RULE

Australian Energy Market Commission

DRAFT RULE DETERMINATION

NATIONAL ELECTRICITY AMENDMENT (TRANSMISSION LOSS FACTORS) RULE 2020

PROPONENT

Adani Renewables

14 NOVEMBER 2019

INQUIRIES

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Reference: ERC0251

CITATION

AEMC, Transmission loss factors, Draft rule determination, 14 November 2019

ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

SUMMARY

1 The Australian Energy Market Commission (AEMC or Commission) has made a more preferable draft rule to provide the Australian Energy Market Operator (AEMO) with greater flexibility to refine and improve the methodology to determine marginal loss factors.

2 This draft rule complements the recent changes the Commission has made to the National Electricity Rules (NER) on improving the transparency of new generation projects. It also supports AEMO's work to improve the transparency and predictability of loss factors. Together, these changes are in the long term interest of consumers as they will enable better, more informed decision-making for prospective investors of generation assets. Additionally, existing market participants will have more transparency and information for the operation of existing assets.

3 Some stakeholders have been concerned about recent volatility in transmission loss factors as this creates revenue variability, and have suggested that these changes have been difficult to forecast. While the Commission understands these concerns, it also recognises the importance of maintaining clear signals for efficient dispatch and future investment in the market, even in times of change. Consumers should not be expected to shoulder such uncertainties when they have no ability to manage or offset them.

4 For these reasons, the more preferable draft rule retains the existing marginal approach to determining transmission loss factors. A marginal loss factor methodology remains the most efficient way of accounting for physical transmission losses in the national electricity market (NEM). In the absence of a full dynamic, locational approach, continuing to set these loss factors on an annual, forward-looking basis remains the most appropriate approach given the existing broader market design.

5 The recent volatility of loss factors experienced by some stakeholders arises from the market-wide transition that is currently underway. Traditional thermal plants are closing, and more renewable and asynchronous generators are connecting to the power system — often in locations remote from load centres that may be serviced by relatively weak transmission lines.

6 Enabling this market transition to occur smoothly will require significant reforms to the market design of the NEM to make long term, robust improvements to the way operational decisions are made and investment is carried out for the long term benefit of consumers. Such changes are being progressed through a range of actions, including:

- the Commission's Coordination of generation and transmission investment (COGATI) review, which includes consideration of the appropriate long-term approach to losses
- the Energy Security Board's work to action the Integrated System Plan, which will govern future transmission planning and investment processes
- the Energy Security Board's development of a post-2025 market design for the NEM.

The rule change requests and Commission's response

7 The Commission has considered two rule changes requested by Adani Renewables. The first

of these proposed that the intra-regional settlement residue (IRSR) should be shared equally between transmission customers and generators. The second, sought to change the marginal loss factor methodology to an average loss factor methodology.

8 In regard to the allocation of the IRSR, the Commission has decided not to make a draft rule in the manner proposed by Adani Renewables. The IRSR arises as the use of marginal loss factors generally tends to result in an over-recovery of funds from settlement. This is currently allocated to transmission customers through reduced transmission use of system (TUOS) charges.

9 Redistributing part of the IRSR to generators would be likely to result in generation asset owners taking into account the anticipated effect of the IRSR in their bidding decisions. This may impact the order of dispatch of generation units in the NEM, resulting in less efficient operation of the market. It may also dampen the locational signals that marginal loss factors provide to prospective investors in new generation assets, and therefore lead to less efficient investment over the long term.

10 In its rule change request, Adani Renewables suggested that redistributing the IRSR would result in lower electricity prices to customers. However, it is unlikely that any such reductions would fully offset the increased TUOS charges that would also occur under this approach. The current arrangements directly pass the benefits of the IRSR to consumers. As consumers pay for transmission infrastructure, it is appropriate that their transmission costs are reduced.

11 For these reasons, the proposed change to share the IRSR with generators would be unlikely to achieve the national electricity objective (NEO) and be in the long-term interest of consumers.

12 The Commission has also concluded that the use of average loss factors would be unlikely to better achieve the NEO than the current marginal loss factor methodology, nor better achieve the NEO than what is proposed in the draft rule. There are a number of reasons for this conclusion:

- The current marginal loss factor methodology provides important locational signals for prospective investors and owners of new generation assets, which are needed to enable efficient decision-making about investment in the generation sector. This is particularly important in the current transformation of the electricity market.
- While an average loss factor method to determining transmission loss factors might result in a reduction in the volatility of loss factor values, it would also dampen locational signals for new efficient generation investment needed for the future. This is undesirable in the current climate where it is important that a variety of generation assets are introduced across the whole market. It may also lead to more generation investment in inefficient locations, increasing physical transmission losses further. This would, in the long-run, be likely to lead to higher electricity costs for consumers.
- The use of average loss factors to address concerns from some investors about revenue volatility and increases in their cost of capital does not outweigh the reduction in efficient investment signals and dispatch decisions in the NEM.

- Continuing to use a marginal loss factor methodology is also consistent with the marginal approach currently used in the NEM for dispatch decision-making and pricing, supporting efficient market operations.
- The use of an average loss factor may change the merit order to dispatch generators, resulting in less efficient use of the generation fleet and reducing the efficient operation of the NEM in real time. This may have the effect of wholesale electricity prices being higher than they would using marginal loss factors.

13 In addition, the Commission notes:

- An average loss factor methodology would represent a move away from the long term direction of using dynamically set marginal loss factors that is being developed through the COGATI review. This would result in a more significant transition as and when those new arrangements are introduced.
- The draft rule retains the benefits of the marginal loss factor approach while providing AEMO, in consultation with market participants, a greater ability to use different calculation techniques within that framework without impacting on accuracy. This aims to enable AEMO to make refinements and improvements to the determination of marginal loss factors consistent with the long term interest of consumers.
- While the loss factor values for many generators have materially declined over the last two to three years, other generators have not had this experience. A move to average loss factors would benefit some generators more than others, and would result in some generators being worse off. This is particularly the case for embedded generators located near major load centres and some batteries. For example, the recent indicative loss factors for 2020-2021 published by AEMO in November 2019 show that loss factors are forecast to worsen for some generators, but are expected to improve for many generators, with one of the largest improvements being for the Gannawarra Energy Storage System in Victoria, which has an indicative generation loss factor of greater than 1.0.

14 The Commission has also considered whether methodologies other than average or marginal approaches should be used to determine transmission loss factors. However, none of the approaches that have the potential to be implementable through this rule change process (cap and collar, grandfathering, or the compression model used in Ireland) appear to better meet the NEO than a marginal approach. Similar to an average loss factor methodology, each of these approaches distort the investment location and operational dispatch signals provided by loss factors. As a result, they raise significant concerns for efficient investment in, and operation of, the NEM and are likely to transfer risks and costs either to other generators or to consumers.

