LOSS FACTOR METHODOLOGY REVIEW

ISSUES PAPER

Published: **September 2016**

Version control

Version	Release date	Changes
1.0	30 September 2016	Initial release
2.0	15 November 2016	Corrected a typographical error in Appendix A (page 17). Text corrected to $MLF_{Published} – MLF_{Backcast}$

EXECUTIVE SUMMARY

Clauses 3.6.1 and 3.6.2 of the National Electricity Rules (NER) require AEMO to determine, publish and maintain a methodology for the determination of inter-regional loss factors and intra-regional loss factors respectively, for each transmission network connection point, to apply for a financial year. Both methodologies are contained in AEMO's published 'Forward Looking Loss Factor Methodology' (Methodology).

The current Methodology was first developed in 2002 and has been the subject of a number of minor reviews, the most recent being in 2014 when, following stakeholder consultation, changes were made to the procedure for the revision of generation and market network service data.

A number of ongoing issues have been raised by stakeholders since the last review. In early 2016, AEMO conducted a series of workshops to identify and describe these issues.

The identified issues can be grouped into three categories by reference to their potential solutions: those that can be addressed by modifications to AEMO's work processes; those requiring amendments to the Methodology, and market design issues that are likely to require changes to the NER. This paper discusses the issues in the first two categories.

To address these issues, AEMO proposes to modify the generating forecast method in the Methodology, to improve its accuracy. Increasing the accuracy of generation forecasts can produce loss factors that better represent the likely flow of electricity through the network.

For completeness, Appendix B lists those in the third category for possible further discussion and development in a separate process. These cannot be addressed in the current consultation.

Stakeholders are invited to submit written responses on the issues and questions identified in this paper by 5:00 pm (Melbourne time) on 9 November 2016, in accordance with the Notice of First Stage of Consultation published with this paper.

CONTENTS

1. INTRODUCTION

This Issues Paper is a first stage of a review of the Loss Factor Methodology (Methodology) that AEMO uses to determine inter-regional loss factors and intra-regional loss factors for each transmission network connection point, per a financial year.

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

2. STAKEHOLDER CONSULTATION PROCESS

As required by the National Electricity Rules (NER), AEMO is consulting on possible revisions to the Methodology referred to in clauses 3.6.1 and 3.6.2 of the NER that AEMO uses to calculate inter-regional and intra-regional loss factors[1].

AEMO's indicative timeline for this review is outlined in Table 1. Dates may be adjusted depending on the number and complexity of issues raised in submissions and any meetings with stakeholders.

Table 1 Review timetable

Stage	Date
Issues Paper published	30 September 2016
Submissions due on Issues Paper	9 November 2016
Draft Report published	8 December 2016
Submissions due on Draft Report	23 December 2016
Final Report published	3 February 2017
Apply revised methodology to 2017-18 MLFs	January – April 2017
Publish MLFs	1 April 2017

Stakeholders can request a meeting with AEMO, by the submissions due date, to discuss the issues and proposed changes raised in this Issues Paper.

3. BACKGROUND

3.1 NER requirements

The NER requires AEMO to calculate, each year, inter-regional loss factor equations and intra-regional loss factors, and to publish the results by 1 April. The NER[2] further requires AEMO to determine, publish and maintain in accordance with the NER consultation procedures, a methodology to determine the inter-regional and intra-regional loss factors to apply for a financial year for each transmission network connection point.

1 Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries

2 Clauses 3.6.1(c) and 3.6.2(d)

3.2 Role of marginal loss factors

Electrical energy losses occur due to the transfer of electricity through a network. The NER separates losses into two components[3]:

- Inter-regional losses, which are due to a notional transfer of electricity from the regional reference node (RRN) in one region to the RRN in an adjacent region.
- Intra-regional losses, which are due to the transfer of electricity between an RRN and transmission network connection points in the same region.

Loss factors describe the marginal electrical energy losses associated with either inter-regional losses or intra-regional losses. They are both used in the central dispatch process to adjust the price of electricity at RRNs and connection points.

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

Inter-regional loss factors are dynamic, determined by equations that calculate the losses between regions. Depending on region flows and demands, the inter-regional losses also adjust generating plant prices in determining the dispatch order of generation to meet demand.

3.3 Context of this consultation

The current Methodology was developed following stakeholder consultation in 2002 and its underlying principles have remained largely unchanged since then. AEMO considers that while some improvements were made to the Methodology in 2014, the current Methodology may need further amendments to better reflect current conditions characterised by steadily increasing changes in generation mix, network usage and consumer demand patterns. This review will consider improvements to the Methodology that will better reflect the current circumstances.

Prior to the commencement of this review, in early 2016, AEMO facilitated a number of meetings to discuss stakeholder views on the current Methodology. Three initial meetings were held in Sydney, Brisbane and Melbourne to discuss the current Methodology and investigate issues identified by stakeholders. These issues were further developed in a stakeholder workshop held via a video conference to further discuss the issues and possible amendments. The minutes of these stakeholder meetings can be found on AEMO's website[4].

Following the stakeholder discussions, three main categories of issues identified were identified relating to the current Methodology:

1. **Methodology implementation issues** – Issues, that if addressed as suggested, require changes to AEMO's internal work processes. If considered beneficial, these changes could be implemented, subject to time and resource constraints, without changing the Methodology.
2. **Methodology design issues** – Issues, that if addressed as suggested, require changes to the Methodology.
3. **Market design issues** – Issues likely to require changes to the NER.

This Issues Paper will primarily consider issues under the first two categories as they relate to changes that can be addressed in this consultation within the framework of the current NER. They are detailed in sections 4 and 5.

Market design issues cannot be addressed in this consultation. However, they are outlined in 0 and may be further developed into a proposal to change the NER if considered appropriate.

[3] Clauses 3.6.1 and 3.6.2

[4] http://www.aemo.com.au/Stakeholder-Consultation/Consultations/Review-of-Methodology-for-calculating-Forward-Looking-Transmission-Loss-Factors

4. METHODOLOGY IMPLEMENTATION ISSUES

This section addresses issues, that if addressed as suggested, require changes to AEMO's internal work processes. These changes could be implemented, subject to time and resource constraints, without changing the Methodology.

4.1 Transparency

Transparency of process

Assumptions on forecast demand, forecast generation, network augmentations and inter and intra-regional flows in the MLF model have a significant impact on the calculation of Forward Looking Loss Factors. AEMO does not currently consult with industry on the inputs and assumptions used in the loss factor calculation.

