2012 Loss Factors

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1 Purpose

The purpose of this document is to present the 2012 final loss factors along with a brief explanation of the results or changes compared to 2011 recalculated loss factors. A loss factor map is included (Appendix III). The loss factors published in this document will be effective from January 01, 2012 to December 31, 2012.

2 Introduction

The AESO has completed the 2012 loss factor process and the results are shown in Table 1 of this document. The process includes the application of the 2012 Generic Stacking Order (GSO) published earlier in the summer and the 2012 Base Cases published on the AESO web site in conjunction with this document. Both the GSO and the Base Cases have been updated and posted based on stakeholder input or more current information during the course of the final calculations. The requirements of the 2007 Transmission Regulation are included.

The loss factor calculation uses four key inputs:

1. 2012 Generic Stacking Order (GSO)
2. New project data
3. Loss factor base cases based on 2012 GSO, load and topology forecast
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.

Table 1 – 2012 Final Loss Factors

MP-ID*	Facility Name	PSS/E Bus	Normalized and Compressed Loss Factor (%)	Loss Factor Asset	Difference % in Loss Factor to System Average
0000034911	ALTAGAS PARKLAND	235	**0.53**	Gen	-3.66
NX01	BALZAC	290	**0.87**	Gen	-3.32
BAR	BARRIER	216	**-0.43**	Gen	-4.62
BR3	BATTLE RIVER #3	1491	**5.97**	Gen	1.78
BR4	BATTLE RIVER #4	1491	**5.97**	Gen	1.78
BR5	BATTLE RIVER #5	1469	**5.10**	Gen	0.91
BCRK	BEAR CREEK G1	10142	**-3.57**	Gen	-7.76
BCR2	BEAR CREEK G2	10142	**-3.57**	Gen	-7.76
BPW	BEARSPAW	184	**0.06**	Gen	-4.14
BIG	BIGHORN	103	**1.88**	Gen	-2.31
BTR1	BLUE TRAIL WIND FARM	328	**2.64**	Gen	-1.55
BRA	BRAZEAU	56153	**2.35**	Gen	-1.84
GOC1	BRIDGE CREEK	1145	**0.00**	Gen	-4.19
0000045411	BUCK LAKE	80	**3.30**	Gen	-0.89
TC01	CARSELAND	5251	**0.99**	Gen	-3.21
CAS	CASCADE	175	**-0.95**	Gen	-5.14
CR1	CASTLE RIVER	234	**2.23**	Gen	-1.96
EC01	CAVAILIER	247	**1.29**	Gen	-2.90
CHIN	CHIN CHUTE	406	**0.00**	Gen	-4.19
CMH1	CITY OF MEDICINE HAT	680	**1.39**	Gen	-2.80
ENC1	CLOVER BAR 1	516	**3.95**	Gen	-0.24
ENC2	CLOVER BAR 2	516	**3.95**	Gen	-0.24
ENC3	CLOVER BAR 3	516	**3.95**	Gen	-0.24
CNR5	CNRL HORIZON	1263	**3.17**	Gen	-1.02
CRE1	COWLEY EXPANSION 1	264	**4.03**	Gen	-0.16
CRE2	COWLEY EXPANSION 2	264	**4.03**	Gen	-0.16
CRE3	COWLEY NORTH	264	**4.03**	Gen	-0.16
PKNE	COWLEY RIDGE WIND POWER PHASE1	264	**4.03**	Gen	-0.16
CRWD	COWLEY RIDGE WIND POWER PHASE2	264	**4.03**	Gen	-0.16
DAI1	DIASHOWA	1088	**-1.80**	Gen	-5.99
DKSN	DICKSON DAM 1	4006	**4.97**	Gen	0.78
DOWGEN15M	DOW GTG	61	**3.51**	Gen	-0.68
DV1	DRAYTON VALLEY PL IPP	4332	**0.00**	Gen	-4.19
DRW1	DRYWOOD 1	4226	**2.28**	Gen	-1.91
CES1	ENMAX CALGARY ENERGY CENTRE CTG	187	**0.94**	Gen	-3.25
CES2	ENMAX CALGARY ENERGY CENTRE STG	187	**0.94**	Gen	-3.25
CRS1	ENMAX CROSSFIELD ENERGY CENTER	503	**1.05**	Gen	-3.14
CRS2	ENMAX CROSSFIELD ENERGY CENTER	503	**1.05**	Gen	-3.14
CRS3	ENMAX CROSSFIELD ENERGY CENTER	503	**1.05**	Gen	-3.14
FNG1	FORT NELSON	20000	**3.69**	Gen	-0.50
AFG1TX	FORTISALBERTA AL-PAC PULP MILL	392	**1.50**	Gen	-2.69
EC04	FOSTER CREEK G1	1301	**3.44**	Gen	-0.75
0000001511	FT MACLEOD	4237	**1.24**	Gen	-2.95
GN1	GENESEE 1	525	**5.65**	Gen	1.45
GN2	GENESEE 2	525	**5.65**	Gen	1.45
GN3	GENESEE 3	525	**5.65**	Gen	1.45
GHO	GHOST	180	**-0.46**	Gen	-4.65
NEP1	GHOST PINE WIND FARM	603	**3.72**	Gen	-0.47
0000022911	GLENWOOD	245	**2.02**	Gen	-2.17
GPEC	GRANDE PRAIRIE ECOPOWER CENTRE	1101	**-3.85**	Gen	-8.04
0000025611	HARMATTAN GAS PLANT DG	4123	**-0.58**	Gen	-4.78
HSH	HORSESHOE	171	**-0.42**	Gen	-4.61
HRM	HR MILNER	1147	**-0.90**	Gen	-5.09
INT	INTERLAKES	376	**0.84**	Gen	-3.35
KAN	KANANASKIS	193	**-0.37**	Gen	-4.56
KH1	KEEPHILLS #1	420	**6.13**	Gen	1.94
KH2	KEEPHILLS #2	420	**6.13**	Gen	1.94
KH3	KEEPHILLS #3	610	**5.57**	Gen	1.38
KHW1	KETTLES HILL WIND ENERGY PHASE 2	402	**2.42**	Gen	-1.77
IOR1	MAHKESES COLD LAKE	56789	**4.54**	Gen	0.35
AKE1	MCBRIDE	901	**2.01**	Gen	-2.18
MKRC	MCKAY RIVER	1274	**2.99**	Gen	-1.20
MEG1	MEG ENERGY	405	**3.44**	Gen	-0.75
MKR1	MUSKEG	1236	**2.93**	Gen	-1.26
NX02	NEXEN OPTI	1241	**3.73**	Gen	-0.47
NPP1	NORTHERN PRAIRIE POWER PROJECT	1120	**-6.15**	Gen	-10.35
NPC1	NORTHSTONE ELMWORTH	1134	**-6.05**	Gen	-10.25
NOVAGEN15M	NOVA JOFFRE	383	**1.84**	Gen	-2.36
OMRH	OLDMAN	230	**2.72**	Gen	-1.47
WEY1	P&G WEYERHAUSER	1146	**-3.03**	Gen	-7.22
0000039611	PINCHER CREEK	224	**2.21**	Gen	-1.98
POC	POCATERRA	214	**0.42**	Gen	-3.77
PH1	POPLAR HILL	1118	**-5.92**	Gen	-10.11
PR1	PRIMROSE	1302	**2.22**	Gen	-1.97

