($5)	($8)

6.6.4 Net Present Value of Each Alternative Relative to Regional Alternative 1

Table 6-14 summarizes the total net present value of each regional alternative relative to Regional Alternative 1.

Table 6-14: Net Present Value Discounted over a 20 year period to 2010, Relative to Alternative 1 (Million)

	Alternative 1	Alternative 2	Alternative 3
PV Revenue Requirement	$0	$114	$35
PV Losses Relative to Alternative 1	$0	($5)	($8)
Total Net Cost	**$0**	**$109**	**$27**

The ranking of alternatives, in term of economic assessment, is shown in Table 6-15.

Table 6-15: Economic Assessment Ranking of Regional Alternatives

Relative Ranking of Regional Alternatives	
1	Alternative 1
2	Alternative 3
3	Alternative 2

6.6.5 Sensitivity Analysis

Single variable sensitivity analysis was performed on the following assumptions. The economic model included in Appendix G contains a 'Sensitivity Analysis' worksheet tab.

Table 6-16: Sensitivity Analysis

Variable	Sensitivity	Result
Capital Cost	+/- 10%	No change to ranking of alternatives
Discount Rate	+/- 2%	No change to ranking of alternatives
Depreciation Rate	+/- 2%	No change to ranking of alternatives
Alberta Power Price	High: Double /Low: Half	No change to ranking of alternatives

Single variable sensitivity analysis did not result in a change to the ranking of regional alternatives.

6.6.6 Conclusions

Results of economic analysis indicate the following:

1. Regional Alternative 1 has the lowest net cost. The net cost of Regional Alternatives 2 and 3 are higher than Regional Alternative 1 by $109 million and $27 million respectively.
2. The estimated capital cost (+/- 30%, 2009$) of Regional Alternative 1 is 29% lower than Regional Alternative 2 and 11% lower than Regional Alternative 3.
3. Estimated system energy losses are comparable for each regional alternative. Therefore, losses did not factor into the economic ranking of regional alternatives.

6.7 Participant Involvement Program (PIP)

In accordance with Appendix A of AUC Rule 007, the AESO prepared and followed a PIP related to the need for transmission reinforcement in the Central East region. The following sections summarize what the PIP included as well as results.

PIP for the Need for Transmission Reinforcement in the Central East Region

The AESO conducted a PIP from May 2009 to April 2010 for transmission development in the Central East region. A variety of methods were used to notify, consult and engage residents, occupants, landowners, businesses, industry, First Nations, Métis settlements, advocacy groups as well as elected and administrative municipal and provincial officials with interests in the Central East region.

Throughout the PIP, the AESO:

- Delivered presentations at 10 meetings with elected and administrative municipal government officials and a separate presentation to industry stakeholders;
- Hosted 11 open houses;
- Mailed information on the need for the project, as well as open house schedules by postal code (unaddressed mail through Canada Post) and directly (addressed mail). In total approximately 71,600 pieces of mail were sent to residences, farms and businesses throughout the study area;
- Posted information on the AESO website;
- Advertised in 12 local newspapers;
- Achieved 10 articles (earned media) on AESO need and consultation efforts in the Central East region;
- Corresponded with stakeholders in person, 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 transmission development in the Central East region:

- To be fully informed about the AESO NID process for reinforcing the transmission system in the Central East region;
- To share their feedback about the need for reinforcement and about transmission alternatives the AESO had proposed to meet this need; and
- To raise questions or concerns about the need for reinforcement.

The PIP also allowed the AESO to identify stakeholders and their concerns, and to take measures where possible to address those concerns.

PIP Conclusions:

Throughout the PIP for the reinforcements required in the Central East region, the AESO summarized the information and feedback received from public, local authorities and industry stakeholders. In general, the following themes emerged:

- Stakeholders did not generally express preference for one alternative over another;
- One siting concern was identified to the AESO by St. Paul County. St. Paul County communicated to the AESO that they would like the existing 72 kV right-of-way located in their County to be utilized as much as feasible. The Transmission Facility Owner ("TFO") is made aware of this

information. The AESO understands that the issue will be considered in relation to the TFO Facilities Application; and

- Stakeholder concerns are outlined in Section 1.2 of Appendix H.