15 Two other potential approaches to the treatment of transmission losses — recovering all costs from customers (as in the Italian market) and dynamic loss factors — were also suggested by stakeholders during this rule change process. In both cases, significant reforms to the operation of the NEM would be required if these approaches were to be implemented. While such changes are outside the scope of this rule change process, the consideration of a more market integrated loss factor approach is being undertaken through the Commission's

COGATI review.

Draft rule and current improvements

16 The draft rule includes three amendments to the NER to enable AEMO to refine and improve the marginal loss factor methodology. These amendments aim to enable AEMO to consult with stakeholders on a greater range of alternative calculation details for the marginal loss factor methodology while maintaining accuracy and providing clear, efficient locational and dispatch signals to the market. Specifically, the draft rule:

- removes the requirement that the inter-regional loss factors must be calculated using a regression analysis, enabling AEMO and stakeholders to consider and test the performance of alternative calculation techniques
- removes the requirement that marginal loss factor values must be based on a 30 minute interval to allow greater time periods to be used as the basis for calculating marginal loss factor values
- removes the requirement that market network service providers be treated as invariant in the calculation of marginal loss factors so that AEMO can forecast variable market network service provider behaviour in its modelling.

17 In addition to these changes, some improvement to the marginal loss factor methodology and information about loss factors are being made by AEMO without any amendments to the NER. Specifically, AEMO has:

- introduced more frequent publication (for example, quarterly) of marginal loss factor values for information purposes only
- undertaken to review the methodology through a consultation process with stakeholders to refine aspects of the MLF methodology so that it remains fit for purpose.

18 The Commission encourages stakeholders to engage in AEMO's consultation processes and assist with the development of these improvements that should result in a greater understanding and transparency of the methodology and the movement of the loss factor values over time.

19 These improvements will be complemented by additional information that will be available as a consequence of the Transparency of new projects rule change. This new rule, published on 24 October 2019, will make more information about new generation projects more readily available, and provide for more regularly updated data on existing and proposed connections of generating plant to the national grid.

20 The Transparency of new projects rule is an important and practical amendment to the NER that will enable better informed investment decision-making to occur, reducing the likelihood of electricity users paying for inefficient investments. It will assist stakeholders in understanding the changing market and, in particular, the prospects for investing in the generation sector. In addition, it will enable existing owners of generation assets to be better informed about market developments and the impact this may have on their business.

Longer term reform program

21 The recent volatility in loss factors is symptomatic of broader issues being experienced in the NEM as a result of the transition underway in generation technologies. It is expected that new generation capacity totalling approximately the current size of the NEM (that is, 50 GW) will connect over the next 10 years. Most existing generation stock will be replaced by 2040.

22 Unlike the existing electricity system, the system of the future is likely to be characterised by numerous relatively small and geographically dispersed generation units located on the periphery of the NEM away from key demand centres to suit fuel sources such as solar or wind. However, the transmission system is typically relatively weak at these locations, and investment in transmission capacity (either under TNSP regulated revenue or by other parties) has not kept up with the increased generation capacity installed at these particular locations. Despite the volatility of the marginal loss factor values, and some connection nodes experiencing declining marginal loss factors, there has been a continued development of new generation assets in those same remote locations. This is exacerbating actual electrical losses on transmission lines and future volatility in marginal loss factors.

23 These issues are part of a broader set of generation and transmission coordination issues that the Commission is considering in detail in its COGATI review. Through the review, the Commission is developing a new access model, based around locational pricing (dynamic regional pricing) and financial transmission rights. Such longer term fundamental reforms are beyond the scope of this rule change process, which can only amend the marginal loss factor and IRSR frameworks.

24 The access model being developed through the COGATI review is expected to include, within its pricing mechanism, marginal loss factors set on a dynamic basis. The review is also considering the design of the financial risk management products that would be made available, including how these could best allow participants to hedge against changes in the losses factors. Accordingly, the COGATI review represents the most appropriate forum to engage in assessing potential reforms that may be able to provide a long-term solution to stakeholders' concerns regarding the transmission loss factor framework.

Next steps

25 Stakeholders are invited to provide written submissions in response this draft rule determination and the draft rule by COB Thursday 16 January 2020.

CONTENTS

1 INTRODUCTION

Adani Renewables has submitted rule change requests in relation to marginal loss factors (MLF) and the intra-regional settlement residue (IRSR). This chapter sets out descriptions of these two rule change requests which form this consolidated rule change process. It outlines the current arrangements in place for MLFs and IRSR as well the next steps for this rule change process.

1.1 The rule change requests

Adani Renewables submitted a rule change request to the Commission on 27 November 2018 seeking to reallocate the IRSR to generators and "network users" equally. It stated that the purpose of this change would be:[1]

> an improved effective MLF (less losses) for generators that have been subject to inaccuracies and therefore more competitive generation bidding, resulting in lower prices to market customers.

The IRSR for the national electricity market (NEM) region is currently distributed to the transmission network service provider (TNSP) for the region and is used to off-set transmission use of service (TUOS) charges paid by transmission customers.[2] TUOS charges ultimately flow through to the prices paid by end-users of electricity.

On 5 February 2019, Adani Renewables submitted a second rule change request. This request sought to change the MLF calculation methodology to an average loss factor methodology. Adani Renewables stated that "current rules are resulting in high inaccuracies and hence, distort the market through inefficiencies in operational and investment decision making". In its view, changing to an average loss factor approach would result in less losses for generators and a more accurate reflection of the cost of generation.[3] In its view, "MLF inaccuracies" result in IRSR accruing.

1.2 Current arrangements

When electricity is transported across a transmission network, some of it is lost as heat. Transmission loss factors are calculated to reflect this loss of electricity. Loss factors are used in the market settlement process so that generators are paid for the electricity received by users rather than the amount generated. Under the current arrangements, transmission losses in the NEM are calculated on a marginal basis.

MLFs represent the value of electrical energy that is lost when the next or marginal unit of electricity is transmitted across the transmission network. Specifically, an MLF value

1 Adani Renewables, rule change request, 27 November 2018, covering letter.

2 The term "transmission customer" is defined in Chapter 10 of the NER as a customer, non-register customer or distribution network service provider (DNSP) having a connection point with a transmission network.

3 Adani Renewables, rule change request, 5 February 2019, covering letter.

represents the losses for the marginal unit of electricity that occur between a generator or load connection point on the network and the regional reference node (RRN).

This "marginal" approach to calculate transmission losses is consistent with how other aspects of dispatch and pricing currently operate in the NEM. It has been used because marginal pricing leads to the most efficient outcomes when it is accurately applied.

Use of the marginal approach will, by design, over-recover total settlements used to pay generators. This over-recovery is the source of the IRSR.

Both the current approach to MLFs and the IRSR are set out below and in more detail in Appendix B of this draft rule determination.

1.2.1 Calculating intra-regional loss factors

The requirements in relation to the calculation of intra-regional loss factors (that is, MLFs) for the NEM transmission networks are found in clauses 3.6.2 and 3.6.2A of the NER.

