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ALBERTA ELECTRIC SYSTEM OPERATOR

2009 Loss Factors

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1.0 Purpose

The purpose of this document is to present the 2009 loss factors complete with a brief explanation of changes. A loss factor map is included. The loss factors published in this document will be effective from January 01, 2009 to December 31, 2009.

2.0 Introduction

The AESO has completed the final analysis of 2009 loss factors and the results are attached. The analysis includes the application of the 2009 Generic Stacking Order (GSO) results published earlier this summer and the 2009 Base Cases published in October on the AESO web site. Both the GSO and the Base Cases have been updated during the course of the final calculations and reposted. The requirements of the 2007 Transmission Regulation are included.

The loss factor calculation uses four key inputs; –

1. 2009 Generic Stacking Order (GSO)
2. New project data
3. Loss factor base cases based on 2009 GSO, load forecast and topology
4. Annual energy and loss volume forecast

The Rule governing the determination of the loss factors is located at **www.aeso.ca** > Rules & Procedures > ISO Rules > Current Rules. To summarize, loss factors for generators are calculated based using the "50% Area Load Methodology Using Corrected Loss Matrix" methodology developed in 2005 with stakeholders and originally based on the 2004 Transmission Regulation. Loss factors for opportunity services (demand and tie line) are based on their total impact on losses.

3.0 2009 Loss Factors

Table 1 shows the 2009 loss factors and Table 2 shows settlement loss factors of the tie lines respectively.