7 Alternative Comparison

The following sections compare the Central East transmission alternatives based on technical, economic and societal factors**.** Table 7-1 presents a summary of the comparison.

7.1 Technical Performance

7.1.1 Meeting Reliability Criteria

Section 6 of the NID presents the results of detailed technical analysis carried out for all three regional alternatives. A summary of results are presented in Sections 6.1 to 6.4. The corresponding power flow plots, PV and QV analysis and transient stability plots are included in Appendices D and E. These results demonstrate that all alternatives meet the Reliability Criteria.

7.1.2 Future Expandability

Regional Alternative 1 consists of re-building the 144 kV line 7L50 from Battle River 757S to Buffalo Creek 526S. Due to physical constraints, it is not feasible to convert it into a 240 kV line. However, the proposed re-build has adequate capacity to meet future needs.

Regional Alternatives 2 and 3 are based on 240 kV double circuit towers with one side strung. Hence these alternatives offer an opportunity to increase transmission capacities by stringing a second circuit when required without any additional rights-of-way.

7.1.3 Operational Flexibility

All three regional alternatives were tested to determine whether they will be able to maintain continuity of supply in the event of outage of all Battle River generation units (or all Battle River units and one Sheerness unit). A complete contingency analysis (Category A and B events) was carried out on the proposed alternatives with all Battle River units out of service. All three alternatives meet the Reliability Criteria except for two contingencies. The resulting overloads could be managed through operational measures. Thus these alternatives provide operational flexibility even under extreme system conditions.

7.2 Economic Factors

Results from the economic comparison of alternatives are included in Table 6-13 and Table 6-14. The regional alternatives were compared based on the net present value of a stream of annual capital cost and loss values. Section 6.6 describes the methodology used for economic evaluation and the results of the analysis.

7.2.1 Capital Costs

Total estimated capital cost (+/-30%, 2009$) for the three regional alternatives, including common developments, is provided in Table 6-7 of Section 6.6. As indicated in this table, Regional Alternatives 1 and 2 require the least and highest amount of capital cost, respectively, while the capital cost for Regional Alternative 3 lies between Regional Alternatives 1 and 2.

7.2.2 System Losses

The assumptions and methodology used for estimating the average hourly system losses for all three alternatives is described in Section 6.6.3. The annual average system losses of all three alternatives are comparable. In fact, average annual hourly losses of the three alternatives were found to be within 1 MW of each other over the 20-year study period. The system losses for Regional Alternatives 2 and 3 are slightly lower than Regional Alternative 1 since they utilized 240 kV lines as their primary development option. Although relative differences in losses were found to be small, they were considered in the economic analysis. The relative cost savings of losses are insignificant compared to the larger differences in capital costs and thus have no impact on the economic ranking of the three alternatives.

Economic analysis of all three alternatives shows that Regional Alternative 1 has the lowest net cost.

7.3 Societal Factors

Societal factors such as land impact, including environment, and stakeholder/pubic feedback were also considered in the comparison of the alternatives.

7.3.1 Land Impact Assessment

The detailed land impact assessment reports are included in Appendix F. A summary of the results of the LIA for all three alternatives is provided summarized in Section 6-5, Table 6.6. All three alternatives are viable and the preferred Regional Alternative 1 has moderate impacts compared to other alternatives.

7.3.2 Stakeholder/Public Feedback

The AESO met with major municipal districts, towns and special interest groups and made presentations to these groups on the Central East region development. The AESO has not received any preference for any of the three alternatives from the public with the exception of the County of St. Paul, which recommended that the existing 72 kV right-of-way in their county be considered as much as feasible for proposed upgrades. The Transmission Facility Owner (“TFO”) is made aware of this information. The AESO anticipates that the issue will be considered in relation to the TFO Facilities Application. Appendix H contains details of the Participant Involvement Program, with a summary given in Section 6.7

7.4 Summary of the Evaluation of the Alternatives

Based on the overall results of the comparison of the alternatives as summarized below, Regional Alternative 1 is the preferred alternative. It is the least cost, technically feasible, and has moderate land impacts.

