Loss Factor Stakeholder Meeting
- Understanding the Calculation Process

December 07, 2007, Modified December 18 2007

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Reliable **Markets**

Reliable **People**

AESO action as a result of stakeholder feedback

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Introduction

- Annual Loss Factor calculation is very detailed and is part of a larger detailed process

- The final Loss Factor is published in late October or early November each year and is the culmination of the process

- The process is described in the LF rule (9.2)

- Generation, Load and Transmission have significant impact on loss factors

- Questions have been raised regarding the process around the 2008 loss factors – **this meeting is to address these questions**

Basic Questions Raised (In no particular order)

- Why are the new generators dispatched to the ICBF?

- What has been done in the past?

- What is reasonable? (Subjective vs objective assessments)

- What is the effect on loss factors for different outputs?

- What is the effect on costs for different outputs?

- How can two generators at the same bus have different loss factors?

- What is new for 2009?

Topics Covered

- Overall Calculation process – Review

- Raw Loss Factor Calculation

- Seasonal Loss Factor Calculation

- Shift Factor Calculation

- 2008 Specific Process

- 2008 Northwest Review

- 2008 Milestones

- History – What have we done in the past? Does it apply?

- 2008 NW Results

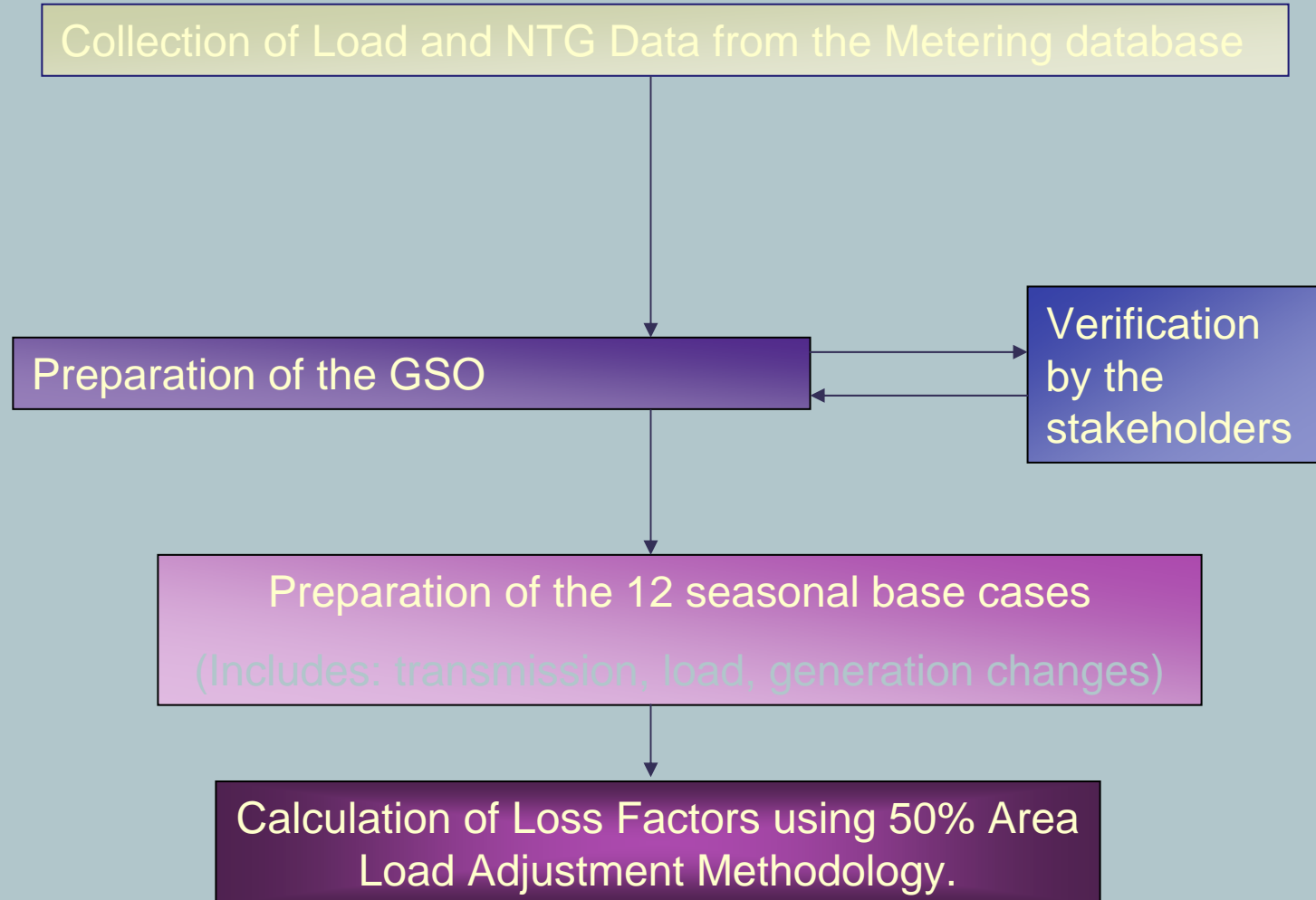- Conclusions and Next Steps

- Others?

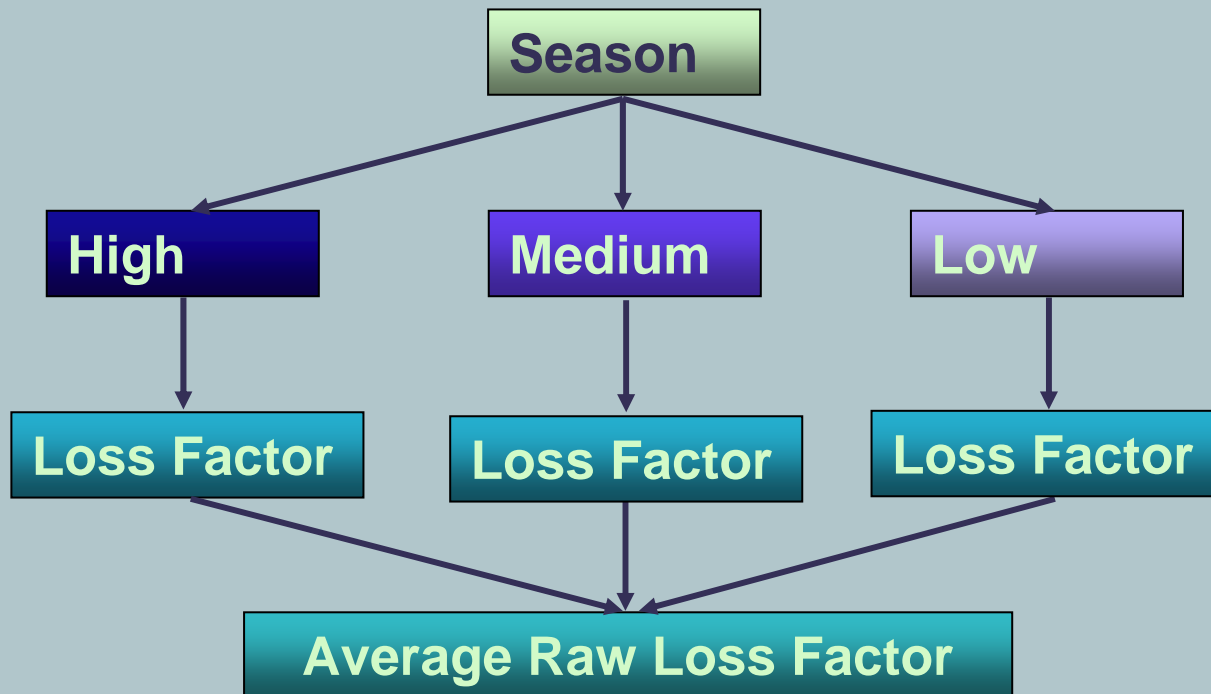# Loss Factor Calculation Process

The building blocks in the loss factor calculation processes are:

- Annual Generic Stacking Order (GSO) – existing, retired, and new generators

- New project data – transmission and load

- Loss factor base cases based on annual GSO, load forecast and topology (topology excludes 'behind the fence' transmission facilities

- Annual energy and loss volume forecast

Loss Factor Calculation Process (2)

Collection of Load and NTG Data from the Metering database

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Preparation of the GSO → Verification by the stakeholders

←

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Preparation of the 12 seasonal base cases

(Includes: transmission, load, generation changes)

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Calculation of Loss Factors using 50% Area Load Adjustment Methodology.