Table 1 – 2009 Final Loss Factors

2009 Alberta Loss Factors - 2008-11-06, Final

MP-ID*	Facility Name	PSS/E Bus	Normalized and Compressed Loss Factor (%)	Loss Factor Asset	Difference % in Loss Factor to System Average
0000016301	Amoco Empress (163S)	262	**0.88**	DOS	-3.67
0000079301	ANG Cochrane (793S)	191	**3.66**	DOS	-0.89
NX01	BALZAC	290	**-0.40**	Gen	-4.95
BAR	BARRIER	216	**-1.46**	Gen	-6.01
BR3	BATTLE RIVER #3	1491	**5.07**	Gen	0.52
BR4	BATTLE RIVER #4	1491	**5.07**	Gen	0.52
BR5	BATTLE RIVER #5	1469	**4.16**	Gen	-0.39
BCHIMP	BCH - Import	56765	**-0.83**	Imp	-5.38
BCRK	BEAR CREEK G1	10142	**-1.43**	Gen	-5.98
BCR2	BEAR CREEK G2	10142	**-1.43**	Gen	-5.98
BPW	BEARSPAW	183	**-1.37**	Gen	-5.92
BLYR	BELLY RIVER IPP	447	**0.00**	Gen	-4.55
BIG	BIGHORN	103	**2.49**	Gen	-2.06
BRA	BRAZEAU	56153	**2.07**	Gen	-2.48
GOC1	BRIDGE CREEK	19145	**0.00**	Gen	-4.55
0000045411	BUCK LAKE	80	**2.32**	Gen	-2.23
CES1	CALPINE CTG	187	**-0.33**	Gen	-4.88
CES2	CALPINE STG	187	**-0.33**	Gen	-4.88
TC01	CARSELAND	5251	**-0.54**	Gen	-5.09
CAS	CASCADE	175	**-2.22**	Gen	-6.77
CR1	CASTLE RIVER	234	**1.40**	Gen	-3.15
EC01	CAVAILIER	247	**-0.43**	Gen	-4.98
CHIN	CHIN CHUTE	406	**0.00**	Gen	-4.55
CMH1	CITY OF MEDICINE HAT	680	**-0.32**	Gen	-4.87
ENC1	CLOVER BAR PEAKER (STAGE 1 - LM6000)	516	**4.19**	Gen	-0.36
ENC2	CLOVER BAR PEAKER (STAGE 2 - LM6000)	516	**4.19**	Gen	-0.36
CRE1	COWLEY EXPANSION 1	264	**3.52**	Gen	-1.03
CRE2	COWLEY EXPANSION 2	264	**3.52**	Gen	-1.03
CRE3	COWLEY NORTH	264	**3.52**	Gen	-1.03
PKNE	COWLEY RIDGE WIND POWER PHASE1	264	**3.52**	Gen	-1.03
CRWD	COWLEY RIDGE WIND POWER PHASE2	264	**3.52**	Gen	-1.03
Project692_1_SUP	Dapp Power Westlock Expansion	99921	**4.66**	Gen	0.11
DAI1	DIASHOWA	1088	**-2.03**	Gen	-6.58
DKSN	DICKSON DAM 1	4006	**0.00**	Gen	-4.55
DOWGEN15M	DOW GTG	61	**3.96**	Gen	-0.59
DV1	DRAYTON VALLEY PL IPP	4332	**0.00**	Gen	-4.55
DRW1	DRYWOOD 1	4226	**1.27**	Gen	-3.28
Project730_1_SUP	ENMAX Crossfield Energy Centre	503	**0.79**	Gen	-3.76
FNG1	FORT NELSON	1016	**7.54**	Gen	2.99
EC04	FOSTER CREEK G1	1301	**7.04**	Gen	2.49
0000001511	FT MACLEOD	4237	**0.72**	Gen	-3.83
GN1	GENESEE 1	525	**5.72**	Gen	1.17
GN2	GENESEE 2	525	**5.72**	Gen	1.17
GN3	GENESEE 3	525	**5.72**	Gen	1.17
GHO	GHOST	180	**-1.53**	Gen	-6.08
0000022911	GLENWOOD	4245	**0.45**	Gen	-4.10
GPEC	GRANDE PRAIRIE ECOPOWER CENTRE	1101	**-1.88**	Gen	-6.43
HSH	HORSESHOE	171	**-1.48**	Gen	-6.03
HRM	HR MILNER	1147	**2.34**	Gen	-2.21
INT	INTERLAKES	376	**-1.06**	Gen	-5.61
KAN	KANANASKIS	193	**-1.37**	Gen	-5.92
KH1	KEEPHILLS #1	420	**5.72**	Gen	1.17
KH2	KEEPHILLS #2	420	**5.72**	Gen	1.17
KHW1	KETTLES HILL WIND ENERGY PHASE 2	402	**1.56**	Gen	-2.99
IOR1	MAHKESES, COLD LAKE	56789	**4.68**	Gen	0.13
MATLIMP	MATLIMP	451	**0.68**	Imp	-3.87
Project703_1_SUP	Maxim Power Deerland Peaking Station	432	**4.08**	Gen	-0.47
AKE1	McBRIDE	901	**1.12**	Gen	-3.43
MKRC	McKAY RIVER	1274	**6.59**	Gen	2.04
ProjectISD762SUP	Meg Energy	405	**6.06**	Gen	1.51
MKR1	MUSKEG	1236	**6.75**	Gen	2.20
NX02	NEXEN OPTI	1241	**6.85**	Gen	2.30
Project672_1_SUP	Northern Prairie Power Project	1120	**-4.79**	Gen	-9.34
NPC1	NORTHSTONE ELMWORTH	19134	**-5.04**	Gen	-9.59
NOVAGEN15M	NOVA JOFFRE	383	**1.25**	Gen	-3.30
OMRH	OLDMAN	230	**2.09**	Gen	-2.46
WEY1	P&G WEYERHAUSER	1141	**-3.01**	Gen	-7.56
0000039611	PINCHER CREEK	4224	**1.52**	Gen	-3.03