The NER specifies that AEMO must determine an intra-regional loss factor for each transmission connection point in accordance with its published methodology.[4]

In preparing its methodology as required by clause 3.6.2(d) of the NER, AEMO must implement a set of principles that can be summarised as follows:[5]

- the intra-regional loss factors are to apply for a financial year
- an intra-regional loss factor must, as closely as is reasonably practicable, describe the average of the marginal electrical energy losses for electricity transmitted between a transmission network connection point and the RRN in the same region for each trading interval of the financial year in which the intra-regional loss factor applies
- the intra-regional loss factors must aim to minimise the impact on the central dispatch process of generation and scheduled load compared to that which would result from a fully optimised dispatch process taking into account the effect of losses
- the intra-regional loss factors are determined using forecast load and generation data, as described in clause 3.6.2A of the NER
- the intra-regional loss factor for a transmission network connection point is determined using a volume weighted average of the marginal loss factors for the transmission network connection point for the financial year in which the intra-regional loss factor applies
- flows in network elements that solely or principally provide market network services will be treated as invariant (that is, unchanged from the historical year, and not adjusted like generation).[6]

4 The loss factor methodology is available on the AEMO website.

5 NER clause 3.6.2(e).

6 The losses within market network services are treated separately.

Generally a single intra-regional loss factor is forecast and applies for each transmission connection point for a financial year.[7] AEMO must publish the intra-regional loss factors it determines by 1 April prior to the financial year in which they are to apply.[8]

While the current MLF methodology is consistent with the principles set out in the NER, it does include some features that enable the calculations to occur but also compromise its accuracy to some degree.[9] For example, the current approach relies on forecast information from parties such as the timing and quantity of generation that will be available. Nevertheless, the marginal approach is designed to achieve efficient dispatch and pricing of generation to meet demand across the NEM.

1.2.2 Calculating inter-regional loss factors

The requirements in relation to the calculation of inter-regional loss factors for the NEM transmission networks are found in clauses 3.6.1 and 3.6.2A of the NER.

Clause 3.6.1 of the NER sets out the requirements relating to the calculation of inter-regional loss factors. Inter-regional loss factors describe the marginal impact of electrical energy losses for electricity transmitted from the RRN in one region to the RRN in an adjacent region.[10] That is, these loss factors describe the losses arising from transporting electricity through a regulated interconnector.[11]

These loss factors are determined dynamically by loss factor equations. Under clause 3.6.1(f) of the NER AEMO must publish the inter-regional loss factor equations that describe the inter-regional electrical losses by 1 April prior to the financial year in which they are to apply.[12] This is to be carried out in accordance with the methodology prepared through a consultative process. In doing so, AEMO must implement a number of principles as set out in clause 3.6.1(d) of the NER, including that inter-regional loss factors:

- apply for a financial year and must be suitable for use in central dispatch for the NEM
- are calculated by equations that "as closely as is reasonably practicable" describe the marginal electrical energy losses for electricity transmitted through a regulated interconnector
- are calculated by using forecast load and generation data for the relevant financial year in a regression analysis.

1.2.3 Settlements residue

The NER requirements on the settlements residue are set out in clause 3.6.5 of the NER. It provides a number of principles for AEMO to allocate, distribute or recover intra-regional and

7 However, two intra-regional loss factors can be applied to a point under certain conditions. NER clause 3.6.2(b)(2)(i).

8 NER clause 3.6.2(f1).

9 Greater accuracy could be achieved by the use of a dynamic marginal approach to determining transmission losses.

10 NER clause 3.6.1(b)(1).

11 The regulated interconnectors in the NEM are currently Terranora, Queensland to New South Wales (QNI), Victoria to New South Wales (Vic1-NSW1), Heywood and Murraylink.

12 NER clause 3.6.1(f).

inter-regional settlements residue. Of particular relevance to this rule change process, the principles include:

- the distribution (or recovery) of settlements residue attributable to regulated interconnectors is to be carried out first in accordance with rule 3.18 of the NER
- the remaining settlements residue, including the portion due to intra-regional loss factors, is to be distributed to (or recovered from) the appropriate TNSP.

The IRSR is subsequently passed on to transmission customers through a reduction (or increase) in TUOS charges. Relevantly, clause 6A.23.3(e) of the NER states that the non-locational component of TNSP revenue is to be adjusted (either up or down) by the settlements residue due to intra-regional loss factors (that is, the IRSR). In addition, the prices for transmission customers to recover this non-locational component of revenue must be set on a postage stamp basis (clause 6A.23.4(e) of the NER). The use of a postage stamp approach to the distribution (or recovery) of IRSR means that transmission customers cannot influence the distribution of funds they received (or the recovery of funds they will pay).

1.3 Proposed solution and rationale

Adani Renewables sought to resolve the issues it perceived in relation to "inaccuracies" in the MLF values and the distribution of the IRSR to only customers via TNSPs by proposing that the NER be amended so that:

- transmission loss factors are calculated as average loss factors (rather than as marginal)
- the IRSR be shared equally between customers and generators.

Adani Renewables has not included a proposed rule with its rule change requests in regard to either of these proposals. However, it has identified that clause 6A.23.3 of the NER requires IRSR to be allocated between transmission customers based on their proportionate use of the relevant transmission assets. Adani Renwables' proposal implies a change to this provision would be necessary to achieve its objective.[13]

In regard to transmission loss factors, Adani Renewables has suggested that "the inaccuracy in forecasting MLF for the following year/s results in generators assuming an artificially increased bid price as a result of an incorrect MLF".[14] This, in its view, subjects generators to increased risk of not being dispatched, resulting in increased cost of generation to all market customers.

To address these concerns, Adani Renewables has proposed to move from the current forward-looking MLF methodology to an average loss factor (ALF) methodology. It asserted that this change "from MLFs (with IRSR reallocation to include generators) to an average loss factor methodology will be a further improvement as average loss factors can be calculated at the commencement of each year (rather than a wash up of IRSRs in arrears)".[15]

13 Adani Renewables, rule change request, 27 November 2018, p. 9.

14 Adani Renewables, rule change request, 5 February 2019, covering letter.

15 Adani Renewables, rule change request, 5 February 2019, p. 3.

Adani Renewables' rationale for generators and transmission network customers to share the IRSR relates to the issues that it has identified with the current approach. Specifically:[16]

- that the calculations of loss factors give rise to approximations rather than actuals
- high IRSR reflects an "error" between actual and forecast transmission loss factors and consequently efficient dispatch is undermined and investment signals are impacted
- the allocation of residues on a postage stamp basis exacerbates the impact of inaccurate MLFs.