Loss Factor Calculation Process (3)

Loss Factor Calculation Process (4)

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Annual Forecast of Loss and Generation for next year

A = Forecasted Seasonal Generation X Raw Loss Factor

Calculation of A for all qualified generators

B = Total Forecasted Seasonal Loss

C = Total Forecasted Seasonal Generation

$$\text{Seasonal Shift Factor} = \frac{\Sigma A - B}{C}$$
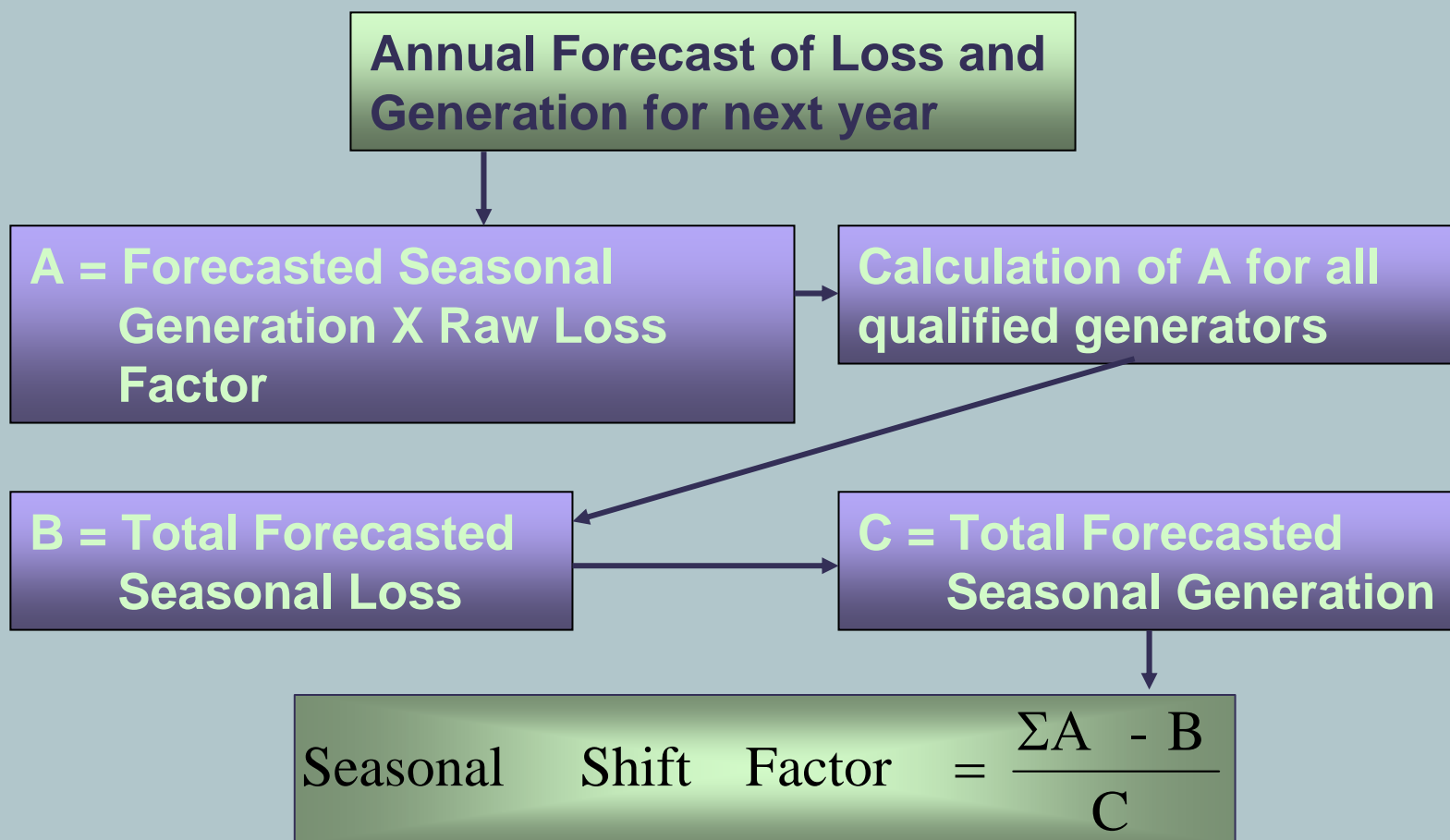
Raw Loss Factor (RLF) Calculation

- Selected Methodology – 50% Area Load Methodology Using Corrected Loss Matrix

    - All 21 methodologies evaluated in 2004-05 share similar characteristics around sensitivities at boundaries of the system

- The loss factor software calculates the gradient for each bus for 12 seasonal loss factor base cases' (snap shots) operating point.