MP-ID*	Facility Name	PSS/E Bus	Normalized and Compressed Loss Factor (%)	Loss Factor Asset	Difference % in Loss Factor to System Average
0000035311	PLAMONDON	4304	**2.87**	Gen	-1.68
POC	POCATERRA	214	**-1.45**	Gen	-6.00
PH1	POPLAR HILL	1118	**-4.81**	Gen	-9.36
PR1	PRIMROSE	1302	**5.46**	Gen	0.91
RB1	RAINBOW 1	1031	**2.79**	Gen	-1.76
RB2	RAINBOW 2	1032	**2.73**	Gen	-1.82
RB3	RAINBOW 3	1033	**2.93**	Gen	-1.62
RL1	RAINBOW 4, RL1	1035	**3.26**	Gen	-1.29
RB5	RAINBOW 5	1037	**2.72**	Gen	-1.83
RYMD	RAYMOND RESERVOIR	413	**0.00**	Gen	-4.55
TC02	REDWATER	50	**4.15**	Gen	-0.40
RG10	ROSSDALE 10	507	**4.43**	Gen	-0.12
RG8	ROSSDALE 8	507	**4.43**	Gen	-0.12
RG9	ROSSDALE 9	507	**4.43**	Gen	-0.12
RUN	RUNDLE	197	**-1.60**	Gen	-6.15
SH1	SHEERNESS #1	1484	**3.81**	Gen	-0.74
SH2	SHEERNESS #2	1484	**3.81**	Gen	-0.74
SHCG	SHELL CAROLINE 378S	3370	**-0.72**	Gen	-5.27
SCTG	SHELL SCOTFORD	43	**4.35**	Gen	-0.20
GWW1	SODERGLEN	358	**1.46**	Gen	-3.09
SPCIMP	SPC - Import	1473	**1.35**	Imp	-3.20
SPR	SPRAY	310	**-1.58**	Gen	-6.13
0000038511	SPRING COULEE	4246	**0.36**	Gen	-4.19
STMY	ST MARY IPP	3448	**0.00**	Gen	-4.55
0000006711	STIRLING	4280	**0.60**	Gen	-3.95
ST1	STURGEON 1	1166	**-0.28**	Gen	-4.83
ST2	STURGEON 2	1166	**-0.28**	Gen	-4.83
IEW1	SUMMERVIEW 1	336	**2.01**	Gen	-2.54
SCR1	SUNCOR	1208	**6.68**	Gen	2.13
SCR3	SUNCOR HILLRIDGE WIND FARM	389	**-0.17**	Gen	-4.72
SCR2	SUNCOR MAGRATH	251	**0.54**	Gen	-4.01
SD1	SUNDANCE #1	135	**6.04**	Gen	1.49
SD2	SUNDANCE #2	135	**6.04**	Gen	1.49
SD3	SUNDANCE #3	135	**6.04**	Gen	1.49
SD4	SUNDANCE #4	135	**6.04**	Gen	1.49
SD5	SUNDANCE #5	135	**6.04**	Gen	1.49
SD6	SUNDANCE #6	135	**6.04**	Gen	1.49
SCL1	SYNCRUDE	1205	**6.71**	Gen	2.16
341S025	Syncrude Standby (848S)	1200	**-4.48**	DOS	-9.03
TAB1	TABER WIND	343	**-0.71**	Gen	-5.26
TAY1	TAYLOR HYDRO	670	**1.68**	Gen	-2.87
TAY2	TAYLOR WIND PLANT	670	**1.68**	Gen	-2.87
THS	THREE SISTERS	379	**-1.43**	Gen	-5.98
VVW1	VALLEYVIEW	1171	**0.80**	Gen	-3.75
VVW2	VALLEYVIEW # 2	1172	**0.77**	Gen	-3.78
WB4	WABAMUN #4	133	**5.73**	Gen	1.18
WTRN	WATER IPP	3449	**0.00**	Gen	-4.55
WST1	WESGEN	14	**0.00**	Gen	-4.55
EAGL	WHITE COURT	410	**0.00**	Gen	-4.55

Notes:
* MP-ID - point where loss factors assessed
For loss factors, "-" means credit, "+" means charge
Loss factors effective from January 01, 2009 to December 31 2009.
System Average Losses, %: 4.55
For more information, please visit www.aeso.ca

Table 2 – 2009 Tie Loss Factors

Tie	Transaction Type	Loss Factor (%)	Average Loss Charge (%)	Settlement LF (%)
BC	**Import**	-0.83	0.99	0.16
	Export	0	1.05	1.05
SK	**Import**	1.35	2.50	3.85
	Export	-	2.30	2.30
MATL	**Import**	0.68	-	0.68
	Export	-	-	-

4.0 2009 and 2008 Loss Factors Calculation

The following items illustrate the major similarities and differences between the 2009 and 2008 loss factors

1. Load Treatment in the Loss Factor Software – Again in the 2009 loss factor calculation, only transmission loads were unassigned and were not included in the calculation as was done in the 2008 loss factor calculation. This refinement represents a more appropriate load assignment process. The loss factors are based on generation less the behind the fence load levels at all relevant Generation Buses while maintaining the appropriate GSO level at the MPID bus.