Adani Renewables has stated that if a generator were to receive part of the IRSR as it has proposed, then that distribution of funds would result in "an improved effective MLF (less losses) for generators that have been subject to inaccuracies and therefore more competitive generation bidding, resulting in lower prices to market customers".[17] Specifically, it stated that redistributing half of the IRSR funds to generators would:[18]

> correct for any inaccuracies associated with the MLFs, and associated inefficiencies caused by these inaccuracies. While this change to the reallocation process will not directly address the cause of inefficiencies caused by inaccurate MLFs, it may go some way to reducing the impacts this inaccuracy has on the investment and operational efficiency of the NEM.

In the rule change request, Adani Renewables stated that under the current system a generator with an artificially low MLF as a result of forecast error, has its revenue and dispatch time reduced, and this works in opposition to micro economic competitive market fundamentals.[19] Adani Renewables summarised the proposed rule change by stating:[20]

> Adani Renewables proposes a rule change so that the process for the allocation of IRSRs be revised to include generation connection points and not only the network users who are subject to non-locational prescribed TUOS charges. The result of this rule change will be lower effective MLFs for generators that have been subject to inaccuracies and therefore more competitive generation bidding, resulting in lower prices to market customers.

1.4 The rule making process

The Commission consolidated the two rule change requests submitted by Adani Renewables under s. 93 of the National Electricity Law (NEL) this has enabled the Commission to address the overlapping issues arising from these requests. On 6 June 2019, the Commission published a notice advising of its commencement of the rule making process and consultation

16 Adani Renewables, rule change request, 27 November 2018, p. 7.

17 Adani Renewables, rule change request, 27 November 2018, covering letter.

18 Adani Renewables, rule change request, 27 November 2018, pp. 7-8.

19 Adani Renewables, rule change request, 27 November 2018, p. 10.

20 Adani Renewables, rule change request, 27 November 2018, p. 3.

in respect of the rule change request.[21] A consultation paper identifying specific issues for consultation was also published. Submissions closed on 18 July 2019.

The Commission received 35 submissions as part of the first round of consultation. It also conducted a public workshop held jointly with AEMO on 4 July 2019 in Brisbane and has held a number of meetings with various stakeholders to discuss issues relating to MLFs and IRSR.

On 26 September 2019, the Commission extended the period of time to make a draft rule determination until 21 November 2019. The Commission considered that this extension was necessary due to the complexity of issues arising from stakeholder submissions requiring further analysis.

The Commission has considered all issues raised by stakeholders in submissions. Issues raised in submissions are discussed and responded to throughout this draft rule determination.

1.5 Consultation on draft rule determination

The Commission invites submissions on this draft rule determination, including a more preferable draft rule, by COB Thursday 16 January 2020.

Any person or body may request that the Commission hold a hearing in relation to the draft rule determination. Any request for a hearing must be made in writing and must be received by the Commission no later than COB Thursday 21 November 2019.

Submissions and requests for a hearing should quote project number ERC0251 and may be lodged online at www.aemc.gov.au.

21 This notice was published under s. 95 of the NEL.

2 DRAFT RULE DETERMINATION

This chapter sets out the Commission's draft rule determination and the reasons for its decision.

2.1 The Commission's draft rule determination

The Commission's draft rule determination is to make a more preferable draft rule. The more preferable draft rule makes minor changes to the MLF methodology principles. These changes will provide AEMO with greater flexibility when updating and refining the MLF methodology and calculating MLFs.

The Commission's reasons for making this draft rule determination are set out in section 2.5 below.

This chapter outlines:

- the rule making test for changes to the NER
- the more preferable rule test
- the assessment framework for considering the rule change request
- the Commission's consideration of the more preferable draft rule against the national electricity objective (NEO).

Further information on the legal requirements for making this draft rule determination is set out in Appendix A.

2.2 Rule making test

2.2.1 Achieving the NEO

Under the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the NEO.[22] The NEO is:[23]

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

2.2.2 Making a more preferable rule

Under s. 91A of the NEL, the Commission may make a rule that is different (including materially different) to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule will or is likely to better contribute to the achievement of the NEO.

22 Section 88 of the NEL.

23 Section 7 of the NEL.

In this instance, the Commission has made a more preferable rule. The reasons are summarised below.

2.3 Assessment framework

In assessing the rule change request against the NEO the Commission has considered:

- The impact on efficient investment

  In the context of MLFs, achieving efficient investment requires the calculated MLF values to send efficient locational signals to potential investors in generation or load. This will occur where:

  - MLFs describe, as closely as reasonably practicable, the impact of electrical losses on dispatch prices
  - MLFs, and changes to them, can be forecast as accurately as reasonably practicable by investors so that they can act on the locational signals provided.

  In assessing potential changes to the MLF framework, the Commission has considered whether the potential changes will improve the provision of information to enable stakeholders to make well-informed decisions on efficient investment in generation or load in the NEM. It has also considered the potential impact that loss factor values may have on generation investor revenues and their cost of capital.

- The impact on the efficient operation of providing electricity services

  MLFs influence generator bidding and plant operation, and therefore changes in how MLFs are determined can influence operational decisions by generators and dispatch decisions by AEMO.

  The Commission has considered whether changes to the transmission loss factor framework will support, and be consistent with, providing electricity services efficiently. This has included considering whether suggested changes will enable more informed operational decisions to be taken by generators and other market participants and enable AEMO to dispatch the lowest cost generation, which should flow through to lower consumer prices.

- Risk allocation

  In general, it is desirable that the party that is allocated a risk has the incentive and ability to manage that risk because there is a clear link between that party's actions on the outcomes of the risk.

  In the case of MLFs, there is a risk to transmission connected market participants in regard to the value that will be calculated by AEMO at any time and that this value may change over time. However, these market participants may also be able to make decisions that impact on the value of the MLF allocated to them. For example, by decisions on where to locate a generator and how to allocate risk under their power purchase agreements. In contrast, consumers are not able to influence or manage the risks associated with MLFs.

In considering whether the marginal loss factor framework should be changed, the Commission has considered the impact that the change may have on the allocation of risk between different market participants, and between market participants and consumers.

2.4 Outline of the draft rule

The more preferable draft rule made by the Commission is attached to and published with this draft rule determination. The key features of the more preferable draft rule are:

- to remove the requirement in clause 3.6.1(d)(5) of the NER to use regression analysis to determine the equations in the MLF methodology
- to remove the requirement to base the MLFs on data from 30 minute trading intervals as set out in clause 3.6.2(e)(4) of the NER
- allow market network service providers (MNSP) to be treated flexibly in the MLF methodology rather than as invariant as currently specified by clause 3.6.2(e)(6) of the NER.

In addition to these amendments, the draft rule also replaces "transmission loss factors" with "intra-regional loss factors" in clauses 3.6.2(b), (g) and (h) and Chapter 10 (for the terms "NMI Standing Data" and "virtual transmission node") of the NER. This clarifies these terms without changing any meaning.

If made, the draft rule should commence at the time of making the final determination. This is currently scheduled for 27 February 2020.