MP-ID*	Facility Name	PSS/E Bus	Normalized and Compressed Loss Factor (%)	Loss Factor Asset	Difference % in Loss Factor to System Average
RB1	RAINBOW 1	1031	**2.17**	Gen	-2.02
RB2	RAINBOW 2	1032	**2.34**	Gen	-1.85
RB3	RAINBOW 3	1028	**2.43**	Gen	-1.76
RL1	RAINBOW 4	83	**2.45**	Gen	-1.74
RB5	RAINBOW 5	1037	**2.28**	Gen	-1.91
RYMD	RAYMOND RESERVOIR	413	**0.00**	Gen	-4.19
TC02	REDWATER	50	**3.24**	Gen	-0.95
RUN	RUNDLE	195	**-0.64**	Gen	-4.83
SH1	SHEERNESS #1	1484	**5.14**	Gen	0.95
SH2	SHEERNESS #2	1484	**5.14**	Gen	0.95
SHCG	SHELL CAROLINE	4370	**-0.22**	Gen	-4.41
SCTG	SHELL SCOTFORD	43	**3.03**	Gen	-1.16
GWW1	SODERGLEN	358	**2.91**	Gen	-1.28
SPR	SPRAY	310	**-0.57**	Gen	-4.76
0000038511	SPRING COULEE	246	**1.41**	Gen	-2.78
STMY	ST MARY IPP	3448	**1.43**	Gen	-2.77
0000006711	STIRLING	3450	**-0.07**	Gen	-4.26
ST1	STURGEON 1	1166	**-1.25**	Gen	-5.44
ST2	STURGEON 2	1166	**-1.25**	Gen	-5.44
IEW1	SUMMERVIEW 1	336	**2.84**	Gen	-1.35
IEW2	SUMMERVIEW 2	336	**2.84**	Gen	-1.35
SCR3	SUNCOR HILLRIDGE WIND FARM	389	**1.25**	Gen	-2.94
SCR2	SUNCOR MAGRATH	251	**1.92**	Gen	-2.27
SCR1	SUNCOR MILLENIUM	1208	**2.97**	Gen	-1.22
SCR4	SUNCOR WINTERING HILLS WIND ENERGY PROJECT	759	**4.84**	Gen	0.64
SD3	SUNDANCE #3	135	**4.54**	Gen	0.35
SD4	SUNDANCE #4	135	**4.54**	Gen	0.35
SD5	SUNDANCE #5	135	**4.54**	Gen	0.35
SD6	SUNDANCE #6	135	**4.54**	Gen	0.35
SCL1	SYNCRUDE	1205	**2.90**	Gen	-1.29
TAB1	TABER WIND	343	**0.84**	Gen	-3.35
TAY1	TAYLOR HYDRO	670	**1.74**	Gen	-2.45
TAY2	TAYLOR WIND PLANT	670	**1.74**	Gen	-2.45
THS	THREE SISTERS	379	**-0.57**	Gen	-4.77
ARD1	TRANSALTA ARDENVILLE WIND FARM	739	**2.96**	Gen	-1.23
VVW2	ATCO VALLEY VIEW 2	1172	**-0.94**	Gen	-5.13
VVW1	VALLEYVIEW	1172	**-0.94**	Gen	-5.13
WTRN	WATER IPP	3449	**1.74**	Gen	-2.45
0000040511	WAUPISOO	417	**1.00**	Gen	-3.19
WST1	WESGEN	21	**0.00**	Gen	-4.19
EAGL	WHITE COURT	410	**0.00**	Gen	-4.19
Project519_1_GEN	ALBERTA WIND ENERGY OLD MAN RIVER WIND FARM	543	**2.53**	Gen	-1.66
Project723_1_SUP	CAPITAL POWER HALKIRK WIND PROJECT	1435	**5.69**	Gen	1.50
0000016301	Amoco Empress (163S)	262	**-0.49**	DOS	-4.68
0000079301	ANG Cochrane (793S)	191	**3.40**	DOS	-0.79
341S025	Syncrude Standby (848S)	1200	**-0.82**	DOS	-5.01

Notes:
* MP-ID - point where loss factors assessed
For loss factors, "-" means credit, "+" means charge
Loss factors effective from January 01, 2012 to December 31 2012.
System Average Losses, %: **4.19**
For more information, please visit www.aeso.ca

Table 2 – 2012 Tie Loss Factors

Tie	Transaction Type	Loss Factor (%)	Average Loss Charge (%)	Settlement LF (%)
BC	Import	1.32	0.94	2.26
	Export	-	0.96	0.96
SK	Import	3.10	2.50	5.60
	Export	-	2.30	2.30

3 2012 Loss Factors Overview

The following items provide an overview of 2012 loss factor process:

1. Load Treatment in the Loss Factor Software – In the 2012 loss factor calculation, only transmission loads are unassigned[1], all non transmission loads ie "behind-the-fence" loads, are assigned to generators within their facility of operation. The loss factors are based on generation less the non-transmission load while maintaining the appropriate GSO dispatch at the MPID bus.