2. Generation & Load Levels – The 2008 Generic Stacking Order was used to populate the loss factor base cases for the 2008 loss factor calculation. The 2009 GSO has been utilized in the same way for the 2009 Cases. The 2009 and 2008 loss factors use actual average generation levels to determine loss factors based on the AESO Rule. Please refer to Appendix-I for a sample comparison. In general, the total gross generation level is higher in the 2009 cases as behind-the-fence loads are added. The addition of behind-the-fence loads has no impact on loss factor calculation. The load is scaled down in all 2009 cases to meet the total GSO capacity.

3. Additions and Decommissioning of Generation – There are no large changes in the existing generators' net to grid (NTG) output except for few generators where scheduled outages forced the NTG to a lower value such as Sundance (SD) 4, SD 5 in summer and fall and Genesee 2 in spring units in summer and fall scenarios. There are a number of new generators in the new 2008 loss factor base cases and were added according to their in-service-date.

4. ISD Equivalents – The Industrial System Designations (ISD's) are modeled in the same way as they were modeled in the 2008 cases. The

total ISD load and generations are modeled at the ISD interface bus with the rest of the AIES.

5. Inter Tie Flows – The tie flows in the 2008 base cases were set to zero as per the requirements of the 2004 Transmission Regulation (total impact on system losses as opposed to average impact on system losses used for the generators). The 2007 Transmission Regulation directs the use of same loss factor calculation methodology (average impact on system losses) for all loss factor customers. The new direction now includes using the historical average net flow on the tie lines in the 2009 base cases.

6. Topology – In the 2009 cases, additions during 2008 and expected additions in 2009 have been added. The major 2008 transmission change is the conversion from 240 kV to 500 kV on the KEG loop. The KEG 500 kV addition reduces system losses. Other system additions have been modeled in the 2009 cases.

7. Average System Losses and Shift Factor – the annual loss forecast for 2009 is 2.73 TWH or 4.55% while average system loss forecast was 4.78% for 2008. The change in the In-Service-Dates of projects and the more accurate annual loss forecast result in a system average loss and consistently low shift factor. Please refer to Table 3 to see the effects of the change in average losses.

Table 3 – 2009 vs. 2008 Final Loss Factors

	2008	2009
System average loss	4.78%	4.55%
Shift Factor	0.81%	0.82%
Loss recovered by RLF	3.97%	3.73%

8. Weighting Factor – In a continuing effort to enhance accuracy, the AESO is applying unequal weighting factor to the raw loss factors based on historical load levels. Please see Table 4 for the 2009 weighting factors used in the loss factor calculation.

Table 4 – 2009 Weighting Factors

	Winter		Spring		Summer		Fall	
	Duraion	Weight	Duraion	Weight	Duraion	Weight	Duraion	Weight
High	150	6.9%	75	3.4%	50	2.3%	175	8.0%
Medium	1125	52.1%	1450	65.7%	2075	94.0%	1150	52.6%
Low	885	41.0%	682	30.9%	83	3.8%	860	39.4%

5.0 2009 Overall Loss Factor Results

The 2009 loss factors are similar to the 2008 loss factors with some minor changes reflecting the results of load scaling, dispatched generation, load and transmission projects. The high level results are summarized below:

1. The Rainbow area has less credit or more charges than in the 2008 Loss Factors. These results are due primarily to lower Ft. Nelson area load levels in the 2009 base cases. The Rainbow area is historically sensitive to load and generation changes. A small deviation in the Rainbow Area net flow can result in a swing in the loss factors on the generators. The loss factor sensitivity in the area is consistent with previous years' findings.