- The seasonal RLFs are then weighted using the duration of each seasonal load scenarios (High, Medium and Low).

Raw Loss Factor (RLF) Calculation (2)

MP_ID	Facility Name	Bus number	2008 Raw Loss Factors (before Base Case Shift Factor Application)											
			WnLw	WnMd	WnPk	SpLw	SpMd	SpPk	SmLw	SmMd	SmPk	FlLw	FlMd	FlPk
HRM	HR MILNER	1147	1.29%	1.67%	2.91%	0.75%	0.23%	2.15%	-0.46%	1.32%	3.33%	4.28%	7.29%	5.34%
Project672_1_SUP	Northern Prairie Power Project	1120	-5.91%	-6.43%	-4.63%	-6.32%	-5.89%	-3.01%	-7.23%	-6.01%	-3.59%	-0.53%	3.67%	0.81%
PH1	POPLAR HILL	1118	-5.91%	-6.43%	-4.63%	-6.32%	-5.89%	-3.01%	-7.23%	-6.01%	-3.59%	-0.56%	3.63%	0.77%
RB1	RAINBOW 1	1031	-4.14%	-3.75%	-1.54%	-3.84%	-2.00%	3.65%	5.74%	-1.65%	1.83%	-0.03%	0.41%	1.62%
RB2	RAINBOW 2	1032	-4.14%	-3.74%	-1.54%	-3.84%	-2.00%	3.65%	5.74%	-1.65%	1.83%	-0.03%	0.41%	1.62%
RB3	RAINBOW 3	1033	-4.13%	-3.74%	-1.54%	-3.83%	-2.00%	3.65%	5.74%	-1.65%	1.83%	-0.03%	0.41%	1.62%
RL1	RAINBOW 4, RL1	1035	-3.87%	-3.57%	-1.34%	-3.54%	-1.74%	3.97%	5.96%	-1.33%	2.09%	0.36%	0.60%	1.82%
RB5	RAINBOW 5	1037	-4.11%	-3.67%	-1.46%	-3.79%	-1.94%	3.75%	5.85%	-1.59%	1.91%	0.03%	0.49%	1.72%
VVW1	VALLEYVIEW	1171	0.29%	0.06%	1.06%	0.07%	0.19%	2.05%	-0.29%	-0.05%	1.22%	1.16%	3.24%	2.19%
Project667_1_SUP	VALLEYVIEW # 2	1172	0.52%						0.00%	0.21%	1.44%	1.47%	3.52%	2.43%

Raw Loss Factor (RLF) Calculation (3)

- A small shift factor is introduced for each load flow in order to recover the effect of SPR&D dispatch in the base cases

2008 Load Flow Shift Factors											
WnLw	WnMd	WnPk	SpLw	SpMd	SpPk	SmLw	SmMd	SmPk	FlLw	FlMd	FlPk
0.083%	0.096%	0.107%	0.069%	0.083%	0.089%	0.066%	0.089%	0.100%	0.066%	0.085%	0.094%

Raw Loss Factor (RLF) Calculation (4)

- The load flow shift factor is added to the raw loss factors

MP_ID	Facility Name	Bus number	2008 Raw Loss Factors (after Base Case Shift Factor Application)											
			WnLw	WnMd	WnPk	SpLw	SpMd	SpPk	SmLw	SmMd	SmPk	FlLw	FlMd	FlPk
HRM	HR MILNER	1147	1.38%	1.67%	2.91%	0.75%	0.23%	2.15%	-0.46%	1.33%	3.33%	4.28%	7.29%	5.34%
Project672_1_SUP	Northern Prairie Power Project	1120	-5.83%	-6.33%	-4.53%	-6.25%	-5.81%	-2.92%	-7.16%	-5.92%	-3.49%	-0.46%	3.75%	0.90%
PH1	POPLAR HILL	1118	-5.83%	-6.33%	-4.53%	-6.25%	-5.81%	-2.92%	-7.16%	-5.92%	-3.49%	-0.50%	3.72%	0.86%
RB1	RAINBOW 1	1031	-4.06%	-3.65%	-1.44%	-3.77%	-1.92%	3.73%	5.80%	-1.56%	1.93%	0.03%	0.50%	1.71%
RB2	RAINBOW 2	1032	-4.06%	-3.65%	-1.44%	-3.77%	-1.92%	3.73%	5.80%	-1.56%	1.93%	0.03%	0.50%	1.71%
RB3	RAINBOW 3	1033	-4.05%	-3.65%	-1.43%	-3.76%	-1.91%	3.74%	5.80%	-1.56%	1.93%	0.04%	0.50%	1.71%
RL1	RAINBOW 4, RL1	1035	-3.79%	-3.47%	-1.23%	-3.47%	-1.66%	4.06%	6.03%	-1.24%	2.19%	0.42%	0.69%	1.91%
RB5	RAINBOW 5	1037	-4.03%	-3.58%	-1.36%	-3.72%	-1.85%	3.83%	5.91%	-1.50%	2.01%	0.10%	0.58%	1.81%
VVW1	VALLEYVIEW	1171	0.38%	0.15%	1.17%	0.14%	0.27%	2.14%	-0.23%	0.04%	1.32%	1.23%	3.33%	2.28%
Project667_1_SUP	VALLEYVIEW # 2	1172	0.60%						0.06%	0.30%	1.54%	1.53%	3.61%	2.53%

