Alberta Electric System Operator

Report on Audit of Current Loss Factor Method

Appendix 1, Audit of Calculations and Procedures

PUBLIC VERSION

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AUDITORS NOTE

There are two versions of this Appendix as follows:

Appendix 1, Audit of Procedures, Public Version
Appendix 1, Audit of Procedures, Confidential Version

The text is identical in both versions of the appendix. Several entries in the following tabulations have been heavily shaded in the public version:

Table 4-1	Differences Between Stacking Order and Power Flow Generation (2003)
Table 5-5	Individual Generator Raw Loss Factors Used in Shift Factor Calculations
Table 6-1	Generator Normalized Loss Factors

In addition, the AESO has requested that the identification of the DOS load mentioned in Section 4.2 may be sensitive, and these have been removed.

The information that is not viewable in the public version is considered to be confidential or could lead to the determination of confidential information. The Auditor and the AESO agree on the exclusion of this information.

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REVISION RECORD

Rev. 1	Dec 22, 2003 Appendix 1 issued to AESO for delivery to CMC incorporating AESO review for confidential information
Rev. 2	March 26, 2003 Appendix 1 issued to AESO for posting incorporating AESO and CMC comments

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1 INTRODUCTION

This appendix details the findings of the procedures used by the TA to develop the loss factors and annual shift factors addressing Part 2 of the CMC Project Terms of Reference, Project A. Audit of Current Loss Factor Method. The objectives of the audit as defined in the RFP were as follows:

> "The Auditor shall review the quantitative methods and computational steps used by the TA to develop the loss factors and the annual shift factor towards meeting the following objectives:
>
> > To evaluate the consistency between the computational steps used in practice and the Loss Factors Method (LFM) directed by AEUB in Decision 2000-01 and 2000-27.
> >
> > To evaluate the integrity of the computational steps and tools related to the application of the LFM.
> >
> > Where the Board's decision was not prescriptive, and the TA has developed discretionary steps, assess the reasonableness of these computational steps and their consistency with the Board's general direction. (eg. import/export, DOS, etc).
>
> The Auditor's report shall include:
>
> > Information on the extent to which the TA's LFM methodology is consistent with the AEUB's directive,
> >
> > An assessment on the reasonableness and adequacy of the TA's existing computational steps used for the determination of loss factors.
>
> The Auditor shall review the business processes used to develop the loss factors and the annual shift factor towards meeting the following objectives :
>
> > To evaluate the reasonableness of the business processes and procedures related to the computing of (raw and Normalised) Loss factors .

To evaluate the extent to which the LFM-related business processes and procedures promote consistency in its application.

The Auditor's report shall include:

Information on the extent to which the TA's LFM process and associated procedures promote consistency.

Information on the extent to which LFM processes and associated procedures compare with industry benchmarks and/or best practices for sound business processes."

To address concerns and quantify answers to some of the questions posed by the CMC, the Auditor intended to review the entire process used to calculate raw and normalized loss factors. This included:

- reviewing the base case load flows and the assumptions used in the development of the load flows
- reviewing the calculation of raw loss factors for generators, interties and DOS loads
- reviewing the calculations of shift factors
- reviewing the calculations of normalized loss factors
- repeating loss factor calculations where necessary, varying assumptions in the process to quantify impact of the assumptions on normalized loss factors

Based on the description of the process provided with the RFP, it was expected that the review would be straightforward since the entire raw loss factor calculation is automated, given base case load flow starting conditions. It was the intention of the Auditor to review the EPCL code used in the raw loss factor calculations, compare the code to the directives provided by the Board, and validate the code for randomly selected facilities over each of the three years.

The instructions provided by the board for the calculation of shift factors are very clear. It was the Auditor's intention to develop a simple spreadsheet that would convert raw loss factors, forecast individual generator volumes and forecast total system losses to re-calculate each of the shift factors published by the AESO.

The instructions provided by the board for the calculation of normalized loss factors again are very clear. It was the Auditor's intention to extend the shift factor calculation spreadsheet to include the calculation of normalized loss factors.

This Appendix describes the technical and numerical analysis that was carried out by the Auditor to address CMC concerns raised in the RFP. The audit of the business processes is described in the main report.

2 SUMMARY OF FINDINGS

The results of the technical and numerical analysis carried out by the Auditor are summarized as follows:

The EPCL code as used by the AESO for calculating raw loss factors follows the procedure established by the Board for raw loss factor calculations for generators, interties and DOS loads. The EPCL code tests for non-converged load flows during the complex calculation process but does not return the test results according to code documentation. The code fails to correctly identify if the load flow failed to solve within the maximum number of iterations.

The spreadsheets used by the AESO for calculating shift factors follow the procedures established by the board.

The spreadsheets used by the AESO for calculating normalized loss factors follow the procedures established by the board.

Raw loss factor calculations are sensitive to the version of the GE PSLF Power Flow Program. Individual "loss per MW" calculations vary up to 1.5% depending on program version. Versions 11.2 through 14 were tested.

The Auditor, even with assistance from the AESO**, was unable to replicate any raw loss factor calculations for 2001**. As a result the Auditor was unable to directly quantify questions relating to the impact of ac system changes between 2001 and 2002 on loss factor and shift factor calculations.

With assistance from the AESO, **the Auditor was only able to replicate 2002 loss factor calculations for some of the new generators added in 2002**.

The Auditor was able to replicate raw loss factor calculations for sample new 2003 generators as well as the Saskatchewan intertie.

The Auditor was able to replicate five sets of shift factors posted by the AESO over the period 2001 to 2003. During the calculation review, the Auditor uncovered a likely data error that would have changed the Winter shift factor for 2003 by 0.3%.

The Auditor was able to replicate normalized loss factors as posted by the AESO.

2.1 AESO Archives of Raw Loss Factor Calculation Data

When the Auditor was originally unable to replicate any of the AESO raw loss factor calculations, the Auditor requested from the AESO complete sets of data for sample loss factor calculations for generators for each of years 2001, 2002 and 2003. To assist the Auditor the AESO agreed to reconfirm the calculations before forwarding the data to the Auditor. The AESO was also unable to replicate calculations for other than new generators in 2002 and 2003.

The failure to reproduce the calculations was attributed to a breakdown in the AESO's data archiving process prior to 2002. After 2002, the data for each raw loss factor calculation is archived including all of the load flows used, the EPCL and text data files, along with spreadsheets used to establish base load flow conditions after the addition of each new generator. Based on the conclusion drawn by the Auditor with regard to sensitivity to program version, each program version should be archived and a link to the appropriate version should be archived with the raw loss factor calculations.

2.2 AESO Archives of Raw Loss Factor Calculation Results

Throughout the audit process, as the Auditor requested historical and actual values of raw loss factors, it was evident that the AESO does not file tabulations of raw loss factors for each generator, intertie and DOS load in an authoritative location. In fact when raw loss factors are required, they are often determined by 'back-calculation' from normalized loss factors and shift factors for the previous year.

The Auditor believes that this 'back-calculation' procedure is fraught with danger. A simple mistake in which a possible incorrect set of shift factors is used could result in incorrect raw loss factors being used for ongoing sets of calculations. A less obvious problem with this process is that accumulation of rounding errors can occur, and rather than raw loss factors being "fixed until 2005" there could be slight variations with time. This was evident in some of the spreadsheets reviewed by the Auditor where, for some calculations, raw loss factors used were expressed with an accuracy of 0.1% while others were expressed with an accuracy of 0.01%.

The 'back-calculation' process may have contributed to the error that occurred in the Winter shift factor for 2003.

3 LOSS FACTOR CALCULATION DATA

The AESO provided the Auditor with the data files and software applications, shown in Table 3-1 during preliminary meetings with the AESO.

Table 3-1 Data Received May 2, 2003

File Name	Creation Date	Size	Description
01caserev3GenDispatch.xls	04/30/2002 05:15p	18,944	Spreadsheet summarizing the output of IBOC and new generation in the 2001 load flows
01FallLow.sav	04/30/2002 01:44p	861,528	Load flow data for 2001 Fall Low Load in GE PSLF binary format
01FallMedium.sav	04/30/2002 01:45p	861,856	Load flow data for 2001 Fall Medium Load in GE PSLF binary format
01FallPeak.sav	04/30/2002 01:46p	861,856	Load flow data for 2001 Fall Peak Load in GE PSLF binary format
01SpringLow.sav	09/21/2001 01:19p	858,024	Load flow data for 2001 Spring Low Load in GE PSLF binary format
01SpringMedium.sav	09/21/2001 01:18p	858,148	Load flow data for 2001 Spring Medium Load in GE PSLF binary format
01SpringPeak.sav	09/21/2001 01:21p	858,148	Load flow data for 2001 Spring Peak Load in GE PSLF binary format
01SummerLow.sav	09/21/2001 01:24p	858,252	Load flow data for 2001 Summer Low Load in GE PSLF binary format
01SummerMedium.sav	10/22/2001 03:03p	858,480	Load flow data for 2001 Summer Medium Load in GE PSLF binary format
01SummerPeak.sav	10/22/2001 03:08p	858,604	Load flow data for 2001 Summer Peak Load in GE PSLF binary format
01WinterLow.sav	04/30/2002 01:52p	861,028	Load flow data for 2001 Winter Low Load in GE PSLF binary format
01WinterMedium.sav	10/23/2001 09:30a	861,524	Load flow data for 2001 Winter Medium Load in GE PSLF binary format
01WinterPeak.sav	10/23/2001 09:51a	861,648	Load flow data for 2001 Winter Peak Load in GE PSLF binary format
02Case2001AllGenDispatch.xls	03/14/2002 11:37p	29,696	Spreadsheet summarizing the output of IBOC and new generation as well as Rainbow Lake generation and intertie flows in the 2002 load flows
02FallLow.sav	03/14/2002 10:44p	897,412	Load flow data for 2002 Fall Low Load in GE PSLF binary format
02FallMedium.sav	03/14/2002 11:07p	897,536	Load flow data for 2002 Fall Medium Load in GE PSLF binary format
02FallPeak.sav	03/14/2002 11:09p	897,536	Load flow data for 2002 Fall Peak Load in GE PSLF binary format
02SpringLow.sav	03/14/2002 11:10p	897,536	Load flow data for 2002 Spring Low Load in GE PSLF binary format
02SpringMedium.SAV	03/14/2002 11:12p	897,536	Load flow data for 2002 Spring Medium Load in GE PSLF binary format
02SpringPeak.SAV	03/14/2002 11:13p	897,536	Load flow data for 2002 Spring Peak Load in GE PSLF binary format
02SummerLow.SAV	03/14/2002 11:14p	897,660	Load flow data for 2002 Summer Low Load in GE PSLF binary format
02SummerMedium.sav	03/14/2002 11:15p	897,660	Load flow data for 2002 Summer Medium Load in GE PSLF binary format
02SummerPeak.sav	03/14/2002 11:16p	897,660	Load flow data for 2002 Summer Peak Load in GE PSLF binary format

File Name	Creation Date	Size	Description
02WinterLow.SAV	03/14/2002 11:17p	897,536	Load flow data for 2002 Winter Low Load in GE PSLF binary format
02WinterMedium.SAV	03/14/2002 11:19p	897,536	Load flow data for 2002 Winter Medium Load in GE PSLF binary format
02WinterPeak.sav	03/14/2002 11:20p	897,536	Load flow data for 2002 Winter Peak Load in GE PSLF binary format
03FalLow.sav	03/11/2003 06:24p	937,060	Load flow data for 2003 Fall Low Load in GE PSLF binary format
03FalMed.sav	03/11/2003 06:24p	936,812	Load flow data for 2003 Fall Medium Load in GE PSLF binary format
03FalPeak.sav	03/11/2003 06:24p	937,184	Load flow data for 2003 Fall Peak Load in GE PSLF binary format
03SprLow.sav	03/11/2003 06:24p	933,248	Load flow data for 2003 Spring Low Load in GE PSLF binary format
03SprMed.sav	03/11/2003 06:24p	933,992	Load flow data for 2003 Spring Medium Load in GE PSLF binary format
03SprPeak.sav	03/11/2003 06:24p	933,496	Load flow data for 2003 Spring Peak Load in GE PSLF binary format
03SumLow.sav	03/11/2003 06:24p	936,220	Load flow data for 2003 Summer Low Load in GE PSLF binary format
03SumMed.sav	03/11/2003 06:24p	936,324	Load flow data for 2003 Summer Medium Load in GE PSLF binary format
03SumPeak.sav	03/11/2003 06:24p	936,200	Load flow data for 2003 Summer Peak Load in GE PSLF binary format
03WinLow.sav	03/11/2003 06:24p	932,700	Load flow data for 2003 Winter Low Load in GE PSLF binary format
03WinMed.sav	03/11/2003 06:24p	932,576	Load flow data for 2003 Winter Medium Load in GE PSLF binary format
03WinPeak.sav	03/11/2003 06:24p	932,948	Load flow data for 2003 Winter Peak Load in GE PSLF binary format
ATC.xls	05/02/2003 10:22a	19,968	Spreadsheet summarizing system load, losses, import exports and Marginal unit output for each of the 2003 load flow cases
GenericStackingOrder (2003Jan10).xls	05/02/2003 01:27p	2,246,144	Spreadsheet summarizing Transmission must run facilities, Northwest Area Load, Dispatch order and summary stacking order sheet
stacking_Jan16.csv	01/17/2003 07:30p	12,543	Comma separated (CSV) text file summarizing Dispatch Order for 2003
0rpti.p	01/15/2003 04:02p	54,515	EPCL code to convert PSS/E raw data file into corresponding PSLF binary history file
add-gen2003.p	02/24/2003 04:18p	22,471	EPCL code to increase output of generator to STS value (or add new) to load flow automatically adjusting units according to data in the Stacking order ".csv" file. Called by "SERP_LossFactor-2passes.p"
caselist.dat	05/02/2003 10:44a	313	Input data file for "Run_LossFactors.p" EPCL code controlling options to be studied, listing files to be used including loadflow base cases to be used
gen-all.dat	06/09/2003 01:11p	182	Input data file for "SERP_LossFactor-2passes.p" EPCL code identifying buses for which loss factors are carried out.
Run_LossFactors.p	02/13/2003 07:50p	3,423	Main EPCL code to carry out loss factor calculations. Reads "caselist.dat" and calls "SERP_LossFactor-2passes.p"
SERP_LossFactor-2passes.p	02/14/2003 02:26p	17,580	EPCL sub-code to calculate loss factors
Base cases Notes.txt	05/02/2003 11:16a	96	Text file indicating that the data for 2001 and 2002 came from the AESO directory "shared\rp\15\01\SERP_loss\BaseCases"

No description of the files was provided. The description given in the table reflects Auditors understanding of the contents.

Additional data was supplied by the AESO over the course of the Audit as shown in Table 3-2.

Table 3-2 Additional Data Supplied by AESO

File Name	Date Supplied	Description
stacking_order.csv	Thu 5/29/2003 12:58 PM	Stacking order for 2003 (.csv)
e-mail (See ANNEX 1)	Thu 5/29/2003 5:46 PM	Historical shift factors
GenListMeritOrder-Aug14.xls	Tue 6/3/2003 2:49 PM	first merit order that was used in loss factor preparation
2001WinterStackingOrder_Peak.xls	Tue 6/3/2003 2:49 PM	Self Explanatory
2002SpringStackingOrder_Peak.xls	Tue 6/3/2003 2:49 PM	Self Explanatory
2002SummerStackingOrder.xls	Tue 6/3/2003 2:49 PM	Self Explanatory
2002FallStackingOrder.xls	Tue 6/3/2003 2:49 PM	Self Explanatory
MuskegSTS170.zip	Thu 6/12/2003 7:04 PM	Sample working directory for Loss Factor calculation
GenericStackingOrder(2003Jan10).xls	Fri 6/13/2003 9:47 AM	Stacking order for 2003 (.xls)
2003SummerDOSLossFactorCalculation-200305261.xls	Wed 6/18/2003 3:15 PM	Self Explanatory
Loss factors calculated during 20031.doc	Wed 6/18/2003 3:15 PM	Self Explanatory
2003LFWorkupPLUSRainbow5SPR&D.xls GROUP1 GROUP2_158_Redwater GROUP2_164_Sundance6 GROUP2_196_Cowley GROUP2_208_Elmworth GROUP2_244_ValleyView GROUP2_265_Rainbow5 Loss Factor Audit - Historical loss factor calculations.doc ReadMeFirst.txt	Tuesday, July 29, 2003, 3:51:33 PM	Down load of Files and working directories from AESO
Loss Factor Audit - Historical loss factor calculations.doc	Thu 7/31/2003 2:12 PM	See ANNEX 2
summary of historical losses.xls	Fri 8/8/2003 11:42 AM	Transmission losses 2001 - 2003
bb.zip	Tuesday, September 09, 2003, 7:31:48 AM	AESO copy of GE PSLF version 11.2
2003_Shift_Factor_CalculationNormalized_Loss_Factors.xls	Mon 10/6/2003 8:47 AM	spreadsheet that was used to calculate 2003 shift factors.
2002ShiftFactorCalculation.xls	Thu 11/20/2003 12:26 PM	spreadsheet that was used to calculate 2002 shift factors
Summer Tie Calculation files.zip	Thu 12/11/2003 12:27 PM	files used for tie line loss factor calculation for the Summer season

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4 CALCULATION OF RAW LOSS FACTORS

4.1 Generators

The Auditor reviewed the EPCL code as supplied by the AESO during the preliminary meetings held in Calgary the week of April 28 to May 2, 2003. It was the Auditor's initial impression that the EPCL code automated the calculation of raw loss factors in accordance with the direction provided by the Board.

The EPCL code follows several steps:

- Adds a generator to the load flow if requested, or increases the reference generator output to its STS value, reducing other generation in the network according to the stacking order.
- Changes the swing bus of the system from the equivalent WSCC generation to Clover Bar, and re-solves the load-flow with all tap-changers, phase shifters, and shunt capacitors fixed.
- Creates a temporary history file
- Adds 5 MW of unity power factor generation to the reference machine load flow bus
- Solves the load flow and calculates the change in total system losses as a result of the increment
- Computes the loss per MW for the change in generation
- Loads the temporary history file and adds -5 MW of unity power factor generation to the reference machine load flow bus
- Solves the load flow and calculates the change in total system losses as a result of the decrement
- Computes the loss per MW for the change in generation
- Stores the results of the two sets of calculations in a text file.

The Auditor initially attempted to use the EPCL code to validate raw loss factors for selected generators using the 2001, 2002 and 2003 power flow models supplied by the AESO. Only generators in merit were evaluated as the EPCL code to add generators to the loadflow "add-gen2003.p"and the corresponding data "stacking_Jan16.csv" both indicated that they applied to 2003 conditions. The Auditor therefore limited initial testing of code to the EPCL routines "Run_LossFactors.p" and "SERP_LossFactor-2passes.p" on generators in merit in the load flow.

On request, the AESO later supplied stacking orders as used for all of the 2001 and 2002 loss factor calculations.

The Auditor considered that as the calculation process was entirely automated, it should have been possible to replicate raw loss factor calculations within a rounding error of 0.1% (absolute). When differences between AESO and the Auditor's calculated raw loss factors of greater than

2% to 3% were evident, the Auditor initially attributed the differences in raw loss factors to a misinterpretation by the Auditor of the application of the EPCL code. The Auditor therefore carried out manual calculations of the raw loss factors. The manual calculations were identical to those calculated using the EPCL code.

After discussions with the AESO, about the differences in results, the AESO supplied the Auditor with a complete set of data files for a generator that was being added to the system in 2003.

The Auditor re-calculated the raw loss factors for the 2003 generators using the new EPCL code and new data. The Auditor's calculation of raw loss factors were identical to the AESO's calculations for several of the dispatch conditions but for other conditions exceeded the 0.1% expected target with differences as large as 1.5% (absolute).

The Auditor continued to investigate the causes of the differences between the AESO values of raw loss factors and the corresponding values determined by the Auditor for 2001 and 2002, both for generators in and out of merit in the load flows.

Even after expending considerable effort reviewing the code, powerflow data and stacking order data the Auditor was still unable to account for the differences. The AESO were then requested to supply complete sets of data for sample loss factor calculations for generators for each of years 2001, 2002 and 2003. To assist the Auditor, the AESO agreed to reconfirm the calculations before forwarding the data to the Auditor.

4.1.1 Comparison of Power Flow Generation with Generator Stacking Order

While the AESO were compiling and testing the complete data sets at the Auditor's request, the Auditor compared the generation in the load flow models supplied with the generation from the stacking orders supplied at the same time. To carry out the comparison, a short FORTRAN program was developed which used the stacking order and tabulations of generation produced by the GE PSLF program as input.

Total Alberta generation was established by summing the dispatched output of all but the generators representing the BC interconnection. Generation was added from the stacking order at each bus including second blocks of output as appropriate, until the total generation allocated based on the stacking order just exceeded the total generation from the power flow.

The Basic differences between the stacking order and the powerflow generation for the 2003 load flow cases are:

- For all cases, Clover Bar (bus 493 unit 1) is dispatched at 25 MW, even though the generator does not appear until close to the end of the stacking order. The basis for the dispatch is that the unit is the swing bus for the increment/decrement segment of the loss factor calculation, its minimum output is 20 MW and to cater for the shift resulting from the addition of 5 MW to the system, it is dispatched at 25 MW. The necessity for this added complication to the load flow is not fully understood by the Auditor. The Clover bar bus could have been maintained as the swing bus with output equal to the stacking order power level (i.e. zero for most conditions) for loss factor calculations. While the base load flow is supposed to be representative of actual system operating conditions, the increment/decrement portion is only a calculation tool to determine incremental losses on the system. This could have been carried out with no output from Clover Bar.

- For the load flow cases investigated, the unit for which the loss factor calculations were being carried out was dispatched at its STS value, which is greater than the dispatch conditions established in the stacking order. No comments were embedded in the load flow or notes attached to the load flow files to indicate this.

- Generation is included in the stacking order that may not be in-service for the load flow condition modeled. There is no data in the stacking order data file to indicate whether the unit may or may not be in service.

To accommodate the major differences, the Auditor modified the comparison program to ignore generation in the stacking order that did not appear in the load flow and also modified the stacking order. An entry for Clover Bar was inserted into the table as the first entry, dispatched at 25 MW, and the stacking order output for the reference unit was increased to its STS value. In the Auditor's initial calculations, the marginal unit was dispatched at the value indicated by the stacking order, and where differences could be explained in the comparison, the Auditor manually subtracted the difference between total stacking order generation and total load flow generation from the output of the marginal unit.

The comparison is shown in Table 4-1 for 2003. Non-zero entries in the table are highlighted. Differences with a magnitude of greater than 0.1MW are heavily shaded because of potential confidentiality issues.

