2014 FORWARD LOOKING LOSS FACTOR METHODOLOGY REVIEW

ISSUES PAPER

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EXECUTIVE SUMMARY

This Issues Paper commences the first stage of an AEMO consultation to consider amendments to the Methodology for Calculating Forward Looking Transmission Loss Factors (Methodology).

AEMO considers that the Methodology, developed in 2002 under more predictable electricity supply industry expectations, might not be optimal for current expectations. This will consider if the current Methodology, applied under current expectations, delivers appropriate MLFs.

AEMO has identified what it believes are the four main issues with the Methodology:

1. Historical generation profiles.
2. Historical MNSP flows.
3. Generating unit capacity reductions.
4. The Methodology document is difficult to read due to the inclusion of commentary in the same document.

AEMO has prepared this issues paper to discuss these issues and consider the following amendments to the Methodology:

1. Give Generators a better opportunity to advise AEMO of manifestly incorrect generation profiles.
2. Allow AEMO to adjust historical flows on MNSP networks to reflect any proposed change in generation profiles.
3. Correct how AEMO currently manages generating unit capacity reductions.
4. Re-write the Methodology to separate the Methodology from the associated commentary.

AEMO invites stakeholders:

- to propose alternative options that would achieve the relevant objectives; and
- to identify any adverse consequences of the proposed options.

Stakeholders are invited to submit written responses on the issues and questions identified in this paper by 5.00 pm (Melbourne time) on 22 August 2014, in accordance with the Notice of First Stage of Consultation published with this paper.

Contents

1 Introduction

This Issues Paper is the first stage of a review of the Forward Looking Loss Factor Methodology (Methodology) that AEMO uses to calculate Marginal Loss Factors (MLF).[1]

The objective of this review is to consider issues and possible solutions to improve the Methodology.

2 Stakeholder Consultation Process

AEMO is required to consult in accordance with the National Electricity Rules (NER) consultation process[2]. Table 1 shows the stages and indicative dates of this consultation process.

Stakeholders can request a meeting with AEMO to discuss the Issues Paper and, in due course, the Draft Determination and Report, prior to a submission due date. AEMO is also planning to conduct industry forums as shown below:

Table 1

STAGE	DATE
Publish Issues Paper	17 July 2014
Due date for Issues Paper submissions	22 August 2014
Industry Forum	3 September 2014
Publish Draft Report	18 September 2014
Due date for Draft Determination and Report submissions	3 October 2014
Industry Forum	15 October 2014
Publish Final Determination and Report	30 October 2014

The outcome of this review is to identify and make changes to the Methodology in time to be applied for the 2015-16 MLF process. Unfortunately, improvements that require NER changes (Rule Change Proposal) cannot be completed in time for the 2015-16 MLF process.

AEMO welcomes suggestions that might be beyond the scope of this review to facilitate a further review of the Methodology that may require NER changes.

3 NER requirements

The NER requires AEMO to calculate, each year, inter-regional loss equations and intra-regional loss factors, and to publish the results by 1 April. The NER further requires AEMO[3] to determine, publish and maintain in accordance with the NER consultation process, a methodology to determine the inter-regional and intra-regional loss factors to apply for a financial year for each transmission network connection point. This methodology was developed after consultation in 2002 and has remained largely unchanged since then.

[1]Available at: http://www.aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries/Methodology-for-Calculating-ForwardLooking-Transmission-Loss-Factors

[2] NER Clause 8.9

[3] NER Clauses 3.6.1(c) and 3.6.2(d)

4 Background to Marginal Loss Factors

AEMO uses marginal costs as the basis for setting electricity prices in accordance with the National Electricity Rules (NER). The accounting for transmission electrical losses involves expanding this method to electricity generation and consumption at different locations.

For electricity transmission, electrical losses are a transport cost that needs to be recovered. A feature of electrical losses is that they also increase with an increase in the electrical power transmitted. That is, the more a transmission line is loaded, the higher the losses. Thus, the price differences between the sending and receiving ends is not determined by the average losses, but by the marginal losses of the last increment of electrical power delivered.

In the NEM, electrical power is traded through the spot market managed by AEMO. There are two basic components of the spot market: the central dispatch process and the Regional Reference Price (RRP), namely the spot price. The central dispatch process schedules different generating plant to meet demand in order to minimise the cost of meeting demand based on generating capacity and price offers.

