Explanatory Paper for
Transmission Loss Adjustment Factor (TLAF) Calculation Methodology

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Document History

This document was first published on the EirGrid and SONI websites (www.eirgrid.com and www.soni.ltd.uk) on 27/09/2012.

1. INTRODUCTION/BACKGROUND

This paper has been prepared by the System Operators (SOs) to describe the current all-island methodology used for the calculation of the Single Electricity Market (SEM) Transmission Loss Adjustment Factors (TLAFs).

Electrical losses occur as electricity is transported along networks from generators/interconnectors to demand centres. Losses occur on both the transmission and distribution networks which, must be accounted for in SEM market settlement.

In SEM, all market settlement is assumed to take place at the interface between the transmission and distribution grids. Transmission losses are allocated to generators/interconnectors, by means of TLAFs.

Some units are responsible for proportionally more transmission losses than others depending on their point of connection to the grid. For this reason, TLAFs are site specific.

At present the following parties that participate in the SEM (market participants) are subject to TLAFs:

- Generators connected to the transmission network,
- Generators connected to the distribution network,
- Interconnectors, and
- Supplier TLAFs (the Trading and Settlement Code (TSC) [1] specifies that TLAFs for Supplier Units will be set equal to 1.0).

1.1 Principles – Losses

The key principles associated with the treatment of transmission losses are:

- The purpose of TLAFs is to allocate transmission losses to market participants in a fair and equitable manner that is reflective of their contribution to transmission losses. The TLAFs therefore promote efficient dispatch. The principle is that market participants that contribute more to transmission losses due to their location should have a lower TLAF[1] than those generators who contribute less to transmission losses
- TLAFs reflect the extent to which a market participant increases or reduces transmission losses. Factors that impact TLAFs include:
    - Generation dispatch quantities which determines the power flows on transmission lines and interconnectors,
    - The level of demand in a particular area,
    - Changes to the transmission network topology, and

[1] For example a low (i.e. lower) TLAF could be 0.941 compared to a high (i.e. higher) TLAF of 1.002

  - The commissioning or decommissioning of generation connections can result in changes in network topology and transmission power flows.

- TLAFs are calculated for all transmission voltage levels at all transmission stations. Market participants are then assigned TLAFs based on the transmission station they are associated with.
- The TLAFs of certain generators can be higher than others because their output has the effect of reducing, rather than increasing, transmission losses.
- The TLAFs of certain generators can be lower than others because their output has the effect of increasing, rather than reducing, transmission losses.
- The TLAFs for interconnectors are calculated in a similar manner to those for generators. The TLAFs for interconnectors are reflective of the transmission losses incurred on the interconnector, based on the modelled expectation of interconnector flows.
- Currently TLAFs are determined at the start of each tariff year for each transmission station. A TLAF value is determined for day and night periods for each month, i.e. 24 values in total.
- TLAFs are calculated by the SOs and can be found on the EirGrid and SONI websites. They are consulted upon prior to their application in the SEM.

  TLAFs and their application are subject to annual change regulated by the Regulatory Authorities (RAs) i.e. the Commission for Energy Regulation (CER) & the Northern Ireland Authority for Utility Regulation (NIAUR).
- In SEM, the TLAFs are used in the calculation of CLAFs (Combined Loss Adjustment Factor). See Appendix B for details.

2. TLAF CALCULATION

EirGrid and SONI prepare the TLAFs for each tariff year in accordance with the Regulatory Decision Papers [4], [7], [8], [10]. This section describes the SO's methodology and assumptions, involved in deriving the TLAFs.

2.1 TLAF Methodology

The fundamental feature of TLAF calculation is the derivation of a location-based Marginal Loss Factor (MLF) for each transmission station.

For a particular load and generation dispatch scenario, the MLF of a particular transmission station can be defined as the ratio of a change in total system demand to the change in generation at the transmission station to meet the change in demand i.e.

$$\text{MLF} = \frac{\Delta\, total\ system\ demand}{\Delta\, in\ generation\ output\ to\ meet\ change\ in\ total\ system\ demand}$$

The MLFs are derived for each transmission station, taking into account forecasted assumptions of average system demand, average generation dispatch and time of the year (month) and day (day-time and night-time). The calculations are carried out by an automated procedure that uses 24 cases to represent these average scenarios throughout the tariff year.