In order to improve transparency in the loss factor calculation, AEMO proposes to:

1. Consult with industry on key inputs and assumptions used in the loss factor calculation. These inputs include, but are not limited to:
   - Transmission network augmentations to be included in network model
   - Inter-regional and intra-regional network power flow limits
   - Forecast generation
2. Publish modelling assumptions.

Note AEMO does not intend to consult on:

- The connection point demand and consumption forecasts – these are developed by AEMO through a separate process. Participants concerned with connection point forecasts should provide feedback to AEMO on the National Electricity Forecasting Report (NEFR) or relevant connection point forecasting report rather than through the MLF calculation procedure.
- Committed and retiring generation. These inputs are decided on in consultation with the relevant participants.

These proposed changes require resource planning and modifications to AEMO's work practice and, will be fully implemented for the 2018-19 MLF calculation process.

Early publication of indicative loss factors

AEMO publishes Forward Looking Loss Factors by 1 April each year as required by the NER. In recent years AEMO has published draft loss factors in March to give stakeholders an opportunity to review and provide feedback. AEMO has also presented at the National Electricity Market Wholesale Consultative Forum (NEMW-CF) to give stakeholders an early indication of expected changes to MLFs.

Stakeholders have indicated that they would prefer draft loss factors to be published earlier to assist in forward planning and to allow more time to review MLFs. Earlier publication would limit the possibility of using more recent historical data and the ability to accommodate late developments in the power system.

In order to provide earlier indication of loss factors, AEMO proposes to:

1. Present expected changes to average sub-regional MLFs to stakeholders in January.
2. Publish the Draft Forward Looking Loss Factor report by 1 March.

These changes require resource planning and modifications to AEMO's work practice and, will be fully implemented for the 2018-19 MLF calculation process.

Backcasting of loss factors

AEMO conducted a study to backcast loss factors in 2015-16, 2014-15 and 2013-14 to determine the accuracy of published MLFs and identify issues with the current Methodology. The backcasting study uses historical demand and generation measured at connection points as an input to the minimal extrapolation process. This results in conditions very close to historical snapshots of the power system with only small amounts of generation scaling required.

See Appendix A for results from the MLF backcasting study.

AEMO proposes to:

1. Conduct a backcast MLF study at the end of each financial year to monitor average sub-regional trends over time so as to track the performance of the MLF calculation process and to increase transparency.
2. Present average sub-regional trends from the backcast study to stakeholders.

Questions

1. What inputs and assumptions used in the loss factor calculation would improve transparency in the calculation process if consulted upon?
2. Considering the trade-off of using more recent historical data compared to earlier publication of draft MLFs, would earlier publication of draft loss factors be beneficial?
3. How is backcasting loss factors beneficial to stakeholders?

5. METHODOLOGY DESIGN ISSUES

5.1 Issue for consultation – process of determining loss factors

What is the issue?

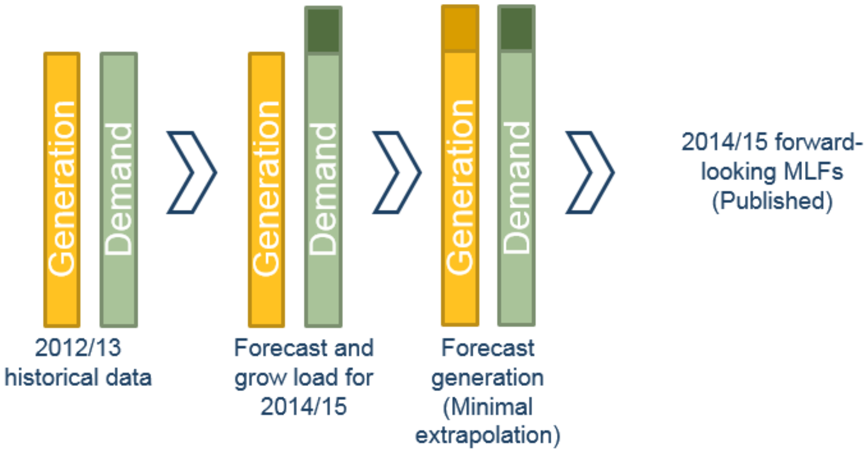
Results from the backcasting studies (Appendix A) for the 2013-14, 2014-15 and 2015-16 financial years indicate that MLFs calculated using the current Methodology have been reasonably accurate under most circumstances. However, the results also indicate some large outliers in electrically weak parts of the power system, usually located adjacent to Interconnectors.

The accuracy of MLFs depends on the inputs to the calculation. Two key inputs are required for the calculation of MLFs – load forecasts and generation forecasts.

AEMO currently uses detailed connection point forecasts consistent with the most recently published NEFR and regional transmission connection point forecasting reports in order to derive load forecasts. These forecasts are under continuous review with recent advances to include impact of residential and industrial growth, rooftop photovoltaic (PV) and energy efficiency.