2. Generation & Load Levels – The 2012 Generic Stacking Order was used to populate the loss factor base cases for the 2012 loss factor calculation. The 2012 loss factors use actual average generation levels to determine loss factors based on the AESO Rule[2]. Please refer to Appendix-I for a sample comparison. The total gross generation level in 2012 is higher than in the 2011 recalculated cases, due primarily to the increase in generation with Keephills unit 3 (KH3) operating at full capacity for 2012. The generation is further increased by the BC intertie increasing its output to offset the termination of Sundance unit 1 and 2 (SD1 and SD2). The load for the 2012 cases has been scaled down in eleven of the twelve cases to meet the total GSO capacity. The seasonal load duration curves are included in Appendix II.

3. Additions and Decommissioning of Generation – Changes in the existing generators' net to grid (NTG) output include an increase in output for the province's coal units explained in the above paragraph. Several new generators were added in the 2012 loss factor base cases. The most significant addition is KH3 operating at its full capacity in all cases. The other generation additions are the Halkirk Wind Project, Old Man River Wind Farm and Fort Nelson unit 2. These projects were added according to their in-service-date. The major generator decommissioning included SD1 and SD2 which have been removed for all cases.

4. Small Power Research and Development (SPR&D) Generators – The SPR&D Act exempted a number of generators from paying transmission losses based on a SPR&D contract. These contracts were valid for 20 years and starting in 2011, some of the SPR&D contracts will begin to expire. Accordingly, former SPR&D contract holders Dickson Dam, Saint Mary Dam IPP and Waterton Dam IPP are partially included in the 2012 loss factor calculation.

5. ISD Equivalents – The Industrial System Designations (ISDs) are modeled in the same way as they were modeled in the 2011 cases. The total ISD load and generation are modeled at the ISD's AIES interface bus.

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[1] Please see Section 2.2 of Loss Factor Calculation Methodology - Effective January 01, 2009
[2] Please see Section 3.2 of Appendix 6 - Transmission loss Factor Methodology & Assumptions

6. Inter Tie Flows –Since 2007, the Transmission Regulation now includes using the historical average net flow on the tie lines. The 2012 import loss factors are higher primarily because of higher forecast import from BC compared to 2011.

7. Topology – The major 2012 planned transmission project additions include the large staged reinforcement projects including the North West Transmission Reinforcement, Hanna, Fort McMurray, and the staged Edmonton/Wabamun upgrade project. All other 2012 planned system additions have also been modeled in the 2012 cases.

8. Average System Losses and Shift Factor (SF) – the annual loss forecast for 2012 is 2.58 TWH or 4.19%. Please refer to Table 3 for a comparison of the system average loss and shift factor.

Table 3 – 2012 vs. 2011 Recalculated Final Loss Factors

	2012	2011
System average loss	4.19%	4.56%
Shift Factor	1.09%	1.63%
Loss recovered by Raw Loss Factor	3.10%	2.93%

9. Weighting Factor – In a continuing effort to enhance accuracy, the AESO has applied unequal weighting factors to the raw loss factors based on forecast load levels. Please see Table 4 for the 2012 weighting factors used in the loss factor calculation.

Table 4 – 2012 Weighting Factors

	Winter		Spring		Summer		Fall	
	Duration (hr)	Weight (%)	Duration (hr)	Weight (%)	Duration (hr)	Weight (%)	Duration (hr)	Weight (%)
High	100	4.6	50	2.3	150	6.8	75	3.4
Medium	1450	66.4	1325	60.0	1150	52.1	1300	59.5
Low	634	29.0	832	37.7	908	41.1	810	37.1

4 2012 Topology Updates from Draft to Final Base Cases

The final base cases differ from the previously posted draft cases in the following aspects.

1. The transformers that connected the now terminated SD1 and SD2 units to the system have been removed from the base cases for all seasons.

2. The model reflecting Fort Nelson (FNG1) and surrounding area has been modified to better represent its actual operation.

3. Additional generation has been dispatched from the Suncor ISD facility (SCR1) to account for the increase in their supply transmission service (STS) contract. This increase in generation has been added to the base cases for all season in accordance with their commercial start date of the STS contract increase.

5 2012 Loss Factor Updates From Draft to Final

The topology updates 1 and 2 listed in section 4 were included in the loss factor calculation when the Draft Loss Factors for 2012 (published October 21, 2011). Update number 3 mentioned in section 4 was taken into account after the draft posting. The differences between the loss factors in the 2012 draft posting and the 2012 final loss factors in Table 1 of this document, are primarily attributed to the increased STS for SCR1. Overall, the increase in generation from the Suncor ISD facility has caused an increase in loss factor charge or a decrease in credit, for loss factor customers in the northern portion of the Alberta. For the southern portion of the province there has been a decrease in loss factor charge or an increase in credit. This section focuses only on the differences between the 2012 draft to 2012 final loss factors. The next section discusses the changes between the 2011 recalculated loss factors and the 2012 final loss factors found in Table 1.

6 2012 Overall Loss Factor Results

There is an overall reduction in the 2012 final loss factors compared to the Final Alberta Recalculated Loss Factors for 2011 posted June 16, 2011. An overall reduction in loss factors occurs because of a reduction in SF for 2012. Further changes in loss factors can be attributed to changes in: dispatched generation, load and transmission topology resulting from new projects. The high level results are summarized below:

1. The Rainbow area with the exception of Rainbow unit 2 has experienced a decrease in loss factor charge despite an increase in net flow from the area. This reduction in loss factors is mainly attributed to new transmission in the area as part of the North West Transmission Reinforcement project and the use of an updated model for Fort Nelson and surrounding area.