Static MLFs represent the intra-regional electrical losses resulting from transporting electricity between a connection point and the Regional Reference Node (RRN). In the central dispatch process, generating plant prices within each region are adjusted by the MLFs to determine the dispatch order of generation.

Dynamic inter-regional loss factor equations calculate the losses between regions. Depending on the flows between regions, the inter-regional losses also adjust generating plant prices in determining the dispatch order of generation to meet demand.

4.1.1 Single loss factor for a financial year

The design of the NEM and the NER require a single loss factor to be used for each connection point for a financial year. In a power system, however, the losses are function of the network and the operating point of each load and generating plant. Therefore, calculating a single MLF using the volume-weighted average principle will necessarily be an approximation to the vast number of power system conditions experienced during a year. Only limited accuracy is possible due to this design limitation.

4.1.2 Loss factors are forward-looking

The NEM design also requires a single intra-regional MLF calculated in advance, rather than determining MLFs in real-time. This is different to the approach used for inter-regional losses, where real-time information is used to dynamically calculate loss sensitivities based on an inter-regional loss equation calculated in advance. This design also limits the accuracy of MLFs.

4.1.3 MLFs reflect the marginal pricing principle

The design of the NEM is based on the economic principle of marginal pricing. It is the settlement price for a spot market participant and is based on the price applicable for a marginal change in the output of generation or load. All three components of price (energy, losses and congestion) are calculated using this principle.

Transmission losses have a non-linear relationship with power flows on a network. When a marginal change in consumption or generation increases the loading on heavily loaded transmission lines, it can lead to a higher marginal loss. Therefore, a load connected electrically close to an interconnector that generally exports out from a region could have a less advantageous MLF. Conversely, loads electrically close to a generally importing interconnector could have advantageous MLFs since an increase in demand can reduce the loading on the lines. In both these situations, while a consumer's operational decisions will usually have little impact on an interconnector flow, the resulting marginal loss factors will reflect the large influence of interconnector flows.

5 Context of this review

Uncertainty in the electricity supply industry is currently high when compared to the past 20 years. Variables, such as generation technology, government policy, and the cost of electricity are changing the generation mix, network usage and consumer demand.

AEMO considers that the Methodology developed in 2002[4] under more predictable electricity supply industry expectations might not be optimal for current expectations. This review will consider if the Methodology delivers appropriate MLFs when applied under the current circumstances.

6 Issues with the Methodology

AEMO has identified four main issues with the Methodology:

1. Use of historical generation profiles.
2. Use of historical Market Network Service Provider (MNSP) flows.
3. Management of generating unit capacity reductions.
4. The methodology requires re-writing to separate the methodology from commentary.

6.1 Historical Generation Profiles

The Methodology relies on historical generation profiles to forecast, by extrapolation, future generation profiles. These profiles are then used to determine MLFs. If the historical generation profiles are a less certain predictor of future generation due to industry change and uncertainty, in turn, the resultant MLFs could be less representative of electrical losses.

6.1.1 Demand-supply balance

Simulation studies are used to calculate MLFs for conditions representative of the financial year that the MLFs are to apply. Each half-hour of the target financial year is studied and a volume-weighted MLF is calculated for each transmission connection point. In doing so, historical load and generation profiles are used as a base, or starting, point. The average energy consumed in the NEM will usually vary greatly each year resulting in changed network flows and losses. In order to match conditions in the financial year under study as closely as possible, the baseload profiles are scaled to match the forecast energy and demand published in the National Electricity Forecasting Report (NEFR).

To meet the forecast energy and demand, the generation has to be adjusted to restore demand-supply balance. Depending on the generation profiles used as a base, the required adjustment can be quite different, and this will have a major impact on interconnector flows and, thereby, MLFs.

In order to restore the demand-supply balance for a forecast load, the Methodology applies the principle of minimal extrapolation to forecast generation. This involves scaling generation from a starting point by the least possible amount in order to restore the demand-supply balance. The Methodology requires that generation is not scaled uniformly[5] and details the priority order in which generation is selected for scaling. For example, energy non-limited and online plant have preference over energy-limited plant and offline plant.