Seasonal LF Calculation

- Seasonal loss factors are weighted averages based on seasonal load duration scenarios

	Winter		Spring		Summer		Fall	
	Duration (Hr)	Weight	Duration (Hr)	Weight	Duration (Hr)	Weight	Duration (Hr)	Weight
High	150	6.9%	75	3.4%	50	2.3%	125	5.7%
Medium	1150	52.7%	1450	65.7%	2075	94.0%	1300	59.5%
Low	884	40.5%	682	30.9%	83	3.8%	760	34.8%

- The equation used to calculate the seasonal RLFs :

$$SeasonalRLF = \frac{HighCaseRLF \times HighCaseDuration + MediumCaseRLF \times MediumCaseDuration + LowCaseRLF \times LowCaseDuration}{TotalSeasonalHours}$$

For example, winter loss factor of PH1 (poplar Hill) is calculated as

$$Seasonal\ RLF = \frac{(-4.53) \times 150 + (-6.33) \times 1150 + (-5.83) \times 884}{150 + 1150 + 884}$$

$$Seasonal\ RLF = \frac{-13116.6}{2184}$$
$$= -6.006$$

Seasonal LF Calculation (3)

MPID	Bus	Seasonal Raw Loss Factors			
		Winter	Spring	Summer	Fall
HRM	1147	1.69%	0.53%	1.39%	6.21%
Project672_1_SUP	1120	-6.01%	-5.85%	-5.91%	2.12%
PH1	1118	-6.01%	-5.85%	-5.91%	2.09%
RB1	1031	-3.66%	-2.30%	-1.21%	0.40%
RB2	1032	-3.66%	-2.30%	-1.21%	0.40%
RB3	1033	-3.66%	-2.29%	-1.20%	0.41%
RL1	1035	-3.45%	-2.02%	-0.89%	0.67%
RB5	1037	-3.61%	-2.24%	-1.14%	0.48%
VVW1	1171	0.31%	0.30%	0.06%	2.54%
Project667_1_SUP	1172	0.31%	0.29%	0.06%	2.53%

- It can be clearly seen from the Table that Rainbow generator seasonal loss factor are very close

Seasonal LF Calculation (4)

- Shift factor is calculated for each season

$$\text{Seaonal Shift Factor} = \frac{\text{Forecasted Seasonal Loss Volume} - \sum_i \text{Seasonal Volume}_i \times \text{Seasonal Raw Loss Factor}_i}{\sum_i \text{Seasonal Volume}_i}$$

Seasonal Shift Factors			
Winter	Spring	Summer	Fall
0.74%	0.87%	1.17%	1.07%

Seasonal LF Calculation (5)

- Shift factor is added to seasonal RLF to calculate seasonal loss factor

MPID	Bus	Seasonal Loss Factors			
		Winter	Spring	Summer	Fall
HRM	1147	2.43%	1.40%	2.56%	7.29%
Project672_1_SUP	1120	-5.27%	-4.98%	-4.74%	3.20%
PH1	1118	-5.27%	-4.98%	-4.74%	3.16%
RB1	1031	-2.92%	-1.43%	-0.03%	1.48%
RB2	1032	-2.92%	-1.43%	-0.03%	1.48%
RB3	1033	-2.92%	-1.43%	-0.03%	1.48%
RL1	1035	-2.71%	-1.15%	0.29%	1.74%
RB5	1037	-2.87%	-1.37%	0.03%	1.56%
VVW1	1171	1.05%	1.17%	1.23%	3.61%
Project667_1_SUP	1172	1.05%	1.16%	1.23%	3.61%