2. The Fort McMurray area has seen a substantial decrease in loss factor charge relative to the 2011 recalculated loss factors. The decrease in charge can be attributed to a large increase in transmission load resulting in a reduction in net flow out of the area.

3. The West area has experienced a decreased loss factor charge or increase in credit. Similar to Fort McMurray the transmission load in the area has increased significantly and there has been a decrease in generation for 10 of the 12 cases.

4. The Wabamun area has seen a decrease in loss factor charge. The raw loss factors for the area have increased due to KH3 operating at full capacity. However, the area experiences a decrease in charge compared to the 2011 recalculation because of the reduced SF.

5. The western portion of the Cold Lake area has received more loss factor charge because its net flow has increased over the 2011 values. The eastern portion of Cold Lake experiences similar conditions as Fort McMurray where the generation has decreased and the load has increased thereby, decreasing the loss factor charge in the area.

6. The East Edmonton area has seen a decrease in loss factor charge due to a decrease in generation and a slight increase in transmission load. The loss factors for units closer to the Wabamun area see less of a decrease over the previous year. This is because of the increased congestion with the addition of KH3.

7. Generation facilities in the Red Deer area have received a decrease in loss factor charge through a combination of increased transmission load and a decrease in generation.

8. The Calgary area experienced a decrease in loss factor charge. Increased import from BC Hydro caused the raw loss factors to increase in Calgary area over last year. However, the loss factor customers in the Calgary area see a decrease in loss factor charge because of the lowered SF.

9. Bow Hydro experienced a reduction in loss factor charge or increase in credit through a small reduction in generation and a small increase in transmission load.

10. The Southeast area receives less loss factor charges or more credit compared to 2011. A small increase in transmission load and reduction in generation caused small changes in the area's loss factors.

11. The Southwest area receives more charges or less credit compared to 2011. Increased import from BC contributed to these changes in the loss factors in 2012.

12. Battle River has had a decrease in loss factor charge due to reduced net flow from the area compared to 2011.

13. Medicine Hat's loss factor charge has increased because over one third of its output was forecast to be during the winter season where its raw loss factor is greatest.

14. Sheerness area's loss factor charges are higher in 2012 due to greater net flow from the area. Increased generation from Sheerness units 1 and 2 and the addition of the Halkirk Wind Project cause this increase in net flow.

7 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 its designated area.

8 Conclusion

The AESO has published the 2012 loss factors as per the AESO's Loss Factor Rule, and has made the calculation and provided results 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 AESO completes the loss factor calculation process and has had the results independently run for comparison purposes. The results from AESO's calculation are identical to the results run independently.

The AESO published the draft values on October 21, 2011 for stakeholders' review. The 2012 loss factors will be applicable from January 01, to December 31, 2012.

Appendix I: Case Comparison - AIL

Winter Peak Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2012	9952.7	148.2	10100.9	21.0	304.9	523.0	-
2011 Recalculation	8855.4	133.6	8989.0	20.7	263.3	398.0	-
2012 - 2011	**1097.3**	**14.6**	**1111.9**	**0.3**	**41.6**		

Winter Medium Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2012	9128.9	155.8	9284.7	21.2	269.0	383.5	-
2011 Recalculation	8177.7	149.7	8327.4	20.7	243.3	186.9	-
2012 - 2011	**951.2**	**6.1**	**957.3**	**0.5**	**25.7**		

Winter Low Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2012	8117.2	166.0	8283.2	21.2	245.3	108.7	-
2011 Recalculation	7434.1	198.4	7632.5	20.8	221.2	-	90.5
2012 - 2011	**683.1**	**-32.4**	**650.7**	**0.4**	**24.1**		

Spring Peak Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2012	9222.4	146.1	9368.5	21.5	289.4	517.6	-
2011 Recalculation	8138.5	155.3	8293.8	20.8	205.4	371.4	-
2012 - 2011	**1083.9**	**-9.2**	**1074.7**	**0.7**	**84.0**		

Spring Medium Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2012	8628.6	144.1	8772.7	21.4	248.8	419.2	-
2011 Recalculation	7937.9	155.1	8093.0	20.6	194.4	245.8	-
2012 - 2011	**690.7**	**-11.0**	**679.7**	**0.8**	**54.4**		

Spring Low Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2012	7581.8	155.8	7737.6	21.5	202.6	320.9	-
2011 Recalculation	6885.0	156.7	7041.7	20.9	168.4	52.0	-
2012 - 2011	**696.8**	**-0.9**	**695.9**	**0.6**	**34.2**		

Summer Peak Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2012	9196.3	176.5	9372.8	21.6	265.7	414.8	-
2011 Recalculation	8702.1	161.6	8863.7	21.1	244.7	385.1	-
2012 - 2011	**494.2**	**14.9**	**509.1**	**0.5**	**21.0**		

Summer Medium Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2012	8221.9	156.2	8378.1	21.8	217.1	250.8	-
2011 Recalculation	7677.6	159.8	7837.4	21.0	199.9	-94.7	-
2012 - 2011	**544.3**	**-3.6**	**540.7**	**0.8**	**17.2**		

Summer Low Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2012	7116.2	175.6	7291.8	21.6	163.3	240.9	-
2011 Recalculation	6571.4	257.8	6829.2	21.3	172.9	-	141.9
2012 - 2011	**544.8**	**-82.2**	**462.6**	**0.3**	**-9.6**		