The differences between the Auditors interpretation of the stacking order and the 2003 load flow results are due only to accumulated rounding error for Winter Peak and Medium, all of the Spring cases, Summer Low and all of the Fall cases. For the Winter Low condition, the power flow dispatch is slightly greater than the Stacking order generation for Bear Creek resulting in a corresponding variation in the output of the Auditor's assumed marginal unit at Ghost. The largest difference occurs for the Summer Peak and Medium load conditions, where the stacking order indicates the second block of Brazeau generation should be dispatched while the power flow model indicates generation at Nova GT2.

On the basis of the comparison, the Auditor concludes that the power flows used in the 2003 loss factor calculations are for the most part based on the generator stacking order.

Table 4-1 Differences Between Stacking Order and Power Flow Generation (2003)

Bus #	Id	Bus Name	Base kV	Winter Peak	Winter Medium	Winter Low	Spring Peak	Spring Medium	Spring Low	Summer Peak	Summer Medium	Summer Low	Fall Peak	Fall Medium	Fall Low
6	1	DICKSOA9	4.16				0	0	0	0	0	0	0	0	0
6	2	DICKSOA9	4.16				0	0	0	0	0	0	0	0	0
6	3	DICKSOA9	4.16				0	0	0	0	0	0	0	0	0
14	1														
33	1														
33	2														
54	2	DOW GEN2	14.4	0	0	0	0	0	0	0	0	0	0	0	0
102	1	BIGHORN1	13.8	0	0	0	0.1	0.1	0	0	0	0	0	0	0
108	2	BIGHORN2	13.8				0	0	0	0	0	0	0	0	0
129	1	SUND#1GN	18	0	0	0	0	0	0	0	0	0	0	0	0
130	3	SUND#3GN	20	0	0	0	0	0	0	0	0	0	0	0	0
139	1	WABA#1GN	13.2	0	0	0	0	0	0	0	0	0	0	0	0
140	2	WABA#2GN	13.2	0	0	0	0	0	0	0	0	0	0	0	0
146	4	WABA#4GN	18.5	0	0	0	0	0	0	0	0	0	0	0	0
151	1	BRAZ#1 9	13.7	0.1	0.1	0	-0.1	-0.1	0	0	0	0	0	0	0
154	2	BRAZ#2 9	13.7							[redacted]	[redacted]	0			
172	1	HORS GEN	12	0	0	0	0	0	0	0	0	0	0	0	0
172	2	HORS GEN	12	0	0	0	0	0	0	0	0	0	0	0	0
172	3	HORS GEN	12	0	0	0	0	0	0	0	0	0	0	0	0
172	4	HORS GEN	12	0	0	0	0	0	0	0	0	0	0	0	0
174	1	SPRAY G1	13.2	0	0	0	0	0	0	-0.1	-0.1	0	0	0	0
176	1	CASCADE9	13.2	-0.1	-0.1	0	0	0	0				0	0	
176	2	CASCADE9	13.2	0	0	0	-0.1	-0.1	0				0	0	
181	2	GHOST A9	13.2	0	0	[redacted]	0	0	0	0	0	0.1	0	0	0
181	3	GHOST A9	13.2	0	0	0	0	0	0	0	0	0	0	0	0
181	4	GHOST A9	13.2	0	0	0	0	0		0	0	0	0	0	
183	1	BEARSPWB	13.8	0	0	0	0	0	0	0	0	0	0	0	0
190	1	SPRAY G2	13.2	0	0	0	-0.1	-0.1	0	0	0	0	0.1	0.1	0
196	1	KANANAS9	12	0	0	0	0	0	0	0	0	0	0	0	0
196	2	KANANAS9	12	0	0	0	0	0	0	0	0	0	0	0	0
196	3	KANANAS9	12	0	0	0	0	0	0	0.1	0.1	0	-0.1	-0.1	0
197	1	RUNDLE G	13.8	0	0	0	0	0	0	0	0	0	0	0	0
197	2	RUNDLE G	13.8	0	0	0	-0.1	-0.1	0	0	0	0	0	0	0
214	1	POCATEA9	13.8	0	0	0	0	0					0	0	
222	1	BARRIER9	13.2	0	0		0	0	0	0	0	0	0	0	
255	1	CHINOOK9	34.5	0	0	0	0	0	0	0	0	0	0	0	0
265	1	US WIND9	34.5	0	0	0	0	0	0	0	0	0	0	0	0
332	1	DVPL IA9	13.8	0	0	0	0	0	0	0	0	0	0	0	0
338	2	SUND#2GN	18	0	0	0	0	0	0	0	0	0	0	0	0
342	4	SUND#4GN	20	0	0	0	0	0	0	0	0	0	0	0	0
345	5	SUND#5GN	20	0	0	0	0	0	0	0	0	0	0	0	0
350	6	SUND#6GN	20	0	0	0	0	0	0	0	0	0	0	0	0
377	1	INTERLA9	4.16	0.1	0.1	0				0	0		0	0	
381	1	THREE S9	6.9	0	0								-0.1	-0.1	0
407	1	CHIN CH9	13.8				0	0	0	0	0	0	0	0	0
408	1	WHITEGE9	12.5	0	0	0	0	0	0	0	0	0	0	0	0
414	1	RAY RES9	13.8				0	0	0	0	0	0	0	0	0
422	1	KEEP#1GN	19	0	0	0	0	0	0	0	0	0	0	0	0
424	2	KEEP#2GN	19	0	0	0	0	0	0	0	0	0	0	0	0
447	1	BELLYIA9	4.16				0	0	0	0	0	0	0	0	0
448	1	MARY IA9	4.16	0	0	0	0	0	0	0	0	0	0	0	0
449	1	WATERIA9	4.16	0	0	0	0	0	0	0	0	0	0	0	0
454	1	DOW GEN1	14.2	0	0	0	0	0	0	0	0	0	0.1	0	0
491	1	GENES 19	20.5	0	0	0	0	0	0	0	0	0	0	0	0
492	2	GENES 29	20.5	0	0	0	0	0	0	0	0	0	0	0	0
493	1	CBAR 1 9	16	0	0	0	0	0	0	0	0	0	0	0	0
494	2														
495	3														
496	4	CBAR 4 9	16										[redacted]		
497	8														
498	9														
499	0														
627	1	AIR LIQC	13.8	0	0	0	0	0	0	0	0	0	0	0	0
667	1	CANCARB9	13.8	0	0	0	0	0	0	0	0	0	0	0	0
683	7	CMH7&10R	13.8	0	0		0	0		0	0		0	0	
683	X	CMH7&10R	13.8	0	0	0	0	0	0	0	0	0	0	0	0
686	2	CMH 12 9	13.8	0	0	0	0	0	0	0	0	0	0	0	0
687	1	CMH 11R9	13.8	0	0	0	0	0	0	0	0	0	0	0	0
688	8B	CMH 8 9	13.8	0	0		0	0		0	0		0	0	
689	9	CMH 9 9	13.8	0	0		0			0			0	[redacted]	
712	3	CMH 3R 9	13.8	0	0		0	0		0	0		0.1	0	

Bus #	Id	Bus Name	Base kV	Winter Peak	Winter Medium	Winter Low	Spring Peak	Spring Medium	Spring Low	Summer Peak	Summer Medium	Summer Low	Fall Peak	Fall Medium	Fall Low
1015	1	FORT NE9	13.8	0	0	0	[redacted]	0	0	0	0	0	0	0	0
1031	1														
1032	2														
1033	3														
1035	4	RBW 4	13.8	0	0	0	0	0	0	0	0	0	0	0	0
1037	5	RBW5	14.4	0	0	0	0	0	0	0	0	0	0	0	0
1089	1	DIASHOW9	13.8	0	0	0	0	0	0	0	0	0	0	0	0
1141	1	P&G 9	13.8	0	0	0	0	0	0	0	0	0	0	0	0
1148	1	HR MILN9	15	0	0	0	0	[redacted]	0	0	0	0	0	0	0
1167	1														
1168	2														
1171	1	VALLEYVI	13.8	-0.1									0		
1482	1	SHEER 1	19	0	0	0	0	0	0	0	0	0	0	0	0
1487	2	SHEER 29	19	0	0	0	0	0	0	0	0	0	0	0	0
1495	3	BAT #3	16	0	0	0	0	0	0	0	0	0	0	0	0
1496	4	BAT #4	16	0	0	0	0	0	0	0	0	0	0	0	0
1497	5	BAT #5	21	0	0	0	0	0	0	0	0	0	0	0	0
2030	2	DOWSTG 9	14.4	0	0	0	0	0	0	0	0	0	0	0	0
2031	1	DOWGTG 9	13.8	0	0	0	0	0	0	0	0	0	0	0	0
2230	1	OLDMAN R	13.8							0	0	0	0	0	0
2230	2	OLDMAN R	13.8							0	0	0	0	0	0
2234	1	CASTRIV2	25	0	0	0	0	0	0	0	0	0	0	0	0
2248	2														
2901	1														
3050	1	REDW GT	13.8	0	0	0	0	0	0	0	0	0	0	0	0
3181	1	GHOST G9	2.3	0	0	0.1	0	0	-0	0	0	0	0	0	0
3187	2														
3234	2	CASTRIV3	25	0	0	0	0	0	0	0	0	0	0	0	0
3247	1	CAVAL_A	13.8	0			0			0			0		
3248	1														
3251	2	CARSELA2	13.8	0	0	0	0	0	0	0	0	0	0	0	0
3290	2	BALZ 3	13.8	0			0			0			0		
3301	1														
3302	2														
3354	1	NOVA GT1	18	0	0	0	0	0	0	0	0	0	0	0	0
3355	2	NOVA GT2	18	0	0	0	0	0	0	-0.1	[redacted]	0	0	0	0
3357	3	NOVA ST1	15.7	0	0	0	0	0	0	0	0	0	-0.1	0	0
3901	2														
4185	1														
4187	1														
4226	1	PALMER R	4.16										0		
4226	2	PALMER R	4.16										0		
4247	2	CAVAL_B	13.8	0			0			0			0		
4247	3	CAVAL_B	13.8	0			-0.1			0			0		
4251	1	CARSELA1	13.8	0	0	0	0	0	0	0	0	0	0	0	0
4264	1	COWLEY N	25	0	0	0	0	0	0	0	0	0	0	0	0
4290	1	BALZ 1&2	13.8	0	-0.1		0			0			0		
4290	3	BALZ 1&2	13.8	0			0			0			0		
4670	1	TAYLOR 9	13.8				0	0	0	0	0	0	0	0	0
7185	2														
10142	1	BEARCK2	13.8			[redacted]									
10236	1	MUSKEG4	13.8	0	0	0	0	0	0	0	0	0	0	0	0
11142	2														
12236	2	MUSKEG6	13.8	0	0	0	0	0	0	0	0	0	0	0	0
16118	1	POPLAR-4	13.8	0									0		
16218	G1	SUNC_G19	13.8	0	0	0	0	0	0	0	0	0	-0.1	-0.1	0
16219	G3	MIL_G3	13.8	0	0	0	0	0	0	0	0	0	0	0	0
17209	G3	SYNC_G39	13.8	0	0	0	0	0	0	0	0	0	0	0	0
17210	G4	SYNC_G49	13.8	0	0	0	0	0	0	0	0	0	0	0	0
18207	1	AUR_GTG1	13.8	0	0	0	0	0	0	0	0	0	0	0	0
18208	G5	MIL_G5 9	13.8	0	0		0	0		0	0		0	0	
18209	G2	SYNC_G29	13.8	0	0	0	0	0	0	0	0	0	0	0	0
18210	G5	SYNC_G59	13.8	0	0	0	0	0	0	0	0	0	0	0	0
18218	G2	SUNC G29	13.8	0	0	0	0	0	0	0	0	0	-0.1	-0.1	0
18223	G4	TAR-GN-2	13.8	0	0	0	0	0	0	0	0	0	0	0	0
18302	1	PRIM GEN	13.8	0	0	0	0	0	0	0	0	0	0	0	0
19145	1	BRDGE C9	25	0	0	0	0	0	0	-0.1	-0.1	-0.1	0	0	0
19208	G6	MIL_G6 9	13.8	0	0	0	0	0	0	0	0	0	0	0	0
19209	G1	SYNC_G19	13.8	0	0	0	0	0	0	0	0	0	0	0	0
19210	G6	SYNC_G69	13.8	0	0	0	0	0	0	0	0	0	0	0	0
20134	5	ELMWORTH	6.9	0	0	0	0	0	0	0	0	0	0	0	0

Similar comparisons between the 2002 load flows and the seasonal stacking orders supplied by the AESO were unsuccessful. Preliminary comparisons were forwarded to the AESO for review and the conclusion reached was that the load flows and the stacking orders that were supplied to the Auditor were not consistent.

As a reasonable comparison could not be made for 2002, the comparison for 2001 was not carried out.

4.1.2 Incorrect Data

After completing their own investigations, the AESO advised the Auditor that they were also unable to reproduce raw loss factor calculations for the generators in-service in 2001 and 2002 (see ANNEX 2).

The load flow cases as originally supplied by the AESO to the Auditor were not the cases that the AESO used to calculate the raw loss factors for these generators.

The AESO supplied complete data files for several generators added in 2002 where they could reproduce the raw loss factors.

The Auditor used the new data and EPCL code and still was not able to achieve the target of 0.1% absolute.

4.1.3 Impact of PSLF Software Versions

In an attempt to uncover the differences between the result's of the AESO's calculations and the Auditor's calculations, using exactly the same load flow data files and EPCL code, the Auditor investigated the impact of operating system version and software changes. The calculations were repeated for each of the configurations of software and hardware shown in Table 4-2. The operating system versions and processor type used by the TA/AESO are not known.

Table 4-3 summarizes the differences in raw loss factor results obtained for one of the new generators included in the 2002 loss factor calculations. The Auditor selected PSLF version 11.2 to carry out the calculations on the understanding that the AESO was also running PSLF version 11.2. The Auditor ran the calculations on a AMD Althon running service pack 4 of Windows 2000. Switching to Service Pack 2 of Windows 2000 on a similar computer system in the Auditor's office gave identical results.

Table 4-2 Software/Hardware Configurations Evaluated

Case Id	PSLF Version	Processor/OS Version
Original (calculation results forwarded by the AESO)	11.2	
Mike 11.2 2000 sp 2	11.2	AMD Althon/ Windows 2000 Service Pack 2
RSB 11.2 2000 sp 4	11.2	AMD Althon/Windows 2000 Service Pack 4
RSB 12 2000 sp 4	12	AMD Althon/Windows 2000 Service Pack 4
RSB 13 2000 sp 4	13	AMD Althon/Windows 2000 Service Pack 4
RSB 14 2000 sp 4	14	AMD Althon/Windows 2000 Service Pack 4
RSB TA 11.2	11.2 (TA Vrsn.)	AMD Althon/Windows 2000 Service Pack 4

Table 4-3 Differences in Raw Loss Factors Due to Software/Hardware Configurations

System Load Condition	Original data less Mike 11.2 2000 sp 2
02winterlow	0.0%
02wintermed	1.5%
02winterpeak	0.0%
02springmed	0.0%
02summerlow	-0.2%
02fallpeak	0.2%

	Mike 11.2 2000 sp 2 less RSB 11.2 2000 sp 4	Original data less RSB 11.2 2000 sp 4
02winterlow	0.0%	0.0%
02wintermed	0.0%	1.5%
02winterpeak	0.0%	0.0%
02springmed	0.0%	0.0%
02summerlow	0.0%	-0.2%
02fallpeak	0.0%	0.2%

	RSB 11.2 2000 sp 4 less RSB 12 2000 sp 4	Mike 11.2 2000 sp 2 less RSB 12 2000 sp 4	Original data less RSB 12 2000 sp 4
02winterlow	0.0%	0.0%	0.0%
02wintermed	-1.5%	-1.5%	0.0%
02winterpeak	-1.6%	-1.6%	-1.6%
02springmed	0.7%	0.7%	0.7%
02summerlow	0.2%	0.2%	0.0%
02fallpeak	0.0%	0.0%	0.3%

	RSB 12 2000 sp 4 less RSB 13 2000 sp 4	RSB 11.2 2000 sp 4 less RSB 13 2000 sp 4	Mike 11.2 2000 sp 2 less RSB 13 2000 sp 4	Original data less RSB 13 2000 sp 4
02winterlow	0.0%	0.0%	0.0%	0.0%
02wintermed	0.0%	-1.5%	-1.5%	0.0%
02winterpeak	1.6%	0.0%	0.0%	0.0%
02springmed	0.0%	0.7%	0.7%	0.7%
02summerlow	-0.2%	0.0%	0.0%	-0.2%
02fallpeak	0.0%	0.0%	0.0%	0.2%

	RSB 13 2000 sp 4 less RSB 14 2000 sp 4	RSB 12 2000 sp 4 less RSB 14 2000 sp 4	RSB 11.2 2000 sp 4 less RSB 14 2000 sp 4	Mike 11.2 2000 sp 2 less RSB 14 2000 sp 4	Original data less RSB 14 2000 sp 4
02winterlow	0.6%	0.6%	0.6%	0.6%	0.6%
02wintermed	0.0%	0.0%	-1.5%	-1.5%	0.0%
02winterpeak	0.0%	1.6%	0.0%	0.0%	0.0%
02springmed	0.0%	0.0%	0.7%	0.7%	0.7%
02summerlow	0.0%	-0.2%	0.0%	0.0%	-0.2%
02fallpeak	0.3%	0.2%	0.3%	0.3%	0.5%

	RSB 14 2000 sp 4 less RSB TA 11.2	RSB 13 2000 sp 4 less RSB TA 11.2	RSB 12 2000 sp 4 less RSB TA 11.2	RSB 11.2 2000 sp 4 less RSB TA 11.2	Mike 11.2 2000 sp 2 less RSB TA 11.2	Original data less RSB TA 11.2
02winterlow	-0.6%	0.0%	0.0%	0.0%	0.0%	0.0%
02wintermed	0.0%	0.0%	0.0%	-1.5%	-1.5%	0.0%
02winterpeak	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%
02springmed	-0.7%	-0.7%	-0.7%	0.0%	0.0%	0.0%
02summerlow	0.2%	0.2%	0.0%	0.2%	0.2%	0.0%
02fallpeak	-0.5%	-0.2%	-0.3%	-0.2%	-0.2%	0.0%

The Auditor investigated PSLF Version 12 on the assumption that the Auditor's understanding of the AESO's facilities had been incorrect. PSLF versions 13 and 14 were also investigated when differences between versions 11.2 and 12 were found. It was found that, in addition to giving slightly different results from the other the versions, the solution flag for each load flow in version 14 indicated that the load flows had not converged to the specified tolerance.

After it was confirmed that the AESO was indeed using version 11.2 of the software, the Auditor requested that the AESO supply a copy of the executable used in the AESO's calculations. When this version was used on the Auditor's computer, it gave exactly the same values of raw loss factors as calculated by the AESO.

Although both the AESO's version and the Auditor's version of the GE PSLF program indicated release 11.2, the date stamps on the executables were different. The AESO's version was dated Friday, January 14, 2000, 12:03:00 PM, and the Auditor's version was dated Wednesday, August 09, 2000, 10:09:46 AM.

For the particular set of calculations reviewed, there were no differences in solution for the Spring Low and Spring Peak load conditions, the Summer Peak and Medium load conditions and the Fall Low and Medium load conditions, and until version 14 was tested, there were no observable differences in results for the Winter Low load condition. The largest differences occur for the Winter Peak and Medium load condition where the largest difference in results is 1.5 to 1.6%.

The Auditor has not reviewed the causes of the observed differences in detail but one possible cause for the differences in results may be that, for the cases tabulated, the load flow did not converge to the specified tolerance within the specified number of iterations. There may also have been changes to the GE PSLF program from the AESO version 11.2 to the Auditor's version 14 that involved improvements to the solution algorithm, where assumed initial conditions for the iterative process could have changed, or even possibly the order in which each bus is calculated were modified to improve or optimize the solution process. A different starting condition could result in a slightly different solution, dependent on the solution criteria.

The Auditor has observed that most of the tabulations of raw and normalized loss factors (both public and internal) have been limited to a displayed accuracy of 0.1%. To obtain this level of accuracy for a 5.0 MW change in power, the change in losses must be calculated to an accuracy of 0.005 MW. The AESO uses a solution criterion of 0.02 MVA mismatch at all buses within the system for the increment/decrement stage of the loss factor calculation. Total mismatch on the system is typically 2 to 3 times larger. As the total system mismatch is reflected in the output of the swing bus, which in turn is an indirect measure of the change in system losses, it is not surprising that calculations of system losses could be affected by minor changes to the load flow starting condition.

To obtain a difference in raw loss factors of 1.6%, the difference in total system mismatch would only be about 0.08 MW, or a swing from -0.04 to +0.04 MW. The largest total system mismatch observed by the Auditor in the starting conditions for each of the increment/decrement load flows was about 0.06MW.

On the basis of this review, the Auditor concludes that the GE PSLF program cannot be used to obtain the implied accuracy of loss factor calculations of ±0.1%, on a consistent basis, using the current AESO solution procedures. Possible options include:

- Modify the solution process. - A possible cause of mismatch is hunting between solutions. This could occur as a result of a generator switching from voltage to maximum reactive power limit control and vice versa. This type of hunting can be avoided by locking the generator status (either voltage or var control) at the same time that tap-changer, phase shifter and switched shunts are locked. This is not a standard load flow feature but could be implemented with an EPCL routine that cycles through each generator and adjusts the generator type based on its output status at the time.

- Increase the numerical precision of the solution. - Mismatch can occur as a result of numerical problems associated with low impedance branches connected to the same bus as high impedance branches. The impact of this type of mismatch could be reduced by increased numerical calculation precision. This would require significant involvement by GE to modify the program and likely significant expense.

- Accept a larger implied inaccuracy and only publish/record loss factors to the accuracy of the calculations.

- Consider other load flow packages

In any event, it is suggested that the AESO review the loss factor calculations carried out and catalogue the number of iterations and solution mismatch at each step of the load flow procedure, to ensure that no loss factor calculations have occurred where the total system mismatch is significantly larger than the target values.

4.1.4 Impact of System Changes On Loss Factors

Although the Auditor was not able to quantify the impact of the changes to the power flow model on raw loss factors and the resulting shift factors, it was possible to identify the extent to which the topology of the modelled network has changed.

Direct Comparison of Load Flow Data

The Auditor compared the AESO supplied power flow models for 2001 and 2003. The differences in topology are extensive.

There is continuity between the two system representations in terms of the bus numbers used. There were a total of 1638 buses modelled in 2001 and 1738 buses in 2003. Of these buses 1529 bus numbers were common to both years, 109 bus numbers were used in 2001 that were not in 2003 and 209 bus numbers were used in 2003 that were not in 2001.
Of the 1529 buses with the same bus number, only 426 had the same bus name, 319 with matching bus name and base kV, (i.e. the base kV has changed at 107 buses).