6.1.2 Minimal extrapolation

The principle of minimal extrapolation was established as a fundamental principle of the Methodology in 2002. Market simulation was considered as an alternative method of obtaining generation forecasts, however, issues over estimating a merit order made it impractical to study the method any further. AEMO believes that the same issues are still relevant, and minimal extrapolation remains

[4] The 2002 consultation documents will be made available on the AEMO website with this document.
[5] Clause 4.5.6 of the Methodology

its method of choice since historical generation profiles are irrefutable, deterministic and easily verifiable. AEMO has, however, commenced investigating the possibility of using market simulations as a basis for generation forecasts for other purposes, but further development work is required to assess the suitability of this process.

The principle of minimal extrapolation has proven to be robust on most occasions, particularly under scenarios where the NEM has experienced steady load growth over the last decade. Since 2012, however, the electricity industry has undergone significant changes in generation patterns.

These changes have not been gradual, but more akin to step changes, for example, changes in generation patterns with the introduction of the carbon price. Minimal extrapolation is vulnerable to step changes in inputs as a change is reflected two years into the future if nothing is done to identify and make corrections to address a forecast change.

6.1.3 Backcasting studies

In order to quantify this issue, following the 2014-15 MLF calculation AEMO evaluated the MLFs for 2011-12 and 2012-13 by backcasting the MLFs[6]. This was in response to outcomes in the 2014-15 MLF process and concerns raised by Generators and Customers.

The outcomes after applying the Methodology and the results of the backcasting studies are listed in Appendix B. While the match between the published and backcast results for most connection points were within a 0.02 error, there were a number of outliers with larger errors. Although any error will have impacts on the financial position of spot market participants, a methodology that estimates a single loss factor for a financial year is expected to show some inaccuracies.

The results in Appendix B show that the major issue causing inaccuracies in the MLFs is the energy-limited generation and MNSP network profiles used for minimal extrapolation being unrepresentative of the conditions in the year of interest. This is mainly due to step changes in the industry, such as the introduction (or repeal) of a carbon price. Unrepresentative generation profiles will distort MLFs that are electrically close to a generating unit. Such unrepresentative profiles can cause interconnector flows to vary and will impact MLFs electrically close to the interconnector and, possibly, in other regions.

6.1.4 Proposed solution

AEMO believes that there is no credible alternative to minimal extrapolation under abnormal conditions in the short term but is interested in other views on this matter.

The Methodology allows for generation profiles to be changed under abnormal conditions in any event. Section 5.5.6 of the Methodology states the following:

> *5.5.6 Accounting for abnormal conditions affecting NEM generation patterns*
>
> *Where a generation pattern appears to have been affected by "unforeseen circumstances", a generator may provide to AEMO by 15 September, an adjusted generation profile. AEMO will then review the adjusted profile provided by the generator, and accept or reject the proposal on the basis of sufficient reasoning for providing an adjusted profile.*
>
> *"Unforeseen circumstances" may refer to physically uncontrollable cases, such as:*
>
> - *drought conditions*
> - *major plant failures which result in significant forced outages of greater than four weeks*
> - *failure in the supply chain impacting on fuel availability"*

AEMO proposes to make the following changes to section 5.5.6 of the Methodology. This is to allow Generators to assess and respond to AEMO where historical generation patterns might not represent their expected generation profile:

[6] AEMO will also conduct the same exercise for the 2013/14 year but due to time constraints this information will be provided as part of the draft determination report.

"Where a Generator believes its historical generation profiles are not an accurate predictor of future generation profiles, it may provide to AEMO by 15 November, an adjusted generation profile. AEMO will then review the adjusted generation profile, and consider whether to use the adjusted generation profile in lieu of the historical generation profile provided:

- *Requests for generation profile revision come from the owner or operator of a generating unit or generating system;*
- *Historical generation profiles must be shown to be obviously not representative of the expected generation profile in the next year;*
- *Revised generation profiles are independently verifiable and are based on physical circumstances only, such as:*
  - *drought conditions;*
  - *major plant failures resulting in significant forced outages of greater than four weeks;*
  - *failure in the supply chain impacting on fuel availability;*
- *Revised generation profiles are not market-related or arise as a result of the financial positions of Generators;*
- *Adjusted generation profiles are not be confidential, as AEMO will publish them along with its reasoning for using an adjusted generation profile as part of the report accompanying the issue of the MLFs; and*

AEMO may seek an independent review of any adjusted generation profile submitted by a Generator."

To enable spot market participants to identify errors in extrapolated generation profiles that AEMO proposes to use as inputs to the MLF calculation, AEMO intends to trial a process of providing the indicative extrapolated generation profiles to the spot market participants for their review.