2.2 TLAF Procedure

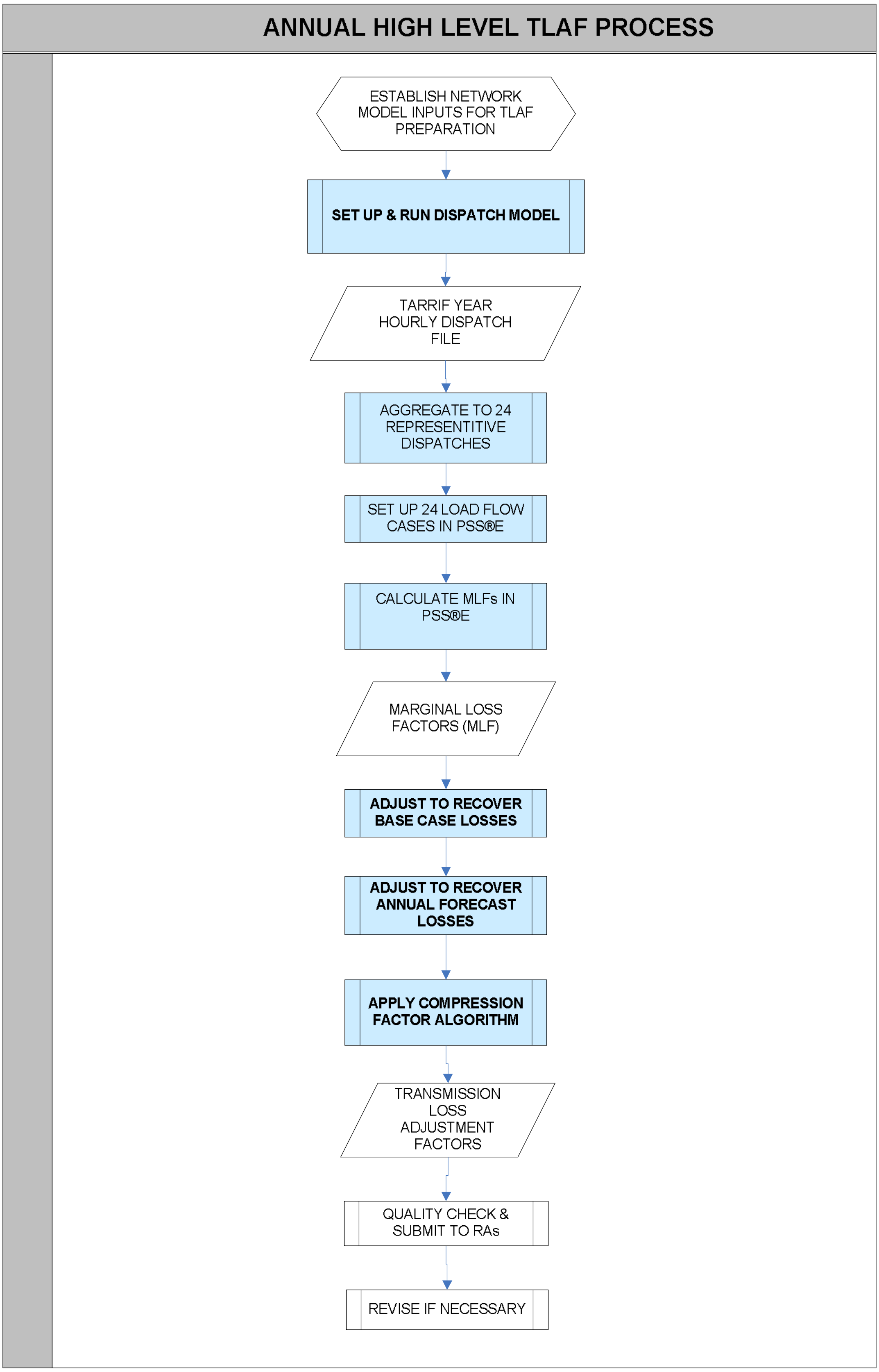


Figure 1: TLAF process

The process map above gives a High Level Overview of the TLAF process.