2. The South area receives more credits/less charges than 2008. Lower generation and higher load has resulted in more favorable loss factors in 2009 than in 2008.

3. The Lake Wabamun area loss factors are lower relative to the 2008 loss factors. The changes are primarily due to the KEG loop energization Genesee and Keep Hills units receives the biggest benefit of the 500 kV KEG loop because of their relative electrical position. However, SD units and WAB4 are still connected through the existing facilities and receives less benefit of the 500 kV conversions.

4. Sheerness and Battle River generation are higher and Empress area loads are lower in most of the 2009 base cases and tie flows (import, in general) are included in the base cases as well. These factors contribute in higher loss factors.

5. The Fort McMurray area loss factors are higher in 2009 due to higher generation dispatches. The higher dispatches have resulted in higher net flow out of area in the cases.

6. Import loss factors in 2009 reflect the implementation of the 2007 Transmission Regulation. Tables 4 and 5 represent the inter-tie loss factors to be used in the settlement process for British Columbia and Saskatchewan. These loss values are calculated as per the process AESO proposed to meet the terms of the 2007 Transmission Regulation.

6.0 Loss Factor Map

The AESO has provided a loss factor map (Figure #1) showing the maximum and minimum loss factors in each area. The tie lines and DOS loss factors are also shown. Each facility with a loss factor is shown in the designated area. Average flows, in response to stakeholder requests, are included.

7.0 Conclusion

The AESO has published the 2009 loss factors as per the Loss Factor Rule and Appendix 6, and has made the calculation by using the best information available. The data process includes gathering data from the billing system, new customer facilities, and system load and topology features. The loss factor software was updated to reflect the 2007 Transmission Regulation changes. The AESO performs the loss factor calculation process initially and has the results independently run for comparison purposes.

The AESO published the draft values on October 21, 2008 for the stakeholders' review. The AESO has made some minor changes in the base cases and this information has been updated on the AESO web site. The 2009 loss factors will be applicable from January 01 to December 31 2009.

APPENDIX I. Case Comparison

Winter Peak Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2009	8691.8	520.4	9212.2	20.4	340.6	456.7	-
2008	7701.9	359.1	8061.0	19.2	353.1	0.4	-
2009 - 2008	**989.9**	**161.3**	**1151.2**	**1.2**	**-12.5**		

Winter Medium Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2009	7713.3	515.8	8229.1	20.7	300.9	37.8	-
2008	7272.9	360.5	7633.3	19.4	333.9	-	0.2
2009 - 2008	**440.5**	**155.3**	**595.8**	**1.3**	**-33.0**		

Winter Low Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2009	6776.7	571.6	7348.3	21.0	288.1	-	317.2
2008	6805.9	367.0	7172.9	19.2	311.3	0.8	-
2009 - 2008	**-29.2**	**204.6**	**175.3**	**1.8**	**-23.2**		

Spring Peak Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2009	8163.9	587.0	8750.9	20.4	327.9	258.3	-
2008	7260.7	391.6	7652.3	19.6	334.5	1.5	-
2009 - 2008	**903.2**	**195.4**	**1098.6**	**0.8**	**-6.6**		

Spring Medium Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2009	7377.1	528.4	7905.5	20.8	255.5	113.8	-
2008	6810.7	338.3	7148.9	19.5	297.8	0.9	-
2009 - 2008	**566.5**	**190.1**	**756.6**	**1.3**	**-42.3**		

Spring Low Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2009	6509.8	437.1	6946.9	20.6	221.3	-	25.7
2008	6222.2	382.4	6604.6	19.5	265.1	0.8	-
2009 - 2008	**287.6**	**54.7**	**342.2**	**1.1**	**-43.8**		

Summer Peak Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2009	8550.7	586.4	9137.1	20.7	294.1	397.2	-
2008	7368.3	385.1	7753.4	19.6	278.1	1.5	-
2009 - 2008	**1182.4**	**201.3**	**1383.7**	**1.1**	**16.0**		