Fall Peak Case

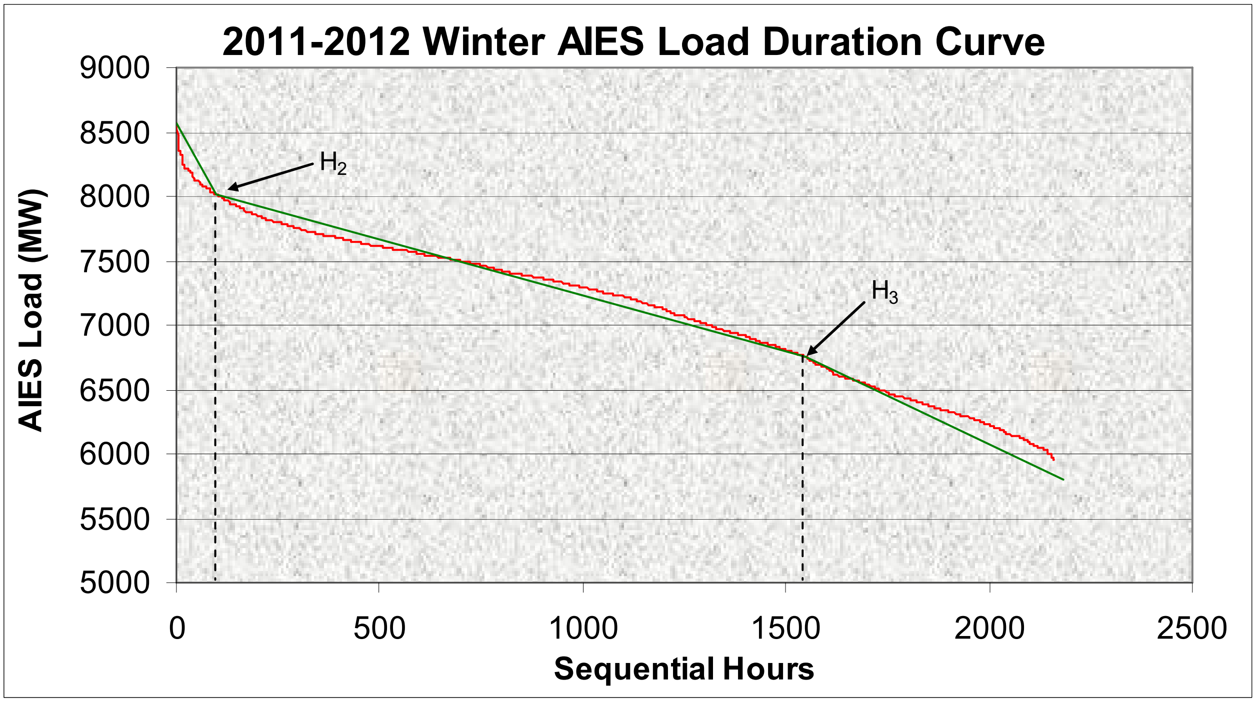
	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2012	9195.9	166.3	9362.2	21.7	266.9	402.1	-
2011 Recalculation	8573.6	164.7	8738.3	21.3	231.2	229.9	-
2012 - 2011	**622.3**	**1.6**	**623.9**	**0.4**	**35.7**		