No.	Task	Description
1	Set up and run a dispatch model	A generation dispatch model is created through Plexos, a techno-economic tool, which produces a forecast hourly generation schedule for the forthcoming tariff year. The model is similar to that used for the Dispatch Balancing Costs model (DBC). See section 2.7 for further details on assumptions used in dispatch model.
2	Aggregate to 24 scenarios	The output from the dispatch model is a modelled dispatch for each generator /interconnector for each hour of the year. As TLAFs are based on 24 periods, this hourly data must be sorted and averaged to reduce the hourly data to 24 representative periods. The day hours are assumed to be 07.00 to 22.00. Night hours are assumed to be 22.00 – 07.00.
3	Set up 24 load flow cases in PSS®E	The 24 load flow cases are set-up in PSS®E based on the network as described in the most recent All-Island Transmission Forecast Statement (TFS) [12].
4	Calculate Marginal Loss Factors (MLF)	The MLFs are then calculated as described in section 2.3. The calculation of the MLF is the nub of the TLAF calculation process.
5	Adjust to recover load flow losses	See section 2.4
6	Adjust to recover annual forecast losses	See section 2.5
7	Apply compression algorithm	See section 2.6
8	Quality check and submit to RAs	The results of the various studies are reviewed for completeness and for any anomalies. Trends in the TLAFs or differences from previous years are identified and understood.

2.3 Power Flow Studies

2.3.1 Initial Base Case Studies

Using power flow modelling software PSS®E, from Siemens, the SOs perform load flow studies to create the 24 cases, that represent day and night for each month. Base case transmission losses are determined from these studies.

2.3.2 Monthly Case Batch Run

Using an automated PSS®E process the following is performed on each transmission station in turn:

1. For a particular transmission station, the first stage is to make it the system swing bus[2] - even if there is no generator already at the station. This means that the swing generator at the transmission station being studied will compensate for changes in generation, load and losses on the system.
2. The system demand is increased by 5 MW on a pro-rata basis across all demand buses. This change in demand is met by the new system swing bus and recorded as +ΔG. The system demand is then decreased by 5 MW. This change in demand is again met by the new system swing bus and recorded as–ΔG.
3. The MLF for the transmission station being studied is thus given as follows:

$$MLF = \frac{\Delta\ total\ system\ demand}{Average\ of\ absolute\ value\ of\ +\Delta G\ and\ -\Delta G}$$

   Where Δ total system demand = 5 MW

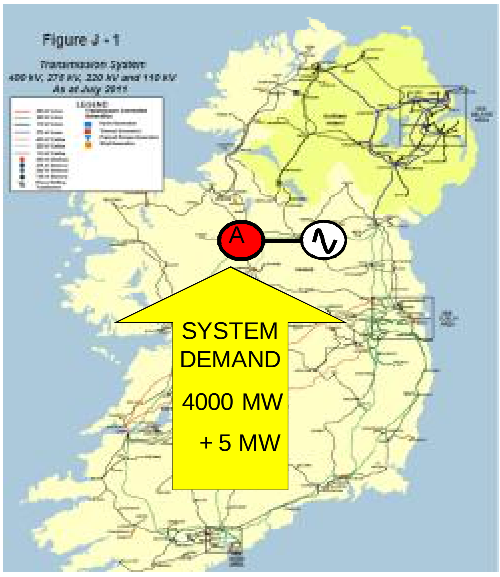
4. This is repeated for every transmission station in all of the 24 load flow cases.

[2] The swing bus is sometimes referred to as the slack bus. In a power flow study it is usual that the sum of the predicted injections at each bus will not exactly meet the total demand including losses. For this reason the injection at one bus must be adjusted, the bus selected for this adjustment is the swing bus.

Figure 2 illustrates the method for calculating the MLFs.