Further detail on the more preferable draft rule can be found in the following chapters of this draft rule determination.

2.5 Summary of reasons

The Commission has considered the rule change requests submitted by Adani Renewables which proposed that the IRSR should be shared equally between customers and generators and that transmission loss factors should be calculated as average loss factors.

Sharing intra-regional settlement residues

In regard to the allocation of IRSR, the Commission has decided not to make a draft rule in the manner proposed by Adani Renewables.

It was proposed that amending the NER to require a sharing of the IRSR was desirable to "offset" the negative impact that MLFs are currently having on owners of, and investors in, generation assets. However, making the proposed change would be likely to result in generation asset owners taking into account the anticipated effect of the IRSR in their bidding decisions. This may impact the order of dispatch of generators in the NEM, resulting in less efficient operation of the market. Additionally, this would represent a move away from the principle of marginal pricing, and as a result, be an economically inefficient arrangement.

In addition, to the extent that generators have regard to the anticipated flow of funds from the IRSR, this may dampen the desirable locational signals that MLFs provide to prospective investors in new generation assets. The Commission considers it important for the long term operation of the NEM that clear investment signals are provided to parties to encourage a variety of investors across a range of assets and locations in the market.

While noting that some stakeholders are seeking relief from the impact of unfavourable changes in MLF values, the Commission considers that sharing the IRSR as proposed does not address the underlying cause of MLF volatility. In fact, sharing the IRSR with generators is simply a redistribution of funds from consumers to generators. It may be that consumers see some benefit in the proposed redistribution through lower wholesale electricity prices. However, it is unlikely that this would offset the increased TUOS charges that would also occur under this approach. Nor would the flow through of the IRSR to consumers be as certain as the current pass through arrangements in place.

Many stakeholders did not agree with the proposed change to the NER. They noted that currently the IRSR appropriately flows through to transmission customers and consequently consumers as it is these participants that fund investment in transmission infrastructure through TUOS charges. As discussed in Chapter 4, the Commission also considers this an important feature of the NEM which acknowledges the investment risk carried by consumers.

For these reasons, the proposed change to share the IRSR with generators would be unlikely to achieve the NEO and be in the long-term interest of consumers.

Using average loss factors

The Commission has also concluded that the use of average loss factors is unlikely to better achieve the NEO than the current marginal loss factor methodology because it does not provide clearer or more accurate long term investment signals nor support efficient dispatch in the NEM.

In addition, using average loss factors does not address the underlying issues regarding transmission and generation investment currently experienced in the NEM arising from the transformation of the sector. Nor is a rule implementing an average loss factor methodology likely to better achieve the NEO than the draft rule. As discussed in Chapter 5, there are a number of reasons for this conclusion:

- The current marginal loss factor methodology provides important locational signals for prospective investors and owners of new generation assets, which are needed to enable efficient decision-making about investment in the generation sector. This is particularly important in the current transformation of the electricity market.
- While an average loss factor method to determining transmission loss factors would be likely to result in a reduction in the volatility of loss factor values, it also dampens locational signals for new efficient generation investment needed for the future. This is undesirable in the current climate where it is important that a variety of generation assets are introduced across the whole market. It may also lead to more generation investment in inefficient locations, increasing physical transmission losses further. This would, in the long-run, be likely to lead to higher electricity costs for consumers.
- The use of average loss factors to address concerns from some investors about revenue volatility and increases in their cost of capital does not outweigh the reduction in efficient investment signals and dispatch decisions in the NEM.

- Using a marginal loss factor methodology is also consistent with the marginal approach currently used in the NEM for dispatch decision-making and pricing, supporting efficient market operations.
- The use of an average loss factor may change the merit order to dispatch generators, resulting in less efficient use of the generation fleet and reducing the efficient operation of the NEM in real time. This may have the effect of wholesale electricity prices being higher than they would using MLFs.

In addition, the Commission notes:

- An average loss factor methodology represents a move away from the long term direction of using dynamically set marginal loss factors that is being developed through the COGATI review. This would result in a more significant transition as and when those new arrangements are introduced.
- The draft rule retains the benefits of the marginal loss factor approach while providing AEMO, in consultation with market participants, a greater ability to use different calculation techniques within that framework without impacting on accuracy. This aims to enable AEMO to make refinements and improvements to the determination of MLFs consistent with the long term interest of consumers.
- While the loss factor values for many generators have materially declined over the last two to three years, other generators have not had this experience. A move to average loss factors would benefit some generators more than others, and would result in some generators being worse off. This is particularly the case for embedded generators located near major load centres and some batteries. For example, the recent indicative loss factors for 2020-2021 published by AEMO in November 2019 show that loss factors are forecast to worsen for some generators, but are expected to improve for many generators, with one of the largest improvements being for the Gannawarra Energy Storage System in Victoria, which has an indicative generation loss factor of greater than 1.0.

Using other loss factor methodologies

The Commission also considered whether methodologies other than average or marginal approaches should be used to determine transmission loss factors. However, none of the approaches that have the potential to be implementable through this rule change process (cap and collar, grandfathering, or the compression model) appear to be likely to better meet the NEO than a marginal approach. Similar to an average loss factor methodology, each of these approaches distort the investment location and operational dispatch signals provided by loss factors. As a result, they raise significant concerns for efficient investment in, and operation of, the NEM because they are likely to transfer risks and costs either to other generators or to consumers. Further discussion on these methods is set out in Appendix C to this draft rule determination.

Two other potential approaches to calculating transmission loss factors — recovering all costs from customers (as occurs in the Italian electricity market) and dynamic loss factors — were also suggested by stakeholders during this rule change process. Both of these approaches integrate transmission loss factors into the operation of the electricity market. As a result, significant reforms to the operation of the NEM would be required if either of these approaches were to be implemented. The considerations required to make a decision on a more market integrated loss factor approach are appropriate for the Commission's COGATI review. This project has the scope to consider and assess longer term, fundamental reforms for the NEM to support efficient transmission and generation investment as Australia moves toward a low carbon economy.

Other changes and reforms

The Commission's decision not to implement the changes proposed in the rule change requests has been made in the context of other changes and reforms currently in progress.

First, concerns expressed by many stakeholders regarding their ability to understand the changing market and, in particular, the prospects for investing in the generation sector. These concerns will be addressed by the amendments to the NER made through the Transparency of new projects rule change. This new rule, published on 24 October 2019, will make more information about new generation projects more readily available, and provide for more regularly updated data on existing and proposed connections of generating plant to the national grid.

The Transparency of new projects rule is an important and practical amendment to the NER that will enable better informed investment decision-making to occur, reducing the likelihood of electricity users paying for inefficient investments. In addition, it will enable existing owners of generation assets to be better informed about market developments and the impact this may have on their business.