Shift Factor Calculation

- Please refer to the excel spread sheet with a sample calculation

	Winter	Spring	Summer	Fall	Total	Notes
Total Gen						
	16031113	14688007	15313771	14998214	61031105	From Forecast
Total Loss						
	795057	727615	686849	700618	2910139	From Forecast
System Loss Factor						
	4.96%	4.95%	4.49%	4.67%		Calculated from forecasted losses and volumes
System Shift Factor						
	0.74%	0.87%	1.17%	1.07%		Calculated as follows

Shift Factor Calculation (2)

Forecasted Seasonal Volumes

MPID	Winter	Spring	Summer	Fall	Total	
MC 1	2404667	2203201	2297066	2249732	**9154666**	From Forecast
MC 2	12824890	11750406	12251017	11998571	**48824884**	
MC 3	801556	734400	765689	749911	**3051555**	
Total	**16031113**	**14688007**	**15313771**	**14998214**	**61031105**	

Seasonal Raw Loss Factors

MPID	Winter	Spring	Summer	Fall	
MC 1	7.10%	7.00%	6.90%	5.70%	From 50% Area Load
MC 2	4.15%	4.10%	3.20%	3.70%	Methodology
MC 3	-3.31%	-4.92%	-5.60%	-4.27%	
Total					

Assigned Energy Losses Based on Raw Loss Factors

MPID	Winter	Spring	Summer	Fall	Total	
MC 1	170731	154224	158498	128235	**611688**	Product of seasonal raw loss
MC 2	532233	481767	392033	443947	**1849979**	factors and seasonal volumes
MC 3	-26537	-36161	-42852	-32045	**-137596**	
Total	676427	599829	507678	540137	**2324071**	

Calculation of Shift Factor

	Winter	Spring	Summer	Fall	Total	
Forecast Energy Loss	795057	727615	686849	700618	**2910139**	From Above
Assigned Total Energy Losses Based on Raw Loss Factor	676427	599829	507678	540137	**2324071**	From above
Unassigned Losses	118630	127786	179171	160481	**586068**	Difference
Total Volumes	16031113	14688007	15313771	14998214	**61031105**	
Required Shift Factor	0.74%	0.87%	1.17%	1.07%		

Shift Factor Calculation (3)

Seasonal Adjusted Loss Factors

MPID	Winter	Spring	Summer	Fall
MC 1	7.84%	7.87%	8.07%	6.77%
MC 2	4.89%	4.97%	4.37%	4.77%
MC 3	-2.57%	-4.05%	-4.43%	-3.20%

Seasonal raw loss factor plus shift factor

Assigned Energy Losses Based on Seasonal Adjusted Loss Factors

MPID	Winter	Spring	Summer	Fall	Total
MC 1	188526	173392	185373	152307	**699598**
MC 2	627137	583995	535369	572332	**2318834**
MC 3	-20606	-29772	-33894	-24021	**-108292**
Total	795057	727615	686849	700618	**2910139**

Product of seasonal adjusted loss factors and seasonal volumes

MPID	Annual Volumes	Annual Loss Factor	Annual Assigned Losses
MC 1	9154666	7.64%	699598
MC 2	48824884	4.75%	2318834
MC 3	3051555	-3.55%	-108292
Total	**61031105**		**2910139**

Annual loss factor is average of seasonal adjusted loss factor weighted by forecast volume

2008 Loss Factor Analysis

- Poplar Hill (PH1 at Bus 1118) and Northern Prairie Power (Project672_1_SUM at Bus 1120) are located very close electrically, but the NLFs are quite different

- The NLF of Northern Prairie Power is determined by only Fall loss factor as it comes in Fall. The volume is set to zero for Northern Prairie Power in other seasons

- Fall loss factor of Poplar Hill (3.16%) is very close to that of Northern Prairie Power (3.20%)

- Poplar Hill NLF is determined by non-zero volume used in all seasons and the Fall volume is the lowest among them.