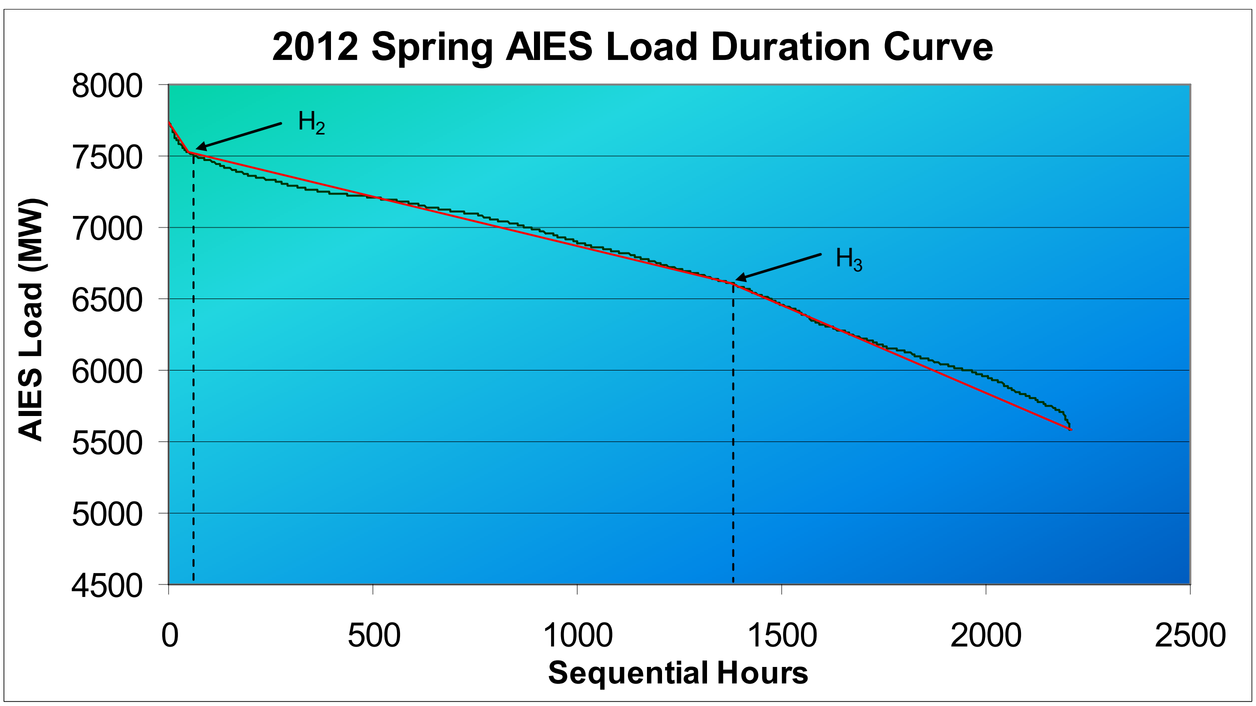
Fall Medium Case

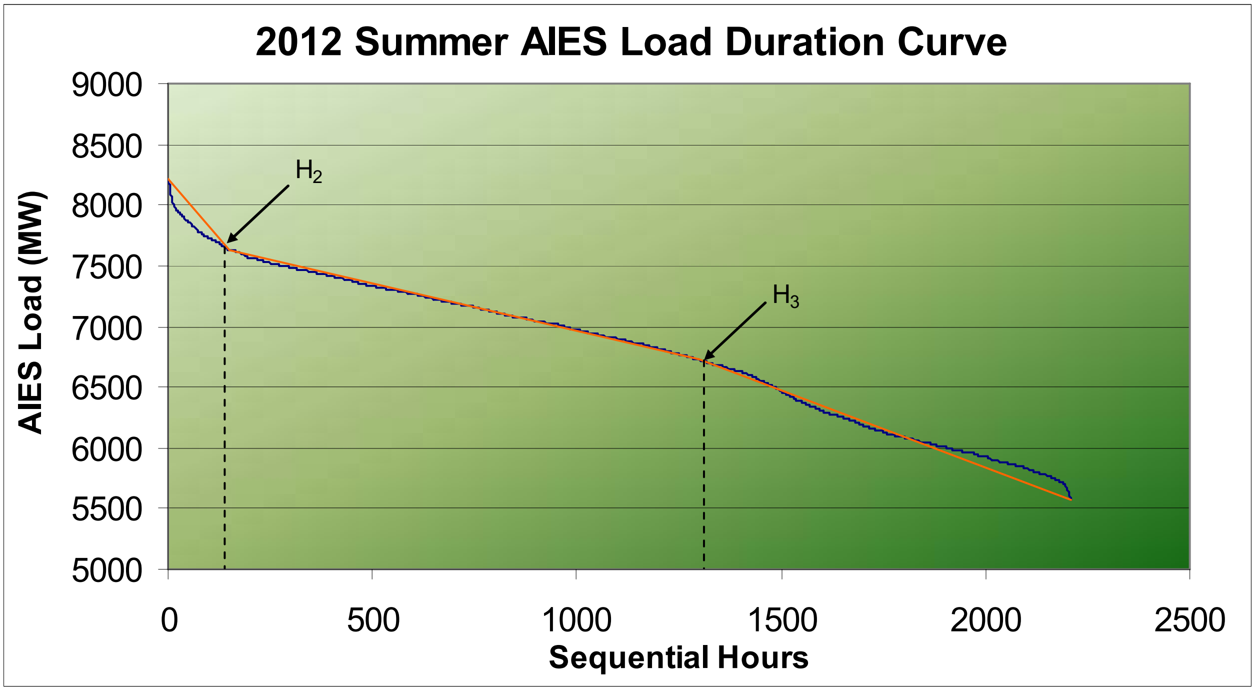
	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2012	8400.0	162.7	8562.7	21.9	238.4	149.3	-
2011 Recalculation	7779.7	156.6	7936.3	21.3	209.2	105.9	-
2012 - 2011	**620.3**	**6.1**	**626.4**	**0.6**	**29.2**		

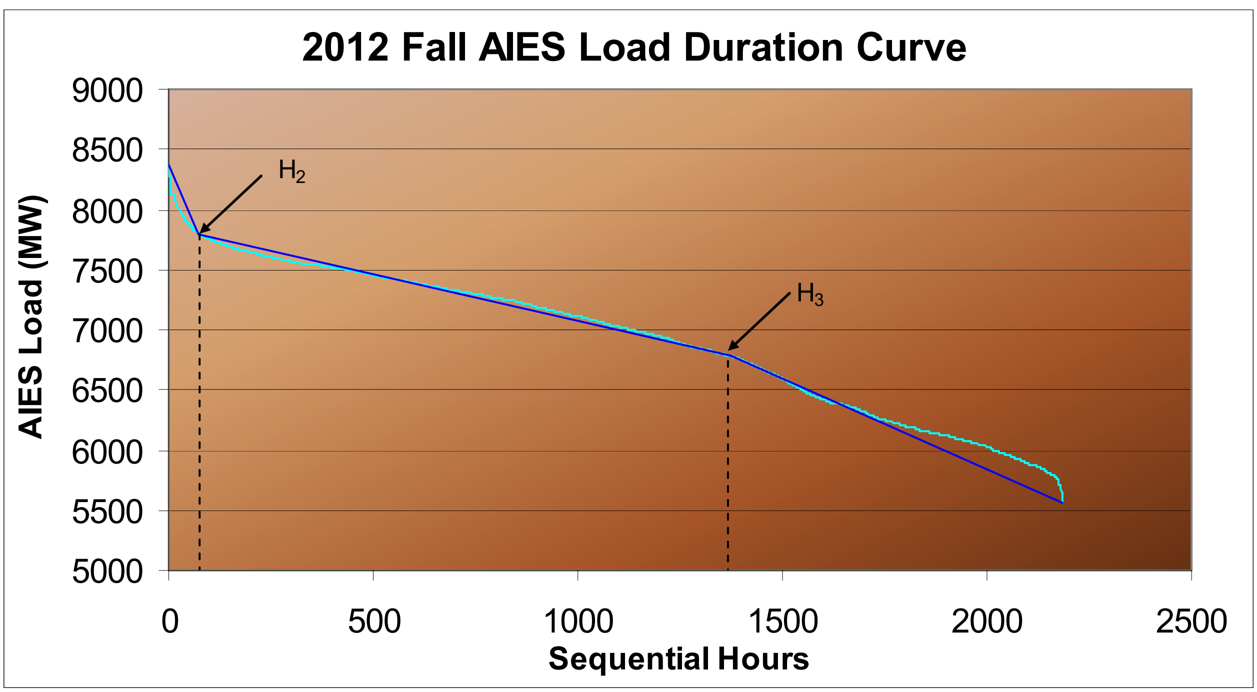
Fall Low Case

	Load (MW)			Loss (MW)		Import (MW)	Export (MW)
	Static	Motor	Total	Shunt	Transmission		
2012	7575.7	258.5	7834.2	21.8	215.1	-	121.3
2011 Recalculation	7161.8	257.2	7419.0	21.3	185.9	-	136.8
2012 - 2011	**413.9**	**1.3**	**415.2**	**0.5**	**29.2**		