AEMO aims to calculate extrapolated generation profiles by the end of September each year. The main inputs of this process are:

- Historical generation from the relevant historical year.
- Network model as per previous year.
- Load forecasts will closely match the energy from the latest NEFR.
- Generation capacities from the latest available Electricity Statement of Opportunities (ESOO).

Questions

- Are there any other practical modifications to minimal extrapolation under unusual conditions, given the constraints of the NEM design principles?
- Is AEMO's proposal to modify clause 5.5.6 of the Methodology sufficient to address the issue? If not, what more can be done?

6.2 Historical MNSP Profiles

The Methodology requires the use of historical MNSP network flows to calculate MLFs.

Section 5.3.1 of the Methodology states:

> *"5.3.1 Controllable Network Elements with historical flow data*
>
> *AEMO will assume that the flows in controllable MNSP network elements are unchanged from the historical flows."*

Currently, Basslink is the only MNSP, and is the only link from Tasmania to the rest of the NEM.

If historical generation profiles on either side of Basslink are varied the flow through Basslink is no longer representative of likely network flows.

For example, if the generation profile for one generating system in Tasmania is changed and Basslink flows are not changed to reflect this, the generation change must be reflected in other generation in Tasmania only. This might not be reflective of actual outcomes.

6.2.1 Possible solutions

Allowing Tasmanian imports and exports to change to match supply-demand conditions in Tasmania and the rest of the NEM can alleviate some of these issues.

Basslink flows might need to be reviewed prior to using Basslink flow as an input to the MLF calculation. This is because there is no practicable way to treat Basslink as an AC interconnector. This can be done in two ways:

(1) Basslink flow adjusted for a change in Tasmania generation only. For example a ±1 MW change in generation will be reflected in ±1 MW change in Basslink flow, within the limits of Basslink.

(2) Basslink flow adjusted for a change in both Tasmania generation and demand.

The difference between the two options is that in option (1) the change in generation in Tasmania results in an equivalent change in Basslink, whereas in option (2) the net change in generation and demand in Tasmania results in an equivalent change in Basslink. Under option (2) any change in Tasmanian demand will be met by generation in the rest of the NEM.

AEMO's preference is to adopt option (1) because this is consistent with the principle of minimal extrapolation.

Questions

- Is a change to the assessment of MNSP network flows justified?
- If so, which option is preferred? Is there another option?
- What are the suitable guidelines to make such changes?

6.3 Generator Outages

The Methodology requires AEMO to adjust historical generation capacities to reflect capacity reductions noted in the most recent ESOO. This could lead to an incorrect use of this capacity reduction in MLF calculations in future years.

The Methodology is silent as to whether the historical generation profile can, or should, be re-adjusted to compensate for the earlier adjustment.

Generating units can be unavailable periodically for planned outages, and to a lesser extent, as a result of forced outages. Incorrectly accounting for these outages in the calculation of the MLFs can have considerable impact on the results, and has to be considered. The following two issues have arisen over the way that outages are treated in the Methodology:

6.3.1 Double-counting of capacity reductions

Section 4.5.11 of the Methodology requires the use of actual historical generation profiles to represent outages consistent with the principle of minimal extrapolation. Since planned or forced outages are captured in historic generation profiles, which are two years old, the effect of these outages manifest with a two-year lag. AEMO considers that this method of accounting for outages is robust and does not require subjective assumptions. Even though the outage is considered with a two-year lag, it results in correct long-term outage rates.

The generation dispatch in MLF studies depends on the forecast capacity of generation in addition to historical generation profiles. Generation dispatch will be reduced if either one or both of the following conditions are satisfied:

- Historical generation profile indicates a reduction in generation; and
- Future generation capacity is reduced.