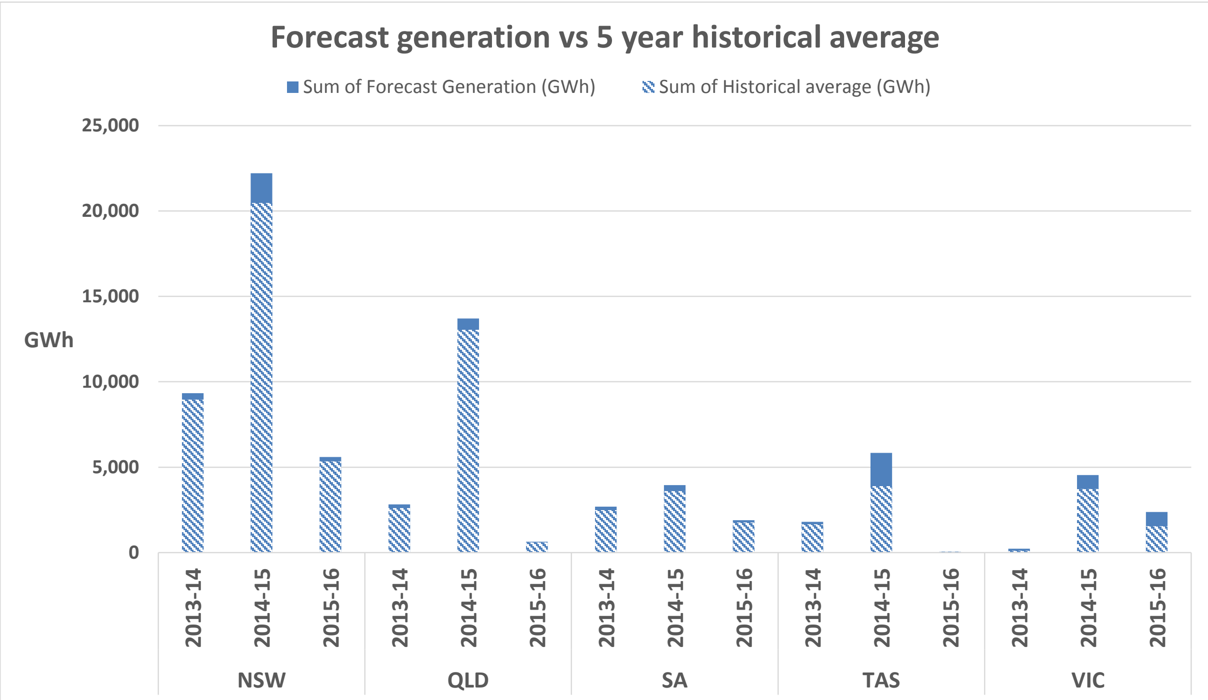
The current Methodology requires generation forecasts to be derived based on extrapolating historical generation profiles. The historical generation profiles are increased or decreased according to a set of rules defined in 5.5.2 of the Methodology such that the demand-supply balance is restored for the forecast load (see Figure 1).

Figure 1 Current Loss Factor Methodology



In recent years, retirement of baseload generation has resulted in remaining generation being extrapolated much higher than historical average generation (see Figure 2). This may not be representative of a generator's capability and could distort MLFs.

Figure 2 Forecast generation exceeding 5-year historical average



Generation forecasting

Several alternative generation forecasting methods were discussed in the stakeholder workshop, including:

1. Short run marginal cost market modelling.
2. Multiple generation forecasts in the MLF calculation process.
3. Using the pre-dispatch engine in offline mode to forecast generation for historical pre-dispatch cases where the demand has been modified to reflect the load forecast.
4. Using energy limits based on historical generation.

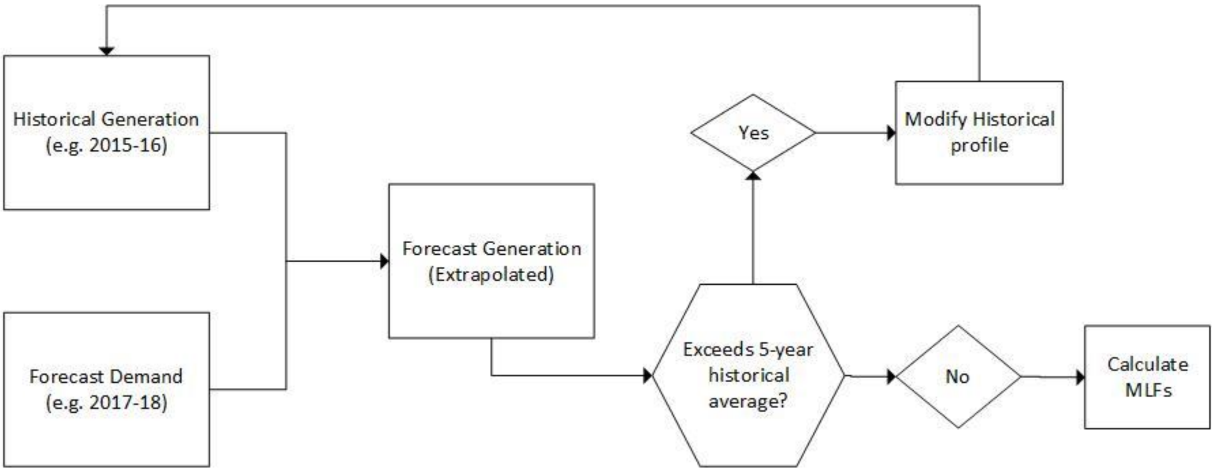
Methods 1 to 3 are complex to implement and require significant analysis to evaluate. As such it is not feasible to implement any of these three methods in time for the 2017-18 MLF calculation process. However, AEMO will further investigate methods 1 to 3 to see if they are likely to produce materially more accurate loss factors, with the possibility of considering them for future consultation.

AEMO has investigated method 4 which is the potential for implementing an energy limit on dispatchable generation based on a 5-year historical average.

Energy limits were considered for all dispatchable generating units with non-energy limited generating units dispatched to cover the supply shortage caused by energy limits. The process is iterative until all forecast generation does not exceed an energy limit based on the 5-year historical average (see Figure 3).

Energy limits were not applied to wind or solar generation as the historical generation profile is an accurate representation of future generation (assuming no change in capacity).

Figure 3 Methodology for applying energy limit for generation forecast



An energy limit is applied on a power station basis if the following condition is met:

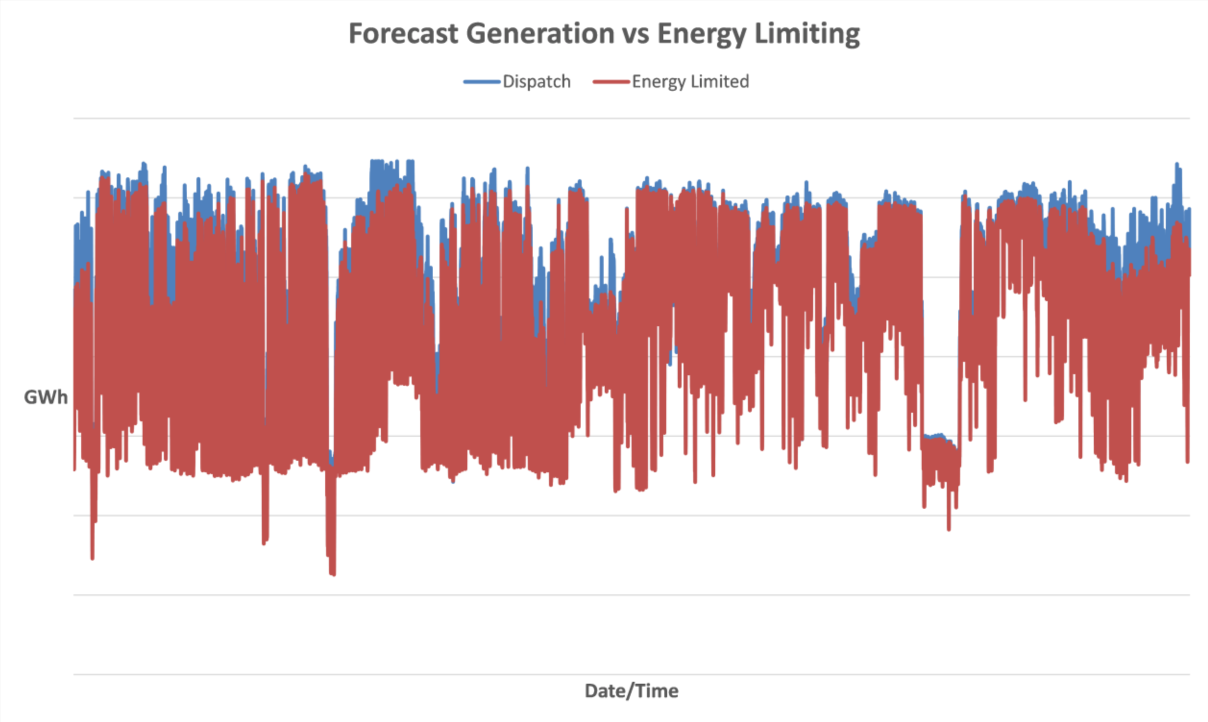
$$Gen_{forecast}(GWh) > Gen_{hist} \times Gen_{ret\_\%} \times Percent\_Demand\_increase \times buffer$$

Where:

- Gen_{hist} = 5-year historical average (gigawatt hour (GWh))
- $Gen_{ret\_\%}$ = Retired generation in Target Year as a % total NEM generation (%)
- $Percent\_Demand\_increase$ = Percentage increase in National Electricity Market (NEM) demand in Target Year compared to Historical Year (%)
- $buffer$ = Factor to account for variations from the 5-year average and/or conditions where insufficient generation exists

Where an energy limit is applied, the historical generation profile is reduced per half hour interval as shown in Figure 4.

Figure 4 Generation profile with energy limit applied



AEMO applied energy limits to the following published MLF studies to analyse the impact.

Table 2 Energy limited MLF studies

Published MLF study	No. of Power Stations where limit applied	Total energy limited by new method (GWh)	Energy limited as % of total generation (%)	Comments
2015-16	16	1,268	0.8%	
2014-15	29	5,499	3.1%	Historical generation abnormally high due to impact of carbon price
2013-14	12	1,047	0.6%	

Figures 5 to 7 show:

- Difference between energy limited MLFs and backcast MLFs (average per sub-region)
- Difference between published MLFs and backcast MLFs (average per sub-region)

Backcast MLFs were used as the baseline as they are more representative of ‘actual’ marginal losses. Therefore if the difference in MLF is close to zero, it is more representative of actual loss factors.