Second, some improvements to the MLF methodology and information about MLFs can be made by AEMO without any amendments to the NER. Specifically, AEMO has:

- commenced work on more frequent publication (for example, quarterly) of MLF values for information purposes
- undertaken to review the methodology through a consultation process with stakeholders to refine aspects of the MLF methodology so that it remains fit for purpose.

These developments work with the transparency in new projects rule to improve information available to prospective investors and existing generators. The Commission encourages stakeholders to engage in AEMO's processes to make these improvements that should result in a greater understanding of the methodology and the movement of the MLF values over time, enabling more informed decision-making to occur.

Draft rule

Consistent with the work to be undertaken by AEMO, the Commission has made three amendments regarding the MLF framework in the draft rule. These amendments aim to enable AEMO to consult with stakeholders on a greater range of alternative calculation details to refine and improve the MLF methodology while maintaining accuracy and providing clear, efficient locational and dispatch signals to the market. If made, the draft rule will:

- remove the requirement that the inter-regional loss factors must be calculated using a regression analysis, enabling AEMO and stakeholders to consider and test the performance of alternative calculation techniques
- remove the requirement that MLF values must be based on a period of 30 minutes to allow greater time periods to be used as the basis for calculating MLF values
- remove the requirement that MNSPs be treated as invariant in the calculation of MLFs so that AEMO could forecast variable MNSP behaviour in its modelling.

This more preferable draft rule is likely to better achieve the NEO than the proposals sought by Adani Renewables. This is because it improves flexibility for AEMO, in consultation with market participants, to determine alternative calculation methodologies for MLFs that may produce more optimal results. In addition, with the greater flexibility, AEMO would be able to refine the MLF calculation process so that it is more transparent and understandable for market participants. This in turn may support better decision-making for investments by prospective owners of generation as well as for AEMO in the operation of the NEM. The Commission is not satisfied that the proposals sought by the proponents would promote the NEO better than the current rules or the draft rule.

Third, the Commission has reflected on the views of stakeholders in identifying the problems at the centre of Adani Renewables' rule change requests. It has concluded that the recent volatility of MLF values and the observation that the IRSR has been significant are symptoms of broader issues in the NEM. Specifically, that a significant amount of new generation is locating on the periphery of the NEM, away from key demand centres, to suit fuel sources such as solar or wind. However, the transmission system is relatively weak at these locations and investment in transmission capacity (either under TNSP regulated revenue or by other parties) has not kept up with the increased generation capacity installed at these particular locations. Despite the volatility of the MLF values, and some connection nodes experiencing declining MLFs recently, there has been a continued development of new generation assets in those same remote locations. This is exacerbating actual electrical losses on transmission lines and the future volatility in MLFs.

These issues reflect a broader set of generation and transmission investment issues that the Commission is considering in detail in its COGATI review. The work carried out in this review indicates that the current lack of coordination between generation and transmission system investment requires significant reforms to the NEM to make long term, robust improvements to the way investment is carried out for the long term benefit of consumers. Through the review, the Commission is developing a new access model, based around locational pricing (dynamic regional pricing) and financial transmission rights. These changes are beyond the scope of this rule change process, which can only amend the MLF and the IRSR frameworks.

Accordingly, the Commission considers that the COGATI review provides the most appropriate forum for stakeholders to engage in discussing and assessing potential reforms that may be able to provide a long term solution to their concerns regarding the transmission loss factor framework. This may include a move to locational pricing (dynamic regional pricing) with financial risk management tools.

The Commission also notes that its work in the COGATI review is one action aimed to address the issues arising from the current transformation of the electricity market. Other key work is being undertaken by the Energy Security Board (ESB). Specifically, to action the Integrated System Plan (which will govern future transmission planning and investment processes) and develop a post-2025 market design for the NEM. Nevertheless, in the interim, greater use of diversification in investments provide opportunities for investors to manage the uncertainties in transmission loss factors.

2.6 Climate change related issues

The Commission notes that climate change is a significant issue that has ramifications for policy decisions. The Australian Government, through the United Nations Framework Convention on Climate Change (UNFCCC) and Conference of the Parties (COP) process has agreed:

- warming should be limited to two degrees Celsius above pre-industrial levels with an aspiration to limit to 1.5 degrees
- the initial target for Australia is to reduce emissions by 26-28 per cent relative to 2005 levels by 2030.

The Commission makes its decisions on rule change requests under the NER with reference to the NEO. This objective does not expressly require the Commission to have regard to the long term interests of consumers with respect to climate change or the environment. However, in making its decisions under the NER the Commission also has regard to relevant factors that can impact on the specific matters identified in the NEO. In relation to climate change this includes consideration of:

- how the physical world is changing or likely to change as a result of climate change (adaptation risk)
- how policy makers, consumers and investors are responding, or are likely to respond, to the risks presented by climate change (mitigation risk)

to the extent that these factors have an effect on the specific matters included in the NEO.

First, in regard to adaptation risk, it is important to note that the draft rule itself is unlikely to result in increased adaptation risk as the only impact of the draft rule is to enable AEMO to revise and improve the current approach to determining marginal loss factors.

Second, the Commission notes that investment in renewable generation assets has responded strongly to the Renewable Energy Target (RET). In addition, the expectation that future investments in renewable energy will continue is high.[24] In light of this, the Commission has taken into account how policy makers, consumers and investors are responding, or are likely to respond, to the risks presented by climate change and how those risks should be allocated under the NER. It also notes that the issue of investment signals for efficient, desirable investment in the NEM is under consideration by the ESB as part of its post 2025 market design work.

24 MinterEllison-Acuris, *Australian renewable energy investment trends and outlook 2019*, p. 16.

3 ISSUE IDENTIFICATION

This chapter assesses the problem that Adani Renewables has suggested exists within the current MLF arrangements and outlines the issues that stakeholders have identified as the cause of the recent changes in MLF values.

It also provides the Commission's analysis of the factors causing the changes in MLF values, and discusses the impact this might be having on existing and new investors in generation assets. This chapter also sets out the Commission's views on future actions that can be taken in response to recent market changes.

3.1 Adani Renewables' views

The proponent’s two rule change requests suggest that the current provisions in the NER relating to MLFs are resulting in high inaccuracies in MLF values although it does not specifically identify these provisions.[25]

Adani Renewables argued that the inaccuracies in the MLF calculations are the cause of the variability in the MLFs in that:[26]

> The IRSR is a representation of the cumulative error between actual marginal loss factors and forecast losses, with this error arising through generation patterns from year to year and forecasting errors.

Adani Renewables stated that this is resulting in market participants bidding higher spot prices to cover the declining losses due to perceived inaccurate MLF values. In both rule change requests, it stated that:[27]

> MLFs are impacted by the current rule as they end up with higher effective bid prices as a result of the inaccurate MLF and potentially will not be dispatched.