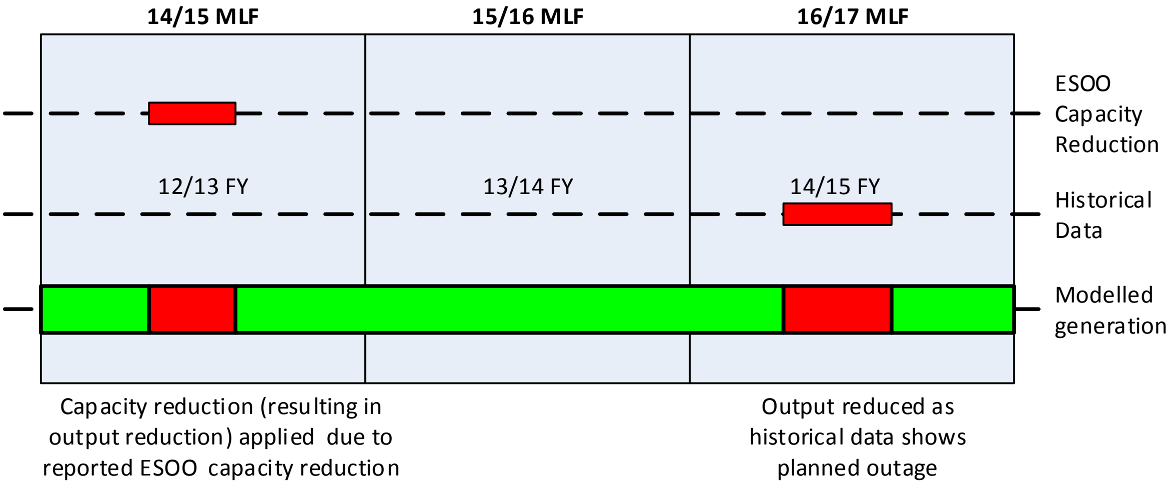
Section 4.5.7 of the Methodology requires that the generation capacity values used in the MLF calculation process are the values published in the most recent ESOO (or ESOO update) with separate values for summer and winter. The generation capacities listed in the ESOO provided by each asset owner for peak winter and summer conditions.

For example, consider a generating system with four units of 500 MW each with a total capacity of 2,000 MW. Due to a planned outage, if the asset owner advises that one generating unit will be unavailable during the summer peak demand period, the ESOO summer capacity will be 1,500 MW, whereas the winter capacity will be 2,000 MW.

Regardless of the nature of the outage, if the capacity is forecast to be reduced for a season, the reduction is modelled in the MLF calculation in accordance with the Methodology. It effectively double-counts the reduction as follows:

- The reduction of generation dispatch is observed in the current MLF calculation due to the capacity being reduced; and
- The reduction of generation is observed when the subject year’s generation traces become the reference traces for the MLF calculation two years later (assuming that the generation actually did reduce in output) due to the historical generation profile indicating reduced generation.

This is further explained in the figure below:



For the 2014/2015 MLF calculation, the ESOO capacity reduction results in a reduced dispatch. In the 2016/2017 MLF calculation, the historical traces considered are the 2014/2015 historical traces. If the generating unit was out of service in 2014/2015, it would result in a reduced dispatch for the 2016/2017 as a result of the MLF calculation. Reduction of capacity for forecast generation outages will result in double-counting the outage.

Analysis of the ESOO reports over the past 10 years indicates numerous reasons for plant limitations such as:

- Permanent changes in generation capacity due to upgrades or downgrades
- Outages due to major repairs or refurbishments
- Fuel supply constraints
- Environmental controls
- Restricted availability of fuels
- Other ad hoc reasons

Another important reason for the capacity of generation to be shown as reduced in the ESOO is due to mothballing. Under current market conditions, some generating units have been mothballed and the trend is likely to continue. AEMO has produced a document entitled 'Guidance for Dry Stored Generators' that defines a generating unit that is mothballed in general terms[7] as follows:

> *"3.2 What is dry storage?*
>
> *The term "dry storage" is used in this document to identify the status of a generation facility that is not in a state of readiness to allow it to be dispatched in the NEM, but remains physically intact, and, after a limited period of restoration, would be capable of being returned to service. Similar terminology used to refer to this state includes "care and maintenance" or "mothballing".*
>
> *A generating facility might be placed into dry storage for a number of reasons, including:*
>
> - *The facility is physically inoperable, and is not likely to be repaired until the owner determines that market conditions warrant the expenditure.*
> - *It is not commercially viable to generate energy and ancillary services for the foreseeable future due to current market conditions, contractual arrangements, and operating costs.*

[7] http://www.aemo.com.au/Electricity/Market-Operations/Generator-Performance-Standards

- *Network access arrangements, including restrictions due to network congestion make it uneconomic to generate for a period of time."*

As explained above, reduction in capacities due to all the above reasons will be double-counted due to the manner in which outages are modelling according to the Methodology.

