2007
Generic Stacking Order Loss Factors

AUGUST 1, 2006

	Name	Signature	Date
Prepared by:	Ashikur Bhuiya, P.Eng.		
Approved by:	Robert Baker, P.Eng.		
Approved by:	Jerry Mossing		

APEGGA Permit to Practice P-8200

TABLE OF CONTENTS

1.0 Purpose

The purpose of this document is to describe the 2007 Generic Stacking Order as the order applies to the loss factor calculation.

2.0 Introduction

The Generic Stacking Order (GSO) is a key component in the loss factor calculation, operational forecasts, planning studies, and General Tariff Application process. Generators are dispatched to meet system demand in the base cases according to the order and generation amount specified in the GSO.

The GSO contains two key pieces of information –

1. Generation supply levels on a net-to-grid basis (NTG) for 12 seasonal cases[1] (four seasons and three load levels) for all generators, and
2. Generation dispatch order.

[1] Loss Factor base cases are relevant to NTG amount whereas operations and planning security base cases use more detailed modeling of the system including the behind the fence elements.

Starting in 2006, the Rule governing the determination of the GSO generation supply levels can be located at www.aeso.ca > Rules & Procedures > ISO Rules > Current Rules. In summary, the generation supply levels are determined using historical data for existing generators (in service for more than a year). For generators that have been in service for less than one year, the supply levels are estimated by the Incapability Factors. To determine dispatch order, a statistical analysis is used to determine a relationship between the generator output and the actual historical hourly pool price. The process is explained in ‘Key Changes’. AESO will request annually from generation owners confirmation that the previous year’s historical data is appropriate to use. Additional blocks are used where necessary to reflect generators’ multiple bidding strategies.

The TMR requirement (please refer to www.aeso.ca > Rules and Procedures >Current Operating Policies and Procedures > ISO Operating Policies and Procedures for details) supersedes all other operational criteria and hence TMR generators are dispatched first on the list when required to fulfill the reliability criteria.

3.0 Background

In 2006, the AESO has started to use a new methodology, 50% Area Load Corrected R-Matrix, for the determination of generator loss factors. The new methodology reflects the requirements of the Alberta Department Of Energy (DOE) 2004 Transmission Regulation. The regulation indicates that loss factors must be calculated from the average impact of generators on the Alberta Interconnected Electric System (AIES). The regulation directed the AESO to implement a new methodology to meet these requirements. The AESO has consulted with stakeholders in the development of the new loss factor methodology including the development of new rules for the preparation of the GSO.

Previous GSO’s, up to 2005, used generators STS contract levels as capacity amounts. Moving to a historical generation basis as was done in 2006 has several advantages, including;

- Amounts of actual generator energy market dispatch representative for the previous year
- Addresses the issue of confidentiality of maintenance data by including actual maintenance and forced outages from the previous period
- Reduces necessity for the AESO to forecast generator / pool price relationships

4.0 2007 GSO Key Changes

The major differences between previous GSOs and the 2007 GSO are;

1. Average historical net-to-grid (NTG) output of a generator is considered for each of the twelve seasonal cases.
2. Generator owners are provided an opportunity to comment and suggest revisions to the GSO capacities to correct calculation errors by the AESO on historical data or proposed operation characteristics on new generation
3. The numbers of hours (H values) used for averaging the historical generator output are taken from the AIES seasonal load duration curve analysis (Please see Appendix-A of AESO Loss Factor Rules).
4. No maintenance or outage data is used in the 2007 GSO as average historical net-to-grid output of a generator inherently contains this information.
5. 12 seasonal net-to-grid generations are assigned to each individual generator at the point of supply (POS).
6. The order except for units such as wind and hydro generation, is determined by the actual price responses of the generators in each group.
7. New generators that are expected to be connected in the forecast year will

be included in the GSO. These are generators with signed contracts to connect or who have made significant financial commitments to connect. Generators who have filed decommissioning plans with the AESO will be removed accordingly.

AESO relies on the Canadian Electricity Association (CEA) information in the event of new generators or in the case of a lack of updated information from the generators on their availability. The incapability Factors (ICBF) is used to calculate the power available to the AIES. (1- ICBF) has been considered as equivalent to Available Capacity Factors (ACF). The ICBFs are obtained from CEA's latest annual report on Generation Equipment Status.

8. The 2007 GSO considers the NTG amount at the point of supply (POS). Since any given loss factor is primarily the function of net to grid amount of generation, the 2007 GSO represents an aggregate of generation at the point of supply. An equivalent generator is considered at the bus from which the NTG amount related to the Measurement Point Identification (MPID) is obtained. For example, Horseshoe has 4 generators with a single MPID which is HSH. The 4 generators are connected to Bus 172 (12 kV). They are represented as a single unit at Bus 171 (138 kV) because the AESO billing database contains NTG data for all of these four units (related to MPID HSH) at Bus 171. The same approach is applied to the Industrial System Designations (ISD). All ISDs are represented by a single equivalent generator and load. The GSO contains a column with bus numbers for corresponding MPIDs.