Adani Renewables also stated that the current rules are out-dated and therefore distorting the market through inefficiencies in operational and investment decision-making.[28]

In addition, it argued that inaccuracies resulting from the current methodology for MLFs prescribed in the NER mean that generators are receiving artificially low MLFs.[29]

3.2 Stakeholder views

In the consultation paper the Commission requested stakeholders consider what could be causing the observed changes in MLF values. The Commission sought feedback on whether the operation of the loss factor provisions in the NER as identified by the proponent was the

25 Adani Renewables, rule change request, 27 November 2018, covering letter; Adani Renewables, rule change request, 5 February 2019, covering letter. The relevant provisions are clauses 3.6.1, 3.6.2, 3.6.2A of the NER.

26 Adani Renewables, rule change request, 27 November 2018, p. 3; Adani Renewables, rule change request, 5 February 2019, p. 3.

27 Adani Renewables, rule change request, 27 November 2018, p. 3; Adani Renewables, rule change request, 5 February 2019, p. 3.

28 Adani Renewables, rule change request, 27 November 2018, covering letter.

29 Adani Renewables, rule change request, 27 November 2018, p. 10; Adani Renewables, rule change request, 5 February 2019, p. 10.

cause of the problem. It also asked if there were other issues which stakeholders considered impacted on the transmission loss factor framework.

3.2.1 Stakeholder responses to Adani Renewables' views

Stakeholder submissions were diverse in opinion as to the cause of year-on-year variability of MLFs in the NEM. Although stakeholders' views varied, there was broad support that the determination of transmission loss factors should be reviewed.

While a number of stakeholders expressed agreement with Adani Renewables' characterisation of the problem, they also considered a number of other contributing factors are causing the variability in MLF values.

Is there an accuracy problem with MLFs?

The consultation paper sought stakeholders' views on whether they agreed with Adani Renewables that the current MLF calculation methodology produces inaccuracies. The majority of stakeholders considered that the current MLF methodology has a level of inherent inaccuracy; as a result of being marginal and an annual forecast. However, stakeholders were divided on whether this was problematic.

The ACT Government EPSDD articulated this and submitted that:[30]

> ...like any forecast, there will always have some inaccuracy, and in some cases may have significant inaccuracies. EPSD notes three sources of inaccuracy that can be observed under the current marginal loss factor framework:
>
> - The use of forecast losses, rather than actual losses;
> - The use of marginal losses rather than average losses; and
> - The use of static, rather than dynamic losses.
>
> However, inaccuracy in the AEMO's loss factor methodology would only have a material impact on the long-term interest of consumers, and therefore contravene the NEO, if it is both significant in its magnitude, and consistent in its direction.

Some stakeholders, although acknowledging the current methodology includes some inaccuracy, did not consider this was problematic. ERM Power submitted that:[31]

> …there is an inherent level of inaccuracy in the current methodology for the calculation of transmission loss factors as it is heavily reliant on a high correlation between forecast and actual outcomes for accuracy. Whilst it can be taken as given that there will be a level of inaccuracy with regards to the calculation of forward-looking loss factors compared to actual losses, it is unclear how material the impact of this is on dispatch efficiency, and longer term investment signals, particularly given the large gaps between short-run marginal costs between generation technologies in the National Electricity Market (NEM) absent the provision of any supporting analysis.

30 ESPDD submission to the consultation paper, p. 3.

31 ERM Power submission to the consultation paper, p. 2.

Other stakeholders simply considered that because the current methodology is forward-looking and the calculation is marginal in nature, there is an inherent level of inaccuracy.[32]

EnergyAustralia commented that there is limited data to support the assertion that the current rules result in high inaccuracies and hence distort the market through inefficiencies in operational and investment decision-making.[33] This was also noted by Origin.[34]

Intelligent Energy Systems (IES), submitted that the changes in MLF values can not all be attributed to the MLF methodology, but the recent changes in values do prompt a search for ways to do things better.[35]

In its submission, the Australian Energy Council (AEC) considered the origins of the current methodology:[36]

> The NEM however deliberately chose a simplification - hub and spoke regions combined with annual static intra-regional loss factors. It was considered that the simplifications of such an approach, with its advantages in supporting the contract markets, justified the resulting inaccuracies.
>
> This trade-off was analysed in detail by the National Electricity Market Management Company (NEMMCO) in the first years of the NEM. Their analysis quantified the error by comparing static loss factors to actual marginal losses. At the time, the error was considered acceptable, but this was in a market characterised by non-variable sources of generation and a reasonably predictable investment pipeline. These conditions have significantly changed, and it is appropriate to recalculate this error.

ENA similarly noted that:[37]

> Adani suggest that there are errors in the MLF framework, however this difference is consciously embedded in the market design and is one of the many trade-offs.

Further, EnergyAustralia submitted that errors will always result in inaccuracies or rather variability in the calculation of loss factors regardless of the choice of using MLFs or ALFs.[38] Ergon Energy and Energex similarly noted that any methodology that predicts future marginal loss factors will be an estimate, meaning any implemented proposal could be construed as "inaccurate".[39]

What is the impact of recent MLF values?

In contrast, some stakeholders did consider that the current methodology is problematic. CEC submitted that the current loss factor approach has resulted in significant year-on-year

32 Submissions to the consultation paper: AusNet Services, cover page; Origin, p. 1.
33 EnergyAustralia submission to the consultation paper, p. 4.
34 Origin submission to the consultation paper, p. 1.
35 IES submission to the consultation paper, p. 2.
36 AEC submission to the consultation paper, p. 3.
37 Energy Networks Australia submission to the consultation paper, p. 4.
38 EnergyAustralia submission to the consultation paper, p. 4.
39 Ergon Energy and Energex submission to the consultation paper, attached table.

variations in MLF values.[40] More specifically, Lighthouse Infrastructure commented that an "MLF is an inaccurate reflection of losses; in fact it is worse than inaccurate, it is a systematic exaggeration of losses".[41] It expanded on this point, commenting that the inaccuracies in the methodology are problematic and that the degree of over-recovery is greater when the underlying losses are greater, as there is now a trend toward greater losses due to fringe of grid renewable developments.[42]

This point was also raised by Powering Australian Renewables Fund (PARF) who submitted that the variability of MLF values is compounded via the rate of change and assumptions being made on timing of connection and generation profiles for competing generators as well as interconnector flows which are all inputs into the current calculation methodology.[43]

Lighthouse Infrastructure further considered that the inaccuracies of the current methodology are a major impediment to investment in new renewable generation which is causing inflated electricity prices to persist, undermining the NEO. It also submitted that the result of inaccuracies and "unnecessary losses will increase the cost of electricity for consumers".[44] In addition, Lighthouse Infrastructure considered that the unpredictability of losses is as much of a barrier to efficient investment as the absolute levels of the MLF values. It stated that the annual resetting of loss factors that creates this unpredictability does not represent a useful economic signal.[45]