6.3.2 Maintenance outages reported as capacity reductions

A second issue is that outages due to plant maintenance have been reported as a reduction in generation capacities in the ESOO. For planned maintenance outages, the generation capacities listed in an ESOO have the following characteristics:

- Not all planned maintenance outages result as capacity reductions in the ESOO; and
- Planned maintenance outages that result in capacity reductions will be included in the ESOO if they affect the anticipated generation capacities for peak winter and summer conditions. These outages are usually greater than one month's duration but could be up to two or three months.
- AEMO believes these types of routine maintenance reductions should not result in an adjustment to generation capacity and that all maintenance outages should be treated alike regardless of whether they are reported in the ESOO.

6.3.3 Proposed solutions

In order to resolve the problems discussed above, AEMO is seeking to clarify in the Methodology how capacities reported in the ESOO will be used to model generation.

AEMO proposes to continue to use generation capacities as published in the latest ESOO, but estimate generation when the current year becomes the reference year in order to "fill" the gap in historical generation during the outage period. This means that the generation will be reduced for the year that the MLFs are modelled, but will not impact studies two years later.

AEMO proposes two possible solutions to resolve maintenance outages being reported as capacity reductions in the ESOO:

(1) Review and ignore capacity reductions reported in the ESOO capacities due to maintenance, and provide a summary in its MLF report on 1 April each year; and

(2) Treat capacity reductions due to maintenance outages the same as other capacity reductions.

The table below lists the advantages and disadvantages of each method:

Method	Advantages	Disadvantages
(1)	• Consistent with minimal extrapolation principle – outages picked up in the reference year resulting in correct long-term outage rates • The duration of the outage is properly captured	• Requires subjective assessment • Reduction in generating unit output only reflected two years later (but is consistent with how all outages not identified in the ESOO are modelled)
(2)	• Transparent and not subjective • Potentially more representative of the year being modelled in the case of longer outages	• Increased workload and tracking between years required • Inconsistent with minimal extrapolation principle • No ability to model the expected outage duration accurately because the capacity will be applied for the entire season, which is usually longer than the proposed outage

AEMO prefers option (1), which is to ignore capacity reductions published in the ESOO if they are for maintenance purposes only. This is consistent with how other planned and unplanned outages are modelled for the purposes of the MLF calculation.

AEMO proposes to review capacity reductions reported in the latest ESOO and identify planned reductions in capacities that appear to be routine maintenance outages[8] and confirm with Generators the nature of the reported outages before ignoring them.

Question

- AEMO seeks comment on this proposal and any indicators to determine what are maintenance outages.

6.4 Methodology Document

AEMO considers that the current Methodology document is poorly written and difficult to read due to the inclusion of commentary in the same document. As part of this review AEMO proposes to re-write the Methodology to remove the commentary. Any commentary will be included as part of the consultation documents.

Question

- Are there any issues with the Methodology other than those identified by AEMO?

[8] Generally characterised as maintenance performed every 5 years of less.

Appendix A - Glossary

TERM OR ACRONYM	MEANING
AC Interconnector	Alternating Current Interconnector
AEMO	Australian Energy Market Operator
Basslink	A direct current interconnector that connects Victoria to Tasmania
ESOO	Electricity Statement of Opportunities
Methodology	Forward Looking Loss Factor Methodology
MLF	Marginal Loss Factors
NEM	National Electricity Market
MNSP	Market Network Service Provider
NER	National Electricity Rules
NEFR	National Electricity Forecasting Report
RRN	Regional Reference Node

Appendix B - Backcasting results

After the publication of the 2014-15 MLFs on 1 April 2014, a number of spot market participants raised concerns about whether the Methodology was still appropriate with respect to generation profiles used in modelling MLFs.

AEMO conducted a limited backcasting exercise to assess the performance of MLFs in the recent past with the actual MLFs calculated retrospectively. Backcasting was performed for the 2011-12 and 2012-13 MLFs. AEMO will complete a similar study for the 2013/14 MLFs and will provide the results of this study with the draft determination and report on the Methodology.