Figure 5 Energy limited versus backcasted MLFs for 2015-16

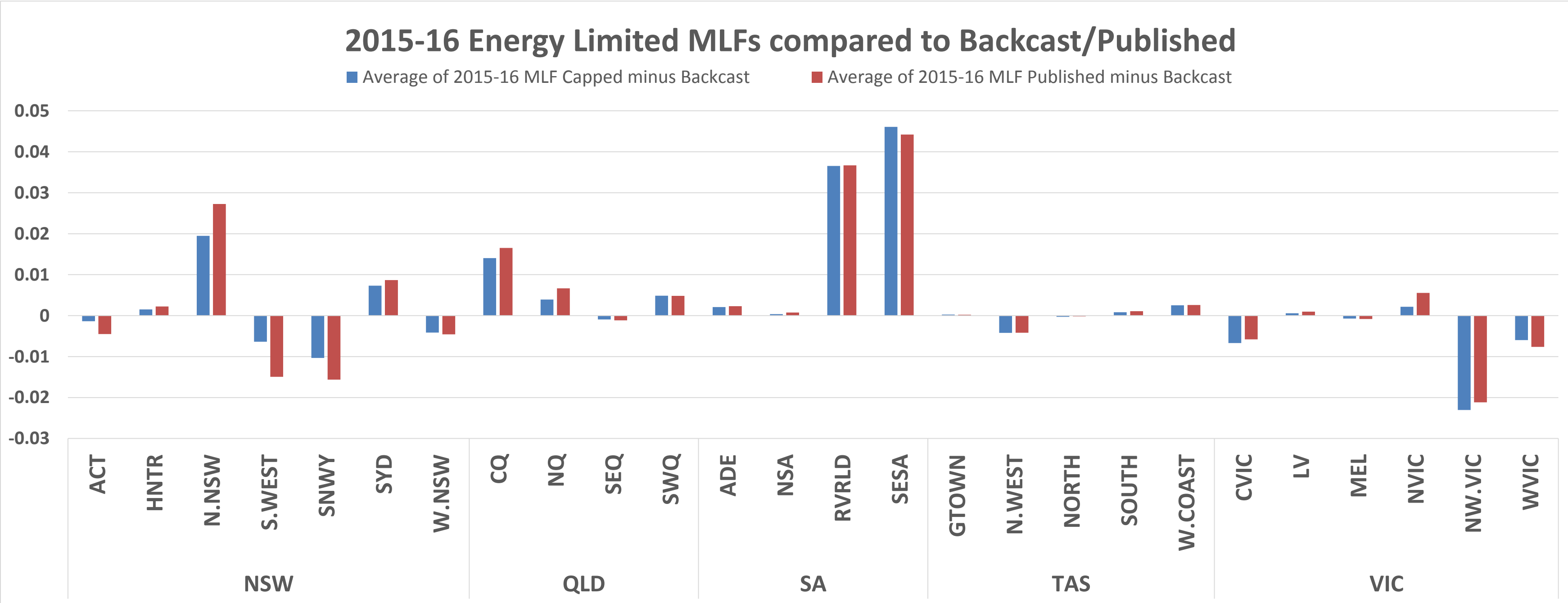


Figure 6 Energy limited versus backcasted MLFs for 2014-15

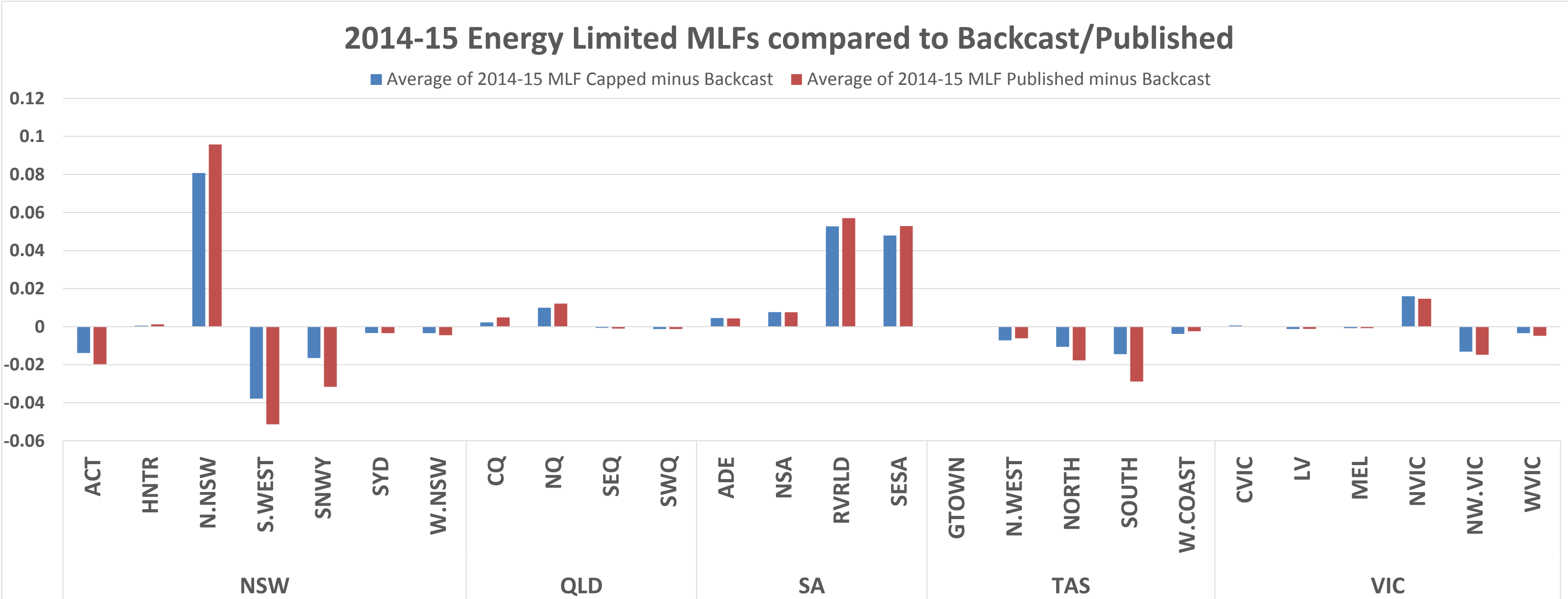
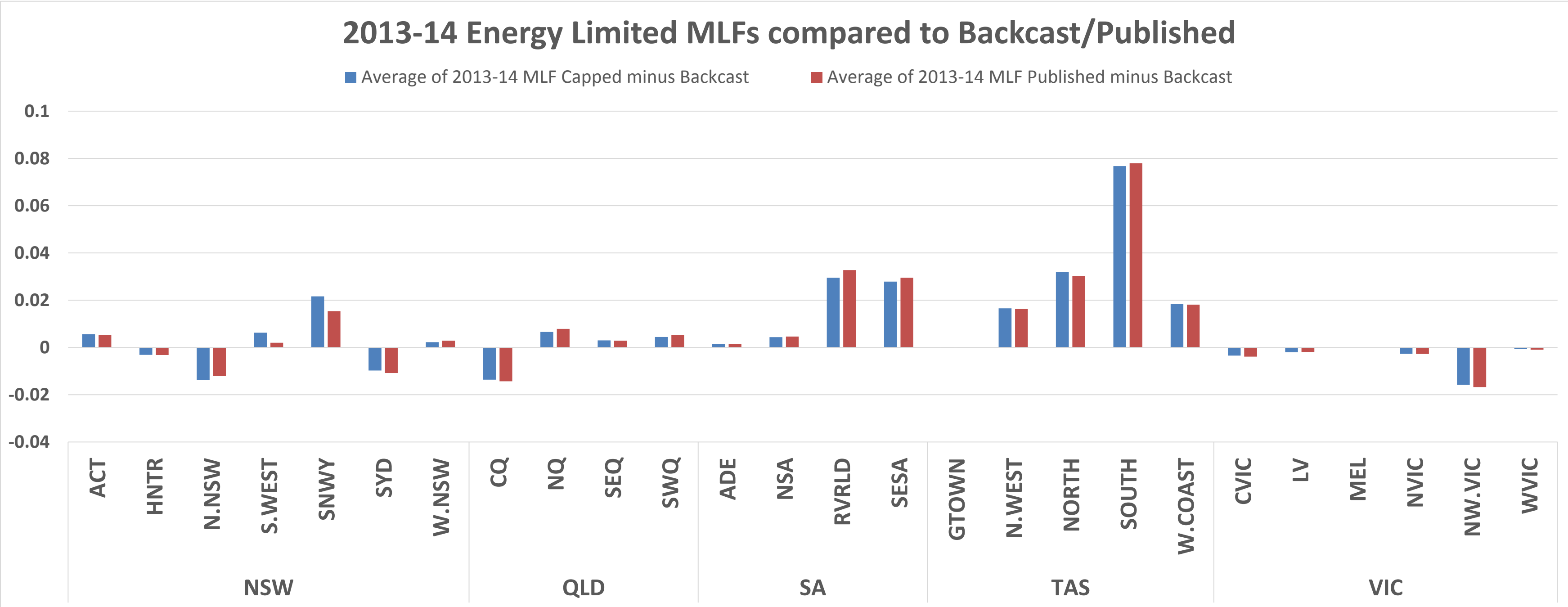


Figure 7 Energy limited versus backcasted MLFs for 2013-14



The results from the MLF Energy Limiting study show:

1. For strong, tightly meshed parts of the network, there is little difference in MLFs between backcast, published and energy limiting studies.
2. In weaker parts of the network, that is those far from the RRN and operating at lower voltage levels, MLFs from the energy limiting study are more closely aligned with backcast results than published MLFs. However, the improvement is marginal.
3. A notable amount of generation was energy limited in 2014-15 (3% of forecast generation) compared to other years. 2014-15 energy limited MLFs were more closely aligned with backcast results than other years studied. This shows that the proposed method of applying an energy limit increases accuracy in loss factors for years where generation grossly exceeds historical.
4. Applying energy limits in Tasmania was iterative as there is less generation enabled to be dispatched to cover the supply shortage.
5. Energy limiting did not improve the accuracy of MLFs in some sub-regions. The MLFs at energy limited power stations increased due to reduced generation and as a result, were not more closely aligned with backcast MLFs compared to published MLFs.