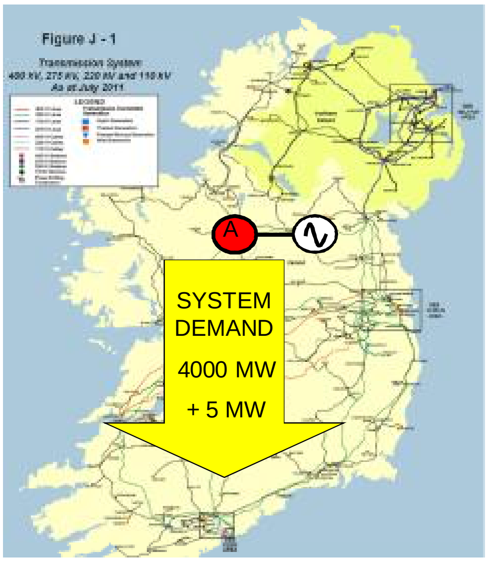
- Take Node A as the study bus
- Make Node A the system swing/slack bus
- **Increase** the system demand by 5 MW
- => 4005 MW
- Record the increase at the study node

=> 5.1 MW



- Decrease the system demand by 5 MW

=> 3995 MW
- Record the decrease at the study node
- => -5.2 MW



$$MLF_{NODE\,A} = \frac{5}{\text{Avg}\ (5.1,\ 5.2)} = 0.971$$

- The program does this for all the transmission nodes in the system model

Station	Export Generation	+5MW	-5MW	MLF
Node A	0.0	5.1	-5.2	0.971
Node B	90.0	5.2	-5.1	0.979
Node C	40.0	5.2	-5.1	0.971
Node D	470.0	5.1	-5.1	0.972
Node E	10.0	5.1	-5.0	0.991
Node F	0.0	5.2	-5.1	0.970
Node G	5.0	5.2	-5.2	0.968
Node H	0.0	4.8	-4.8	1.047
Node I	25.0	5.1	-5.1	0.985
Node J	0.0	5.1	-5.1	0.986

Figure 2: Marginal loss factor calculation

2.4 Adjustment to Recover Base Case Losses

When the MLFs are multiplied by the generation dispatch, the resulting transmission losses do not equal the PSS®E model base case transmission losses. As a result there is a requirement for an adjustment to the MLFs to ensure that the base case transmission losses, as determined by the power flow studies, are allocated.

To resolve this issue the MLFs are scaled to meet the base case transmission losses. This is done using a shift method (subtractive or additive) until a point is reached when MLFs multiplied by the assumed generation dispatch equals the allocation of transmission losses as determined by the base case load flow models. This same procedure is repeated for all monthly day and night scenarios. These scaled MLFs are termed SMLFs (Scaled Marginal Loss Factors).

2.5 Adjustment to Recover Annual Forecast Losses

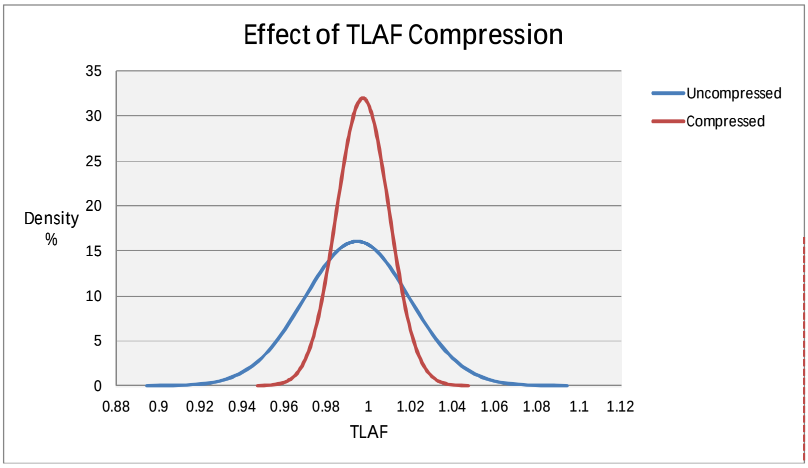
As the various monthly load flow models represent an average demand, average generation dispatches and a fully intact network, the total transmission losses calculated will be below the actual expected transmission losses for the year - for instance, transmission outages generally cause higher power flows on other lines and increase overall system losses. Therefore the already Scaled MLFs (SMLFs) need to undergo a further scaling.