Backcasting methodology

Since the aim of backcasting is to calculate MLFs retrospectively, historical demands measured at load and connection points were used as an input to the minimal extrapolation process to restore supply and demand. This results in conditions very close to historical snapshots of the power system with only small amounts of generation scaling. The key features of the backcasting methodology are highlighted in the table below:

	Forward Looking MLFs	Backcasted MLFs
Method	Use data from reference year (two years old) to calculate MLFs for the next year	Use data from the same year to calculate MLFs for the same year
Load inputs	Half-hourly load forecasts for every load connection point	Actual metered load data for the same year
Generation inputs	Half-hourly metered generation data from the reference year, with minimal extrapolation to restore demand-supply balance	Actual metered generation data for the same year, with minimal extrapolation to restore demand-supply balance
Minimal extrapolation	Potentially large amount of generation scaling to restore demand-supply balance	Small amount of generation scaling to restore demand-supply balance
MNSPs (Basslink)	Half-hourly metered data from the reference year	Actual metered data for the same year

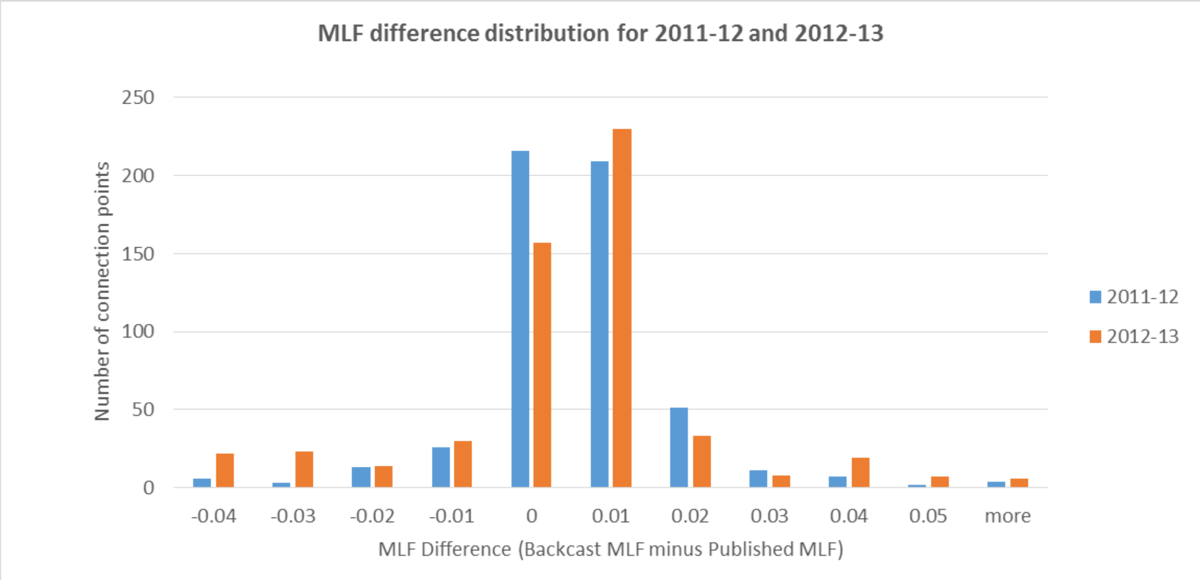
The difference between the backcasting results and the published MLFs is used as the criterion for comparison and is defined as: $MLF_{Backcast} – MLF_{Published}$

Backcasting results

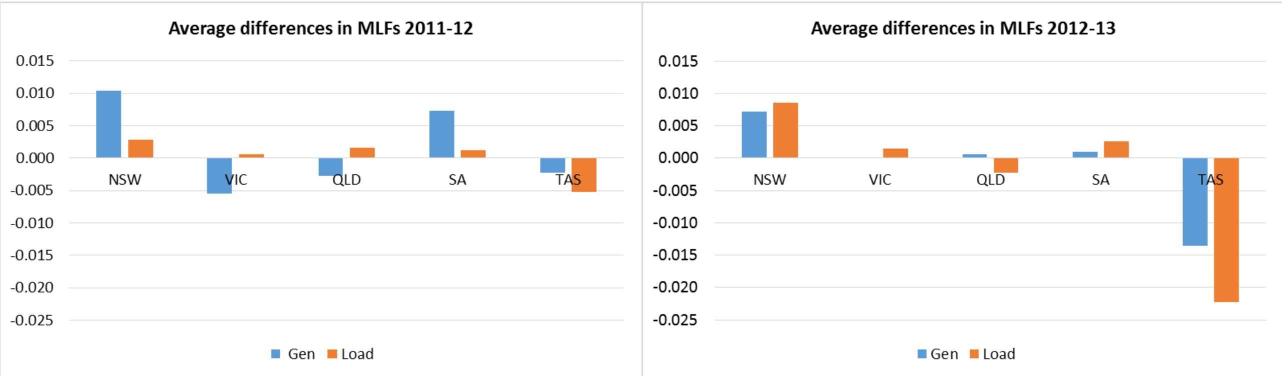
The absolute differences in MLFs are summarised in the table below.