Questions

1. Is a 5-year historical average a better representation of forecast generation, rather than using the historical profile from the most recently completed financial year? Is there an alternative method that would be a better representation (e.g. 5-year historical maximum)?
2. Given the marginal improvement in results, should the current method of generation forecasting be changed?

APPENDIX A. BACKCASTING RESULTS

AEMO conducted a backcasting exercise to assess the performance of MLFs in the recent past with MLFs calculated retrospectively using actual demand and generation data in the target year. Backcasting was performed for the 2013-14, 2014-15 and 2015-16 MLFs.

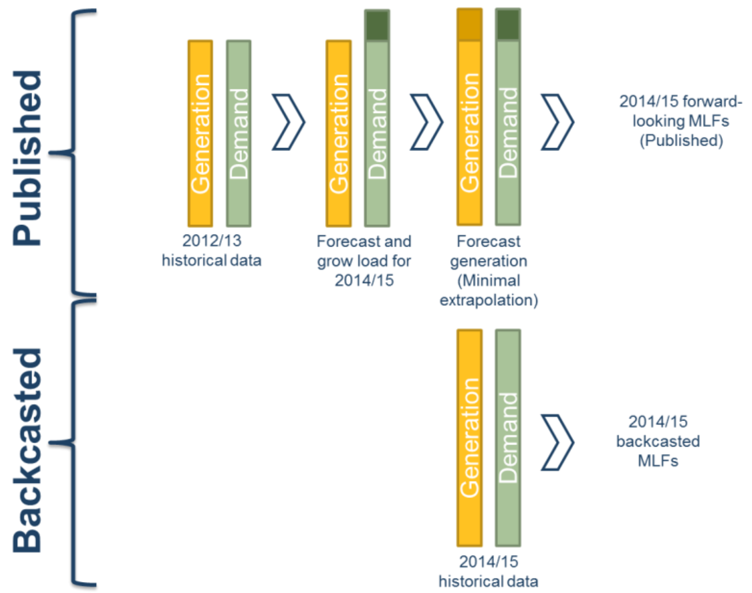
A.1 Backcasting methodology

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.
Market Network Service Provider (MNSPs)	Half-hourly metered data from the reference year.	Actual metered data for the same year.

As an example the differences in the published versus backcasted MLF calculation method for 2014-15 can be summarised in Figure 8.

Figure 8 Published versus backcasted MLF calculation method for 2014-15



As can be seen in Figures 9, 10 and 11 below, there are differences between the forecasted and backcasted generation and demand for each region due to uncertainties in load forecasting, and the minimal extrapolation method for generation.