- The Rainbow area loss factors can be easily explained using the algorithm explained above

2008 Base Cases - NW Area Highlights

- Based on information available at the time of GSO and base case development
- Generation grows in general – Valleyview 2 ISD is June 01, 2008 and Northern Prairie Power Project ISD is September 01, 2008
- For 2008, load has been forecasted in several areas to be smaller than in 2007
- NW is highly sensitive to load-generation or NET flow changes
- An average load addition of 20 MW at Fort Nelson reduces Fort Nelson LF from 8.75% to 1.18%.

| | Static Load (Type 99) | | Generation (All) | | Change (2008 - 2007) | | | |
| | | | | | Static Load (Type 99) | | Generation (All) | |
Area	2007	2008	2007	2008	Absolute	Percentage	Absolute	Percentage
17	58.5	55.4	107.6	110.1	-3.1	-4.9%	2.5	2.6%
19	136.7	131.2	27.5	30.6	-5.5	-3.7%	3.2	11.6%
20	216.9	223.8	36.1	81.9	6.9	3.2%	45.8	150.4%
21	98.4	76.1	0.0	0.0	-22.3	-22.6%	0.0	
22	20.4	22.9	93.3	104.2	2.5	12.8%	11.0	14.3%
23	30.9	29.9	6.7	30.8	-1.0	-2.4%	24.1	
24	50.3	50.8	0.0	0.0	0.5	1.3%	0.0	
26	272.0	273.2	23.6	22.4	1.1	2.7%	-1.2	-5.0%
29	89.1	86.3	0.0	0.0	-2.8	-2.8%	0.0	
40	109.8	116.0	3778.2	3845.7	6.2	6.1%	67.5	1.9%

2008 LF Process Milestones

- Individual GSO data were sent on June 26, 2007 for existing generators

- The 2008 GSO (existing and new generators) was published on August 28, 2007

- The 2008 base cases published on September 19, 2007

- The draft 2008 loss factors were published on September 27, 2007

- The final 2008 loss factors were published on October 24, 2008

Similar Past Issues

- The current loss factor methodology was implemented from January 01, 2006.
- AESO sent the GSO data to all stakeholders on June 08, 2005 and July 07, 2005 in two phases (3 seasons and 1 season)
- EPCOR
  - GN3 was included in the 2006 GSO using the ICBF of GN2
  - EPCOR neither agreed nor disagreed with the GN3 numbers when the GSO numbers were sent out for confirmation
  - Later, EPCOR commented that the output looked high
  - AESO responded about EPCOR's stand on the GSO data confirmation
  - EPCOR accepted the argument and the loss factor
- HRM
  - The average output from Milner calculated in the 2006 GSO is 97.4 MW based on historical data (June 01, 2004 to May 31, 2005).
  - Milner sent their reply on July 25, 2005 showing their average forecast output as 84.3 MW.
  - AESO uses Milner's Forecast in the 2006 base cases for loss factor calculation
  - Milner's actual average generation was 101.2 or 20% higher than their own prediction.

2008 LF – impact of New NW Gen & HRM Forecast

- AESO has conducted multiple scenarios that include loss factor calculation

  - Without new NW generators

  - Without new NW generators and with HRM forecast

  - The detailed results will be available in hard copy

  - Some of most benefited and affected generators are shown in the next slide

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- The loss factors for 3 most benefited and 3 most affected generators (based on E-B) are shown –

  – Negative means more credit

MP_ID	Names from GSO	C-B	D-B	E-B
NPC1	NORTHSTONE ELMWORTH	-3.11%	-3.52%	-0.95%
WEY1	P&G WEYERHAUSER	-2.60%	-3.03%	-0.81%
ST1	STURGEON 1	-1.51%	-1.60%	-0.52%
Project513_1_SUP	PEACE BUTTE WIND FARM	0.44%	0.49%	0.19%
SPCIMP	SPC - Import	-2.98%	-2.98%	0.22%
0000004813	POCATERRA DG	2.16%	2.16%	0.25%
MATL_IMP	MATL - Import	-2.16%	-2.16%	0.29%

Note: Data Source
2007 LF (A)
2008 LF (B)
2008 LF W/O new NW Gen (C)
2008 LF HRM Forecast & W/O new NW Gen (D)
2008 LF with revised NW new Gen (E)

Conclusion – and Next Steps

- ICBF is the basis of the new generator forecast

- Historic precedence with two units and ICBF

- Two generators at the same bus can have different loss factors

- As a result of Stakeholders' feedback the outputs of the three new gas turbines have been adjusted in the 2008 base cases and the loss factors re-calculated

- The new Rule does address the forecast issue