There appears to have been a substantial change in the way the bus names have been assigned. There are 1357 buses where the first six characters of the bus name are the same, 1090 buses where the first six characters of the bus name are the same and base kV's are same, 248 buses where the first six characters are the same but base kV has changed. The major change in bus naming has been in the last 2 characters. The number of buses where the first five characters of the bus name are the same is only 1360.
There are a total of 1858 branches modelled in 2001 and 2028 branches modelled in 2003. There are 390 branches in the 2001 data that are not modelled in 2003 and 560 branches in 2003 that are not modelled in 2001.

Of the 1468 branches that are common to both sets of data there were 872 branches where the data changed, and 596 identical branches. The changes to 87 of the branches were minor (i.e. in the 4th significant figure of accuracy).

There were a total of 68 switched shunts modelled in 2001 and 79 modelled in 2003. There were a total of 61 buses where shunts were modelled in both years. I.e., 7 buses with shunts that are present in 2001 but not in 2003 and18 buses with shunts that are present in 2003 but not in 2001.

Of the 61 buses with shunts modelled in both years, changes were made to 42 of the shunts.

Changes to TASMo

At the request of the Auditor, the AESO reviewed versioning information of TASMo and extracted from the versioning table, all changes occurring between 2001-06-26 when the Oracle version of TASMo was commissioned, and the end of 2002, showing bus names and nominal voltages. A versioning record is produced every time a save operation is conducted, even when the operator re-saves the same data. So, some records will show no net change, but are included as changes in the following analyses.

A total of 670 changes were made to bus versioning table and 277 of these were changes to buses that had been changed before in the same time frame. A total of 393 buses were changed during the period.

A total of 817 changes were made to line connectivity table and 303 overlapped earlier changes. A total of 514 line connection changes were made.

A total of 5937 changes were made to the line-segment versioning table (line data) and 4451 overlapped earlier changes. A total of 1486 lines were modified.

A total of 4562 changes were made to the transformer connectivity table and 1036 overlapped earlier changes. A total of 3526 bushing connection changes were made.
A total of 541 changes were made to the transformer data table and 183 overlapped earlier changes. A total of 358 transformers were modified.

A total of 228 changes were made to the shunt data table and 146 overlapped earlier changes. A total of 82 shunts were modified.

Project-related changes will show up in loss-factor calculations only when the project driving the change receives its energization certificate (for non-generator projects) or commissioning certificate (for generator projects). A summary of extractions from the "system_elements" versioning table indicated 1482 changes to projects of which 566 were overlapping changes or a total of 916 changes were made to different projects

Overview of changes

The changes reported in the TASMo versioning tables are a subset of the changes that appear between the two load flows.

Both sources of information indicate substantial changes to network topology and data modelled in the load flow. The AESO has indicated that many of the changes are as a direct result of actual changes to the network as a result of new facilities and projects. There have also been substantial changes to the model as a result of the AESO's internal continuing review process.

When these changes are considered together with the changes in system load and accompanying generation dispatch, the Auditor considers it likely that they would have had a significant impact on the loss factors calculated using these load flows.

4.2 DOS Customers

The EPCL code that is used for generators is also used for the calculation of raw loss factors for DOS Customers. When a DOS Customer is added to the load flow, comparable generation is added in accordance with the generator stacking order creating a temporary new base-case load flow. The EPCL procedure adds 5 MW of generation (reduces load by 5 MW) then reduces the new base-case load flow generation by 5 MW. Loss per MW values are computed the same way as for generation. The change is loss for each step is divided by +5 MW and –5 MW respectively and the results averaged to obtain loss per MW values for each load flow condition. The three loss per MW values for each season are averaged to obtain the seasonal raw loss factors.

As the procedure was originally developed for generation, the 'raw' loss factors thus calculated are in fact the negative of a load loss factor, (i.e., loss per MW change in load).

This is taken care of in the calculation of normalized loss factors. The normalized loss factor is calculated equal to the negative value of raw loss factor less the shift factor.

The Auditor believed that it was not necessary to replicate any raw loss factor calculations for DOS loads, as the EPCL code had been carefully reviewed and validated for generator calculations.

The Auditor did review and confirms the calculations of normalized loss factors for the following 10 DOS loads:

[redacted]

4.3 Imports-Exports Raw Loss Factors For Interties

Data was supplied by the AESO as shown in Table 4-4 and Table 4-5 for the 2003 Summer tabulations of loss factors. The AESO presumably copied this data from a spreadsheet into to a word document for review by the Auditor. The AESO later supplied the original spreadsheets used to calculate the normalized loss factors.

Note that, in both the MS Word file and the spreadsheet, there is a discrepancy between the heading (Spring) and heading date (2003, June 1 to 2003 August 31). There is also a discrepancy between scheduled import/export levels for normalized and raw loss factors.

Table 4-4 Normalized Loss Factors for Interties As Supplied by the AESO

Normalized loss factors for 2003 Spring (2003 June 1 to 2003 August 31)				
Tie Name	On peak(MW)	Off peak(MW)	On peak(MW)	Off peak(MW)
	Import(150)	Import(125)	Export(25)	Export(75)
Sask	5.9%	-8.5%	20.7%	39.6%
Sask*	8.4%	-5.9%	22.6%	41.5%
	Import(375)	Import(250)	Export(50)	Export(275)
BCH	-1.3%	-4.1%	16.2%	25.1%

* Includes losses at the converter station.

Table 4-5 Raw Loss Factors for Interties As Supplied by the AESO

	Raw loss factors			
Tie Name	On peak(MW)	Off peak(MW)	On peak(MW)	Off peak(MW)
	Import(150)	Import(125)	Export(50)	Export(75)
Sask	-0.2%	-14.6%	-14.6%	-33.5%
Sask*				
	Import(200)	Import(125)	Export(75)	Export(375)
BCH	-7.4%	-10.2%	-10.1%	-19.0%

Normalized Loss Factors as Published on the AESO Website for the Summer period are shown in Table 4-6, and are consistent with the normalized loss factors (including converter station losses) shown in Table 4-4.

The Shift Factor for the same period is –6.09%.

The normalized loss factors are consistent with raw loss factors and the shift factor. Exports are treated as negative generators hence shift factors are applied to the negative value of the calculated raw loss factor.

The Auditor was originally concerned about the relatively large change in raw loss factors for the Saskatchewan intertie when losses at the converter station are included in the calculation.

Table 4-6 Normalized Loss Factors as Published on the AESO Website

Normalized loss factors for 2003 Summer				
(2003 June 1 to 2003 August 31)				
Tie Name	On peak	Off peak	On peak	Off peak
	Import	Import	Export	Export
Sask*	8.45%	-5.93%	22.65%	41.52%
BCH	-1.27%	-4.12%	16.21%	25.14%
* Includes losses at the convertor station.				

To assist the Auditor, the AESO was able to supply the base-case load flows, EPCL code and data files that were used to calculate the raw loss factors. The response to the request was made with absolutely no delays indicating to the Auditor that the files for the above intertie loss factor calculations had been properly archived. Dates on the files indicate that the archive was created on May 26, 2003.

The McNeill converter station was modelled as an equivalent load in the base-case load flow files supplied for the Saskatchewan intertie calculations, with the values shown in Table 4-7.

Table 4-7 McNeill Load Flow Representation

Load Flow Condition	Base Case Load Flow	McNeill Load
On Peak Import	SP_IMP_ONPK.sav	-150 MW
Off Peak Import	SP_IMP_OFPK.sav	-125 MW
On Peak Export	SP_EXP_ONPK.sav	50 MW
Off Peak Export	SP_EXP_OFPK.sav	75 MW

Using the EPCL code supplied by the AESO, the Auditor was able to reproduce exactly, the values shown for McNeill in the raw loss factor Table 4-5. As the export/import levels also match, the Auditor has concluded that the import/export levels in Table 4-4 are incorrect.

A review of the AESO spreadsheet indicates the headings for both the raw and normalized loss factors are defined explicitly. The Auditor thinks that the spreadsheet is a copy of a previous intertie summary, and that the headings of the raw loss factor table were changed, but not the corresponding headings of the normalized loss factor table.

The import and export levels are used only in the calculation of raw loss factors. They are not posted and should not affect the loss settlement process. However, what appear to be documentation errors could lead to confusion in future verification of calculations. They could possibly lead to calculation errors if the wrong information is used as a starting point for future calculations.

A review of the base case load flows supplied for the BC tie calculations showed the interchange between Alberta and British Columbia as given below in Table 4-8.

Table 4-8 BC Interie Load Flow Representation

Load Flow Condition	Base Case Load Flow	AB to BC Flow
On Peak Import	BC_IMP_ONPK.sav	-199.6 MW
Off Peak Import	BC_IMP_OFPK.sav	-123.1 MW
On Peak Export	BC_EXP_ONPK.sav	72.3 MW
Off Peak Export	BC_EXP_OFPK.sav	375.3 MW

The intertie flows are also consistent with the headings given in the raw loss factor Table 4-5.

The Auditor did not attempt to repeat the AESO calculations for the BC intertie.

The Auditor did however review the Saskatchewan intertie calculations because of the concern over the change in loss factors when converter station losses are included.

The AESO confirmed to the Auditor that:

- The McNeill converter is included as part of the AIES system
- Settlement is based on volumes measured on the Saskatchewan 230 kV bus.

The losses at the converter station should therefore be included in the loss factor calculation. To accomplish this, the AESO simply adds the converter station losses, expressed as a percentage of the converter power, to the loss factor calculated on the Alberta side to obtain the raw loss factor for the intertie.

Only two sets of losses are used by the AESO. The converter losses as used by the AESO are:

Import Conditions 2.59%
Export Conditions 1.93%

As the percent losses are used directly as an adder to the loss factors they must represent the incremental losses of the converter. The shape of loss characteristic determined from the incremental losses is as shown in Figure 4-1. The curve (derived by the Auditor) is the integral of the loss factors stated by the AESO. The constant of integration 'zero' assumed by the Auditor for zero power transfers is consistent with the ability to completely shut down the station.

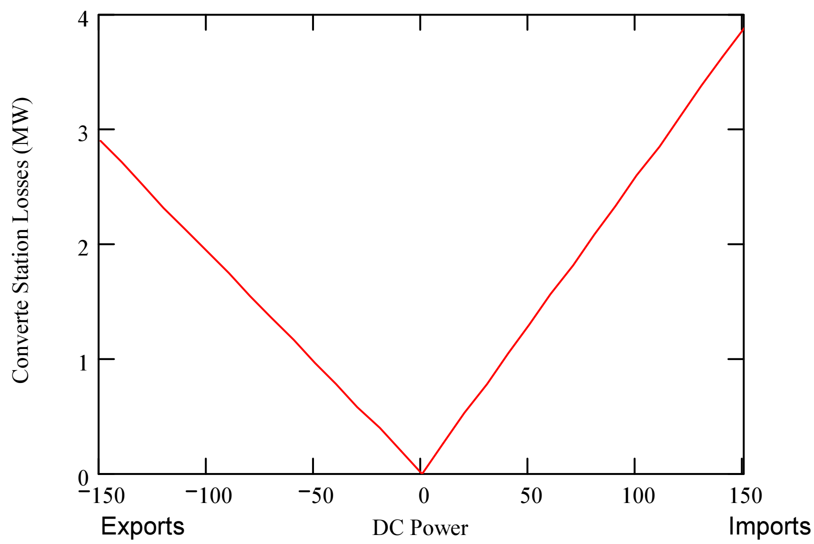

Figure 4-1 Variation of Converter Station Losses as used by AESO

It is difficult however to model converter station losses in the load flow without using a dc model. The Auditor agrees with the AESO that the use of the dc model is undesirable for the loss factor type of calculation. Treatment of the interconnection as a constant power, unity power factor load (or negative load for imports) is a reasonable representation, as it reflects basic dc converter operation but does not introduce the slight variations in real and reactive power flow that occur in practice but which would significantly alter the results of calculations based on differences between small numbers.

The Auditor carried out a more rigorous calculation of loss factors by assuming that the converter station losses could be treated like any other transmission component. In order to include the effect of losses in a more rigorous manner, calculations outside of the load flow are required both before and after the incremental process is applied, as follows:

- The intertie flow is defined on the Saskatchewan side of the converter.
- Converter station losses based on Figure 4-1 are subtracted to determine the equivalent load or injection on the Alberta side.
- The load flow is solved with the resultant equivalent load at the McNeill 138 kV bus.
- Total system losses are set equal to the sum of losses of the ac system (as determined from the load flow) and the converter station losses as used to determine the equivalent load.
- The calculation is repeated with an additional 5 MW of generation on the Saskatchewan side (load reduced by 5 MW) and the total system losses determined.
- The calculation is again repeated with a reduction in generation (increase in load) of 5 MW on the Saskatchewan side.

- The changes in total system losses are divided by +5 MW and –5 MW respectively to determine incremental losses.
- The incremental losses are averaged to obtain the raw loss factor (including converter losses).

The AESO's and Auditor's methods of calculating the influence of converter station losses are compared in Table 4-9.

The Auditor repeated the calculations made by the AESO using results of load flows that were carried out with manual adjustments of the equivalent injections at McNeill. The base case for each of the solutions was selected to be the "temp.sav" file created for each condition when the Auditor validated the results using the base case and the EPCL code that was supplied for each operating condition.

The "temp.sav" file is a temporary intermediate file created by the EPCL code and represents the load flow condition to which the plus and minus 5 MW injections are applied.

The comparison shown in Table 4-9 indicates that the AESO's stated normalized loss factors and the Auditor's manual calculations of loss factors using the AESO Calculation Methodology are the same.

It should be noted that all of the load flow calculations reached the maximum number of iterations (80) without achieving the scheduled tolerance of .02 MVA. For all cases, the MW tolerance was achieved but the Mvar mismatch was about 0.04 Mvar. Also for all four cases, the voltage at bus 4264 [COWLEY N] 25.00 (kV) exceeded the voltage criteria of 1.15 p.u. The tap position fixed by the load flow solution during the creation of the "temp.sav" file was inappropriate. As the bus is a radial bus, adjustment of the tap to a reasonable value would have no impact on the loss factor calculations.

Table 4-9 also shows the results of loss factor calculations using the more rigorous methodology suggested by the Auditor. The absolute difference between the two methodologies ranges from about 0.1% (for the off-peak import condition) to 0.9% for the off-peak export condition.

While the absolute differences between the two methods seem relatively large, the differences expressed as a percentage of the AESO's normalized loss factors are small.

Table 4-9 Comparison of Normalized Loss Factors for Saskatchewan Intertie, Summer 2003

	SkImportOnPeak			SkImportOffPeak			SkExportOnPeak			SkExportOffPeak		
Repeat of AESO Calculation		**Plus5MW**	**Minus5MW**		**Plus5MW**	**Minus5MW**		**Plus5MW**	**Minus5MW**		**Plus5MW**	**Minus5MW**
Load Flow Generation (MW)	150.000	155.000	145.000	125.000	130.000	120.000	-50.000	-45.000	-55.000	-75.000	-70.000	-80.000
New Losses (MW)		332.434	332.457		268.018	269.478		327.2	328.663		321.412	324.762
Base Losses (MW)		332.436	332.436		268.737	268.737		327.916	327.916		323.068	323.068
∆ Losses (MW)		-0.002	0.021		-0.719	0.741		-0.716	0.747		-1.656	1.694
∆ P (MW)		5	-5		5	-5		5	-5		5	-5
Loss Per MW		-0.0004	-0.0042		-0.1438	-0.1482		-0.1432	-0.1494		-0.3312	-0.3388
Average Loss Per MW (%)	-0.23%			-14.60%			-14.63%			-33.50%		
Shift Factor (%)	-6.09%			-6.09%			-6.09%			-6.09%		
Converter Losses (%)	2.59%			2.59%			1.93%			1.93%		
Normalized Loss Factor (%)	**8.45%**			**-5.92%**			**22.65%**			**41.52%**		
AESO Normalized Loss Factor	8.45%			-5.93%			22.65%			41.52%		
Auditor's Method		**Plus5MW**	**Minus5MW**		**Plus5MW**	**Minus5MW**		**Plus5MW**	**Minus5MW**		**Plus5MW**	**Minus5MW**
Base Power (MW)	150.000	155.000	145.000	125.000	130.000	120.000	-50.000	-45.000	-55.000	-75.000	-70.000	-80.000
Converter Station Losses (MW)	3.885	4.015	3.756	3.238	3.367	3.108	0.965	0.869	1.062	1.448	1.351	1.544
Load Flow Generation (MW)	146.115	150.986	141.245	121.763	126.633	116.892	-50.965	-45.869	-56.062	-76.448	-71.351	-81.544
New Losses (MW)		332.434	332.487		268.499	269.951		327.323	328.825		321.856	325.293
Base Losses (MW)		332.451	332.451		269.214	269.214		328.058	328.058		323.554	323.554
∆ Losses (MW)		-0.017	0.036		-0.715	0.737		-0.735	0.767		-1.698	1.739
∆ Converter Station Losses (MW)		0.130	-0.130		0.130	-0.130		-0.097	0.097		-0.097	0.097
Total Change in Losses (MW)		0.113	-0.093		-0.585	0.608		-0.832	0.863		-1.794	1.836
∆ P (MW)		5	-5		5	-5		5	-5		5	-5
Loss Per MW		0.0225	0.0187		-0.1171	-0.1215		-0.1663	-0.1727		-0.3589	-0.3671
Average Loss Per MW (%)	2.06%			-11.93%			-16.95%			-36.30%		
Shift Factor (%)	-6.09%			-6.09%			-6.09%			-6.09%		
Normalized Loss Factor (%)	**8.15%**			**-5.84%**			**23.04%**			**42.39%**		
Difference (Absolute) (%)	**0.30%**			**-0.08%**			**-0.39%**			**-0.87%**		
Difference (% of AESO Normalized Loss Factor)	3.55%			1.35%			-1.72%			-2.10%		

5 CALCULATION OF ANNUAL SHIFT FACTORS

The Auditor has reviewed the calculation of six sets of shift factors as shown in Table 5-1.

Table 5-1 Summary of Shift Factor Calculations Reviewed During the Audit

	Shift Factors					
Year	**Winter**	**Spring**	**Summer**	**Fall**	**Winter**	**Sources**
	(J,F,D)	(M,A,M)	(J,J,A)	(S,O,N)	(D)	
2003	-6.7	-6.7	-6.09	-4.5		1,2
2002	-6.2	-7.1	-7.3	-6.1		3,4
2002 (report)	-4.8	-4.3	-4.8	-4.3		5,6
2001 (report)	-3.0	-3.0	-4.8	-3.0	-2.6	5,7
2001 2nd half	-3.0	-3.0	-4.8	-3.0	-2.6	5,7,8
2001 1st half	-3.0	-3.0	-4.8	-3.6		9

Notes:
1) 2003_Shift_Factor_CalulationNormalized_Loss_factors.xls
2) 2003 Normalized Loss Factors for Generators, posted at www.aeso.ca/files/2003LFforWeb12.pdf (negative of Clover Bar)
3) 2002ShiftFactorCalculation.xls
4) 2002 Normalized Loss Factors for All Generating Units, posted at www.aeso.ca/files/LossFactors.pdf (negative of Clover Bar)
5) ESBI Loss Factor Calculation Methodology (Confidential document for ESBI internal use only) April 5th, 2001
6) 2002-2005 Loss Factors for Generating Units Revised July 20, 2000 (Posted) (negative of Clover Bar)
7) 2001 Loss Factors for Generating Units Revised July 20, 2000 (Posted) (negative of Clover Bar)
8) Normalization Model - 2001 2nd half.xls
9) Normalization Model.xls

The Auditor was able to recalculate the shift factors as tabulated using data provided by the AESO.

5.1.1 Method of Calculation

The shift factor is calculated for each season in accordance with the following formulae:

$$S = \frac{\sum_{i=1}^{n} (V_i \cdot Lf_i) - L_t}{\sum_{i=1}^{n} V_i}$$

Where:

V_i	is the forecast individual generator energy output
Lf_i	is the raw loss factor for the individual generator
L_t	is the total forecast energy losses for the season
i	is the number of the individual generator
n	Total number of generators

This equation is in accordance with the Board's directives.

5.1.2 Forecast Losses

The forecast total losses 'L_t' used in the Auditor's calculations are as shown in Table 5-2. The source of the data for the 2001 cases and the 2002 report as described in notes to the AESO spreadsheets is:

"*These are the losses volume forecast used in EAL's 2000 tariff. They are taken from the Case 242.*"

Table 5-2 Forecast Loss Volumes used in Audited Shift Factor Calculations

	Forecast Loss (MWh)				
Year	**Winter**	**Spring**	**Summer**	**Fall**	**Winter**
	(J,F,D)	(M,A,M)	(J,J,A)	(S,O,N)	(D)
2003	855,303	795,172	676,861	603,023	
2002	874,032	953,864	926,693	899,445	
2002 (report)	732,746	652,826	678,830	695,770	
2001 (report)	732,746	652,826	678,830	695,770	732,746
2001 2nd half	732,746	652,826	678,830	695,770	732,746
2001 1st half	732,746	652,826	678,830	695,770	

The total losses as used in the 2002 calculation is based on a forecast total annual volume of losses 'L_f' of "*3,702,077*" MWh and the actual total losses recorded for 2001 'L_{2001}' of 3,677,977 MWh. The source for the forecast losses 'L_f' was not documented. The actual 2001 losses are based on hourly records taken from a spreadsheet "*2001 Transmission Losses-02.xls*". The values for Winter are equal to the Jan-Feb totals scaled up by a factor of 3/2.

The distribution for 2002 is based on the actual 2001 seasonal distribution of losses based on metering information.

The total annual losses actually used in the shift factor calculations is 3,654,034 MWh and is calculated using the formula:

$$L_t = L_{2001} \cdot \left(\frac{L_{2001}}{L_f} \right)$$

$$\frac{L_t}{L_f} = 99.35\%$$

No explanation for this correction to the forecast losses was provided. It appears to be an error. As the correction was close to unity, and because it was being applied to a forecast number, the Auditor did not pursue the reasons for the correction.

No documentation was provided as to the source of the 2003 forecast losses.

The increase in forecast losses from the 2002 (report) to the final 2002 values is 32% or about 894,000 MWh. This equates to an average increase in system transmission losses of about 100 MW. Based on the AESO public document Loss Factor Calculation Methodology-Appendix C "www.aeso.ca/files/Loss_Factor_Calculation_Methodology.pdf", this is consistent with a shift of between 200 to 600 MW of generation from southern Alberta to the North depending on initial north-south loadings on the 240 kV north-south transmission corridor.

The reduction in forecast losses to less than 2001 levels in the 2003 forecast is consistent with increased supply and new generation in southern Alberta.