Summer Medium Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2009	7364.2	578.5	7942.7	20.8	246.8	72.5	-
2008	6718.5	398.7	7117.2	19.5	250.2	0.1	-
2009 - 2008	**645.6**	**179.8**	**825.4**	**1.3**	**-3.4**		

Summer Low Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2009	6477.7	549.8	7027.5	20.7	216.4	-	179.7
2008	5931.7	377.2	6308.9	19.4	229.2	0.1	-
2009 - 2008	**546.0**	**172.7**	**718.6**	**1.3**	**-12.8**		

Fall Peak Case

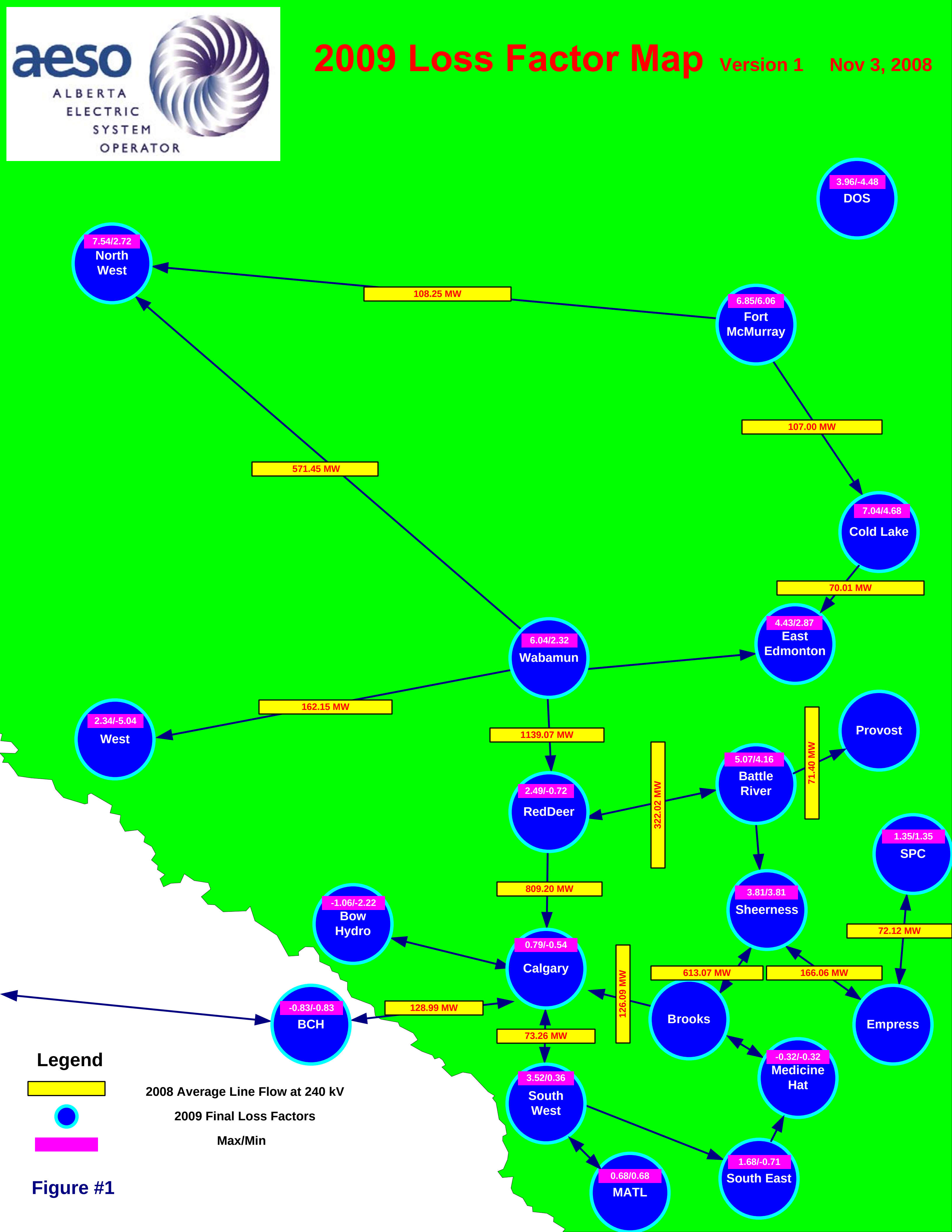
	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2009	8515.0	520.4	9035.4	20.4	340.9	146.5	-
2008	7765.9	304.4	8070.3	19.6	306.2	1.0	-
2009 - 2008	**749.1**	**216.0**	**965.1**	**0.8**	**34.7**		