Table 7-1: Comparison of Regional Alternatives[9]

Alternative	Alternative 1	Alternative 2	Alternative 3
Technical Factors			
Meets Reliability Criteria	Yes	Yes	Yes
Future Expandability	Limited	Offers good opportunity	Offers good opportunity
Economic Factors			
Capital Cost	Lowest	Highest	High
System Losses*	higher	lower	lower
Societal Factors			
Land Impact Assessment	Impacts moderately	Impacts the most	Impacts the least
Stakeholder/Public Feedback	No preference	No preference	No preference

* Difference in losses among these three alternatives is about 1 MW.

8 Recommended Proposal

The results presented in this NID are an extension of the preliminary work carried out in the AESO Long-term Transmission System Plan (the “Plan”). This NID is consistent with information contained within the Plan and it provides a recommendation based on an in-depth analysis of technical, economics, land impacts and feedback from public consultation.

Based on the results presented in Section 7, Regional Alternative 1 is recommended as the AESO’s preferred alternative to reliably supply forecasted loads and provide access to cogeneration and wind farm development in the Central East region. The recommended proposal is shown in Figure 8-1. The total estimated cost for the recommended proposal is $370 million (+/-30%, 2009$).

The AESO recommends a staged approach for implementation of the recommended plan.

Stage I is recommended to facilitate the need for integrating generation projects in the Cold Lake area and to alleviate other system constraints. The targeted in-service date for completion of Stage I is on or before Q4, 2012.

Stage II is required by Q4, 2017 to meet forecast load in the region.

Table 8-1 summarizes the recommended plan in two stages.