The historical transmission losses are shown in Table 5-3

Table 5-3 Historical Transmission Losses

	Losses(MWh)				
	Winter	**Spring**	**Summer**	**Fall**	**Total**
2000	783,287	657,304	745,639	800,976	2,987,206
2001	691,318	747,062	682,290	616,782	2,737,452
2002	671,435	734,092	700,463	668,958	2,774,948

The actual losses for 2002 did not change significantly from the 2001 levels.

Table 5-4 Forecast Total Generator Volumes Used in Audited Shift Factor Calculations

Year	Forecast Total Generator Volumes (MWh)				
	Winter	Spring	Summer	Fall	Winter
	(J,F,D)	(M,A,M)	(J,J,A)	(S,O,N)	(D)
2003	12,378,272	11,386,959	12,268,030	12,300,618	
2002	14,139,164	13,394,801	13,549,419	13,668,110	
2002 (report)	13,997,958	13,273,702	13,443,356	13,496,135	
2001 (report)	13,997,958	13,273,702	13,443,356	13,496,135	13,997,958
2001 2nd half	13,997,958	13,273,702	13,443,356	13,496,135	13,997,958
2001 1st half	13,997,958	13,273,702	13,443,356	13,496,135	

5.1.3 Generator Volumes

The forecast total generator output is given in Table 5-4 and individual generator forecast volumes are given in Table 5-5 through Table 5-10 as follows:

- Table 5-5 Individual Generator Raw Loss Factors Used in Shift Factor Calculations
- Table 5-6 Individual Generator Output (MWh) Used in Shift Factor Calculations (Winter)
- Table 5-7 Individual Generator Output (MWh) Used in Shift Factor Calculations (Spring)
- Table 5-8 Individual Generator Output (MWh) Used in Shift Factor Calculations (Summer)
- Table 5-9 Individual Generator Output (MWh) Used in Shift Factor Calculations (Fall)
- Table 5-10 Individual Generator Output (MWh) Used in Shift Factor Calculations

Table 5-11 summarizes total annual volumes for all generators.

There were inconsistencies in the naming of generators between the original sources of information. In the 2002 and 2003 spreadsheets, 'MP_ID' was introduced as a unique description of the generator. The Auditor used these "id's" as a basis for attempting to tie all of the information together. Prior to the 2002 spreadsheet, only total generation at Cloverbar, Genesee, Keephills, Rossdale, Sundance, Sheerness and Wabamun was included in the calculation. The generators were treated individually in the 2002 and 2003 spreadsheets, with their own unique MP_ID. The Auditor's assignment of the total generation to a single MP_ID was done only on the basis of matching corresponding raw loss factors.

In calculating the shift factors for all of the 2001 calculations, and the 2002 (report), the AESO included a number of small entries in the spreadsheet, presumably to accommodate additions of future generators, loads, etc. Each of these entries is assigned a volume of 1 MWh per season. The Auditor did not include these volumes, which accounted for the slight difference of about 40 MWh in each of the four tables.

Total generator volumes are identical in each of the 2001 and 2002 (report) shift factor calculations. Distribution by generator is also identical, with the exception of the 2002 (report) for the Taylor (Magrath) and Three Sisters generators. No volumes were supplied for Taylor and volumes were supplied for Three Sisters in the 2002 (report) shift factor calculations while in the 2001 cases, volumes were supplied for Taylor and no volumes were supplied for 'Three Sisters'. The volumes for 'Three Sisters' in the 2002 (report) are the same volumes as used for Taylor in the 2001 cases.

The total volumes for 2001 and 2002 (report) include equivalent generation from Langdon (BC intertie), McNeill (Sask. Intertie) and two other sources, namely: 'Bridge Ck.' And 'DVPL IPP'.

The 2002 spreadsheet includes volumes for the two interties as well as for Three Sisters, but these are not included in the shift factor calculations. In the 2002 spreadsheet, generation from the City of Medicine Hat, and Interlakes was dropped from the earlier set of calculations for 2002 (report), and volumes from Cloverbar, Poplar Hill, Rossdale, Suncor and Sturgeon significantly reduced. Significant volumes were added at Shell Scotsford, Dow Chemical, Fort Nelson, Syncrude, Turbo Balzac, Rainbow Lake, Namaka and Carseland with smaller volumes added at Taylor and Westlock. The AESO advises that *"generation volume for Medicine Hat was dropped in 2002 because behind- fence-load was taken into consideration"*.

With the significant increase in forecast losses (894,000 MWh) between the 2002 (report) and 2002 cases, the Auditor would have expected an even greater increase in total generator volumes taking into account a possible increase in system size and capacity. This is not the case as the estimated total generator volumes increased by only 540,000 MWh.

For the 2003 shift factor calculations, generation volumes were restored for the City of Medicine Hat, Interlakes and Three Sisters and Generation at Westlock was dropped. New volumes were added at Diashowa, Redwater, Shell Scotsford, Valleyview, and Proctor &Gamble and Volumes at Fort Nelson were reduced to close to 2001 levels. Generation at Turbo Balzac and Namaka were reduced to less than half the 2002 volumes. Rossdale and Sturgeon generation volumes were restored to less than ½ of the 2001 levels while volumes were shifted between Suncor and Syncrude. In addition there were large reductions in the volumes forecast for Sheerness and Wabamun.

The total generation volumes are reduced from the 2002 forecast levels and are actually less than the 2001 forecast levels.

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Table 5-5 Individual Generator Raw Loss Factors Used in Shift Factor Calculations

				2003				2002				2002 (report)				2001 (report)					2001-2nd half					2001-1st half			
MP_ID	Name	Transmission Station Name	Facility Code	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall	dec	Winter	Spring	Summer	Fall	dec	Winter	Spring	Summer	Fall
ALS1	AIR LIQU	SHELL SCOTFORD	409S	-3.6%	-1.9%	-3.4%	-2.5%	-3.6%	-1.8%	-3.4%	-2.5%	-3.6%	-1.8%	-3.4%	-2.5%	-1.9%	-3.0%	-1.9%	-1.8%	-1.7%	-1.9%	-3.0%	-1.9%	-1.8%	-1.7%	-1.9%	-3.0%	-1.9%	-1.1%
BAR	BARRIER	BARRIER HYDRO PLANT	32S	-17.4%	-12.6%	-15.5%	-13.9%	-17.4%	-12.6%	-15.5%	-13.9%	-17.4%	-12.6%	-15.5%	-13.9%	-13.1%	-11.8%	-12.2%	-9.2%	-9.9%	-13.1%	-11.8%	-12.2%	-9.2%	-9.9%	-13.1%	-11.8%	-12.2%	-11.2%
BIG	BIGHORN	BIGHORN HYDRO PLANT	250P	-10.4%	-6.3%	-9.7%	-7.5%	-10.4%	-6.3%	-9.7%	-7.6%	-10.4%	-6.3%	-9.7%	-7.6%	-3.1%	-6.0%	-3.6%	-4.9%	-1.5%	-3.1%	-6.0%	-3.6%	-4.9%	-1.5%	-3.1%	-6.0%	-3.6%	-6.1%
BPW	BEARSPAW	BEARSPAW HYDRO PLANT	44S	-15.9%	-12.1%	-14.8%	-12.4%	-15.9%	-12.0%	-14.8%	-12.5%	-15.9%	-12.0%	-14.8%	-12.5%	-15.7%	-12.1%	-15.0%	-9.7%	-12.1%	-15.7%	-12.1%	-15.0%	-9.7%	-12.1%	-15.7%	-12.1%	-15.0%	-11.6%
BR3	Battle River 3&4	BATTLE RIVER (UNITS 3 & 4)	757S	1.7%	-6.9%	-0.3%	-0.6%	1.6%	-6.9%	-0.3%	-0.6%	1.6%	-6.9%	-0.3%	-0.6%	4.5%	1.5%	-5.1%	0.0%	1.1%	4.5%	1.5%	-5.1%	0.0%	1.1%	4.5%	1.5%	-5.1%	-0.7%
BR4	Battle River 3&4	BATTLE RIVER (UNITS 3 & 4)	757S	1.7%	-6.9%	-0.3%	-0.6%	1.6%	-6.9%	-0.3%	-0.6%																		
BR5	Battle River 5	BATTLE RIVER (UNIT 5)	757S	-0.2%	-7.4%	-1.3%	-2.4%	-0.2%	-7.4%	-1.3%	-2.5%	-0.2%	-7.4%	-1.3%	-2.5%	1.7%	0.3%	-7.7%	-2.8%	0.1%	1.7%	0.3%	-7.7%	-2.8%	0.1%	1.7%	0.3%	-7.7%	-4.0%
BRA	BRAZEAU	BRAZEAU HYDRO PLANT	62S	-3.7%	-2.8%	-3.8%	-2.1%	-3.7%	-2.7%	-3.8%	-2.1%	-3.7%	-2.7%	-3.8%	-2.1%	-0.5%	-1.6%	-1.4%	-0.8%	0.7%	-0.5%	-1.6%	-1.4%	-0.8%	0.7%	-0.5%	-1.6%	-1.4%	-1.6%
CAS	CASCADE	CASCADE HYDRO PLANT	29S	-17.8%	-12.5%	-16.4%	-13.9%	-17.8%	-12.5%	-16.4%	-13.9%	-17.8%	-12.5%	-16.4%	-13.9%	-13.1%	-12.2%	-11.9%	-9.7%	-9.8%	-13.1%	-12.2%	-11.9%	-9.7%	-9.8%	-13.1%	-12.2%	-11.9%	-11.7%
CG1	Cloverbar	CLOVERBAR	Cloverbar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CG2	Cloverbar	CLOVERBAR	Cloverbar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CG3	Cloverbar	CLOVERBAR	Cloverbar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CG4	Cloverbar	CLOVERBAR	Cloverbar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CMH1	CMH 7&10	CITY OF MEDICINE HAT POWER PLANT	CMH PLANT	-0.3%	-17.3%	-12.9%	-7.6%					-0.3%	-17.3%	-12.9%	-7.6%	-8.9%	-5.2%	-16.0%	-4.2%	-6.6%	-8.9%	-5.2%	-16.0%	-4.2%	-6.6%	-8.9%	-5.2%	-16.0%	-6.2%
DAI1	DSH PLNT	DIASHOWA	839S	-23.4%	-13.6%	-19.0%	-21.7%																						
DOW1	Dow	DOWCHEMICAL FORT SASKATCHEWAN	166S	-2.0%	-0.3%	-1.5%	-1.0%	-2.0%	-0.3%	-1.5%	-1.1%	-2.0%	-0.3%	-1.5%	-1.1%	-1.5%	-1.0%	-1.5%	-2.5%	-1.3%	-1.5%	-1.0%	-1.5%	-2.5%	-1.3%	-1.5%	-1.0%	-1.5%	-0.7%
DOWG	Dow	DOWCHEMICAL FORT SASKATCHEWAN	166S	-2.0%	-0.3%	-1.5%	-1.0%																						
DRW1	Drywood			-15.8%	-12.7%	-15.0%	-12.5%																						
FNG1	FORT NEL	FORT NELSON	FNG	-13.8%	-14.7%	-9.1%	-23.2%	-13.9%	-14.7%	-9.1%	-23.2%	-13.9%	-14.7%	-9.1%	-23.2%	-4.8%	-2.3%	-9.8%	-5.1%	-4.3%	-4.8%	-2.3%	-9.8%	-5.1%	-4.3%	-4.8%	-2.3%	-9.8%	-5.5%
GHO	GHOST GE	GHOST HYDRO PLANT	20S	-16.8%	-12.7%	-15.8%	-13.4%	-16.9%	-12.7%	-15.8%	-13.4%	-16.9%	-12.7%	-15.8%	-13.4%	-14.7%	-12.5%	-13.8%	-9.9%	-11.2%	-14.7%	-12.5%	-13.8%	-9.9%	-11.2%	-14.7%	-12.5%	-13.8%	-11.9%
GN1	Genesee	GENESEE	GENESEE	2.5%	2.8%	1.7%	3.1%	2.5%	2.8%	1.7%	3.1%	2.5%	2.8%	1.7%	3.1%	3.8%	2.9%	2.2%	3.4%	4.2%	3.8%	2.9%	2.2%	3.4%	4.2%	3.8%	2.9%	2.2%	3.0%
GN2	Genesee	GENESEE	GENESEE	2.5%	2.8%	1.7%	3.1%	2.5%	2.8%	1.7%	3.1%																		
HRM	HR MILNR	H.R. MILNER	740S	4.0%	-5.6%	-10.8%	-13.9%	-16.4%	-5.6%	-10.8%	-13.8%	-16.4%	-5.6%	-10.8%	-13.8%	-1.9%	-8.3%	-13.2%	-10.0%	-1.4%	-1.9%	-8.3%	-13.2%	-10.0%	-1.4%	-1.9%	-8.3%	-13.2%	-10.2%
HSH	HORS GEN	SEEBE HYDRO PLANT	245S	-17.1%	-13.0%	-16.3%	-13.8%	-17.2%	-13.0%	-16.2%	-13.8%	-17.2%	-13.0%	-16.2%	-13.8%	-13.7%	-12.2%	-12.8%	-9.8%	-10.5%	-13.7%	-12.2%	-12.8%	-9.8%	-10.5%	-13.7%	-12.2%	-12.8%	-11.5%
INT	Interlakes			-17.7%	-14.0%	-16.4%	-14.2%					0.0%	0.0%	0.0%	0.0%	-6.0%	-6.1%	-5.1%	0.0%	0.0%	-6.0%	-6.1%	-5.1%	0.0%	0.0%	-6.0%	-6.1%	-5.1%	-4.9%
JOF1	Nova	A.G.E JOFFRE	535S	-2.9%	-0.9%	-2.5%	-1.3%	-2.9%	-0.9%	-2.5%	-1.3%	-2.9%	-0.9%	-2.5%	-1.3%	0.0%	-4.3%	-0.7%	-3.4%	1.3%	0.0%	-4.3%	-0.7%	-3.4%	1.3%	0.0%	-4.3%	-0.7%	-4.7%
KAN	KANANASK	KANANASKIS HYDRO	2S	-17.3%	-13.1%	-15.7%	-13.8%	-17.4%	-13.0%	-15.6%	-13.8%	-17.4%	-13.0%	-15.6%	-13.8%	-13.5%	-12.0%	-12.6%	-9.5%	-10.3%	-13.5%	-12.0%	-12.6%	-9.5%	-10.3%	-13.5%	-12.0%	-12.6%	-11.3%
KH1	KEEP#1GN	KEEPHILLS	320P	2.5%	2.5%	2.0%	3.2%	2.5%	2.6%	2.0%	3.2%	2.5%	2.6%	2.0%	3.2%	3.8%	2.7%	2.0%	3.4%	4.2%	3.8%	2.7%	2.0%	3.4%	4.2%	3.8%	2.7%	2.0%	2.8%
KH2	KEEP#2GN	KEEPHILLS	320P	2.5%	2.5%	2.0%	3.2%	2.5%	2.6%	2.0%	3.2%	2.5%	2.6%	2.0%	3.2%	3.8%	2.7%	2.0%	3.4%	4.2%	3.8%	2.7%	2.0%	3.4%	4.2%	3.8%	2.7%	2.0%	2.8%
NX01	BALZAC T	TURBO BALZAC	391S	-15.6%	-11.8%	-15.0%	-11.2%	-15.6%	-11.8%	-15.0%	-11.2%																		
PC01	NAMAKA	NAMAKA	428S	-15.0%	-11.2%	-14.9%	-10.8%	-15.0%	-11.2%	-14.9%	-10.8%																		
PH1	POPLAR-4	POPLAR HILL	790S	-26.9%	-14.3%	-17.5%	-26.6%	-27.0%	-14.3%	-17.5%	-26.6%	-27.0%	-14.3%	-17.5%	-26.6%	-18.7%	-20.8%	-26.9%	-23.4%	-18.0%	-18.7%	-20.8%	-26.9%	-23.4%	-18.0%	-18.7%	-20.8%	-26.9%	-23.3%
POC	POCATERR	POCATERRA HYDRO PLANT	48S	-17.7%	-14.0%	-16.4%	-14.2%	-17.7%	-14.0%	-16.4%	-14.2%	-17.7%	-14.0%	-16.4%	-14.2%	-13.5%	-11.8%	-12.4%	-9.4%	-10.6%	-13.5%	-11.8%	-12.4%	-9.4%	-10.6%	-13.5%	-11.8%	-12.4%	-10.5%
PR1	PRIM GEN	PRIMROSE	859S	-4.7%	-1.5%	-1.6%	-3.4%	-4.7%	-1.5%	-1.6%	-3.4%	-4.7%	-1.5%	-1.6%	-3.4%	-1.5%	0.3%	-1.3%	0.1%	-1.3%	-1.5%	0.3%	-1.3%	0.1%	-1.3%	-1.5%	0.3%	-1.3%	-0.1%
RB2	Rainbow	RAINBOW LAKE	791S					-14.4%	-13.2%	-9.8%	-22.0%					-7.5%	-2.8%	-10.3%	-5.9%	-7.0%	-7.5%	-2.8%	-10.3%	-5.9%	-7.0%	-7.5%	-2.8%	-10.3%	-6.0%
RB3	Rainbow	RAINBOW LAKE	791S	-14.4%	-13.2%	-9.8%	-22.0%	-14.4%	-13.2%	-9.8%	-22.0%	-14.4%	-13.2%	-9.8%	-22.0%	-7.5%	-2.8%	-10.3%	-5.9%	-7.0%	-7.5%	-2.8%	-10.3%	-5.9%	-7.0%	-7.5%	-2.8%	-10.3%	-6.0%
RB5	Rainbow Lake 5 (CUPC)			[redacted]																									
RG10	Rossdale	ROSSDALE	ROSSDALE	-0.7%	0.7%	-0.8%	0.1%	-0.7%	0.7%	-0.7%	0.2%	-0.7%	0.7%	-0.7%	0.2%	-0.3%	0.3%	-0.6%	0.9%	0.1%	-0.3%	0.3%	-0.6%	0.9%	0.1%	-0.3%	0.3%	-0.6%	0.5%
RG8	Rossdale	ROSSDALE	ROSSDALE	-0.7%	0.7%	-0.8%	0.1%	-0.7%	0.7%	-0.7%	0.2%	-0.7%	0.7%	-0.7%	0.2%	-0.3%	0.3%	-0.6%	0.9%	0.1%	-0.3%	0.3%	-0.6%	0.9%	0.1%	-0.3%	0.3%	-0.6%	0.5%
RG9	Rossdale	ROSSDALE	ROSSDALE	-0.7%	0.7%	-0.8%	0.1%	-0.7%	0.7%	-0.7%	0.2%	-0.7%	0.7%	-0.7%	0.2%	-0.3%	0.3%	-0.6%	0.9%	0.1%	-0.3%	0.3%	-0.6%	0.9%	0.1%	-0.3%	0.3%	-0.6%	0.5%
RL1	Rainbow Lake (CUPC)			-14.4%	-13.2%	-9.8%	-22.0%	-14.4%	-13.2%	-9.8%	-22.0%																		
RUN	RUNDLE G	RUNDLE HYDRO PLANT	35S	-17.0%	-12.4%	-15.9%	-13.8%	-17.1%	-12.4%	-15.9%	-13.8%	-17.1%	-12.4%	-15.9%	-13.8%	-12.7%	-11.9%	-11.7%	-9.3%	-9.5%	-12.7%	-11.9%	-11.7%	-9.3%	-9.5%	-12.7%	-11.9%	-11.7%	-11.3%
SCL1	Syncrude	SYNCRUDE	SYNCRUDE	1.2%	3.5%	0.9%	2.8%	1.1%	3.5%	0.9%	2.8%	1.1%	3.5%	0.9%	2.8%	5.9%	6.9%	5.8%	7.0%	6.2%	5.9%	6.9%	5.8%	7.0%	6.2%	5.9%	6.9%	5.8%	6.8%
SCR1	Suncor	SUNCOR	753S	2.8%	5.5%	2.9%	4.1%	2.8%	5.5%	2.9%	4.1%	2.8%	5.5%	2.9%	4.1%	5.4%	6.4%	5.2%	6.2%	5.7%	5.4%	6.4%	5.2%	6.2%	5.7%	5.4%	6.4%	5.2%	6.3%
SCTG	Air Liquide (Shell Scotsford)			[redacted]																									
SD1	Sundance	SUNDANCE	310P	3.5%	5.2%	3.4%	3.8%	3.5%	5.2%	3.4%	3.8%	3.5%	5.2%	3.4%	3.8%	5.4%	5.7%	4.7%	6.0%	5.9%	5.4%	5.7%	4.7%	6.0%	5.9%	5.4%	5.7%	4.7%	5.7%
SD2	Sundance	SUNDANCE	310P	3.5%	5.2%	3.4%	3.8%	3.5%	5.2%	3.4%	3.8%	3.5%	5.2%	3.4%	3.8%	5.4%	5.7%	4.7%	6.0%	5.9%	5.4%	5.7%	4.7%	6.0%	5.9%	5.4%	5.7%	4.7%	5.7%
SD3	Sundance	SUNDANCE	310P	3.5%	5.2%	3.4%	3.8%	3.5%	5.2%	3.4%	3.8%	3.5%	5.2%	3.4%	3.8%	5.4%	5.7%	4.7%	6.0%	5.9%	5.4%	5.7%	4.7%	6.0%	5.9%	5.4%	5.7%	4.7%	5.7%
SD4	Sundance	SUNDANCE	310P	3.5%	5.2%	3.4%	3.8%	3.5%	5.2%	3.4%	3.8%	3.5%	5.2%	3.4%	3.8%	5.4%	5.7%	4.7%	6.0%	5.9%	5.4%	5.7%	4.7%	6.0%	5.9%	5.4%	5.7%	4.7%	5.7%
SD5	Sundance	SUNDANCE	310P	3.5%	5.2%	3.4%	3.8%	3.5%	5.2%	3.4%	3.8%	3.5%	5.2%	3.4%	3.8%	5.4%	5.7%	4.7%	6.0%	5.9%	5.4%	5.7%	4.7%	6.0%	5.9%	5.4%	5.7%	4.7%	5.7%
SD6	Sundance	SUNDANCE	310P	3.5%	5.2%	3.4%	3.8%	3.5%	5.2%	3.4%	3.8%	3.5%	5.2%	3.4%	3.8%	5.4%	5.7%	4.7%	6.0%	5.9%	5.4%	5.7%	4.7%	6.0%	5.9%	5.4%	5.7%	4.7%	5.7%
SH1	Sheerness	SHEERNESS	807S	-0.4%	-4.5%	-2.4%	-0.5%	-0.4%	-4.5%	-2.4%	-0.4%	-0.4%	-4.5%	-2.4%	-0.4%	-1.4%	-0.3%	-5.7%	0.0%	-0.7%	-1.4%	-0.3%	-5.7%	0.0%	-0.7%	-1.4%	-0.3%	-5.7%	-1.8%
SH2	Sheerness	SHEERNESS	807S	-0.4%	-4.5%	-2.4%	-0.5%	-0.4%	-4.5%	-2.4%	-0.4%	-0.4%	-4.5%	-2.4%	-0.4%	-1.4%	-0.3%	-5.7%	0.0%	-0.7%	-1.4%	-0.3%	-5.7%	0.0%	-0.7%	-1.4%	-0.3%	-5.7%	-1.8%
SPR	Spray	SPRAY HYDRO PLANT	33S	-17.0%	-12.3%	-15.7%	-13.3%	-17.0%	-12.2%	-15.7%	-13.2%	-17.0%	-12.2%	-15.7%	-13.2%	-12.5%	-11.7%	-11.4%	-9.1%	-9.2%	-12.5%	-11.7%	-11.4%	-9.1%	-9.2%	-12.5%	-11.7%	-11.4%	-11.1%
ST1	STURGEON	STURGEON	734S	-14.4%	-6.2%	-11.0%	-12.5%	-14.4%	-6.1%	-11.0%	-12.5%	-14.4%	-6.1%	-11.0%	-12.5%	-7.8%	-7.3%	-11.2%	-8.9%	-7.1%	-7.8%	-7.3%	-11.2%	-8.9%	-7.1%	-7.8%	-7.3%	-11.2%	-8.7%
ST2	STURGEON	STURGEON	734S	-14.4%	-6.2%	-11.0%	-12.5%	-14.4%	-6.1%	-11.0%	-12.5%																		
TAY1	TAYLOR	MAGRATH	225S	-9.9%	-6.3%	-8.3%	-7.7%	-10.0%	-6.3%	-8.3%	-7.6%	-10.0%	-6.3%	-8.3%	-7.6%	-4.5%	-4.2%	-3.7%	-9.0%	-11.6%	-4.5%	-4.2%	-3.7%	-9.0%	-11.6%	-4.5%	-4.2%	-3.7%	-3.7%
TC01	CARSELAN	CARSELAND	525S	-15.6%	-11.7%	-15.1%	-11.1%	-15.6%	-11.7%	-15.1%	-11.1%																		
TC02	Redwater Cogen (TCP)			[redacted]																									
THS	THREE SI			-17.0%	-12.4%	-15.9%	-13.8%					0.0%	0.0%	0.0%	0.0%														
VVW1	Valleyview			[redacted]																									
WB1	Wabamun 1&2	WABAMUN (UNITS 1 & 2)	19S	3.2%	5.6%	4.5%	4.6%	3.1%	5.6%	4.5%	4.7%	3.1%	5.6%	4.5%	4.7%	6.4%	7.7%	6.2%	7.6%	6.8%	6.4%	7.7%	6.2%	7.6%	6.8%	6.4%	7.7%	6.2%	7.4%
WB2	Wabamun 1&2	WABAMUN (UNITS 1 & 2)	19S	3.2%	5.6%	4.5%	4.6%	3.1%	5.6%	4.5%	4.7%																		
WB3	Wabamun 3&4	WABAMUN (UNITS 3 & 4)	19S					3.3%	4.5%	3.3%	3.5%					4.9%	5.3%	4.3%	5.3%	5.4%	4.9%	5.3%	4.3%	5.3%	5.4%	4.9%	5.3%	4.3%	5.3%
WB4	Wabamun 3&4	WABAMUN (UNITS 3 & 4)	19S	3.3%	4.5%	3.2%	3.5%	3.3%	4.5%	3.3%	3.5%	3.3%	4.5%	3.3%	3.5%														
WST1	WESGEN	WESTLOCK	DAPP					-2.2%	2.0%	-1.1%	-0.7%																		
WEY1	P&G	PROCTER & GAMBLE	808S	-22.1%	-10.5%	-15.7%	-19.6%																						
	BRDGE CK (NOVA GOLD CREEK)															-12.7%	-14.3%	-19.7%			-12.7%	-14.3%	-19.7%			-12.7%	-14.3%	-19.7%	-16.6%
	DVPL IPP											-3.1%	-0.9%	-3.0%	-1.2%	-0.5%	-0.8%	-1.6%	-0.3%	0.4%	-0.5%	-0.8%	-1.6%	-0.3%	0.4%	-0.5%	-0.8%	-1.6%	-0.9%
	LANGDON											-12.5%	-10.7%	-12.5%	-9.9%	-12.1%	-8.9%	-11.9%	-6.0%	-9.1%	-12.1%	-8.9%	-11.9%	-6.0%	-9.1%	-12.1%	-8.9%	-11.9%	-7.7%
	MCNEILL											-5.7%	-15.7%	-9.3%	-7.1%	-14.0%	-12.6%	-17.6%	-12.3%	-12.2%	-14.0%	-12.6%	-17.6%	-12.3%	-12.2%	-14.0%	-12.6%	-17.6%	-14.3%