Fall Medium Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2009	7781.0	548.8	8329.8	20.4	291.8	53.9	-
2008	7081.6	379.4	7461.0	19.6	263.7	0.6	-
2009 - 2008	**699.4**	**169.4**	**868.8**	**0.8**	**28.1**		

Fall Low Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2009	7055.2	524.0	7579.1	20.4	266.3	-	246.0
2008	6524.7	375.8	6900.5	19.6	230.7	-	-
2009 - 2008	**530.5**	**148.1**	**678.6**	**0.8**	**35.6**		


aeso
ALBERTA ELECTRIC SYSTEM OPERATOR
2009 Loss Factor Map
Version 1
Nov 3, 2008
3.96/-4.48
DOS
7.54/2.72
North West
108.25 MW
6.85/6.06
Fort McMurray
107.00 MW
571.45 MW
7.04/4.68
Cold Lake
70.01 MW
4.43/2.87
East Edmonton
6.04/2.32
Wabamun
162.15 MW
2.34/-5.04
West
1139.07 MW
322.02 MW
71.40 MW
Provost
5.07/4.16
Battle River
2.49/-0.72
RedDeer
1.35/1.35
SPC
809.20 MW
3.81/3.81
Sheerness
-1.06/-2.22
Bow Hydro
72.12 MW
0.79/-0.54
Calgary
126.09 MW
613.07 MW
166.06 MW
-0.83/-0.83
BCH
128.99 MW
Brooks
Empress
73.26 MW
-0.32/-0.32
Medicine Hat
3.52/0.36
South West
1.68/-0.71
South East
0.68/0.68
MATL
Legend
2008 Average Line Flow at 240 kV
2009 Final Loss Factors
Max/Min
Figure #1

Location	MPID	Loss Factor(%)	Gen Name
North West	RB1	2.79	RAINBOW 1
	RB2	2.73	RAINBOW 2
	RB3	2.93	RAINBOW 3
	RL1	3.26	RAINBOW 4, RL1
	RB5	2.72	RAINBOW 5
	FNG1	7.54	FORT NELSON
West	HRM	2.34	HR MILNER
	PH1	-4.81	POPLAR HILL
	NPC1	-5.04	NORTHSTONE ELMWORTH
	DAI1	-2.03	DIASHOWA
	BCR2	-1.43	BEAR CREEK G2
	BCRK	-1.43	BEAR CREEK G1
	GPEC	-1.88	GRANDE PRAIRIE ECOPOWER CENTRE
	ST1	-0.28	STURGEON 1
	ST2	-0.28	STURGEON 2
	VVW1	0.80	VALLEYVIEW
	VVW2	0.77	VALLEYVIEW # 2
	WEY1	-3.01	P&G WEYERHAUSER
	Project672_1_SUP	-4.79	Northern Prairie Power Project
Fort McMurray	MKR1	6.75	MUSKEG
	MKRC	6.59	McKAY RIVER
	SCL1	6.71	SYNCRUDE
	SCR1	6.68	SUNCOR
	NX02	6.85	NEXEN OPTI
	ProjectISD762SUP	6.06	Meg Energy
Wabamun	GN1	5.72	GENESEE 1
	GN2	5.72	GENESEE 2
	GN3	5.72	GENESEE 3
	KH1	5.72	KEEPHILLS #1
	KH2	5.72	KEEPHILLS #2
	SD1	6.04	SUNDANCE #1
	SD2	6.04	SUNDANCE #2
	SD3	6.04	SUNDANCE #3
	SD4	6.04	SUNDANCE #4
	SD5	6.04	SUNDANCE #5
	SD6	6.04	SUNDANCE #6
	WB4	5.73	WABAMUN #4
	0000045411	2.32	BUCK LAKE
	Project692_1_SUP	4.66	Dapp Power Westlock Expansion
Cold Lake	IOR1	4.68	MAHKESES, COLD LAKE
	PR1	5.46	PRIMROSE
	EC04	7.04	FOSTER CREEK G1
East Edmonton	0000035311	2.87	PLAMONDON
	RG8	4.43	ROSSDALE 8
	RG9	4.43	ROSSDALE 9
	RG10	4.43	ROSSDALE 10
	SCTG	4.35	SHELL SCOTFORD
	TC02	4.15	REDWATER
	ENC1	4.19	CLOVER BAR PEAKER (STAGE 1 - LM6000)
	ENC2	4.19	CLOVER BAR PEAKER (STAGE 2 - LM6000)
	Project703_1_SUP	4.08	Maxim Power Deerland Peaking Station
Red Deer	NOVAGEN15M	1.25	NOVA JOFFRE
	BIG	2.49	BIGHORN
	BRA	2.07	BRAZEAU
	SHCG	-0.72	SHELL CAROLINE 378S