2011-2012 Winter AIES Load Duration Curve
AIES Load (MW)
9000
8500
8000
7500
7000
6500
6000
5500
5000
H2
H3
0
500
1000
1500
2000
2500
Sequential Hours


2012 Spring AIES Load Duration Curve
AIES Load (MW)
8000
7500
7000
6500
6000
5500
5000
4500
H2
H3
0
500
1000
1500
2000
2500
Sequential Hours


2012 Summer AIES Load Duration Curve
AIES Load (MW)
9000
8500
8000
7500
7000
6500
6000
5500
5000
H2
H3
0
500
1000
1500
2000
2500
Sequential Hours


2012 Fall AIES Load Duration Curve
AIES Load (MW)
9000
8500
8000
7500
7000
6500
6000
5500
5000
H2
H3
0
500
1000
1500
2000
2500
Sequential Hours

Appendix III: 2012 Loss Factor Map

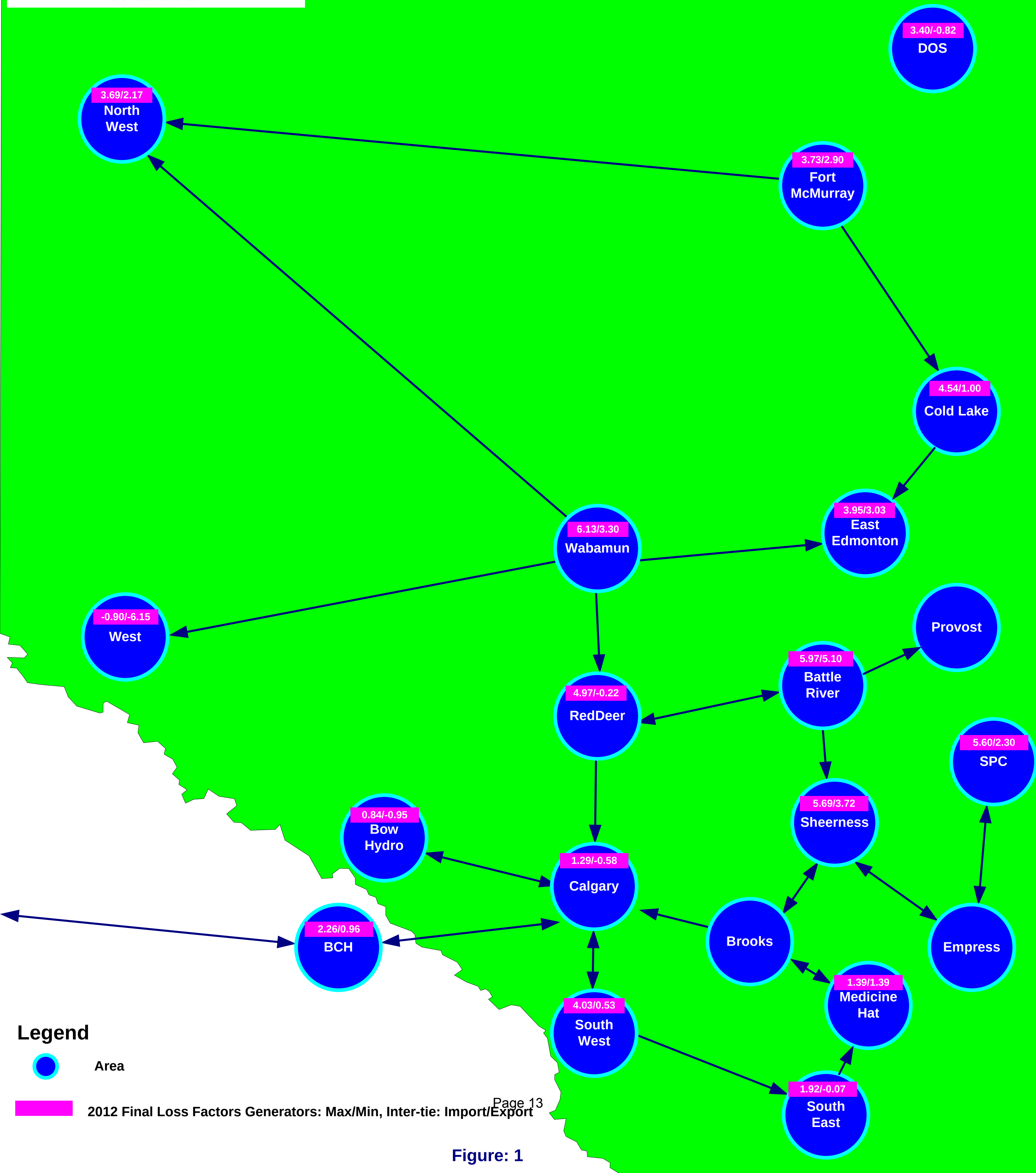


Figure: 1

Location	MPID	Loss Factor(%)	Gen Name
North West	RB1	2.17	RAINBOW 1
	RB2	2.34	RAINBOW 2
	RB3	2.43	RAINBOW 3
	RL1	2.45	RAINBOW 4
	RB5	2.28	RAINBOW 5
	FNG1	3.69	FORT NELSON
West	HRM	-0.90	HR MILNER
	PH1	-5.92	POPLAR HILL
	NPC1	-6.05	NORTHSTONE ELMWORTH
	DAI1	-1.80	DIASHOWA
	BCR2	-3.57	BEAR CREEK G2
	BCRK	-3.57	BEAR CREEK G1
	GPEC	-3.85	GRANDE PRAIRIE ECOPOWER CENTRE
	ST1	-1.25	STURGEON 1
	ST2	-1.25	STURGEON 2
	VVW1	-0.94	VALLEYVIEW
	VVW2	-0.94	ATCO VALLEY VIEW 2
	WEY1	-3.03	P&G WEYERHAUSER
	NPP1	-6.15	NORTHERN PRAIRIE POWER PROJECT
Fort McMurray	MKR1	2.93	MUSKEG
	MKRC	2.99	MCKAY RIVER
	SCL1	2.90	SYNCRUDE
	SCR1	2.97	SUNCOR MILLENIUM
	NX02	3.73	NEXEN OPTI
	MEG1	3.44	MEG ENERGY
	CNR5	3.17	CNRL HORIZON
Wabamun	GN1	5.65	GENESEE 1
	GN2	5.65	GENESEE 2
	GN3	5.65	GENESEE 3
	KH1	6.13	KEEPHILLS #1
	KH2	6.13	KEEPHILLS #2
	KH3	5.57	KEEPHILLS #3
	SD3	4.54	SUNDANCE #3
	SD4	4.54	SUNDANCE #4
	SD5	4.54	SUNDANCE #5
	SD6	4.54	SUNDANCE #6
	0000045411	3.30	BUCK LAKE
	IOR1	4.54	MAHKESES COLD LAKE

Cold Lake	PR1	2.22	PRIMROSE
	EC04	3.44	FOSTER CREEK G1
	0000040511	1.00	WAUPISOO
	AFG1TX	1.50	FORTISALBERTA AL-PAC PULP MILL
East Edmonton	SCTG	3.03	SHELL SCOTFORD
	TC02	3.24	REDWATER
	ENC1	3.95	CLOVER BAR 1
	ENC2	3.95	CLOVER BAR 2
	ENC3	3.95	CLOVER BAR 3
	DOWGEN15M	3.51	DOW GTG
Red Deer	NOVAGEN15M	1.84	NOVA JOFFRE
	BIG	1.88	BIGHORN