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Table 5-6 Individual Generator Output (MWh) Used in Shift Factor Calculations (Winter)

Individual Generator Output (MWh) Used in Shift Factor Calculations									
				winter					
MP_ID	Name	Transmission Station Name	Facility Code	2003	2002	2002 (rep.)	2001(rep.)	2001-2nd	2001-1st
ALS1	AIR LIQU	SHELL SCOTFORD	409S	119,145	163,548	48,019	48,019	48,019	48,019
BAR	BARRIER	BARRIER HYDRO PLANT	32S	8,386	10,008	9,895	9,895	9,895	9,895
BIG	BIGHORN	BIGHORN HYDRO PLANT	250P	108,445	159,690	128,592	128,592	128,592	128,592
BPW	BEARSPAW	BEARSPAW HYDRO PLANT	44S	11,295	11,295	14,189	14,189	14,189	14,189
BR3	Battle River 3&4	BATTLE RIVER (UNITS 3 & 4)	757S	238,904	276,368	466,694	466,694	466,694	466,694
BR4	Battle River 3&4	BATTLE RIVER (UNITS 3 & 4)	757S	33,439	280,361	-	-	-	-
BR5	Battle River 5	BATTLE RIVER (UNIT 5)	757S	240,886	728,095	720,237	720,237	720,237	720,237
BRA	BRAZEAU	BRAZEAU HYDRO PLANT	62S	77,053	43,600	57,155	57,155	57,155	57,155
CAS	CASCADE	CASCADE HYDRO PLANT	29S	20,293	14,472	20,811	20,811	20,811	20,811
CG1	Cloverbar	CLOVERBAR	Cloverbar	-	9,634	359,313	359,313	359,313	359,313
CG2	Cloverbar	CLOVERBAR	Cloverbar	110,444	19,229	-	-	-	-
CG3	Cloverbar	CLOVERBAR	Cloverbar	84	40,869	-	-	-	-
CG4	Cloverbar	CLOVERBAR	Cloverbar	139,357	80,906	-	-	-	-
CMH1	CMH 7&10	CITY OF MEDICINE HAT POWER PLANT	CMH PLANT	196,669		47,537	47,537	47,537	47,537
DAI1	DSH PLNT	DIASHOWA	839S	13,061		-			
DOW1	Dow	DOWCHEMICAL FORT SASKATCHEWAN	166S	110,587	252,649	57,555	57,555	57,555	57,555
DOWG	Dow	DOWCHEMICAL FORT SASKATCHEWAN	166S	201,733		-	-	-	-
DRW1	Drywood			19					
FNG1	FORT NEL	FORT NELSON	FNG	14,003	98,520	14,672	14,672	14,672	14,672
GHO	GHOST GE	GHOST HYDRO PLANT	20S	26,392	25,011	29,803	29,803	29,803	29,803
GN1	Genesee	GENESEE	GENESEE	488,064	797,470	1,584,860	1,584,860	1,584,860	1,584,860
GN2	Genesee	GENESEE	GENESEE	477,300	769,653	-	-	-	-
HRM	HR MILNR	H.R. MILNER	740S	197,986	262,891	248,597	248,597	248,597	248,597
HSH	HORS GEN	SEEBE HYDRO PLANT	245S	16,131	14,347	18,510	18,510	18,510	18,510
INT	Interlakes			393		2,639	2,639	2,639	2,639
JOF1	Nova	A.G.E JOFFRE	535S	695,230	511,278	701,783	701,783	701,783	701,783
KAN	KANANASK	KANANASKIS HYDRO	2S	16,355	14,873	18,958	18,958	18,958	18,958
KH1	KEEP#1GN	KEEPHILLS	320P	508,586	800,411	1,585,577	1,585,577	1,585,577	1,585,577
KH2	KEEP#2GN	KEEPHILLS	320P	738,176	753,807	-	-	-	-
NX01	BALZAC T	TURBO BALZAC	391S	127,732	203,328				
PC01	NAMAKA	NAMAKA	428S	21,390	232,675				
PH1	POPLAR-4	POPLAR HILL	790S	61,018	35,466	43,762	43,762	43,762	43,762
POC	POCATERR	POCATERRA HYDRO PLANT	48S	7,694	7,343	10,172	10,172	10,172	10,172
PR1	PRIM GEN	PRIMROSE	859S	109,335	123,650	157,207	157,207	157,207	157,207
RB2	Rainbow	RAINBOW LAKE	791S		85,230	89,077	89,077	89,077	89,077
RB3	Rainbow	RAINBOW LAKE	791S	1,219	44,292				
RB5	Rainbow Lake 5 (CUPC)			84,460		-			
RG10	Rossdale	ROSSDALE	ROSSDALE	1,384	1,640	91,074	91,074	91,074	91,074
RG8	Rossdale	ROSSDALE	ROSSDALE	26,799	396	-	-	-	-
RG9	Rossdale	ROSSDALE	ROSSDALE	24,157	385	-	-	-	-
RL1	Rainbow Lake (CUPC)			106,334	96,489	-	-	-	-
RUN	RUNDLE G	RUNDLE HYDRO PLANT	35S	17,932	14,308	22,744	22,744	22,744	22,744
SCL1	Syncrude	SYNCRUDE	SYNCRUDE	179,389	120,598	62,512	62,512	62,512	62,512
SCR1	Suncor	SUNCOR	753S	360,902	275,647	467,387	467,387	467,387	467,387
SCTG	Air Liquide (Shell Scotsford)			195,388					
SD1	Sundance	SUNDANCE	310P	580,716	553,877	4,018,796	4,018,796	4,018,796	4,018,796
SD2	Sundance	SUNDANCE	310P	606,798	582,415	-	-	-	-
SD3	Sundance	SUNDANCE	310P	750,450	711,053	-	-	-	-
SD4	Sundance	SUNDANCE	310P	761,027	720,098	-	-	-	-
SD5	Sundance	SUNDANCE	310P	764,216	730,399	-	-	-	-
SD6	Sundance	SUNDANCE	310P	868,898	746,596	-	-	-	-
SH1	Sheerness	SHEERNESS	807S	120,868	732,900	1,478,965	1,478,965	1,478,965	1,478,965
SH2	Sheerness	SHEERNESS	807S	859,854	768,255	-	-	-	-
SPR	Spray	SPRAY HYDRO PLANT	33S	50,526	43,293	67,300	67,300	67,300	67,300
ST1	STURGEON	STURGEON	734S	-	10	4,351	4,351	4,351	4,351
ST2	STURGEON	STURGEON	734S	951	30	-	-	-	-
TAY1	TAYLOR	MAGRATH	225S	-	12	-	887	887	887
TC01	CARSELAN	CARSELAND	525S	178,784	169,790				
TC02	Redwater Cogen (TCP)			88,390					
THS	THREE SI			622		887			
VVW1	Valleyview			5,539					
WB1	Wabamun 1&2	WABAMUN (UNITS 1 & 2)	19S	138,630	129,168	252,726	252,726	252,726	252,726
WB2	Wabamun 1&2	WABAMUN (UNITS 1 & 2)	19S	115,846	127,588	-	-	-	-
WB3	Wabamun 3&4	WABAMUN (UNITS 3 & 4)	19S		245,804	687,176	687,176	687,176	687,176
WB4	Wabamun 3&4	WABAMUN (UNITS 3 & 4)	19S	229,768	478,960				
WST1	WESGEN	WESTLOCK	DAPP		18,481				
WEY1	P&G	PROCTER & GAMBLE	808S	122,834					
	BRDGE CK (NOVA GOLD CREEK)					7772	7,772	7,772	7,772
	DVPL IPP					3,388	3,388	3,388	3,388
	LANGDON					326,057	326,057	326,057	326,057
	MCNEILL					71,169	71,169	71,169	71,169
	Total			12,378,272	14,139,161	13,997,918	13,997,918	13,997,917	13,997,917
	Original Total			12,378,272	14,139,161	13,997,959	13,997,958	13,997,958	13,997,958
	Difference			-	-	(41)	(40)	(41)	(41)

Table 5-7 Individual Generator Output (MWh) Used in Shift Factor Calculations (Spring)

Individual Generator Output (MWh) Used in Shift Factor Calculations									
				spring					
MP_ID	Name	Transmission Station Name	Facility Code	2003	2002	2002 (rep.)	2001(rep.)	2001-2nd	2001-1st
ALS1	AIR LIQU	SHELL SCOTFORD	409S	112,490	157,074	52,286	52,286	52,286	52,286
BAR	BARRIER	BARRIER HYDRO PLANT	32S	11,382	10,734	10,946	10,946	10,946	10,946
BIG	BIGHORN	BIGHORN HYDRO PLANT	250P	101,851	106,377	108,487	108,487	108,487	108,487
BPW	BEARSPAW	BEARSPAW HYDRO PLANT	44S	13,805	18,575	18,944	18,944	18,944	18,944
BR3	Battle River 3&4	BATTLE RIVER (UNITS 3 & 4)	757S	234,738	282,379	385,904	385,904	385,904	385,904
BR4	Battle River 3&4	BATTLE RIVER (UNITS 3 & 4)	757S	97,054	286,459	-	-	-	-
BR5	Battle River 5	BATTLE RIVER (UNIT 5)	757S	199,064	743,930	724,178	724,178	724,178	724,178
BRA	BRAZEAU	BRAZEAU HYDRO PLANT	62S	69,136	38,782	39,551	39,551	39,551	39,551
CAS	CASCADE	CASCADE HYDRO PLANT	29S	8,232	6,906	7,043	7,043	7,043	7,043
CG1	Cloverbar	CLOVERBAR	Cloverbar	-	1,825	267,809	267,809	267,809	267,809
CG2	Cloverbar	CLOVERBAR	Cloverbar	75,155	6,212	-	-	-	-
CG3	Cloverbar	CLOVERBAR	Cloverbar	1,758	31,559	-	-	-	-
CG4	Cloverbar	CLOVERBAR	Cloverbar	2,166	69,793	-	-	-	-
CMH1	CMH 7&10	CITY OF MEDICINE HAT POWER PLANT	CMH PLANT	219,513		34,881	34,881	34,881	34,881
DAI1	DSH PLNT	DIASHOWA	839S	8,567		-			
DOW1	Dow	DOWCHEMICAL FORT SASKATCHEWAN	166S	116,193	239,841	61,654	61,654	61,654	61,654
DOWG	Dow	DOWCHEMICAL FORT SASKATCHEWAN	166S	213,075		-	-	-	-
DRW1	Drywood			380					
FNG1	FORT NEL	FORT NELSON	FNG	11,597	100,663	18,029	18,029	18,029	18,029
GHO	GHOST GE	GHOST HYDRO PLANT	20S	28,594	52,652	53,697	53,697	53,697	53,697
GN1	Genesee	GENESEE	GENESEE	379,027	814,815	1,434,293	1,434,293	1,434,293	1,434,293
GN2	Genesee	GENESEE	GENESEE	378,550	521,413	-	-	-	-
HRM	HR MILNR	H.R. MILNER	740S	255,469	268,733	276,205	276,205	276,205	276,205
HSH	HORS GEN	SEEBE HYDRO PLANT	245S	17,338	19,504	19,891	19,891	19,891	19,891
INT	Interlakes			4,847		410	410	410	410
JOF1	Nova	A.G.E JOFFRE	535S	701,599	494,806	710,131	710,131	710,131	710,131
KAN	KANANASK	KANANASKIS HYDRO	2S	18,062	23,556	24,023	24,023	24,023	24,023
KH1	KEEP#1GN	KEEPHILLS	320P	518,335	817,819	1,379,240	1,379,240	1,379,240	1,379,240
KH2	KEEP#2GN	KEEPHILLS	320P	790,849	762,107	-	-	-	-
NX01	BALZAC T	TURBO BALZAC	391S	95,143	207,009				
PC01	NAMAKA	NAMAKA	428S	12,710	237,735				
PH1	POPLAR-4	POPLAR HILL	790S	61,539	27,443	52,920	52,920	52,920	52,920
POC	POCATERR	POCATERRA HYDRO PLANT	48S	10,454	2,641	2,693	2,693	2,693	2,693
PR1	PRIM GEN	PRIMROSE	859S	129,490	115,323	154,008	154,008	154,008	154,008
RB2	Rainbow	RAINBOW LAKE	791S		87,084	87,178	87,178	87,178	87,178
RB3	Rainbow	RAINBOW LAKE	791S	1,930	43,779				
RB5	Rainbow Lake 5 (CUPC)			84,151		-			
RG10	Rossdale	ROSSDALE	ROSSDALE	4,854	103	66,213	66,213	66,213	66,213
RG8	Rossdale	ROSSDALE	ROSSDALE	13,155	-	-	-	-	-
RG9	Rossdale	ROSSDALE	ROSSDALE	9,224	-	-	-	-	-
RL1	Rainbow Lake (CUPC)			99,153	98,587	-	-	-	-
RUN	RUNDLE G	RUNDLE HYDRO PLANT	35S	13,379	15,407	15,713	15,713	15,713	15,713
SCL1	Syncrude	SYNCRUDE	SYNCRUDE	167,266	109,736	59,278	59,278	59,278	59,278
SCR1	Suncor	SUNCOR	753S	349,741	234,178	470,635	470,635	470,635	470,635
SCTG	Air Liquide (Shell Scotsford)			229,276					
SD1	Sundance	SUNDANCE	310P	521,209	565,923	3,837,160	3,837,160	3,837,160	3,837,160
SD2	Sundance	SUNDANCE	310P	404,557	595,358	-	-	-	-
SD3	Sundance	SUNDANCE	310P	613,632	726,517	-	-	-	-
SD4	Sundance	SUNDANCE	310P	625,910	663,783	-	-	-	-
SD5	Sundance	SUNDANCE	310P	512,103	746,285	-	-	-	-
SD6	Sundance	SUNDANCE	310P	889,585	522,375	-	-	-	-
SH1	Sheerness	SHEERNESS	807S	245,038	740,877	1,387,314	1,387,314	1,387,314	1,387,314
SH2	Sheerness	SHEERNESS	807S	777,601	639,916	-	-	-	-
SPR	Spray	SPRAY HYDRO PLANT	33S	39,697	46,283	47,201	47,201	47,201	47,201
ST1	STURGEON	STURGEON	734S	-	-	4,252	4,252	4,252	4,252
ST2	STURGEON	STURGEON	734S	987	-	-	-	-	-
TAY1	TAYLOR	MAGRATH	225S	-	-	-	221	221	221
TC01	CARSELAN	CARSELAND	525S	175,213	169,319				
TC02	Redwater Cogen (TCP)			90,520					
THS	THREE SI			3		221			
VVW1	Valleyview			3,288					
WB1	Wabamun 1&2	WABAMUN (UNITS 1 & 2)	19S	116,357	90,376	279,319	279,319	279,319	279,319
WB2	Wabamun 1&2	WABAMUN (UNITS 1 & 2)	19S	118,099	130,363	-	-	-	-
WB3	Wabamun 3&4	WABAMUN (UNITS 3 & 4)	19S		251,150	781,137	781,137	781,137	781,137
WB4	Wabamun 3&4	WABAMUN (UNITS 3 & 4)	19S	288,964	436,184				
WST1	WESGEN	WESTLOCK	DAPP		14,550				
WEY1	P&G	PROCTER & GAMBLE	808S	93,905					
	BRDGE CK (NOVA GOLD CREEK)					7,721	7,721	7,721	7,721
	DVPL IPP					1,545	1,545	1,545	1,545
	LANGDON					350,038	350,038	350,038	350,038
	MCNEILL					41,512	41,512	41,512	41,512
	Total			11,386,959	13,394,798	13,273,660	13,273,660	13,273,661	13,273,661
	Original Total			11,386,959	13,394,798	13,273,703	13,273,702	13,273,702	13,273,702
	Difference			-	-	(43)	(42)	(41)	(41)

Table 5-8 Individual Generator Output (MWh) Used in Shift Factor Calculations (Summer)