9. An energy stacking order is created for all generation units based on 12 months of historical data. The generation energy market behavior analysis is updated with the latest historical data from the period June 1 2005 to May 31 2006. Each generator's hourly bidding prices and associated generation MW changes are put together and sorted as a multi-block stacking order for that generation unit for the 12 months period. The

generation unit is then divided into two blocks. The reason to use the two blocks is to avoid additional complexity for limited modeling improvement. A statistical analysis is applied to define the first and second blocks from its multi-block stacking order. A low end price with the highest occurring percentage in the 12 months period is selected as the first block. Its block size is defined as the average size of all the occurred times. Generation volumes above the first bock size belong to the second block. This block price is defined by using weighted average of all the prices above the first block. The weighted factor is generation MW changes at each price and its percentage happened in the history. The second block size is calculated by averaging of all blocks above the first block. However, not all generators have a 2nd block. The statistical analysis shows that some generators have an insignificant amount of generation in the 2nd block which indicates their price insensitivity. A weighted average of generator output of 12 seasonal outputs is calculated based on the H values or duration of the scenarios. A second block for a generator is considered, in general, if the weighted average is equal to or more than 5 MW. In some cases the second block is not assigned to a generator even though the weighted average is more than 5 MW such as for SPR&D or Wind generators.

The price response analysis used to construct the GSO is consistent with the losses forecast as filed with the AESO's General Tariff Application.

The 2007 GSO is similar to its predecessors in the following aspects:

1. The wind and hydro units are ranked according to their relative loss factors.
2. No bid price, specific TMR, maintenance schedules, or heat rate information is revealed.
3. Multiple blocks (two blocks) are used to represent the historical response of the generators to pool price.

4. STS contract and incapability factors (ICBF) is used to determine the amount of predicted generation level for new generators.

5. The GSO is separated into two blocks (where necessary) and into similar generation technologies (i.e. wind, co-gen, coal, etc)

5.0 2007 Generic Stacking Order

The following describes the application of the GSO to the loss factor base cases:

1) Transmission Must Run (TMR) generators – the generators represent the expected TMR dispatch (of gas, combined cycle, or other units) beyond area generation energy market participation. The TMR units are listed in the AESO OPPs 501, 510 and 521. TMR is required in specific areas of the AIES to meet reliability criteria The total net-to-grid (NTG) amount assigned to the TMR generators in the 2007 GSO is obtained from the following two sources:

   a) The average historical net-to-grid (NTG) is calculated for 12 seasonal cases in the past twelve months (June 1 2005 to May 31 2006). The AIES seasonal load duration curve analysis is used to obtain the NTG amount of each generator.

   b) The minimum TMR requirement is obtained using OPPs 501, 510 and 521.

      According to the OPPs when the area criteria requirement is not met by the generation from local generators through energy market dispatches, TMR dispatches will be issued to TMR-contracted generators to make up the shortfall. TMR-contracted generators will be dispatched according to the TMR dispatch orders. The actual TMR dispatch order is confidential to the AESO.

      Area load is required to determine the minimum TMR requirement for any TMR area such as North-West area. The minimum TMR requirement is function of local area load. The area load forecast is applied for high, medium and low seasonal cases. Using the historical hourly area load levels and using the regression analysis as explained in Appendix-A of the AESO Rule on Loss Factors, a minimum TMR generation requirement is assigned to generators listed in the OPPs according to these seasonal load levels. The historical TMR level as calculated in Appendix A is adjusted as per the relevant OPP if necessary to meet the minimum reliability requirements.

2) Most of the data used in 2007 GSO such as Alberta system load, hourly pool price and generation amount at each POS are historical and taken from the most recent 12 months' data found in the AESO's billing system. The data extraction period is June 1 2005 to May 31 2006.

3) In general, the energy stacking order is formed to more closely reflect an actual operational perspective. The generators may bid multiple blocks but the typical block size beyond the 2nd block is very small.

4) **Wind Generation** – Wind generation does not have a relationship to pool price.

5) **Small Power Research & Development** – The relative order remains the same as the 2006 GSO. SPR&D generators are exempt by law from paying for losses.

6) **Distribution Connected Generation** – consists of distribution connected generators with STS contracts who occasionally supplies power to the AIES. Several prime movers may exist at a distribution generation location. The placement of the distribution generation in the stacking order is determined mainly by the predominant source of generation at the STS location and ranked by historical hourly pool price.

7) **Preliminary Generation** – consists of the generators with preliminary status. These generators do not have a contract with the AESO but are included in the 2007 GSO as it is expected they will connect.