Calgary	CES1	-0.33	CALPINE CTG
	CES2	-0.33	CALPINE STG
	TC01	-0.54	CARSELAND
	EC01	-0.43	CAVAILIER
	NX01	-0.40	BALZAC
	Project730_1_SUP	0.79	ENMAX Crossfield Energy Centre
Bow Hydro	BAR	-1.46	BARRIER
	BPW	-1.37	BEARSPAW
	CAS	-2.22	CASCADE
	GHO	-1.53	GHOST
	HSH	-1.48	HORSESHOE
	KAN	-1.37	KANANASKIS
	POC	-1.45	POCATERRA
	INT	-1.06	INTERLAKES
	RUN	-1.60	RUNDLE
	THS	-1.43	THREE SISTERS
	SPR	-1.58	SPRAY
South East	SCR2	0.54	SUNCOR MAGRATH
	TAY1	1.68	TAYLOR HYDRO
	TAY2	1.68	TAYLOR WIND PLANT
	0000006711	0.60	STIRLING
	SCR3	-0.17	SUNCOR HILLRIDGE WIND FARM
	TAB1	-0.71	TABER WIND
	KHW1	1.56	KETTLES HILL WIND ENERGY PHASE 2
Battle River	BR3	5.07	BATTLE RIVER #3
	BR4	5.07	BATTLE RIVER #4
	BR5	4.16	BATTLE RIVER #5
Medicine Hat	CMH1	-0.32	CITY OF MEDICINE HAT
Sheerness	SH1	3.81	SHEERNESS #1
	SH2	3.81	SHEERNESS #2
South West	AKE1	1.12	McBRIDE
	DRW1	1.27	DRYWOOD 1
	IEW1	2.01	SUMMERVIEW 1
	CR1	1.40	CASTLE RIVER
	OMRH	2.09	OLDMAN
	0000022911	0.45	GLENWOOD
	0000039611	1.52	PINCHER CREEK
	0000038511	0.36	SPRING COULEE
	CRE1	3.52	COWLEY EXPANSION 1
	CRE2	3.52	COWLEY EXPANSION 2
	CRE3	3.52	COWLEY NORTH
	CRWD	3.52	COWLEY RIDGE WIND POWER PHASE2
	0000001511	0.72	FT MACLEOD
	PKNE	3.52	COWLEY RIDGE WIND POWER PHASE1
	GWW1	1.46	SODERGLEN
BCH	BCHIMP	-0.83	BCH - Import
SPC	SPCIMP	1.35	SPC - Import
MATL	MATLIMP	0.68	MATLIMP
DOS	0000016301	0.88	Amoco Empress (163S)
	DOWGEN15M	3.96	DOW GTG
	0000079301	3.66	ANG Cochrane (793S)
	341S025	-4.48	Syncrude Standby (848S)