Individual Generator Output (MWh) Used in Shift Factor Calculations									
				summer					
MP_ID	Name	Transmission Station Name	Facility Code	2003	2002	2002 (rep.)	2001(rep.)	2001-2nd	2001-1st
ALS1	AIR LIQU	SHELL SCOTFORD	409S	117,574	150,759	51,702	51,702	51,702	51,702
BAR	BARRIER	BARRIER HYDRO PLANT	32S	15,855	13,568	12,338	12,338	12,338	12,338
BIG	BIGHORN	BIGHORN HYDRO PLANT	250P	115,794	167,211	152,053	152,053	152,053	152,053
BPW	BEARSPAW	BEARSPAW HYDRO PLANT	44S	24,797	30,046	27,323	27,323	27,323	27,323
BR3	Battle River 3&4	BATTLE RIVER (UNITS 3 & 4)	757S	233,917	282,251	487,541	487,541	487,541	487,541
BR4	Battle River 3&4	BATTLE RIVER (UNITS 3 & 4)	757S	98,123	189,805	-	-	-	-
BR5	Battle River 5	BATTLE RIVER (UNIT 5)	757S	221,205	743,593	523,812	523,812	523,812	523,812
BRA	BRAZEAU	BRAZEAU HYDRO PLANT	62S	89,695	146,752	133,449	133,449	133,449	133,449
CAS	CASCADE	CASCADE HYDRO PLANT	29S	855	6,316	5,743	5,743	5,743	5,743
CG1	Cloverbar	CLOVERBAR	Cloverbar	20,813	9,991	286,675	286,675	286,675	286,675
CG2	Cloverbar	CLOVERBAR	Cloverbar	51,609	8,751	-	-	-	-
CG3	Cloverbar	CLOVERBAR	Cloverbar	2,358	40,682	-	-	-	-
CG4	Cloverbar	CLOVERBAR	Cloverbar	88,775	74,748	-	-	-	-
CMH1	CMH 7&10	CITY OF MEDICINE HAT POWER PLANT	CMH PLANT	198,415		20,592	20,592	20,592	20,592
DAI1	DSH PLNT	DIASHOWA	839S	9,160		-			
DOW1	Dow	DOWCHEMICAL FORT SASKATCHEWAN	166S	95,084	221,608	57,502	57,502	57,502	57,502
DOWG	Dow	DOWCHEMICAL FORT SASKATCHEWAN	166S	201,158		-	-	-	-
DRW1	Drywood			333					
FNG1	FORT NEL	FORT NELSON	FNG	10,114	100,617	17,388	17,388	17,388	17,388
GHO	GHOST GE	GHOST HYDRO PLANT	20S	77,574	74,114	67,396	67,396	67,396	67,396
GN1	Genesee	GENESEE	GENESEE	574,804	814,446	1,662,617	1,662,617	1,662,617	1,662,617
GN2	Genesee	GENESEE	GENESEE	604,246	700,559	-	-	-	-
HRM	HR MILNR	H.R. MILNER	740S	274,079	216,155	268,666	268,666	268,666	268,666
HSH	HORS GEN	SEEBE HYDRO PLANT	245S	29,299	31,291	28,455	28,455	28,455	28,455
INT	Interlakes			2,437		3,397	3,397	3,397	3,397
JOF1	Nova	A.G.E JOFFRE	535S	678,072	444,472	715,750	715,750	715,750	715,750
KAN	KANANASK	KANANASKIS HYDRO	2S	35,929	34,431	31,310	31,310	31,310	31,310
KH1	KEEP#1GN	KEEPHILLS	320P	671,121	817,448	1,604,507	1,604,507	1,604,507	1,604,507
KH2	KEEP#2GN	KEEPHILLS	320P	671,487	796,387	-	-	-	-
NX01	BALZAC T	TURBO BALZAC	391S	83,725	204,353				
PC01	NAMAKA	NAMAKA	428S	30,168	236,449				
PH1	POPLAR-4	POPLAR HILL	790S	51,350	29,429	54,539	54,539	54,539	54,539
POC	POCATERR	POCATERRA HYDRO PLANT	48S	8,801	9,971	9,067	9,067	9,067	9,067
PR1	PRIM GEN	PRIMROSE	859S	117,326	108,632	140,040	140,040	140,040	140,040
RB2	Rainbow	RAINBOW LAKE	791S		87,044	96,744	96,744	96,744	96,744
RB3	Rainbow	RAINBOW LAKE	791S	-	45,235				
RB5	Rainbow Lake 5 (CUPC)			84,035		-			
RG10	Rossdale	ROSSDALE	ROSSDALE	11,415	2,082	57,323	57,323	57,323	57,323
RG8	Rossdale	ROSSDALE	ROSSDALE	8,156	373	-	-	-	-
RG9	Rossdale	ROSSDALE	ROSSDALE	23,873	1,023	-	-	-	-
RL1	Rainbow Lake (CUPC)			104,704	98,543	-	-	-	-
RUN	RUNDLE G	RUNDLE HYDRO PLANT	35S	25,212	17,018	15,476	15,476	15,476	15,476
SCL1	Syncrude	SYNCRUDE	SYNCRUDE	181,646	103,776	58,189	58,189	58,189	58,189
SCR1	Suncor	SUNCOR	753S	360,968	219,841	423,918	423,918	423,918	423,918
SCTG	Air Liquide (Shell Scotsford)			215,499					
SD1	Sundance	SUNDANCE	310P	504,067	565,667	3,658,155	3,658,155	3,658,155	3,658,155
SD2	Sundance	SUNDANCE	310P	620,433	478,875	-	-	-	-
SD3	Sundance	SUNDANCE	310P	773,705	726,188	-	-	-	-
SD4	Sundance	SUNDANCE	310P	673,948	735,426	-	-	-	-
SD5	Sundance	SUNDANCE	310P	741,737	510,705	-	-	-	-
SD6	Sundance	SUNDANCE	310P	600,847	762,488	-	-	-	-
SH1	Sheerness	SHEERNESS	807S	240,334	765,504	1,331,075	1,331,075	1,331,075	1,331,075
SH2	Sheerness	SHEERNESS	807S	714,619	665,157	-	-	-	-
SPR	Spray	SPRAY HYDRO PLANT	33S	75,856	52,105	47,382	47,382	47,382	47,382
ST1	STURGEON	STURGEON	734S	15	7	4,701	4,701	4,701	4,701
ST2	STURGEON	STURGEON	734S	2,396	23	-	-	-	-
TAY1	TAYLOR	MAGRATH	225S	28,158	26,484	-	1,333	1,333	1,333
TC01	CARSELAN	CARSELAND	525S	180,859	166,641				
TC02	Redwater Cogen (TCP)			87,522					
THS	THREE SI			2,274		1,333			
VVW1	Valleyview			8,841					
WB1	Wabamun 1&2	WABAMUN (UNITS 1 & 2)	19S	142,670	131,918	267,335	267,335	267,335	267,335
WB2	Wabamun 1&2	WABAMUN (UNITS 1 & 2)	19S	91,112	130,304	-	-	-	-
WB3	Wabamun 3&4	WABAMUN (UNITS 3 & 4)	19S		251,036	869,965	869,965	869,965	869,965
WB4	Wabamun 3&4	WABAMUN (UNITS 3 & 4)	19S	127,239	287,021				
WST1	WESGEN	WESTLOCK	DAPP		14,096				
WEY1	P&G	PROCTER & GAMBLE	808S	129,835					
	BRDGE CK (NOVA GOLD CREEK)					7,052	7,052	7,052	7,052
	DVPL IPP					1,239	1,239	1,239	1,239
	LANGDON					216,314	216,314	216,314	216,314
	MCNEILL					25,256	25,256	25,256	25,256
	Total			12,268,030	13,549,416	13,443,319	13,443,319	13,443,315	13,443,315
	Original Total			12,268,030	13,549,416	13,443,357	13,443,356	13,443,356	13,443,356
	Difference			-	-	(38)	(37)	(41)	(41)

Table 5-9 Individual Generator Output (MWh) Used in Shift Factor Calculations (Fall)

Individual Generator Output (MWh) Used in Shift Factor Calculations									
				fall					
MP_ID	Name	Transmission Station Name	Facility Code	2003	2002	2002 (rep.)	2001(rep.)	2001-2nd	2001-1st
ALS1	AIR LIQU	SHELL SCOTFORD	409S	102,011	154,506	47,921	47,921	47,921	47,921
BAR	BARRIER	BARRIER HYDRO PLANT	32S	6,885	8,285	8,853	8,853	8,853	8,853
BIG	BIGHORN	BIGHORN HYDRO PLANT	250P	124,515	107,676	196,868	196,868	196,868	196,868
BPW	BEARSPAW	BEARSPAW HYDRO PLANT	44S	18,546	11,881	13,925	13,925	13,925	13,925
BR3	Battle River 3&4	BATTLE RIVER (UNITS 3 & 4)	757S	187,921	227,131	490,332	490,332	490,332	490,332
BR4	Battle River 3&4	BATTLE RIVER (UNITS 3 & 4)	757S	80,082	283,345	-	-	-	-
BR5	Battle River 5	BATTLE RIVER (UNIT 5)	757S	217,796	735,844	550,005	550,005	550,005	550,005
BRA	BRAZEAU	BRAZEAU HYDRO PLANT	62S	79,441	47,858	53,750	53,750	53,750	53,750
CAS	CASCADE	CASCADE HYDRO PLANT	29S	15,276	17,426	17,841	17,841	17,841	17,841
CG1	Cloverbar	CLOVERBAR	Cloverbar	-	5,120	421,847	421,847	421,847	421,847
CG2	Cloverbar	CLOVERBAR	Cloverbar	56,321	12,376	-	-	-	-
CG3	Cloverbar	CLOVERBAR	Cloverbar	-	6,965	-	-	-	-
CG4	Cloverbar	CLOVERBAR	Cloverbar	13,668	56,562	-	-	-	-
CMH1	CMH 7&10	CITY OF MEDICINE HAT POWER PLANT	CMH PLANT	163,145		56,102	56,102	56,102	56,102
DAI1	DSH PLNT	DIASHOWA	839S	9,238		-			
DOW1	Dow	DOWCHEMICAL FORT SASKATCHEWAN	166S	99,105	234,588	63,638	63,638	63,638	63,638
DOWG	Dow	DOWCHEMICAL FORT SASKATCHEWAN	166S	202,133		-	-	-	-
DRW1	Drywood			-					
FNG1	FORT NEL	FORT NELSON	FNG	11,919	99,569	16,883	16,883	16,883	16,883
GHO	GHOST GE	GHOST HYDRO PLANT	20S	42,915	24,955	30,834	30,834	30,834	30,834
GN1	Genesee	GENESEE	GENESEE	569,289	805,958	1,405,870	1,405,870	1,405,870	1,405,870
GN2	Genesee	GENESEE	GENESEE	564,676	777,845	-	-	-	-
HRM	HR MILNR	H.R. MILNER	740S	266,395	166,498	187,046	187,046	187,046	187,046
HSH	HORS GEN	SEEBE HYDRO PLANT	245S	27,182	15,499	17,687	17,687	17,687	17,687
INT	Interlakes			4,127		4,281	4,281	4,281	4,281
JOF1	Nova	A.G.E JOFFRE	535S	647,537	473,001	689,246	689,246	689,246	689,246
KAN	KANANASK	KANANASKIS HYDRO	2S	25,109	15,874	18,336	18,336	18,336	18,336
KH1	KEEP#1GN	KEEPHILLS	320P	662,794	773,372	1,556,046	1,556,046	1,556,046	1,556,046
KH2	KEEP#2GN	KEEPHILLS	320P	805,142	788,088	-	-	-	-
NX01	BALZAC T	TURBO BALZAC	391S	57,531	203,338				
PC01	NAMAKA	NAMAKA	428S	1,982	154,812				
PH1	POPLAR-4	POPLAR HILL	790S	42,971	27,595	50,641	50,641	50,641	50,641
POC	POCATERR	POCATERRA HYDRO PLANT	48S	7,700	8,517	9,052	9,052	9,052	9,052
PR1	PRIM GEN	PRIMROSE	859S	123,147	115,012	155,902	155,902	155,902	155,902
RB2	Rainbow	RAINBOW LAKE	791S		86,137	91,911	91,911	91,911	91,911
RB3	Rainbow	RAINBOW LAKE	791S	-	40,828				
RB5	Rainbow Lake 5 (CUPC)			85,797		-			
RG10	Rossdale	ROSSDALE	ROSSDALE	-	39	104,143	104,143	104,143	104,143
RG8	Rossdale	ROSSDALE	ROSSDALE	9,640	-	-	-	-	-
RG9	Rossdale	ROSSDALE	ROSSDALE	5,348	-	-	-	-	-
RL1	Rainbow Lake (CUPC)			101,241	97,516	-	-	-	-
RUN	RUNDLE G	RUNDLE HYDRO PLANT	35S	23,329	19,044	17,639	17,639	17,639	17,639
SCL1	Syncrude	SYNCRUDE	SYNCRUDE	175,398	112,496	59,696	59,696	59,696	59,696
SCR1	Suncor	SUNCOR	753S	322,832	248,279	443,526	443,526	443,526	443,526
SCTG	Air Liquide (Shell Scotsford)			204,534					
SD1	Sundance	SUNDANCE	310P	532,305	529,015	3,940,805	3,940,805	3,940,805	3,940,805
SD2	Sundance	SUNDANCE	310P	613,579	537,116	-	-	-	-
SD3	Sundance	SUNDANCE	310P	762,077	679,136	-	-	-	-
SD4	Sundance	SUNDANCE	310P	740,753	727,762	-	-	-	-
SD5	Sundance	SUNDANCE	310P	773,204	738,173	-	-	-	-
SD6	Sundance	SUNDANCE	310P	878,786	754,542	-	-	-	-
SH1	Sheerness	SHEERNESS	807S	126,260	757,526	1,232,696	1,232,696	1,232,696	1,232,696
SH2	Sheerness	SHEERNESS	807S	828,800	776,432	-	-	-	-
SPR	Spray	SPRAY HYDRO PLANT	33S	69,119	56,353	53,372	53,372	53,372	53,372
ST1	STURGEON	STURGEON	734S	-	-	4,703	4,703	4,703	4,703
ST2	STURGEON	STURGEON	734S	-	-	-	-	-	-
TAY1	TAYLOR	MAGRATH	225S	9,283	-	-	1,537	1,537	1,537
TC01	CARSELAN	CARSELAND	525S	175,281	166,486				
TC02	Redwater Cogen (TCP)			86,520					
THS	THREE SI			1,505		1,537			
VVW1	Valleyview			-					
WB1	Wabamun 1&2	WABAMUN (UNITS 1 & 2)	19S	141,699	130,543	249,662	249,662	249,662	249,662
WB2	Wabamun 1&2	WABAMUN (UNITS 1 & 2)	19S	117,680	121,861	-	-	-	-
WB3	Wabamun 3&4	WABAMUN (UNITS 3 & 4)	19S		229,311	823,242	823,242	823,242	823,242
WB4	Wabamun 3&4	WABAMUN (UNITS 3 & 4)	19S	170,509	484,058				
WST1	WESGEN	WESTLOCK	DAPP		15,953				
WEY1	P&G	PROCTER & GAMBLE	808S	108,643					
	BRDGE CK (NOVA GOLD CREEK)					7,967	7,967	7,967	7,967
	DVPL IPP					3,947	3,947	3,947	3,947
	LANGDON					320,053	320,053	320,053	320,053
	MCNEILL					78,284	78,284	78,284	78,284
	Total			12,300,618	13,668,107	13,496,089	13,496,089	13,496,094	13,496,094
	Original Total			12,300,618	13,668,107	13,496,136	13,496,135	13,496,135	13,496,135
	Difference			-	-	(47)	(46)	(41)	(41)

Table 5-10 Individual Generator Output (MWh) Used in Shift Factor Calculations

				Winter						Spring						Summer						Fall					
MP_ID	Name	Transmission Station Name	Facility Code	2003	2002	2002 (rep.)	2001(rep.)	2001-2nd	2001-1st	2003	2002	2002 (rep.)	2001(rep.)	2001-2nd	2001-1st	2003	2002	2002 (rep.)	2001(rep.)	2001-2nd	2001-1st	2003	2002	2002 (rep.)	2001(rep.)	2001-2nd	2001-1st
ALS1	AIR LIQU	SHELL SCOTFORD	409S	119,145	163,548	48,019	48,019	48,019	48,019	112,490	157,074	52,286	52,286	52,286	52,286	117,574	150,759	51,702	51,702	51,702	51,702	102,011	154,506	47,921	47,921	47,921	47,921
BAR	BARRIER	BARRIER HYDRO PLANT	32S	8,386	10,008	9,895	9,895	9,895	9,895	11,382	10,734	10,946	10,946	10,946	10,946	15,855	13,568	12,338	12,338	12,338	12,338	6,885	8,285	8,853	8,853	8,853	8,853
BIG	BIGHORN	BIGHORN HYDRO PLANT	250P	108,445	159,690	128,592	128,592	128,592	128,592	101,851	106,377	108,487	108,487	108,487	108,487	115,794	167,211	152,053	152,053	152,053	152,053	124,515	107,676	196,868	196,868	196,868	196,868
BPW	BEARSPAW	BEARSPAW HYDRO PLANT	44S	11,295	11,295	14,189	14,189	14,189	14,189	13,805	18,575	18,944	18,944	18,944	18,944	24,797	30,046	27,323	27,323	27,323	27,323	18,546	11,881	13,925	13,925	13,925	13,925
BR3	Battle River 3&4	BATTLE RIVER (UNITS 3 & 4)	757S	238,904	276,368	466,694	466,694	466,694	466,694	234,738	282,379	385,904	385,904	385,904	385,904	233,917	282,251	487,541	487,541	487,541	487,541	187,921	227,131	490,332	490,332	490,332	490,332
BR4	Battle River 3&4	BATTLE RIVER (UNITS 3 & 4)	757S	33,439	280,361	-	-	-	-	97,054	286,459	-	-	-	-	98,123	189,805	-	-	-	-	80,082	283,345	-	-	-	-
BR5	Battle River 5	BATTLE RIVER (UNIT 5)	757S	240,886	728,095	720,237	720,237	720,237	720,237	199,064	743,930	724,178	724,178	724,178	724,178	221,205	743,593	523,812	523,812	523,812	523,812	217,796	735,844	550,005	550,005	550,005	550,005
BRA	BRAZEAU	BRAZEAU HYDRO PLANT	62S	77,053	43,600	57,155	57,155	57,155	57,155	69,136	38,782	39,551	39,551	39,551	39,551	89,695	146,752	133,449	133,449	133,449	133,449	79,441	47,858	53,750	53,750	53,750	53,750
CAS	CASCADE	CASCADE HYDRO PLANT	29S	20,293	14,472	20,811	20,811	20,811	20,811	8,232	6,906	7,043	7,043	7,043	7,043	855	6,316	5,743	5,743	5,743	5,743	15,276	17,426	17,841	17,841	17,841	17,841
CG1	Cloverbar	CLOVERBAR	Cloverbar	-	9,634	359,313	359,313	359,313	359,313	-	1,825	267,809	267,809	267,809	267,809	20,813	9,991	286,675	286,675	286,675	286,675	-	5,120	421,847	421,847	421,847	421,847
CG2	Cloverbar	CLOVERBAR	Cloverbar	110,444	19,229	-	-	-	-	75,155	6,212	-	-	-	-	51,609	8,751	-	-	-	-	56,321	12,376	-	-	-	-
CG3	Cloverbar	CLOVERBAR	Cloverbar	84	40,869	-	-	-	-	1,758	31,559	-	-	-	-	2,358	40,682	-	-	-	-	-	6,965	-	-	-	-
CG4	Cloverbar	CLOVERBAR	Cloverbar	139,357	80,906	-	-	-	-	2,166	69,793	-	-	-	-	88,775	74,748	-	-	-	-	13,668	56,562	-	-	-	-
CMH1	CMH 7&10	CITY OF MEDICINE HAT POWER PLANT	CMH PLANT	196,669		47,537	47,537	47,537	47,537	219,513		34,881	34,881	34,881	34,881	198,415		20,592	20,592	20,592	20,592	163,145		56,102	56,102	56,102	56,102
DAI1	DSH PLNT	DIASHOWA	839S	13,061		-				8,567		-				9,160		-				9,238		-			
DOW1	Dow	DOWCHEMICAL FORT SASKATCHEWAN	166S	110,587	252,649	57,555	57,555	57,555	57,555	116,193	239,841	61,654	61,654	61,654	61,654	95,084	221,608	57,502	57,502	57,502	57,502	99,105	234,588	63,638	63,638	63,638	63,638
DOWG	Dow	DOWCHEMICAL FORT SASKATCHEWAN	166S	201,733		-	-	-	-	213,075		-	-	-	-	201,158		-	-	-	-	202,133		-	-	-	-
DRW1	Drywood			19						380						333						-					
FNG1	FORT NEL	FORT NELSON	FNG	14,003	98,520	14,672	14,672	14,672	14,672	11,597	100,663	18,029	18,029	18,029	18,029	10,114	100,617	17,388	17,388	17,388	17,388	11,919	99,569	16,883	16,883	16,883	16,883
GHO	GHOST GE	GHOST HYDRO PLANT	20S	26,392	25,011	29,803	29,803	29,803	29,803	28,594	52,652	53,697	53,697	53,697	53,697	77,574	74,114	67,396	67,396	67,396	67,396	42,915	24,955	30,834	30,834	30,834	30,834
GN1	Genesee	GENESEE	GENESEE	488,064	797,470	1,584,860	1,584,860	1,584,860	1,584,860	379,027	814,815	1,434,293	1,434,293	1,434,293	1,434,293	574,804	814,446	1,662,617	1,662,617	1,662,617	1,662,617	569,289	805,958	1,405,870	1,405,870	1,405,870	1,405,870
GN2	Genesee	GENESEE	GENESEE	477,300	769,653	-	-	-	-	378,550	521,413	-	-	-	-	604,246	700,559	-	-	-	-	564,676	777,845	-	-	-	-
HRM	HR MILNR	H.R. MILNER	740S	197,986	262,891	248,597	248,597	248,597	248,597	255,469	268,733	276,205	276,205	276,205	276,205	274,079	216,155	268,666	268,666	268,666	268,666	266,395	166,498	187,046	187,046	187,046	187,046
HSH	HORS GEN	SEEBE HYDRO PLANT	245S	16,131	14,347	18,510	18,510	18,510	18,510	17,338	19,504	19,891	19,891	19,891	19,891	29,299	31,291	28,455	28,455	28,455	28,455	27,182	15,499	17,687	17,687	17,687	17,687
INT	Interlakes			393		2,639	2,639	2,639	2,639	4,847		410	410	410	410	2,437		3,397	3,397	3,397	3,397	4,127		4,281	4,281	4,281	4,281
JOF1	Nova	A.G.E JOFFRE	535S	695,230	511,278	701,783	701,783	701,783	701,783	701,599	494,806	710,131	710,131	710,131	710,131	678,072	444,472	715,750	715,750	715,750	715,750	647,537	473,001	689,246	689,246	689,246	689,246
KAN	KANANASK	KANANASKIS HYDRO	2S	16,355	14,873	18,958	18,958	18,958	18,958	18,062	23,556	24,023	24,023	24,023	24,023	35,929	34,431	31,310	31,310	31,310	31,310	25,109	15,874	18,336	18,336	18,336	18,336
KH1	KEEP#1GN	KEEPHILLS	320P	508,586	800,411	1,585,577	1,585,577	1,585,577	1,585,577	518,335	817,819	1,379,240	1,379,240	1,379,240	1,379,240	671,121	817,448	1,604,507	1,604,507	1,604,507	1,604,507	662,794	773,372	1,556,046	1,556,046	1,556,046	1,556,046
KH2	KEEP#2GN	KEEPHILLS	320P	738,176	753,807	-	-	-	-	790,849	762,107	-	-	-	-	671,487	796,387	-	-	-	-	805,142	788,088	-	-	-	-
NX01	BALZAC T	TURBO BALZAC	391S	127,732	203,328					95,143	207,009					83,725	204,353					57,531	203,338				
PC01	NAMAKA	NAMAKA	428S	21,390	232,675					12,710	237,735					30,168	236,449					1,982	154,812				
PH1	POPLAR-4	POPLAR HILL	790S	61,018	35,466	43,762	43,762	43,762	43,762	61,539	27,443	52,920	52,920	52,920	52,920	51,350	29,429	54,539	54,539	54,539	54,539	42,971	27,595	50,641	50,641	50,641	50,641
POC	POCATERR	POCATERRA HYDRO PLANT	48S	7,694	7,343	10,172	10,172	10,172	10,172	10,454	2,641	2,693	2,693	2,693	2,693	8,801	9,971	9,067	9,067	9,067	9,067	7,700	8,517	9,052	9,052	9,052	9,052
PR1	PRIM GEN	PRIMROSE	859S	109,335	123,650	157,207	157,207	157,207	157,207	129,490	115,323	154,008	154,008	154,008	154,008	117,326	108,632	140,040	140,040	140,040	140,040	123,147	115,012	155,902	155,902	155,902	155,902
RB2	Rainbow	RAINBOW LAKE	791S		85,230	89,077	89,077	89,077	89,077		87,084	87,178	87,178	87,178	87,178		87,044	96,744	96,744	96,744	96,744		86,137	91,911	91,911	91,911	91,911
RB3	Rainbow	RAINBOW LAKE	791S	1,219	44,292					1,930	43,779					-	45,235					-	40,828				
RB5	Rainbow Lake 5 (CUPC)			84,460		-				84,151		-				84,035		-				85,797		-			
RG10	Rossdale	ROSSDALE	ROSSDALE	1,384	1,640	91,074	91,074	91,074	91,074	4,854	103	66,213	66,213	66,213	66,213	11,415	2,082	57,323	57,323	57,323	57,323	-	39	104,143	104,143	104,143	104,143
RG8	Rossdale	ROSSDALE	ROSSDALE	26,799	396	-	-	-	-	13,155	-	-	-	-	-	8,156	373	-	-	-	-	9,640	-	-	-	-	-
RG9	Rossdale	ROSSDALE	ROSSDALE	24,157	385	-	-	-	-	9,224	-	-	-	-	-	23,873	1,023	-	-	-	-	5,348	-	-	-	-	-
RL1	Rainbow Lake (CUPC)			106,334	96,489	-	-	-	-	99,153	98,587	-	-	-	-	104,704	98,543	-	-	-	-	101,241	97,516	-	-	-	-
RUN	RUNDLE G	RUNDLE HYDRO PLANT	35S	17,932	14,308	22,744	22,744	22,744	22,744	13,379	15,407	15,713	15,713	15,713	15,713	25,212	17,018	15,476	15,476	15,476	15,476	23,329	19,044	17,639	17,639	17,639	17,639
SCL1	Syncrude	SYNCRUDE	SYNCRUDE	179,389	120,598	62,512	62,512	62,512	62,512	167,266	109,736	59,278	59,278	59,278	59,278	181,646	103,776	58,189	58,189	58,189	58,189	175,398	112,496	59,696	59,696	59,696	59,696
SCR1	Suncor	SUNCOR	753S	360,902	275,647	467,387	467,387	467,387	467,387	349,741	234,178	470,635	470,635	470,635	470,635	360,968	219,841	423,918	423,918	423,918	423,918	322,832	248,279	443,526	443,526	443,526	443,526
SCTG	Air Liquide (Shell Scotsford)			195,388						229,276						215,499						204,534					
SD1	Sundance	SUNDANCE	310P	580,716	553,877	4,018,796	4,018,796	4,018,796	4,018,796	521,209	565,923	3,837,160	3,837,160	3,837,160	3,837,160	504,067	565,667	3,658,155	3,658,155	3,658,155	3,658,155	532,305	529,015	3,940,805	3,940,805	3,940,805	3,940,805
SD2	Sundance	SUNDANCE	310P	606,798	582,415	-	-	-	-	404,557	595,358	-	-	-	-	620,433	478,875	-	-	-	-	613,579	537,116	-	-	-	-
SD3	Sundance	SUNDANCE	310P	750,450	711,053	-	-	-	-	613,632	726,517	-	-	-	-	773,705	726,188	-	-	-	-	762,077	679,136	-	-	-	-
SD4	Sundance	SUNDANCE	310P	761,027	720,098	-	-	-	-	625,910	663,783	-	-	-	-	673,948	735,426	-	-	-	-	740,753	727,762	-	-	-	-
SD5	Sundance	SUNDANCE	310P	764,216	730,399	-	-	-	-	512,103	746,285	-	-	-	-	741,737	510,705	-	-	-	-	773,204	738,173	-	-	-	-
SD6	Sundance	SUNDANCE	310P	868,898	746,596	-	-	-	-	889,585	522,375	-	-	-	-	600,847	762,488	-	-	-	-	878,786	754,542	-	-	-	-
SH1	Sheerness	SHEERNESS	807S	120,868	732,900	1,478,965	1,478,965	1,478,965	1,478,965	245,038	740,877	1,387,314	1,387,314	1,387,314	1,387,314	240,334	765,504	1,331,075	1,331,075	1,331,075	1,331,075	126,260	757,526	1,232,696	1,232,696	1,232,696	1,232,696
SH2	Sheerness	SHEERNESS	807S	859,854	768,255	-	-	-	-	777,601	639,916	-	-	-	-	714,619	665,157	-	-	-	-	828,800	776,432	-	-	-	-
SPR	Spray	SPRAY HYDRO PLANT	33S	50,526	43,293	67,300	67,300	67,300	67,300	39,697	46,283	47,201	47,201	47,201	47,201	75,856	52,105	47,382	47,382	47,382	47,382	69,119	56,353	53,372	53,372	53,372	53,372
ST1	STURGEON	STURGEON	734S	-	10	4,351	4,351	4,351	4,351	-	-	4,252	4,252	4,252	4,252	15	7	4,701	4,701	4,701	4,701	-	-	4,703	4,703	4,703	4,703
ST2	STURGEON	STURGEON	734S	951	30	-	-	-	-	987	-	-	-	-	-	2,396	23	-	-	-	-	-	-	-	-	-	-
TAY1	TAYLOR	MAGRATH	225S	-	12	-	887	887	887	-	-	-	221	221	221	28,158	26,484	-	1,333	1,333	1,333	9,283	-	-	1,537	1,537	1,537
TC01	CARSELAN	CARSELAND	525S	178,784	169,790					175,213	169,319					180,859	166,641					175,281	166,486				
TC02	Redwater Cogen (TCP)			88,390						90,520						87,522						86,520					
THS	THREE SI			622		887				3		221				2,274		1,333				1,505		1,537			
VVW1	Valleyview			5,539						3,288						8,841						-					
WB1	Wabamun 1&2	WABAMUN (UNITS 1 & 2)	19S	138,630	129,168	252,726	252,726	252,726	252,726	116,357	90,376	279,319	279,319	279,319	279,319	142,670	131,918	267,335	267,335	267,335	267,335	141,699	130,543	249,662	249,662	249,662	249,662
WB2	Wabamun 1&2	WABAMUN (UNITS 1 & 2)	19S	115,846	127,588	-	-	-	-	118,099	130,363	-	-	-	-	91,112	130,304	-	-	-	-	117,680	121,861	-	-	-	-
WB3	Wabamun 3&4	WABAMUN (UNITS 3 & 4)	19S		245,804	687,176	687,176	687,176	687,176		251,150	781,137	781,137	781,137	781,137		251,036	869,965	869,965	869,965	869,965		229,311	823,242	823,242	823,242	823,242
WB4	Wabamun 3&4	WABAMUN (UNITS 3 & 4)	19S	229,768	478,960					288,964	436,184					127,239	287,021					170,509	484,058				
WST1	WESGEN	WESTLOCK	DAPP		18,481						14,550						14,096						15,953				
WEY1	P&G	PROCTER & GAMBLE	808S	122,834						93,905						129,835						108,643					
	BRDGE CK (NOVA GOLD CREEK)					7772	7,772	7,772	7,772			7721	7,721	7,721	7,721			7052	7,052	7,052	7,052			7967	7,967	7,967	7,967
	DVPL IPP					3,388	3,388	3,388	3,388			1,545	1,545	1,545	1,545			1,239	1,239	1,239	1,239			3,947	3,947	3,947	3,947
	LANGDON					326,057	326,057	326,057	326,057			350,038	350,038	350,038	350,038			216,314	216,314	216,314	216,314			320,053	320,053	320,053	320,053
	MCNEILL					71,169	71,169	71,169	71,169			41,512	41,512	41,512	41,512			25,256	25,256	25,256	25,256			78,284	78,284	78,284	78,284
	Total			12,378,272	14,139,161	13,997,918	13,997,918	13,997,917	13,997,917	11,386,959	13,394,798	13,273,660	13,273,660	13,273,661	13,273,661	12,268,030	13,549,416	13,443,319	13,443,319	13,443,315	13,443,315	12,300,618	13,668,107	13,496,089	13,496,089	13,496,094	13,496,094
	Original Total			12,378,272	14,139,161	13,997,959	13,997,958	13,997,958	13,997,958	11,386,959	13,394,798	13,273,703	13,273,702	13,273,702	13,273,702	12,268,030	13,549,416	13,443,357	13,443,356	13,443,356	13,443,356	12,300,618	13,668,107	13,496,136	13,496,135	13,496,135	13,496,135
	Difference			-	-	(41)	(40)	(41)	(41)	-	-	(43)	(42)	(41)	(41)	-	-	(38)	(37)	(41)	(41)	-	-	(47)	(46)	(41)	(41)