Figure 8-1: Recommended Plan (Regional Alternative 1) with Potential Generations

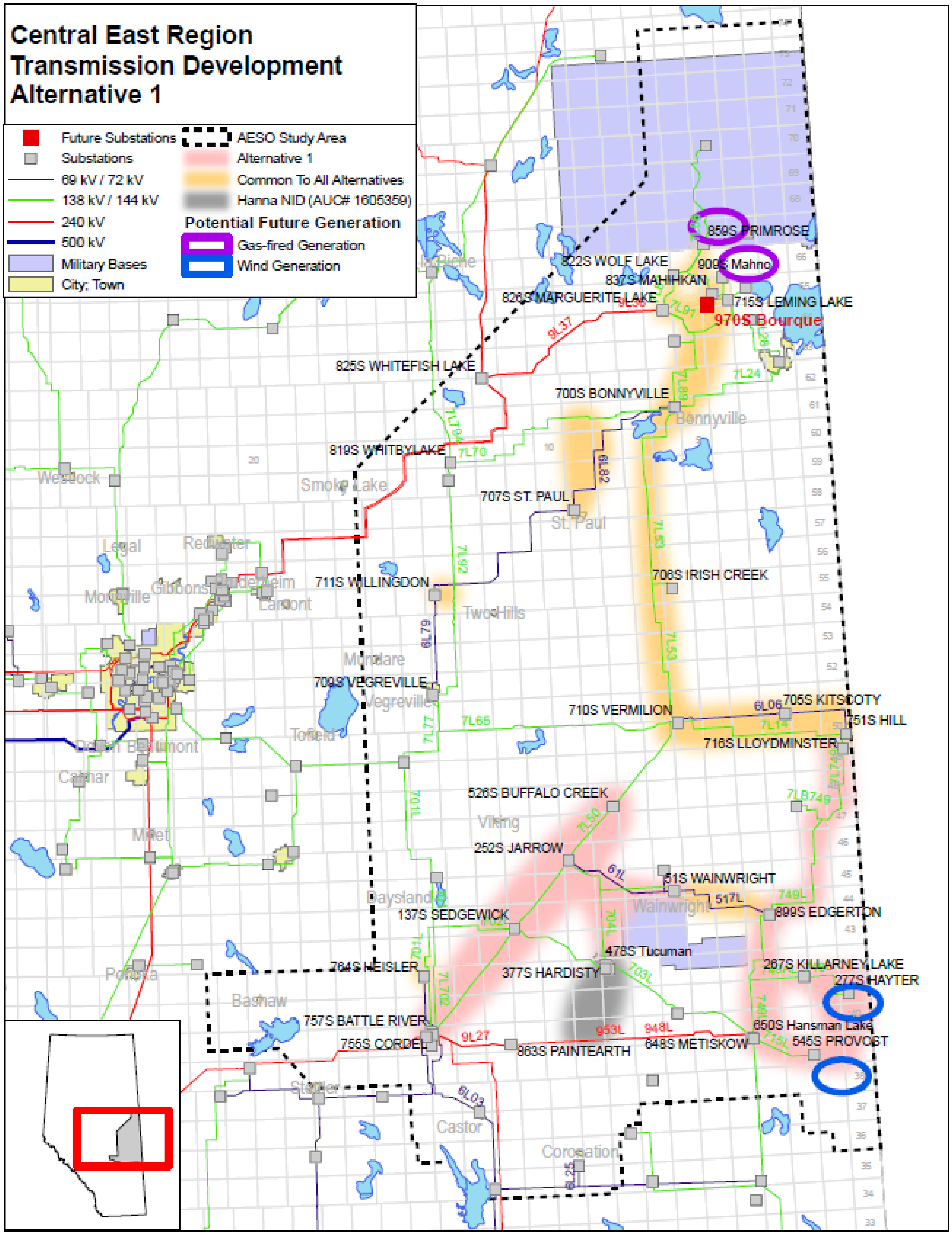


Table 8-1: Details of the Recommended Plan (Regional Alternative 1)

Item #	Description of Development	Details
STAGE I (ISD: Q4 2012)		
I-1	Conversion of St. Paul and Willingdon to 144 kV Substations	Re-build the existing 72 kV Willingdon 711S substation to 144 kV and connect it to the nearby 144 kV line 7L92. Install one 15/20/25 MVA 144/25 kV transformer at Willingdon. Retain the 72 kV line 6L79 72 kV as back-up supply from Vegreville 709S.
		Convert the existing 72 kV St. Paul 707S substation to 144 kV and connect it to the 144 kV line 7L70 in an in and out configuration. Demobilize all 72 kV equipment and install two 25/33/41.6 MVA 144/25 kV low noise transformers at St. Paul. Open the existing 72 kV lines 6L79 and 6L82 as these are no longer required for transmission purposes. (Note: Portions of these lines may be converted for use by ATCO Distribution pending further analysis by ATCO.)
		Remove all 72 kV equipment from Bonnyville 700S including the 144/72 kV tie transformer as well as the two 72/25 kV transformers. Install one 24/33/41.6 MVA 144/25kV transformer.
I-2	Cold Lake Area Reinforcements	Build a new 240 kV switching station designated Bourque 970S near the existing Mahihkan 837S substation. The switching station to be initially energized at 144 kV.
		Build a new double circuit 144 kV line (< 2 km) from Bourque 970S to Mahihkan 837S, with 1x477 kcmil ACSR conductor per phase.
I-3	Cold Lake Area Reinforcements	Build a new double circuit 240 kV line (approximately 50 km in length) from Bourque 970S to Bonnyville 700S, with 2x795 kcmil ACSR conductors per phase, one side strung. This line to be initially energized at 144 kV.
I-4	Cold Lake Area Reinforcements	Re-build the single circuit 144 kV line 7L87 (approximately 15 km in length) from Marguerite Lake 826S to Wolf Lake 822S with 1x795 kcmil ACSR conductor per phase
		Re-build the single circuit 144 kV line 7L74 (approximately 20 km in length) from Wolf Lake 822S to Bourque 970S with 1x795 kcmil ACSR conductor per phase.
		Re-build the single circuit 144 kV line 7L83 (approximately 10 km in length) from Bourque 970S to Leming Lake 715S with 1x477 kcmil ACSR conductor per phase on a new right-of- way and salvage the existing line.
I-5	Provost & Lloydminster Areas Line	Re-build the single circuit 144 kV line 7L749 (approximately 77 km in length) from Edgerton 899S to Lloydminster 716S using 1x477 kcmil ACSR conductor per phase.