	BRA	2.35	BRAZEAU
	SHCG	-0.22	SHELL CAROLINE
	DKSN	4.97	DICKSON DAM 1
Calgary	CES1	0.94	ENMAX CALGARY ENERGY CENTRE CTG
	CES2	0.94	ENMAX CALGARY ENERGY CENTRE STG
	TC01	0.99	CARSELAND
	EC01	1.29	CAVAILIER
	NX01	0.87	BALZAC
	CRS1	1.05	ENMAX CROSSFIELD ENERGY CENTER
	CRS2	1.05	ENMAX CROSSFIELD ENERGY CENTER
	CRS3	1.05	ENMAX CROSSFIELD ENERGY CENTER
	0000025611	-0.58	HARMATTAN GAS PLANT DG
Bow Hydro	BAR	-0.43	BARRIER
	BPW	0.06	BEARSPAW
	CAS	-0.95	CASCADE
	GHO	-0.46	GHOST
	HSH	-0.42	HORSESHOE
	KAN	-0.37	KANANASKIS
	POC	0.42	POCATERRA
	INT	0.84	INTERLAKES
	RUN	-0.64	RUNDLE
	THS	-0.57	THREE SISTERS
	SPR	-0.57	SPRAY
South East	SCR2	1.92	SUNCOR MAGRATH
	TAY1	1.74	TAYLOR HYDRO
	TAY2	1.74	TAYLOR WIND PLANT
	0000006711	-0.07	STIRLING

	SCR3	1.25	SUNCOR HILLRIDGE WIND FARM
	TAB1	0.84	TABER WIND
Battle River	BR3	5.97	BATTLE RIVER #3
	BR4	5.97	BATTLE RIVER #4
	BR5	5.10	BATTLE RIVER #5
Medicine Hat	CMH1	1.39	CITY OF MEDICINE HAT
Sheerness	SH1	5.14	SHEERNESS #1
	SH2	5.14	SHEERNESS #2
	NEP1	3.72	GHOST PINE WIND FARM
	Project723_1_SUP	5.69	CAPITAL POWER HALKIRK WIND PROJECT
	SCR4	4.84	SUNCOR WINTERING HILLS WIND ENERGY PR
South West	AKE1	2.01	MCBRIDE
	DRW1	2.28	DRYWOOD 1
	IEW1	2.84	SUMMERVIEW 1
	IEW2	2.84	SUMMERVIEW 2
	CR1	2.23	CASTLE RIVER
	OMRH	2.72	OLDMAN
	0000022911	2.02	GLENWOOD
	0000039611	2.21	PINCHER CREEK
	0000038511	1.41	SPRING COULEE
	CRE1	4.03	COWLEY EXPANSION 1
	CRE2	4.03	COWLEY EXPANSION 2
	CRE3	4.03	COWLEY NORTH
	CRWD	4.03	COWLEY RIDGE WIND POWER PHASE2
	0000001511	1.24	FT MACLEOD
	PKNE	4.03	COWLEY RIDGE WIND POWER PHASE1
	GWW1	2.91	SODERGLEN
	0000034911	0.53	ALTAGAS PARKLAND
	BTR1	2.64	BLUE TRAIL WIND FARM
	ARD1	2.96	TRANSALTA ARDENVILLE WIND FARM
	Project519_1_GEN	2.53	ALBERTA WIND ENERGY OLD MAN RIVER WIN
	KHW1	2.42	KETTLES HILL WIND ENERGY PHASE 2
BCH	BCHIMP	2.26	BCH - Export
	BCHEXP	0.96	BCH - Import
SPC	SPCIMP	5.60	SPC - Export
	SPCEXP	2.30	SPC - Import
DOS	0000016301	-0.49	Amoco Empress (163S)
	0000079301	3.40	ANG Cochrane (793S)
	341S025	-0.82	Syncrude Standby (848S)