The annual losses recovery factor (or K factor), as described in Appendix A, is calculated to do this and is applied to the SMLFs.

To arrive at uncompressed TLAFs, the K factor is subtracted from (or added to) the SMLFs so that their allocation increases (or decreases) slightly in each of the monthly scenarios in order to exactly recover the actual expected transmission system losses over the course of the tariff year.

2.6 Compression

The RAs requested that a compression step be implemented in the TLAF process [7], [8], [10]. The purpose of compression is to reduce the range and therefore volatility of TLAFs. The effect of the compressed TLAFs is illustrated by the graph below.



2.6.1 Details of Compression Factor

The Compression factor algorithm is described below where:

X = uncompressed TLAF value
NN = normalisation number

If X < NN, $\frac{NN-X}{2*NN}+X$

If X > NN, $X-\frac{X-NN}{2*NN}$

The algorithm is normalised around the normalisation number (NN). A normalised number is calculated for each scenario. The normalisation number is a point of reference for the TLAFs to be compressed around. The NN is chosen to ensure that, after compression is applied, the compressed losses are equal to the uncompressed losses (i.e. the forecast transmission losses for that month). The NN is approximately 0.98 but varies depending on the losses for each month and day and night.

2.6.2 Compression Factor Example

The algorithm can be normalised around any number. For the purpose of explaining the methodology the algorithm is normalised around 1.

For a data set where

X = uncompressed TLAF and assuming that the uncompressed TLAF falls within the range of 0.90 and 1.10

NN = normalisation number =1

If $X < 1$, $\frac{1-X}{2}+X$

If $X > 1$, $X-\frac{X-1}{2}$

Under the above conditions, each TLAF in the range of 0.9 to 1.1 (which encompasses all TLAFs) is ‘squeezed’ towards 1.0, while retaining the relative order.

The algorithm is self-limiting, i.e. it naturally selects its minimum and maximum limits based on two factors:

- an initial TLAF range of between 0.9 and 1.0,
- the algorithm normalisation number. Assuming the algorithm is normalised around 1.0 the minimum and maximum limits will become 0.95 and 1.05. The range is reduced here by approximately 50%.

This equates to a reduction in the effects of volatility by approximately 50%.

The result is that TLAFs becomes more consistent and the effects of volatility on the TLAF are reduced by approximately 50%.

2.7 Assumptions

A summary of the assumptions in the TLAF calculation model is provided below:

2.7.1 Assumptions in the Plexos dispatch model

Assumption	Description
Load - Forecast hourly demand	The demand forecast is based on that published in the All-Island Generation Capacity Statement. However, as the Generation Capacity Statement provides calendar year (Jan to Dec) demand forecasts, it requires conversion to a tariff year forecast (Oct to Sept). An hourly demand profile is modelled, the shape and distribution of which is based on historical demand data. The demand profile is scaled to the annual forecast demand as appropriate.
Generation Portfolio	The expected connected generation portfolio assumed for the tariff year under examination is based on: o The latest All-Island Transmission Forecast Statement [12], and o Updated Connection Agreement timeline information before data freeze.
Generation Characteristics	The commercial and technical characteristics of each generator are modelled based on fuel price and generator commercial and technical offer data assumptions. These parameters are based on the RAs validated SEM Plexos Forecast model dataset [11]. Generator outage schedules (both planned and forced) are also modelled.
Transmission system constraints	Transmission system constraints are also considered in the Plexos dispatch model, including the following: • Network constraints – the transmission network is modelled for the tariff year in question. The network used is based on that described in the latest All-Island Transmission Forecast Statement [12]. • Reserve and security constraints • the dispatch considers only an intact network, i.e. N-1 contingencies are not modelled

Assumption	Description
Interconnector	Interconnector power flows are modelled by considering the price differences between modelled SEM and BETTA markets.