	Rebuilds	Build a new the single circuit 138 kV line (approximately 30 km in length) from Provost 545S to Hayter 277S using 1x795 kcmil ACSR conductor per phase.
		Re-build the single circuit 138 kV line 748L (approximately 21 km in length) from Hayter 277S to Killarney Lake 267S using 1x795 kcmil ACSR conductor per phase.
		Re-build the single circuit 138 kV line 715L (approximately 22 km in length) from Hansman Lake 650S to Provost 545S using 1x795 kcmil ACSR conductor per phase.
		Re-build the single circuit 138 kV line 749L (approximately 38 km in length) from Metiskow 648S to Edgerton 899S using 1x795 kcmil ACSR conductor per phase. Build a double circuit 138 kV line (approximately 18 km in length) from the existing Killarney Lake tap on 749L to Killarney Lake 267S in an in and out configuration.
I-6	Wainwright Area Upgrades	Build a new single circuit 138 kV line (approximately 40 km in length) on the existing 69 kV line right-of-way from Wainwright 51S to Edgerton 899S using 1x477 kcmil ACSR conductor per phase.
		Re-build the single circuit 138 kV lines 704L and 704AL between Wainwright 51S, Tucuman 478S and Jarrow 252S using 1x477 kcmil ACSR conductor per phase. Wainwright will be connected to Jarrow via a double circuit line from the existing Wainwright tap point.
I-7	Line Clearance Mitigations	Restore the ratings of the 144 kV lines 7L14, 7L701, and 7L53 to their respective full conductor thermal capacities by mitigating line clearance issues.
I-8	Battler River & Lloydminster Areas Reinforcements	Upgrade the existing 72 kV Heisler 764S and Kitscoty 705S substations to 144 kV by connecting them to nearby lines 7L701 and 7L14 lines respectively.
		Re-locate the 144/72/25 kV tie transformer from Vermilion 710S to Heisler 764S. Install a second 25/33/41.6 MVA 144/25 kV transformer at Vermilion 710S.
		Salvage the 72 kV line 6L06 from Kitscoty 705S to Vermilion 710S and demobilize all 72 kV equipment from Vermilion 710S.
I-9	Vermilion Area Voltage Support	Install a 25 MVAr capacitor bank at Vermilion 710S.
STAGE II (ISD: Q4 2017)		
II-1	7L50 Re-build	Re-build 7L50 using 1x477 kcmil ACSR and single circuit construction from Battle River 757S to Buffalo Creek 526S (approximately 160 km in length). Include OPGW on 7L50 to mitigate sequential clearing on 7L50 with the Jarrow 252S connection.
II-2	Cold Lake Area Additions	Build a new double circuit 240 kV line (with one circuit strung initially) from Bourque 970S to Marguerite Lake 826S using 2x795 kcmil ACSR conductors per phase. This line will be initially operated at 144 kV.

8.1 Rationale for the Recommended Plan

The rationale for the major components of the recommended plan is discussed and summarized in the following sections.

8.1.1 7L50 Re-build from Battle River to Buffalo Creek (Items II-1 and I-9)

One of the major sources of supply into the Vermilion area is the 144 kV line 7L50 from the Battle River plant. As mentioned in Section 5.2, this line is near the end of its service life.

The AESO recommends re-building 7L50 from Battle River 757S to Buffalo Creek 526S in 2017 to eliminate its overloads during certain contingencies. The estimated length of the re-build is 160 km to allow for new routing. The existing thermal protection scheme on this line will be removed after commissioning of the new line.