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Table 5-11 Individual Generator Output (MWh) Used in Shift Factor Calculations (Total)

Individual Generator Output (MWh) Used in Shift Factor Calculations						total			
MP_ID	**Name**	**Transmission Station Name**	**Facility Code**	**2003**	**2002**	**2002 (rep.)**	**2001(rep.)**	**2001-2nd**	**2001-1st**
ALS1	AIR LIQU	SHELL SCOTFORD	409S	451,220	625,887	199,928	199,928	199,928	199,928
BAR	BARRIER	BARRIER HYDRO PLANT	32S	42,507	42,595	42,032	42,032	42,032	42,032
BIG	BIGHORN	BIGHORN HYDRO PLANT	250P	450,605	540,954	586,000	586,000	586,000	586,000
BPW	BEARSPAW	BEARSPAW HYDRO PLANT	44S	68,444	71,798	74,381	74,381	74,380	74,380
BR3	Battle River 3&4	BATTLE RIVER (UNITS 3 & 4)	757S	1,204,179	2,108,101	1,830,471	1,830,471	1,830,471	1,830,471
BR4	Battle River 3&4	BATTLE RIVER (UNITS 3 & 4)	757S			-	-	-	-
BR5	Battle River 5	BATTLE RIVER (UNIT 5)	757S	878,951	2,951,463	2,518,232	2,518,232	2,518,232	2,518,232
BRA	BRAZEAU	BRAZEAU HYDRO PLANT	62S	315,325	276,992	283,905	283,905	283,906	283,906
CAS	CASCADE	CASCADE HYDRO PLANT	29S	44,657	45,120	51,438	51,438	51,439	51,439
CG1	Cloverbar	CLOVERBAR	Cloverbar	562,507	475,222	1,335,644	1,335,644	1,335,644	1,335,644
CG2	Cloverbar	CLOVERBAR	Cloverbar			-	-	-	-
CG3	Cloverbar	CLOVERBAR	Cloverbar			-	-	-	-
CG4	Cloverbar	CLOVERBAR	Cloverbar			-	-	-	-
CMH1	CMH 7&10	CITY OF MEDICINE HAT POWER PLANT	CMH PLANT	777,742	-	159,112	159,112	159,111	159,111
DAI1	DSH PLNT	DIASHOWA	839S	40,027	-	-	-	-	-
DOW1	Dow	DOWCHEMICAL FORT SASKATCHEWAN	166S	420,970	948,685	240,349	240,349	240,349	240,349
DOWG	Dow	DOWCHEMICAL FORT SASKATCHEWAN	166S	818,099	-	-	-	-	-
DRW1	Drywood			731	-	-	-	-	-
FNG1	FORT NEL	FORT NELSON	FNG	47,633	399,368	66,972	66,972	66,972	66,972
GHO	GHOST GE	GHOST HYDRO PLANT	20S	175,475	176,733	181,730	181,730	181,729	181,729
GN1	Genesee	GENESEE	GENESEE	4,035,957	6,002,159	6,087,640	6,087,640	6,087,639	6,087,639
GN2	Genesee	GENESEE	GENESEE			-	-	-	-
HRM	HR MILNR	H.R. MILNER	740S	993,928	914,278	980,514	980,514	980,514	980,514
HSH	HORS GEN	SEEBE HYDRO PLANT	245S	89,950	80,642	84,543	84,543	84,543	84,543
INT	Interlakes			11,804	-	10,727	10,727	10,727	10,727
JOF1	Nova	A.G.E JOFFRE	535S	2,722,438	1,923,557	2,816,910	2,816,910	2,816,911	2,816,911
KAN	KANANASK	KANANASKIS HYDRO	2S	95,456	88,734	92,627	92,627	92,626	92,626
KH1	KEEP#1GN	KEEPHILLS	320P	5,366,490	6,309,439	6,125,370	6,125,370	6,125,369	6,125,369
KH2	KEEP#2GN	KEEPHILLS	320P			-	-	-	-
NX01	BALZAC T	TURBO BALZAC	391S	364,130	818,029	-	-	-	-
PC01	NAMAKA	NAMAKA	428S	66,250	861,672	-	-	-	-
PH1	POPLAR-4	POPLAR HILL	790S	216,878	119,934	201,862	201,862	201,862	201,862
POC	POCATERR	POCATERRA HYDRO PLANT	48S	34,649	28,472	30,984	30,984	30,984	30,984
PR1	PRIM GEN	PRIMROSE	859S	479,298	462,617	607,157	607,157	607,157	607,157
RB2	Rainbow	RAINBOW LAKE	791S	341,593	519,628	364,910	364,910	364,911	364,911
RB3	Rainbow	RAINBOW LAKE	791S			-	-	-	-
RB5	Rainbow Lake 5 (CUPC)					-	-	-	-
RG10	Rossdale	ROSSDALE	ROSSDALE	138,007	6,041	318,753	318,753	318,753	318,753
RG8	Rossdale	ROSSDALE	ROSSDALE			-	-	-	-
RG9	Rossdale	ROSSDALE	ROSSDALE			-	-	-	-
RL1	Rainbow Lake (CUPC)			411,433	391,134	-	-	-	-
RUN	RUNDLE G	RUNDLE HYDRO PLANT	35S	79,852	65,778	71,572	71,572	71,572	71,572
SCL1	Syncrude	SYNCRUDE	SYNCRUDE	703,699	446,606	239,675	239,675	239,675	239,675
SCR1	Suncor	SUNCOR	753S	1,394,444	977,945	1,805,466	1,805,466	1,805,467	1,805,467
SCTG	Air Liquide (Shell Scotsford)			844,697	-	-	-	-	-
SD1	Sundance	SUNDANCE	310P	16,114,543	15,609,775	15,454,916	15,454,916	15,454,916	15,454,916
SD2	Sundance	SUNDANCE	310P			-	-	-	-
SD3	Sundance	SUNDANCE	310P			-	-	-	-
SD4	Sundance	SUNDANCE	310P			-	-	-	-
SD5	Sundance	SUNDANCE	310P			-	-	-	-
SD6	Sundance	SUNDANCE	310P			-	-	-	-
SH1	Sheerness	SHEERNESS	807S	3,913,373	5,846,567	5,430,050	5,430,050	5,430,051	5,430,051
SH2	Sheerness	SHEERNESS	807S			-	-	-	-
SPR	Spray	SPRAY HYDRO PLANT	33S	235,198	198,034	215,255	215,255	215,254	215,254
ST1	STURGEON	STURGEON	734S	4,350	70	18,007	18,007	18,006	18,006
ST2	STURGEON	STURGEON	734S			-	-	-	-
TAY1	TAYLOR	MAGRATH	225S	37,441	26,496	-	3,978	3,977	3,977
TC01	CARSELAN	CARSELAND	525S	710,138	672,236	-	-	-	-
TC02	Redwater Cogen (TCP)			352,951	-	-	-	-	-
THS	THREE SI			4,403	-	3,978	-	-	-
VVW1	Valleyview			17,668	-	-	-	-	-
WB1	Wabamun 1&2	WABAMUN (UNITS 1 & 2)	19S	982,092	992,120	1,049,042	1,049,042	1,049,043	1,049,043
WB2	Wabamun 1&2	WABAMUN (UNITS 1 & 2)	19S			-	-	-	-
WB3	Wabamun 3&4	WABAMUN (UNITS 3 & 4)	19S	816,481	2,663,524	3,161,520	3,161,520	3,161,521	3,161,521
WB4	Wabamun 3&4	WABAMUN (UNITS 3 & 4)	19S			-	-	-	-
WST1	WESGEN	WESTLOCK	DAPP	-	63,080	-	-	-	-
WEY1	P&G	PROCTER & GAMBLE	808S	455,217	-	-	-	-	-
				-	-	-	-	-	-
	BRDGE CK (NOVA GOLD CREEK)			-	-	30,512	30,512	30,512	30,512
	DVPL IPP			-	-	10,119	10,119	10,119	10,119
	LANGDON			-	-	1,212,462	1,212,462	1,212,462	1,212,462
	MCNEILL			-	-	216,221	216,221	216,221	216,221
	Total			48,333,879	54,751,482	54,210,986	54,210,986	54,210,987	54,210,987
	Original Total			48,333,879	54,751,482	54,211,155	54,211,151	54,211,151	54,211,151
	Difference					(169)	(165)	(164)	(164)

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5.1.4 Raw Loss Factors

Individual generator raw loss factors as used in the calculations are shown in Table 5-5.

The highlighted individual raw loss factors shown in Table 5-5 indicate changes in values from the set of values in the columns immediately to the right. The change in values indicated for the Fall and December columns of the set titled "2001-2nd half" and the values for all seasons in the set titled "2002 (report)" are due to the recalculation of loss factors directed by the Board.

The value of raw loss factor for H.R.Milner that was used in the 2003 Winter calculations of 4% appears to be in error. The raw loss factor as indicated in the AESO report and as reverse engineered (by the Auditor) from the published 2003 normalized loss factors is –16.4%. Using the latter value, the 2003 Winter shift factor would have been -7.0% instead of the published value of –6.7%.

A note appended to the raw loss factors in the 2003 spreadsheet *"Raw Loss Factors are calculated from MNBP using (Normalized Loss Factor-CG1 Loss Factor)"* indicates reverse engineering was used by the AESO to obtain the raw loss factors as used in the shift factor calculations for 2003.

There are some inconsistencies between the raw loss factor information and the individual generator volumes information. No explanation is given for these. The observed inconsistencies are as follows:

- With the exception of the 2002 spreadsheet, generator volumes were supplied for the Interlakes generators, but loss factors were not included for Fall and December of the 2001 (2nd half) and 2001 (report) calculations. No loss factors were included for any of the seasons for the 2002 (report).
- For the 2002 (report) calculations volumes were supplied for Three Sisters but no loss factors. Loss factors were provided for Taylor but no volumes.
- Volumes were supplied for Bridge Ck (Nova Gold Creek) for each of the 2001 and 2002 (report) calculations. Similar to the Interlakes, loss factors were not included for Fall and December of the 2001 (2nd half) and 2001 (report) calculations, and no loss factors were included for any of the seasons for the 2002 (report). *The AESO advises that these are Small Power Projects and they are exempted from paying any losses.*

The net impact of the inconsistencies is that the individual volumes are included in the denominator of the shift factor calculation but not in the numerator. As the volumes are small for these generators, the net impact on the shift factor calculation is small.

5.1.5 Variation In Shift Factors

With reference to Table 5-1, discussed above, the variation in the shift factors between the 2001-1st-half calculations and the2001-2nd-half and the variation between the 2001 and 2002 (report) calculations is due entirely to the use of new recalculated raw loss factors as directed by the Board. Generator volumes and seasonal volume distribution in the four cases are identical. Relatively minor inconsistencies were introduced by the absence of raw loss factor information for several generators with relatively low volumes. This is not likely to have influenced the magnitude of the shift factors calculated as the total volumes involved are small (less than 0.1% of the total volume).

The variation between the 2002 (report) shift factors and the final 2002 shift factors is due primarily to a 32% increase in forecast transmission losses. There was some adjustment of individual generator volumes to accommodate the modest increase in forecast generation (1%), and redistribution of generation, presumable to reflect changes in market conditions. The breakdown of the causes for the variation in 2002 shift factors is shown in Table 5-12:

Table 5-12 Causes of Variation in Shift Factors (2002)

	Shift Factor			
	Winter	**Spring**	**Summer**	**Fall**
2002 (report)	-4.75%	-4.29%	-4.79%	-4.28%
Adjustment due to increased load and distribution	-0.49%	-0.55%	-0.67%	-0.36%
Adjustment due to increased losses	-1.00%	-2.25%	-1.83%	-1.49%
Final 2002	-6.24%	-7.08%	-7.29%	-6.13%

The change in shift factors from 2002 to 2003 is again dominated by the change (reduction) in the loss forecast for 2003. The change due to changes in total generation and distribution is in the opposite direction to the change due to losses. The breakdown of the changes from 2002 to 2003 is shown in Table 5-13.

Table 5-13 Causes of Variation in Shift Factors (2002-2003)

	Shift Factor			
	Winter	**Spring**	**Summer**	**Fall**
Final 2002	-6.24%	-7.08%	-7.29%	-6.13%
Adjustment due to load and distribution	-0.61%	-1.01%	-0.83%	-0.78%
Adjustment due to decreased losses	0.15%	1.39%	2.04%	2.41%
Final 2003	-6.70%	-6.70%	-6.09%	-4.50%

6 CALCULATION OF NORMALIZED LOSS FACTORS

The Auditor reviewed the normalized generator loss factors as posted on the AESO website for the years 2002, and 2003, and as reported in the AESO internal document "Loss Factor Calculation Methodology, Confidential: for ESBI internal use only (April 5, 2001). The normalized loss factors are calculated using the following equation:

$$Ln_i = Lf_i - Sf$$

where:

Ln_i	is the normalized loss factor for the individual generator
Lf_i	is the raw loss factor for the individual generator
Sf	is the shift factor for the season

The raw loss factors as published on the AESO website for the years 2002 and 2003 are shown in Table 6-1. The 2002 (report) and 2001 (report) columns replicate some of the data included as Appendix H to the AESO internal document. The Auditor has assumed that the Appendix H data has been made available to the public.

The normalized loss factors posted for 2003 are entirely consistent with the raw loss factor and shift factor information available.

However, in years 2001 and 2002, some inconsistencies were noted between posted loss factors and supporting information. Highlighted entries in Table 6-1 indicate data that is either not consistent with raw loss factor information or that no supporting data was available, as follows:

- Normalized loss factors were posted for the Interlakes. No supporting calculations for Interlakes were included in the 2002 spreadsheet available to the Auditor.

- Normalized loss factors were posted for Three Sisters in 2002. There was an entry in the 2002 spreadsheet for Three Sisters (including estimated volumes), but no raw loss factors were included, hence the 2002 spreadsheet calculations of normalized loss factors for Three Sisters are not correct and do not agree with the posted normalized loss factors.