2.7.2 Assumptions in PSS®E model

Assumption	Description
Network Topology	The network configuration is based on that as described in the latest All-Island Transmission Forecast Statement [12]. The interconnectors (Moyle and EWIC) were modelled separately in explicit detail to account for detailed transmission loss calculation.
Generator Models	The generator load flow models are based on those as described in the latest latest All-Island Transmission Forecast Statement [12]
System Demand and Generation	System demands for the 24 representative load flow cases are derived from the average generation dispatches that are produced by Plexos, i.e. generators are dispatched in the PSS®E models and demand is scaled on a pro rata basis to balance the generation and distribution and transmission losses.
AC Load Flow Cases	All-island load flow cases are used. The Northern Ireland model is produced by SONI and the Ireland model is produced by EirGrid. Both models are then merged to produce all-island load flow cases. The transmission network is assumed intact, i.e. no maintenance is assumed and no contingency analysis is performed. Transmission system capacitors are in service, where necessary, to keep voltages within normal operational limits.
Transmission Planning Criteria	The load flows are calculated such that the transmission system is within voltage and thermal limits.

3. APPENDIX A: EXAMPLE OF CALCULATION AND METHOD

An example TLAF calculation is provided below. This example uses fictitious values and is purely for illustrative purposes looking at the derivation of transmission loss factors for 10 generators:

1. Marginal Allocation Calculation

Unit	Dispatch MW	System Demand Change (ΔSD) MW	Average Generator Dispatch Change (ΔDG_i) MW at transmission bus (output from PSS®E)	Marginal Loss Factor (MLF = $\Delta SD / \Delta DG_i$)	Marginal Losses MW (Dispatch x (1 - Marginal Loss Factor))
G1	100	5	4.75	1.053	-5.263
G2	100	5	4.9	1.020	-2.041
G3	100	5	5.125	0.976	2.439
G4	100	5	5.175	0.966	3.382
G5	100	5	5.2	0.962	3.846
G6	100	5	5.225	0.957	4.306
G7	100	5	5.25	0.952	4.762
G8	100	5	5.25	0.952	4.762
G9	100	5	5.325	0.939	6.103
G10	90	5	5.5	0.909	8.182
	990				30.5

2. Determination of the Scaling Factor required to obtain SMLFs

For this particular monthly case, base case transmission losses for these 10 generators was calculated from **PSS®E** to total 19.9 MW. We see that marginal losses (30.5MW) are do not equal the base case losses (19.9MW). The scaling factor is required to shift these losses so their allocation due to the marginal calculation will equal the base case transmission losses.

	Transmission Losses (MW)
Marginal calculation	30.5
Base case model	19.9

Scaling Factor = (marginal losses –base case transmission losses)/total generation

= (30.5 – 19.9)/990

Scaling Factor, SF = 0.0107

A scaling factor is calculated for each monthly day/night case.

3. Annual Losses Recovery (k) Factor

To ensure that the annual modelled base case transmission losses are equal to the annual forecast transmission losses, an Annual Losses Recovery (k) factor is calculated from:

$$\text{k factor} = \frac{\text{annual forecast transmission losses} - \text{annual base case transmission losses}}{\text{total annual exported generation}}$$

In this example, it is assumed that the annual forecast transmission losses (as a percentage of total annual exported generation) are 2.036%.

The annual base case transmission losses (as a percentage of total generation) is obtained from the PSS®E output as being 1.579%. The annual base case transmission losses is obtained by summing the total MWh losses for each of the 24 cases (as a percentage of total MWh generation for the 24 cases).

Therefore for this example:

$$\text{k factor} = \frac{\text{annual forecast transmission losses} - \text{annual base case transmission losses}}{\text{total annual expoted generation}}$$

= (2.036% - 1.579%)

→k = 0.00457

3. Compression

The TLAFs are then compressed to reduce their range using the following equation below where:

X = uncompressed TLAF value

NN = normalisation number, which is set to 0.9754 in this case

If X < NN, $\frac{NN-X}{2*NN}+X$

X > NN, $X-\frac{X-NN}{2*NN}$

Unit	Dispatch MW	System Demand Change (ΔSD) MW	Average Generator Dispatch Change (ΔDGi) MW at transmission bus (output from PSS®E)	Marginal Loss Factor (ΔSD/ ΔDG_i)	SMLF (MLF + SF)	TLAF (SMLF -k)	Scaled losses after K adjustment	Compressed TLAF	Compressed Equivalent Generation (MW)	Losses (MW)
G1	100	5	4.75	1.053	1.063	1.059	-5.877	1.016	101.6	-1.601
G2	100	5	4.9	1.020	1.031	1.027	-2.655	1.000	100.0	-0.030
G3	100	5	5.125	0.976	0.986	0.982	1.825	0.978	97.8	2.153
G4	100	5	5.175	0.966	0.977	0.972	2.768	0.974	97.4	2.613
G5	100	5	5.2	0.962	0.972	0.968	3.232	0.972	97.2	2.839
G6	100	5	5.225	0.957	0.968	0.963	3.693	0.969	96.9	3.063
G7	100	5	5.25	0.952	0.963	0.959	4.148	0.967	96.7	3.285
G8	100	5	5.25	0.952	0.963	0.959	4.148	0.967	96.7	3.285
G9	100	5	5.325	0.939	0.950	0.945	5.490	0.961	96.1	3.939
G10	90	5	5.5	0.909	0.920	0.915	7.629	0.946	85.1	4.856
MW	990						24.402		965.6	24.402

4. Appendix B: Application of TLAF in the SEM

In SEM, the TLAFs are used in the calculation of CLAFs (Combined Loss Adjustment Factor) where:

- CLAF = TLAF x DLAF
- And DLAFs (Distribution Loss Adjustment Factors) are calculated annually by the Distribution System Operator (DSO) for distribution connected generators.

In effect CLAFs account for the distribution and transmission losses incurred by market participants.

For transmission-connected market participants, the DLAF is assumed to be 1.0, therefore for transmission-connected market participants:

- CLAF = TLAF x 1.0 = TLAF

The resulting CLAFs are used in the SEMO central market systems that calculate settlement. This means that payments to or charges due from participants are based on loss-adjusted volumes.

All market settlement is assumed to take place at the interface between the transmission and distribution grids. This ensures that all quantities are calculated on a consistent basis.

Figure 3 illustrates the concept of the adjustment of generator metered energy being adjusted by CLAFs. There are four transmission generators of 400 MW each located in different parts of the transmission network. The energy each generator can trade in the market is adjusted by its CLAF.

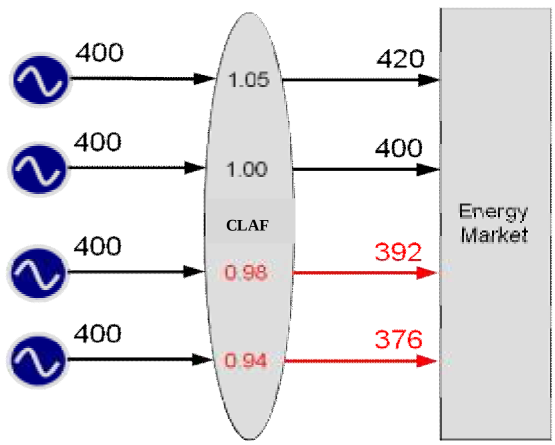


Figure 3: CLAFs applied to tradable energy

5. APPENDIX C: GLOSSARY OF TERMS

Term	**Explanation**
Annual Loss Recovery Factor (K factor)	The factor required to shift total modelled transmission losses for the year up to the level of actual expected transmission losses.
Base Case Transmission Losses	The average system transmission losses as determined by a power system software model for each monthly day/night dispatch case.
Forecast Transmission Losses	The forecast transmission losses for a given year are based on expected actual transmission losses.
Marginal Loss Factors (MLFs)	For a particular transmission station, the MLF, can be defined as the ratio of a change in total system demand to the change in generation output of the transmission station to meet the change in demand.
Scaled Marginal Loss Factor (SMLFs)	The resultant loss factors when MLFs are scaled to match base-case system losses.

6. REFERENCES

[1] Trading and Settlement Code, available at

http://www.sem-o.com/MarketDevelopment/Pages/MarketRules.aspx

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[10] Decision Paper Treatment of Losses in the SEM, SEM-12-049, 26 June 2012

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