As part of this development, a capacitor bank is required at Vermilion 710S to maintain voltage in the Vermilion area under contingencies (e.g. when 7L50 is out of service).

8.1.2 Conversion of St. Paul and Willingdon Substations to 144 kV (Item I-1)

Since the winter of 2008, the present 72 kV system between Bonnyville and Vegreville that supports the urban loads at Bonnyville, St. Paul and Willingdon has not been meeting planning criteria. The TFO has taken measures to divert all supply of all possible loads from St. Paul 707S to distribution feeders from neighboring substations to alleviate potential overloads under contingencies. Furthermore, since 2008, St. Paul 707S has been fed radially to prevent overloading of 6L79. This poses a significant risk to the critical urban load at St. Paul. Presently, about 6 MW of load can not be restored at St. Paul if a permanent fault occurs on 6L82 which causes overloading on 6L79. This situation will deteriorate further with load growth in the area. In order to maintain a reliable supply to the town of St. Paul, it is proposed to convert the existing 72 kV St. Paul 707S to 144 kV and connect it to 7L70. The proposed arrangement provides operational flexibility as compared to feeding it from 7L53.

The existing 72 kV Willingdon 711S substation is near the end of its service life. Because of this and the inability of the 72 kV network to supply the loads, it is recommended to build a new 144 kV Willingdon substation, located as close as possible to the existing Willingdon substation to facilitate interconnection of distribution feeders and equipment.

As part of this local area reinforcement plan, a 144/72 kV tie transformer and two 72/25 kV load transformers at Bonnyville 700S will be demobilized. In their place, a new 144/25 kV load transformer will be installed to improve the reliability of power supply to the town of Bonnyville.

8.1.3 Cold Lake Area Reinforcements - New Switching Station (Item I-2)

The main constraints in the Cold Lake planning area are thermal overloads and limited capacity to meet the growing demand. New generation cannot be reliably connected to the local grid. The need for reinforcements is recognized through system studies and hence major system reinforcements are required on or before Q4 2012.

The proposed alternative involves building a new 144 kV switching station (designated Bourque 970S) near the existing Mahihkan 837S with the intent of expanding it to a 240 kV station to facilitate future load and generation growth. Provision has been made to acquire sufficient land to accommodate such expansion. Bourque 970S facilitates the connection of proposed new cogeneration facilities and it will be connected to the existing Mahihkan 837S via a double circuit 144 kV line and other lines will be terminated there as well. This strategic location coupled with re-configuration of lines improves the system reliability.

8.1.4 Cold Lake Area Reinforcements - New 240 kV Lines Energized at 144 kV (Items I-3 and II-2)

The strategy to build 240 kV lines ahead of immediate need and operate them initially at 144 kV is based on the considerations outlined in Section 5.1.1. The proposed reinforcement plan lays the ground work to align with long-term strategic goal of tying this area to the bulk system. .

Accordingly, the plan proposes the building of two double circuit 240 kV lines with one side strung using 2x795 kcmil ACSR conductors per phase.

The first line will run from Bourque 970S to Bonnyville 700S (in service 2012) and the second from Bourque 970S to Marguerite Lake 826S (in service 2017)

The above facilities will eliminate the need for the thermal protection schemes currently in place to mitigate thermal overloading of various transmission lines in the Cold Lake planning area.

8.1.5 Cold Lake Area Reinforcements - 144 kV Line Re-builds (Item I-4)

The existing 144 kV lines 7L87, 7L74, 7L83 in the Cold Lake area that run from Marguerite Lake 826S to generation sources in the Mahihkan area via Wolf Lake 822S need to be re-built using large capacity conductors because they have limited capacity to serve forecasted future loads. Due to the anticipated difficulties with outages in the area, these lines will be re-built on new rights-of-way to minimize service interruptions to the existing customers during the re-construction period. The existing lines will be salvaged upon commissioning of the new lines.