- The AESO report Appendix H tabulations for 2001 and 2002 include an entry for Cowley Ridge Wind Farm. The Spring and Summer normalized loss factors for 2002 (report) are not consistent with the raw loss factors for Cowley. The difference however is small, i.e., less than 0.2%. The difference as illustrated below may be due to compounded rounding.

	Spring	Summer
Normalized Loss Factors as Posted	-3.0%	-5.0%
Normalized Loss Factors Based on Shift and Raw Loss Factors	-2.8%	-4.8%

- Although normalized loss factors were provided in the AESO report Appendix H tabulations for Drywood for 2001 and 2002, no supporting calculations were given.

- No Entries were given in the AESO report Appendix H tabulations for 2001 and 2002 for Interlakes or Three Sisters.

- The 2001 (report) calculated normalized loss factors for the Interlakes for Winter, Spring and Summer but as noted above, these were not posted.

The method of calculating normalized loss factors for the generators from raw loss factors and shift factors is in accordance with the Board directives. The Auditor does not consider the observed inconsistencies to be significant.

Table 6-1 Generator Normalized Loss Factors

Individual Normalized Loss Factors (As posted)

MP_ID	Name	Transmission Station Name	Facility Code	2003 Winter	2003 Spring	2003 Summer	2003 Fall	2002 Winter	2002 Spring	2002 Summer	2002 Fall	2002 (rep.) Winter	2002 (rep.) Spring	2002 (rep.) Summer	2002 (rep.) Fall	2001(rep.) Winter	2001(rep.) Spring	2001(rep.) Summer	2001(rep.) Fall	2001(rep.) dec
		Shift Factors From AESO Spread Sheets		-6.70%	-6.70%	-6.09%	-4.50%	-6.24%	-7.07%	-7.29%	-6.12%	-4.75%	-4.29%	-4.79%	-4.28%	-2.98%	-2.97%	-4.82%	-2.97%	-2.58%
ALS1	AIR LIQU	SHELL SCOTFORD	409S	3.06%	4.86%	2.68%	2.02%	2.60%	5.20%	3.90%	3.60%	1.10%	2.40%	1.40%	1.80%	1.10%	0.00%	2.90%	1.20%	0.90%
BAR	BARRIER	BARRIER HYDRO PLANT	32S	-10.69%	-5.89%	-9.44%	-9.44%	-11.20%	-5.50%	-8.20%	-7.80%	-12.60%	-8.30%	-10.70%	-9.70%	-10.20%	-8.90%	-7.30%	-6.20%	-7.30%
NX01	BALZAC T	TURBO BALZAC	391S	-8.95%	-5.10%	-8.89%	-6.75%	-9.40%	-4.70%	-7.70%	-5.10%	-9.60%	-6.70%	-8.80%	-7.00%	-12.70%	-8.80%	-10.20%	-6.10%	-8.20%
BIG	BIGHORN	BIGHORN HYDRO PLANT	250P	-3.74%	0.43%	-3.63%	-3.06%	-4.20%	0.80%	-2.40%	-1.40%	-5.70%	-2.00%	-4.90%	-3.30%	-0.10%	-3.00%	1.20%	-1.90%	1.10%
BPW	BEARSPAW	BEARSPAW HYDRO PLANT	44S	-9.22%	-5.33%	-8.72%	-7.97%	-9.70%	-5.00%	-7.50%	-6.30%	-11.20%	-7.70%	-10.00%	-8.20%	-12.70%	-9.20%	-10.20%	-6.70%	-9.60%
BR3	Battle River 3&4	BATTLE RIVER (UNITS 3 & 4)	757S	8.35%	-0.22%	5.76%	3.86%	7.90%	0.20%	7.00%	5.50%	6.40%	-2.60%	4.50%	3.60%	7.40%	4.50%	-0.30%	3.00%	3.70%
BR5	Battle River 5	BATTLE RIVER (UNIT 5)	757S	6.46%	-0.65%	4.76%	2.03%	6.00%	-0.30%	6.00%	3.70%	4.50%	-3.10%	3.50%	1.80%	4.60%	3.30%	-2.90%	0.20%	2.60%
BRA	BRAZEAU	BRAZEAU HYDRO PLANT	62S	3.00%	3.97%	2.29%	2.35%	2.50%	4.30%	3.50%	4.00%	1.10%	1.60%	1.00%	2.10%	2.40%	1.30%	3.40%	2.20%	3.30%
CAS	CASCADE	CASCADE HYDRO PLANT	29S	-11.15%	-5.81%	-10.26%	-9.40%	-11.60%	-5.40%	-9.10%	-7.80%	-13.10%	-8.20%	-11.60%	-9.60%	-10.10%	-9.30%	-7.10%	-6.70%	-7.30%
CHIN	CHIN CHUTE	CHIP CHUTE-IPP	315S	-5.75%	-4.09%	-5.40%	-5.68%	-6.20%	-3.70%	-4.20%	-4.10%	-7.70%	-6.50%	-6.70%	-5.90%	-10.20%	-6.10%	-9.30%	-4.20%	-8.00%
CG1	Cloverbar	CLOVERBAR	Cloverbar	6.70%	6.70%	6.09%	4.50%	6.20%	7.10%	7.30%	6.10%	4.80%	4.30%	4.80%	4.30%	3.00%	3.00%	4.80%	3.00%	2.60%
TC01	CARSELAN	CARSELAND	525S	-8.91%	-4.96%	-8.99%	-6.60%	-9.40%	-4.60%	-7.80%	-5.00%	-6.20%	-4.10%	-5.40%	-3.90%	-12.60%	-8.70%	-10.30%	-5.50%	-5.20%
PC01	NAMAKA	NAMAKA	428S	-8.30%	-4.46%	-8.78%	-6.27%	-8.80%	-4.10%	-7.60%	-4.70%	-0.50%	1.80%	0.20%	1.50%	-12.00%	-8.20%	-10.10%	-0.10%	-0.30%
CRWD	COWLEY	COWLEY RIDGE WINDPLANT	322S	-3.41%	-0.56%	-3.71%	-1.98%	-3.90%	-0.20%	-2.50%	-0.40%	-5.40%	-3.00%	-5.00%	-2.20%	-3.00%	0.50%	-0.40%	2.10%	-2.30%
CMH1	CMH 7&10	CITY OF MEDICINE HAT POWER PLANT	CMH PLANT	6.39%	-10.62%	-6.84%	-3.08%	5.90%	-10.20%	-5.60%	-1.50%	4.40%	-13.00%	-8.10%	-3.30%	-5.90%	-2.30%	-11.20%	-1.20%	-4.00%
DAI1	DSH PLNT	DIASHOWA	839S	-16.78%	-6.87%	-12.89%	-17.23%	-17.20%	-6.50%	-11.70%	-15.60%	-18.70%	-9.30%	-14.20%	-17.40%	-13.90%	-12.20%	-15.40%	-14.10%	-14.00%
DOW1	Dow	DOWCHEMICAL FORT SASKATCHEWAN	166S	4.71%	6.42%	4.58%	3.43%	4.20%	6.80%	5.80%	5.10%	2.80%	4.00%	3.30%	3.20%	1.50%	2.00%	3.30%	0.50%	1.30%
DRW1	Drywood	DRYWOOD	415S	-9.15%	-5.99%	-8.90%	-7.98%	-9.60%	-5.60%	-7.70%	-6.40%	-11.10%	-8.40%	-10.20%	-8.20%	-7.60%	-3.80%	-5.00%	-3.10%	-8.20%
FNG1	FORT NEL	FORT NELSON	FNG	-7.18%	-8.01%	-3.02%	-18.68%	-7.60%	-7.60%	-1.80%	-17.10%	-9.10%	-10.40%	-4.30%	-18.90%	-1.80%	0.60%	-5.00%	-2.10%	-1.70%
GHO	GHOST GE	GHOST HYDRO PLANT	20S	-10.16%	-5.99%	-9.72%	-8.88%	-10.60%	-5.60%	-8.50%	-7.30%	-12.10%	-8.40%	-11.00%	-9.10%	-11.70%	-9.50%	-9.00%	-6.90%	-8.60%
GN1	Genesee	GENESEE	GENESEE	9.18%	9.49%	7.79%	7.62%	8.70%	9.90%	9.00%	9.20%	7.20%	7.10%	6.50%	7.40%	6.80%	5.90%	7.00%	6.40%	6.80%
HRM	HR MILNR	H.R. MILNER	740S	-9.73%	1.13%	-4.68%	-9.38%	-10.20%	1.50%	-3.50%	-7.80%	-11.70%	-1.30%	-6.00%	-9.60%	1.10%	-5.40%	-8.40%	-7.00%	1.20%
HSH	HORS GEN	SEEBE HYDRO PLANT	245S	-10.48%	-6.32%	-10.15%	-9.28%	-10.90%	-5.90%	-9.00%	-7.70%	-12.40%	-8.70%	-11.40%	-9.50%	-10.80%	-9.20%	-8.00%	-6.80%	-7.90%
INT	Interlakes	INTERLAKES	49S	-11.00%	-7.32%	-10.32%	-9.68%	-11.50%	-6.90%	-9.10%	-8.10%									
JOF1	Nova	A.G.E JOFFRE	535S	3.76%	5.81%	3.62%	3.22%	3.30%	6.20%	4.80%	4.80%	1.80%	3.40%	2.30%	3.00%	3.00%	-1.40%	4.10%	-0.40%	3.90%
KAN	KANANASK	KANANASKIS HYDRO	2S	-10.68%	-6.34%	-9.55%	-9.28%	-11.10%	-6.00%	-8.40%	-7.70%	-12.60%	-8.80%	-10.80%	-9.50%	-10.50%	-9.10%	-7.80%	-6.50%	-7.70%
KH1	KEEP#1GN	KEEPHILLS	320P	9.21%	9.27%	8.08%	7.72%	8.70%	9.60%	9.30%	9.30%	7.30%	6.90%	6.80%	7.50%	6.80%	5.70%	6.80%	6.40%	6.80%
PH1	POPLAR-4	POPLAR HILL	790S	-20.26%	-7.60%	-11.45%	-22.08%	-20.70%	-7.20%	-10.20%	-20.50%	-22.20%	-10.00%	-12.70%	-22.30%	-15.70%	-17.80%	-22.10%	-20.40%	-15.40%
POC	POCATERR	POCATERRA HYDRO PLANT	48S	-11.00%	-7.32%	-10.32%	-9.68%	-11.50%	-6.90%	-9.10%	-8.10%	-12.90%	-9.70%	-11.60%	-9.90%	-10.50%	-8.80%	-7.60%	-6.40%	-8.00%
PR1	PRIM GEN	PRIMROSE	859S	1.96%	5.24%	4.47%	1.12%	1.50%	5.60%	5.70%	2.70%	0.00%	2.80%	3.20%	0.90%	1.50%	3.30%	3.50%	3.00%	1.30%
WEY1	P&G	PROCTER & GAMBLE	808S	-15.40%	-3.82%	-9.65%	-15.08%	-15.90%	-3.40%	-8.40%	-13.50%	-17.30%	-6.20%	-10.90%	-15.30%	-9.10%	-10.80%	-14.30%	-12.80%	-8.90%
RB3	Rainbow	RAINBOW LAKE	791S	-7.72%	-6.49%	-3.72%	-17.48%	-8.20%	-6.10%	-2.50%	-15.90%	-9.70%	-8.90%	-5.00%	-17.70%	-4.60%	-0.10%	-5.50%	-2.90%	-4.40%
RG8	Rossdale	ROSSDALE	ROSSDALE	5.99%	7.38%	5.35%	4.62%	5.50%	7.80%	6.50%	6.20%	4.00%	5.00%	4.10%	4.40%	2.70%	3.30%	4.20%	3.90%	2.70%
RUN	RUNDLE G	RUNDLE HYDRO PLANT	35S	-10.38%	-5.66%	-9.84%	-9.26%	-10.80%	-5.30%	-8.60%	-7.70%	-12.30%	-8.10%	-11.10%	-9.50%	-9.80%	-8.90%	-6.90%	-6.40%	-6.90%
SCL1	Syncrude	SYNCRUDE	SYNCRUDE	7.83%	10.18%	6.98%	7.32%	7.40%	10.60%	8.20%	8.90%	5.90%	7.80%	5.70%	7.10%	8.80%	9.90%	10.60%	10.00%	8.80%
SCR1	Suncor	SUNCOR	753S	9.49%	12.20%	8.97%	8.62%	9.00%	12.60%	10.20%	10.20%	7.50%	9.80%	7.70%	8.40%	8.30%	9.40%	10.00%	9.20%	8.30%
SD1	Sundance	SUNDANCE	310P	10.21%	11.95%	9.51%	8.32%	9.70%	12.30%	10.70%	9.90%	8.30%	9.50%	8.20%	8.10%	8.40%	8.70%	9.50%	8.90%	8.40%
SH1	Sheerness	SHEERNESS	807S	6.27%	2.22%	3.71%	4.02%	5.80%	2.60%	4.90%	5.60%	4.30%	-0.20%	2.40%	3.80%	1.60%	2.70%	-0.80%	2.90%	1.80%
SPR	Spray	SPRAY HYDRO PLANT	33S	-10.30%	-5.53%	-9.60%	-8.78%	-10.80%	-5.20%	-8.40%	-7.20%	-12.20%	-7.90%	-10.90%	-9.00%	-9.50%	-8.70%	-6.60%	-6.20%	-6.60%
ST1	STURGEON	STURGEON	734S	-7.73%	0.57%	-4.91%	-7.98%	-8.20%	0.90%	-3.70%	-6.40%	-9.70%	-1.80%	-6.20%	-8.20%	-4.80%	-4.30%	-6.30%	-5.90%	-4.60%
TAY1	TAYLOR	MAGRATH	225S	-3.27%	0.39%	-2.21%	-3.18%	-3.70%	0.80%	-1.00%	-1.60%	-5.20%	-2.00%	-3.50%	-3.40%	-1.50%	-1.30%	1.10%	-6.00%	-9.10%
THS	THREE SI			-10.38%	-5.66%	-9.84%	-9.28%	-10.80%	-5.30%	-8.60%	-7.70%									
WB1	Wabamun 1&2	WABAMUN (UNITS 1 & 2)	19S	9.84%	12.32%	10.57%	9.12%	9.40%	12.70%	11.80%	10.70%	7.90%	9.90%	9.30%	8.90%	9.40%	10.70%	11.00%	10.60%	9.40%
WB4	Wabamun 3&4	WABAMUN (UNITS 3 & 4)	19S	9.96%	11.21%	9.34%	8.02%	9.50%	11.60%	10.50%	9.60%	8.00%	8.80%	8.00%	7.80%	7.90%	8.20%	9.10%	8.30%	8.00%
EAGL	WHITEGEN	WHITECOURT	268S	7.08%	10.74%	6.82%	6.32%	6.60%	11.10%	8.00%	7.90%	5.10%	8.30%	5.50%	6.10%	5.70%	6.40%	6.60%	6.40%	5.90%
WST1	WESGEN	WESTLOCK	DAPP	4.55%	8.71%	4.94%	3.82%	4.10%	9.10%	6.10%	5.40%	2.60%	6.30%	3.60%	3.60%	3.90%	5.30%	5.30%	5.10%	3.90%
TC02	Redwater Cogen (TCP)	(not posted)		[redacted]																
VVW1	Valleyview	(not posted)																		
	BRDGE CK (NOVA GOLD CREEK)											-	-	-	-	-	-	-	-	-
	DVPL IPP											-	-	-	-	2.48%	2.17%	3.22%	2.67%	2.98%
	LANGDON											-7.70%	-6.40%	-7.70%	-5.60%	-9.10%	-5.90%	-7.10%	-3.10%	-6.50%
	MCNEILL											-1.00%	-11.40%	-4.50%	-2.80%	-11.00%	-9.60%	-12.80%	-9.40%	-9.60%

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ANNEX 1

E-mail From AESO on Historical Shift Factors

Robert S. Burton (Bob)

From: paul.koss@aeso.ca
Sent: Thursday, May 29, 2003 5:46 PM
To: Robert S. Burton (Bob)
Subject: Historical shift factors

Hi Bob:
These are the historical values from the the Loss Factor Calculation Methodology document and 2003 values we use currently:

2001	-2.983%	-9.968%	-4.819%	-2.577%
2002	-4.754%	-4.286%	-4.793%	-4.276%
2003	-6.700%	-6.700%	-6.090%	-4.500%

Paul

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ANNEX 2

E-mail From AESO on Historical Loss Factor Calculations

Robert S. Burton (Bob)

From: Paul Kos [kosp@powersystemsolutions.com]
Sent: Thursday, July 31, 2003 2:12 PM
To: Robert S. Burton (Bob)
Subject: Loss Factor Audit - Historical Loss Factor Calculations

Loss Factor Audit - Historical...

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Loss Factor Audit – Historical Loss Factor Calculations

Introduction

The auditor (Teshmmont), in their effort to duplicate loss factor calculations has requested archived load flow base cases and other relevant information that was used to calculate the loss factors for units that have already been commissioned. This data includes the load flow base cases, PSLF code used to add new units, PSLF code used to calculate loss factors and control files used during the code execution.

After first providing an incorrect set of base cases, AESO has undergone a significant effort to assemble the data and confirm that the data has been indeed used for calculation of stated final loss factors before passing it onto the auditor. This document presents some of the findings from this work and summarizes the results.

Background

The archived base cases and other relevant information can be divided into three groups based on chronological developments in loss factor calculation methodology as follows:

1 Base cases and other relevant information used to calculate loss factors for units that were commissioned prior to 2001
2 Base cases and other relevant information used to calculate loss factors for units commissioned in 2001 and 2002 (excl. December).
3 Base cases and other relevant information used to calculate loss factors for units commissioned after December 2002.

The first group relates to all units that were already in existence at the time of initial loss factor calculation. Loss factors were calculated for all units on the system. Last MW in was used for all units with the exception of IBOC generation where first MW in approach was used. This means that for all non-IBOC units that were already dispatched in the base case, the loss factor was calculated simply using the plus minus 5 MW addition at the appropriate bus. For existing units that were not dispatched in the base cases (according to the merit order), the unit had to be dispatched first, other unit(s) had to be backed off as per stacking order and only then the loss factor could be calculated using the plus minus 5 MW unit addition. The latter is inherently more involved calculation that requires application of several programs and/or human intervention during the calculation process. Of note is that as per Board order the calculation for the existing units had to be repeated when IBOC generators were commissioned. The resulting loss factors are the values presently posted on the WEB site. These recalculated values superceded all previous calculations and hence base cases and other relevant information was sought for these recalculated data.

Second group relates to units that were commissioned during 2001 and 2002. For these units, all loss factor related data are archived together with the other project related info. The calculations were done using a then current version of PSLF code.

Third group relates to units commissioned in 2003. Data and other related information are also archived together with other project related information. The calculations are performed using the most recent versions of base cases and PSLF code. Auditor has already received sample of this group of data and it is my understanding that calculation could be duplicated.

The following discussion is divided into the three groups as outlined above.

Group 1 – Units Commissioned Prior to 2001

The primary issue affecting the efforts to compile all relevant information used to calculate loss factors for this group of generators is that there is no single directory or a archive (zip) file that would contain load flow base cases, PSLF code and other files (if any) that were used during the calculation. Also, AESO could not find documentation that would be detailed enough to explain the exact sequence of steps required and input files used to calculate the results.

AESO server contains numerous versions of load flow base cases that have been used for loss factor calculations at some point during the development.

The difficulty with replicating the calculations used to obtain loss factors in this first group of generators is compounded by following factors:

1 There exist multiple versions of the PSLF code
2 Most versions of PSLF code has directory structure hard coded and modifications are required just in order to execute them
3 Control files differ for different versions of the code and modifications are required prior to their use in calculations
4 Other PSLF code files may have been used to modify the base cases prior to calculation (these include but are not limited to code used to add IBOC units)
5 Manual intervention by the operator may have been used during the calculations

Probably the most severe impediment to assembling the information to exactly replicate the historical calculation is the fact that the personnel who performed these calculations is no longer with AESO.

Considerable effort have been made to try and verify loss factor calculations for various load flow base case sets and PSLF code files against the results as posted on the AESO web site. In the end, this effort has failed to produce the exact results that were expected if the exact sequence of calculation steps was repeated on the proper set of input files.

Following the discontinuation of the effort to replicate the historical calculations precisely, a new question was posed as follows:

How closely can the results as filed on the AESO web site be replicated if the present version of PSLF code and methodology is applied to one of the sets of load flow base cases that were filed during the time when the original calculation were performed.

To simplify the analysis due to time constraints, loss factors were compared only for the units that are already dispatched within the base cases. Three seasonal cases (fall) were arbitrarily chosen.

Analysis shows that the average difference between the loss factors as shown on the web and those obtained from the calculation was less than 0.2% (absolute % - e.g. if the loss factor for a given generator was posted on the web as 6% the corresponding calculated results would be either 5.8% or 6.2%). The maximum difference was less than 0.38% (again absolute%).

The above analysis excluded all units that may not have been fully dispatched. In addition, Sundance unit loss factor was also excluded since the control file did not include calculation of loss factor for unit #1. In the absence of unit #1, the discrepancy for Sundance was 0.66%.

A summary of loss factor differences between web posted values and values calculated for selected large coal units is shown in the following table:

Unit	Fall season difference
SUNDANCE	-0.66%
GENESEE	0.27%
Wabamun 1&2	-0.11%
Wabamun 3&4	0.28%
Battle River 3&4	0.18%
Keephills	0.17%

Inclusion of all hydro units in the above comparison did not materially influence the average difference (slight improvement).

Review of the load flow base cases showed that the IBOC units were not included. In all likelihood these units were added manually at the time of calculation. Due to time constraints, no attempt was made to add these units and repeat the analysis.

Group 2 – Unit Commissioned in 2001 and 2002

Based on review of projects that were commissioned in 2001 and 2002 a list of 6 generators were prepared for review. These are summarized in following table together with the results of the comparative analysis:

Project	Result
196 Cowley North	Exact match verified for spring cases only
208 Elmworth	Wrong version of final loss factor base cases was filed
158 Redwater	Exact match found
164 Sundance	Exact match found
244 Valleyview	Exact match found
265 Rainbow 5	Exact match found

In case of 196 Cowley North, the exact match was verified only for the spring cases, due to divergence of load flow program encountered thereafter. Due to time constraint, further effort was discontinued and it was concluded that the base cases are the ones used to calculate final loss factors.

In case of 208 Elmworth, a wrong set of final loss factor base cases was apparently saved by mistake. This conclusion was reached since the *.LOS files contain correct results but the use of archived base case files produces quite different loss factor values.

For all other projects, final loss factors as filed matched exactly the loss factors as calculated from the filed base cases.

Group 3 – Units commissioned from December 2002

Final loss factor calculation is archived with all input data and PSLF code required to replicate the calculation and hence there are no issues with selecting the cases that produce the final loss factors.