Figure 9 Generation and load forecast performance for 2013-14

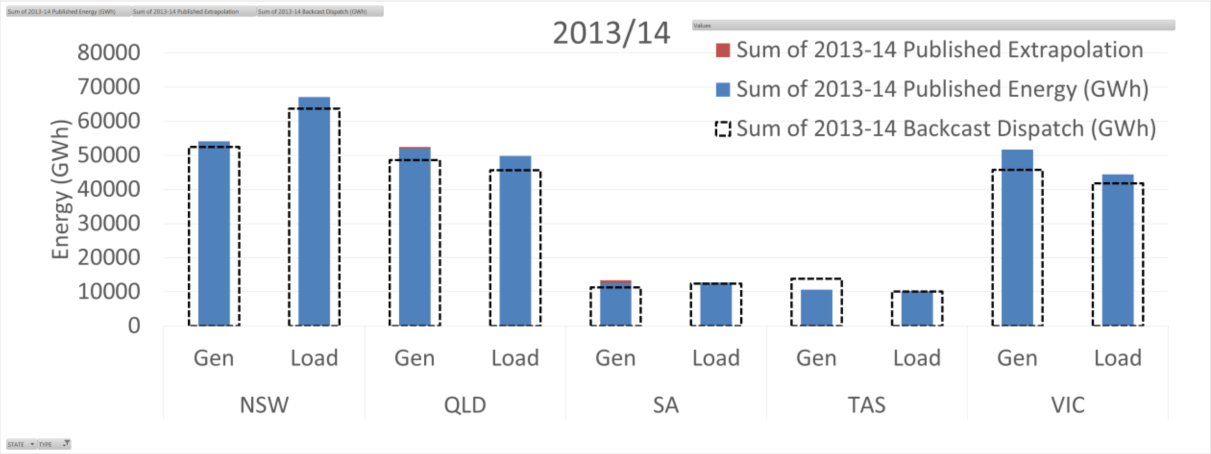


Figure 10 Generation and load forecast performance for 2014-15

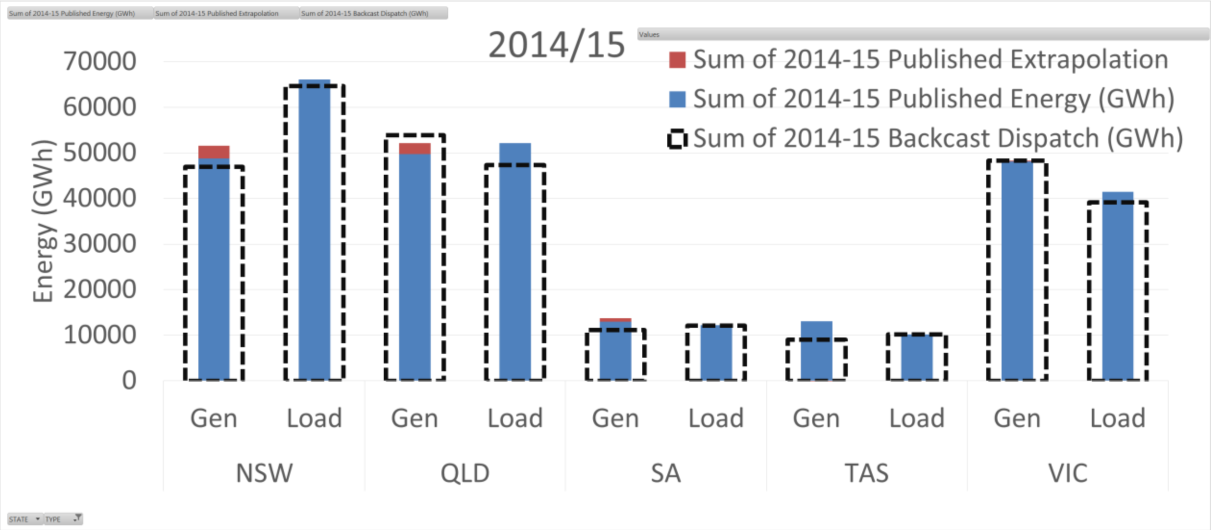
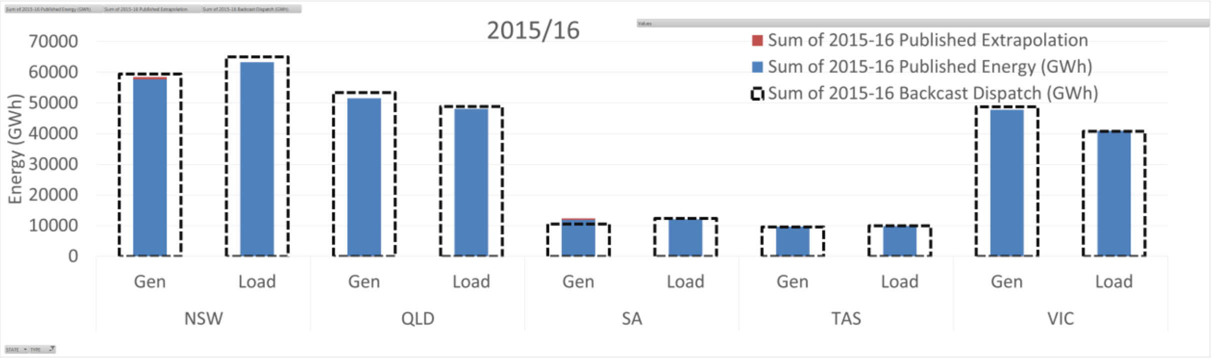
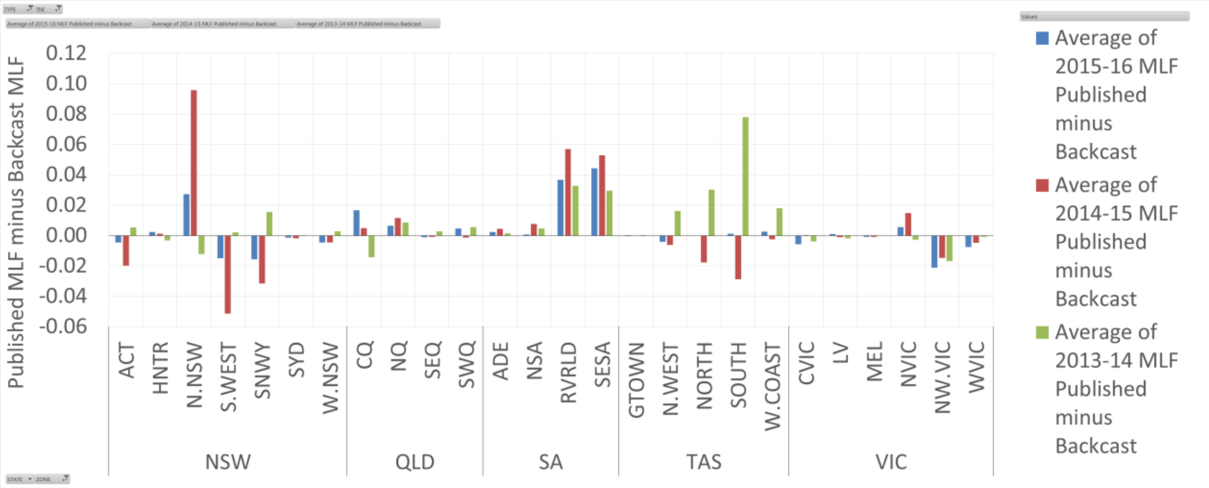


Figure 11 Generation and load forecast performance for 2015-16



These differences in generation and load forecasts in turn caused predicted interconnector flows to vary from the backcasted interconnector flows, and thereby causing the published MLFs to vary from the backcasted MLFs. The difference between the backcasting results and the published MLFs is used as the criterion for comparison and is defined as: $MLF_{Published} - MLF_{Backcast}$.

Figure 12 Backcast results for 2015-16, 2014-15 and 2013-14



The results in Figure 12 indicate that the variation in load and generation forecasts from backcasted values has:

- A small impact on the majority of sub-regions which are tightly meshed. E.g. south-east Queensland (QLD), and Sydney.
- A large impact on weaker parts of the network, usually located electrically close to Interconnectors. E.g. northern New South Wales (NSW), south-western NSW, south-east South Australia (SA), and the Riverland region in SA.

It should be noted that the backcast results for Tasmania in 2015-16 were more aligned with published MLFs than 2014-15 and 2013-14. This is due to the modifications to the methodology done in 2014 to address revisions to forecast generator profiles that are unrepresentative of historical profiles.

APPENDIX B. MARKET DESIGN ISSUES

B.1 Background

In mid-2016, AEMO conducted a series of meetings with stakeholders to identify and describe issues in the current MLF process. A number of issues that were brought up are closely linked to the current market design, and are likely to require changes to the NER in order to address them. The issues go beyond the scope of what can be achieved in the current consultation of the methodology.

These issues could be addressed in a separate process, potentially supported by an appropriate stakeholder forum, if there is a case for change and it can be shown that the market benefits outweigh the costs. AEMO has posed a series of potential issues that stakeholders may wish to consider in order to further develop these ideas. These issues can be further considered by any party to progress a rule change.

B.2 Use of marginal pricing

Background

The rationale for marginal pricing in public utilities such as electricity is a well-established principle[5] for energy services delivered in the market as it reflects the incremental cost of providing energy into the market. Marginal loss pricing reflects the incremental cost of transmission.