Year	Difference within ±0.02	Difference within ±0.03
2011-12	92%	96%
2012-13	82%	86%

The distribution of the differences is shown in the figure below:



The average differences between backcast and actual MLFs results grouped regionally between generation and load can be seen in the following figure:



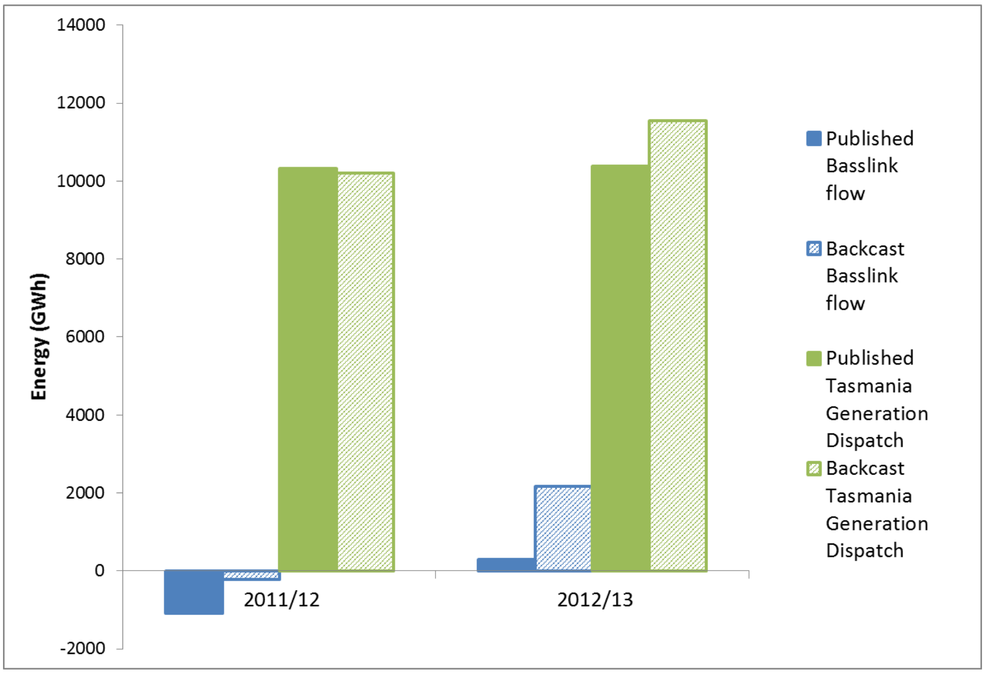
The following observations can be made from these results:

Step changes in the industry

There is a marked increase in average differences between backcast and actual MLFs in 2012-13, as compared with 2011-12.

The figure below shows, for 2011-12, the generation dispatched in Tasmania was comparable to the forecast generation that was used as an input to the MLF calculation.

In 2012-13, there is a greater difference between the generation dispatched in Tasmania and the forecast generation that was used as the input to the MLF calculation. This resulted in potentially less accurate MLF values.



In the backcast study, the Basslink export from Tasmania to Victoria has increased dramatically, possibly as a result of externalities resulting in a step change in the Basslink flow. This was not captured in the published MLFs and as a result, the Tasmanian MLFs appear lower in the backcast study.

The 2011-12 study is typical of early to mid-2000s where change was gradual, and the published MLFs correlate well with the backcast MLFs.

By way of example, most generation in Tasmania is energy-limited and might not be able to maintain high outputs year-on-year. Since the Methodology requires that the reference generation for minimal extrapolation is two-year-old historic data, adjustments need to be made to these profiles to ensure the MLFs are more representative of likely generation profiles for the study year. This problem is exacerbated by the use of historical MNSP network profiles.

Small loads and generation

Results also show that small loads and generating units/generating systems showed a greater range of inaccuracy than the larger loads and generating units/generating systems. This is a known issue due to the difficultly in accurately predicting the output of small load and generation, and because the smaller sample of data causes a more volatile volume-weighting when calculating the MLFs.