8.1.6 Provost and Lloydminster Areas Line Re-builds (Item I-5)

Presently, the Provost 545S substation supplies urban, rural, and industrial load in the area and is radially connected to Metiskow 648S. As a result of the radial connection, the substation loads, primarily the Town of Provost, cannot be reliably supplied. In order to improve the reliability of supply to these combined loads, it is proposed to provide a second supply line into Provost 545S by building a 138 kV line from Killarney Lake 267S.

The overriding factors for recommending high capacity lines (1x795 kcmil ACSR conductor per phase) are the need to serve the immediate as well as long-term load and generation development in the region.

8.1.7 Clearance Mitigation of 7L53, 7L14 and 7L701 (Item I-7)

Three 144 kV lines, 7L53 from Bonnyville 700S to Vermilion 710S, 7L14 from Vermilion 710S to Hill 751S, and 7L701 from Battle River 757S to Vermilion 710S, have been derated due to line clearance issues. It is recommended that they be restored to their full conductor thermal capacities.

8.1.8 Battle River and Lloydminster Areas Reinforcements (Item I-8)

The Battle River 144/72 kV tie transformer is a critical support element for supplying the 72 kV network within both the Central East region and the Hanna region. Within the Central East region, opening of the 72 kV line 6L02 separates the two regions and prevents overloading on the 72 kV system in the area. It is necessary to add a new transformer in the area to prevent voltage collapse when the critical Battle River tie transformer is out of service. Due to space restrictions, this transformer can not be located at the Battle River, Mannix Mine, or Bigfoot substations. The Heisler substation was selected instead as it can be expanded. It will be converted into a 144 kV substation.

Another issue to be resolved is the overload of the 72 kV line 6L06 from Vermilion 710S to Kitscoty 705S for the loss of the 144/72/25 kV tie transformer at Vermilion 710S.

In order to mitigate the above constraints, a number of reinforcements were proposed in the Kitscoty, Heisler and Vermilion areas, as detailed in Table 8-1.

8.1.9 New 138 kV Line from Wainwright to Edgerton (Item I-6)

Due to the projected load growth along the eastern part of the system (i.e. along the Metiskow to Lloydminster transmission path), the existing 144 kV system in the region cannot reliably supply the forecasted loads. For example, any loss of the Metiskow source into the Edgerton and Lloydminster areas will cause overload on 7L14 from Vermilion 710S to Lloydminster 716S as well as low voltages in the area. To mitigate these issues, a new line is required into the Edgerton and Lloydminster areas. Given the military base near Wainwright, a potential right-of-way is the salvaged 69 kV 517L line route between Wainwright 510S and Edgerton 899S. This new 138 kV line, combined with the 240 kV Nilrem source station, improves the reliability of supply to the Edgerton, Wainwright and Lloydminster areas.

8.1.10 Wainwright Area Upgrades (Item 6)

The Wainwright area has the highest load growth in the region. Some sections of 704L and 704AL between Wainwright, Tucuman and Jarrow substations utilizes 1x266 kcmil conductors per phase and are subject to overloads under N-1-1 contingency conditions. Hence, these low capacity lines must be re-built with sufficient capacity to avoid overloads. To maximize the reliability of supply to the larger Wainwright area, it is beneficial to convert the Wainwright substation to an in and out configuration on 704L line.

8.2 Advancement of Expenses

In order to advance Stage I and II project development to meet the projected in-service dates and enable the connection of cogeneration and wind power projects, the AESO intends to direct both AltaLink and ATCO to proceed with certain activities as preparatory activities in advance of approval of the NID, and in advance of approval of the subsequent TFOs Facility Applications for permit and license.

The total estimated capital cost for Stages I and II is approximately $370 million (+/- 30%, 2009$).

With the above assumptions, and in order to maintain project schedule, it is estimated that approximately $4.5 million and $9.5 million will be incurred by AltaLink and ATCO respectively prior to the NID being approved. These cost estimates are based on order-of-magnitude estimates.