The design of the NEM uses this principle in:

- The central dispatch process, which aims to maximise value of spot market trading based on dispatched load and generation bids and offers.[6]
- The dispatch price at a regional reference node, which represents the marginal value of supply.[7]
- The price for each market ancillary service, which represents the sum of the marginal prices of meeting global and local market ancillary service requirements for each service.[8]
- Pricing of transmission losses, which are based on marginal inter-regional and intra-regional loss factors.[9]
- Australian Energy Regulator (AER) spot price reporting requirements, who are required to identify marginal unit offers above $5,000/MWh.[10]
- Access arrangements for Network Service Providers, where the use of system services charge is based on the long run marginal cost of network augmentations.[11]
- Distribution pricing rules, which require tariffs to be based on the long run marginal cost of providing services to retail customers.[12]

[5] See for example "Bidding in energy-only wholesale electricity markets", Regulatory Policy Institute, November 2014, prepared for the Australian Energy Market Commission as part of its consultation on the bidding in good faith rule change proposal. http://www.aemc.gov.au/Rule-Changes/Bidding-in-Good-Faith
[6] Clause 3.8.1(b) of the NER.
[7] Clause 3.9.2(d) of the NER.
[8] Clause 3.9.2A(b) of the NER.
[9] Clause 3.6.1 and 3.6.2 of the NER.
[10] Clause 3.13.7(d) of the NER.
[11] Clause 5.4A and 5.5 of the NER
[12] Clause 6.18.5(f) of the NER.

Average pricing is used in some specific situations such as:

- Pricing of distribution losses, which are based on average losses factors.[13]
- Application of the market price cap, which requires that dispatch prices in regions that have an energy flow toward another region must not exceed the market price cap divided by the average loss factor.[14]
- Application of the market floor price and administered, which has similar requirements to the price cap.[15]
- Application of the administered price cap, which has similar requirements to the price cap.[16]

Locational signals from loss factors

Stakeholders have queried whether MLFs are sending correct locational signals for the location of new generation and loads. Relevant considerations include whether loss factors are accurately representing electrical losses compared to the regional reference nodes, and whether regional areas are receiving a biased or inconsistent pricing signal.

Revenue over-recovery

MLFs were perceived by stakeholders as resulting in revenue over recovery in the market.

This issue arises from the fact that in a simple electrical circuit, losses are proportional to the square of the current. The marginal loss for a given flow, which is the derivative of the loss curve, will be twice the average loss for the same flow. Intra-regional marginal loss factors are price multipliers and this tends to result in a surplus of revenue collected from consumers over payments to generators.

Averaged versus dynamic loss factors

Stakeholders have noted there is an inherent flaw in using forward estimates for MLFs. The calculation estimates, using averages, do not reflect losses as they occur. The benefits of marginal decision making through MLFs are not achieved.

Instead pricing should reflect real-time loss factors based on real time dispatch and flows, with participants responding to these in real time.

Issues to consider

- The appropriateness of marginal losses for pricing the market impact of losses on the transmission system.
- Alternatively, the appropriateness of smoothing loss factors via averaging and its impact to pricing signals.

B.3 Suitability of MLF outcomes

Sensitivity of intra-regional loss factors to interconnector flows

Stakeholders with transmission network connection points electrically close to interconnectors have noted they are subject to volatile MLFs that are influenced by the Interconnector flow. Intra-regional loss factors should not be influenced by Interconnector flows.

This issue arises principally in northern NSW, and south eastern and north eastern SA, where flows on the interconnector account for a relatively large proportion of the overall network flows. The marginal losses for loads in these areas will be heavily influenced by the overall interconnector flow.

[13] Clause 3.6.3(b) of the NER.
[14] Clause 3.9.5 of the NER.
[15] Clause 3.9.6A of the NER.
[16] Clauses 3.14.2 and 3.14.5 of the NER.

Volatility of loss factors year-on-year

Stakeholders have queried whether a process that can produce a high degree of volatility between MLFs year-on-year is consistent with the National Electricity Objective. MLFs have typically been volatile in areas of the NEM where flows are more sensitive to larger scale changes to regional outcomes, such as a region being a net importer in one year followed by a net exporter in the next year, or where a generation centre has a large change in overall generation from one year to the next.

The NER have no specific mechanisms for managing energy price volatility. On the other hand, prices for recovering the adjusted locational component of transmission use of system charges incorporate explicit limits on the year-to-year change.[17]

Other potential measures to limit year-on-year volatility could include imposing upper and lower caps on the MLF, to use statistical measures to limit the impact of extreme modelling scenarios on the outcome, smoothing or using longer term data analysis.

Issues to consider

- The technical possibility of separating the impact of interconnector flows from the calculation of intra-regional losses and consequently marginal loss factors.
- The impact of year-on-year variation in interconnector flows on the volatility of MLFs.
- Mechanisms for limiting volatility in loss factors.
- The possibility of loss factor volatility being reconciled by applying dynamic loss factors.

B.4 Settlement inaccuracy from using forecast loss factors

Settlement revisions based on back cast results

Backcasting has been discussed earlier as a means of identifying areas for potential discrepancy in loss factors. Stakeholders have considered whether there should be a “true-up” process where prices for connection points affected by inaccurate loss factors would be adjusted using backcast results.

Under the NEM, routine settlement adjustments can be made up to 30 weeks after the relevant billing period.[18] Using backcasting to recalculate settlement amounts would be inconsistent with the current settlement process, and associated regulated and commercial pass through arrangements. Backcast loss factors for each transmission connection point would probably not be available for several months into the next financial year, meaning adjustments would be required up to 18 months after the event.

The true-up process concept was not developed in detail, but design questions to be addressed would also include appropriate thresholds and timetables for making the revisions.

Issues to consider

- The impact to financial trading and contracting in the market.
- Funding arrangements if the true-up process resulted in a net settlement deficit.

[17] 6A.23.4(b)(2) of the NER.
[18] Clause 3.15.19(b) of the NER.

GLOSSARY

Term	Description
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
GWh	Gigawatt hour
Method	Forward Looking Loss Factor Methodology
MLF	Marginal Loss Factor
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NEMW-CF	National Electricity Market Wholesale Consultative Forum
NER	National Electricity Rules
NSW	New South Wales
PV	Photovoltaic
QLD	Queensland
RRN	Regional Reference Node
SA	South Australia