The Investor Group[46] (whose submission was provided by John Laing on behalf of the group) also considered the impact of the current MLF calculation methodology producing inaccurate results, and submitted that the Commission should consider the theoretical lens in which it is being examined. The Investor Group suggested that viewed through an economic lens, the current methodology offers a theoretically sound basis for signalling efficient generation and investment decisions. However, when viewed through a project finance or technical lens, it could be deemed less accurate than a methodology such as the ALF methodology given its propensity to over-recover IRSR year-on-year.[47]

QIC expressed similar views to Adani Renewables. It also linked inaccuracies in the current calculation methodology with unpredictable MLF values. It stated that:[48]

> …the current methodology of utilising a marginal loss factor as a proxy for transmission losses produces unpredictable results, and that alternate transmission loss estimation

40 CEC submission to the consultation paper, p. 1.

41 Lighthouse Infrastructure submission to the consultation paper, p. 2.

42 Lighthouse Infrastructure submission to the consultation paper, p. 2.

43 PARF submission to the consultation paper, p. 2.

44 Lighthouse Infrastructure submission to the consultation paper, p. 2.

45 Lighthouse Infrastructure submission to the consultation paper, p. 2.

46 The Investor Group includes: Ararat Wind Farm Pty Ltd, BayWa r.e Solar Projects Pty Ltd, Blackrock Investment Management (Australia) Ltd, Epuron Projects Pty Ltd, ESCO Pacific Pty Ltd, Foresight Group Australia Pty Ltd, FRV Services Australia Pty Ltd, Infrastructure Capital Group Ltd, Innogy Renewables Australia Pty Ltd, Laing Investments Management Services (Australia) Ltd, Lighthouse Solar Management Pty Ltd, Macquarie Corporate Holdings Pty Ltd, Neoen Australia Pty Ltd, Pacific Hydro Investments Pty Ltd, Palisade Investment Partners Ltd, PARF Company 2 Pty Ltd (Powering Australian Renewables Fund), Total Eren Australia Pty Ltd, Windlab Ltd and Wirsol Enregy Pty Ltd.

47 Investor Group submission to the consultation paper, p. 13.

48 QIC submission to the consultation paper, p. 3.

> methods, would yield more stable estimates and provide a higher degree of certainty for generators. This is particularly the case for generators located on the fringe portions of the transmission network which is where the majority of Australia's wind and solar resources are. Given that between $8-27bn in new investment is forecast to be required to replace retiring generation capacity and meet demand growth, it is paramount that the transmission loss factor methodology ultimately adopted is able to, and is perceived to be able to, deliver stable and reliable results.

A number of stakeholders who have a relationship with MLFs through financing or investing (debt and/or equity) in new generation in the NEM expanded on the points above and considered the current arrangements problematic as they are increasing the cost of capital for investment in new generation, which will ultimately be passed onto consumers.[49]

Stakeholders who considered the inaccuracies resulting from the current MLF calculation arrangements as problematic also considered other contributing factors. For example, AGL submitted that the current MLF methodology and the NER are in part associated with the decreases in MLF values through static, yearly MLF values.[50]

3.2.2 Other impacts on the transmission loss factor framework

Stakeholders also identified a number of other contributing factors that they considered were causing problems with the transmission loss factor framework which are resulting in the observed volatility of MLF values in the NEM.

AGL submitted that other attributes that could be attributed to the changes in MLF values such as:[51]

> ...the growing rate of renewable generators seeking connection to the grid and their level of understanding of the NEM, the NER and the role of MLFs; and/or the lack of information and general transparency about other developments taking place in a defined region (and the uncertainty and volatility this creates in the minds of debt and equity financiers).

AGL further noted that the largest impacts of changing MLF values are seen where there is "a combination of high renewable penetration, lower grid strength and are situated further from large load centres."[52]

Many stakeholders submitted that the rapid transformation of generation in the NEM is contributing unpredictability and variability in the NEM.[53] These stakeholders identified a number of features of the transformation, such as significant development of new generation in remote parts of the NEM in addition to co-location, that they considered have impacted of

49 Submissions to consultation paper: Investor Group, PARF, QIC, Lighthouse Infrastructure, CEC supplementary submission.

50 AGL submission to the consultation paper, p. 2.

51 AGL submission to the consultation paper, p. 2.

52 AGL submission to the consultation paper, p. 1.

53 Submissions to the consultation paper: Origin, p. 3; First Solar, p. 2; Investor Group, pp. 4, 6; EnergyAustralia, cover page and p. 4; PARF, pp. 1, 2, 9; Major Energy Users Inc, p. 3; CEC, Baringa report, p. 5; SnowyHydro, cover page; EUAA, p. 1; AGL, p. 2.

loss factor values. These features are further exacerbated by inadequate coordination of transmission infrastructure development to support the new generation.[54] PARF submitted that as:[55]

> ...the NEM transitions to low carbon resources, generators will increasingly be located in areas where the transmission network was not originally designed for them. This has placed, and will continue to place, strain on the network in these areas. As more and more new generators connect to 'untraditional' areas, power flows and therefore losses on the network increase…

Origin submitted that there are two factors contributing to investments being made that are potentially inconsistent with MLF signals:

- a potential disconnect between generation project developers and the ultimate operators of a facility – it is possible insufficient regard is being given to the impact of transmission losses on the economic viability of a generation project during the initial development phase, where the primary factor driving site selection may be access to the associated fuel resource (e.g. wind); and
- a general lack of transparency around the status of prospective generation projects and their potential network impacts – where a developer's ability to assess the potential impact of its prospective generator is impeded, or there is a lack of visibility around other prospective projects, this could lead to inefficient investment decisions such as generators co-locating in the same area to their own detriment from a loss factor perspective.

The first factor identified by Origin of a lack of coordination between generation project developers and the ultimate operator of a facility was also noted by SnowyHydro and AGL.[56] Similar points were raised by EnergyAustralia, who considered that:[57]

> The speed at which new renewable projects can be financed, installed and commissioned has led to large changes in MLFs...

In reference to the speed of change occurring, the Investor Group and First Solar submitted that there is an information asymmetry problem resulting in consultants not being able to provide the best possible forecasts for potential developments.[58]

Similarly, some stakeholders suggested that there is a general lack of transparency around prospective generation projects and their potential network impacts which is also an underlying problem that impacts on loss factor values.[59] However, most of these stakeholders

54 CEC submission to the consultation paper, Baringa report, p. 6.

55 PARF submission to the consultation paper, p. 5.

56 SnowyHydro submission to the consultation paper, p. 2; AGL submission to the consultation paper, p. 2.

57 EnergyAustralia submission to the consultation paper, cover page.

58 Investor Group submission to the consultation paper, p. 5; First Solar submission to the consultation paper, p. 7.

59 Investor Group submission to the consultation paper, p. 5. See also submissions to the consultation paper: First Solar, p. 7; Origin, p. 3; Stanwell, p. 2; EnergyAustralia, p. 4.

did acknowledge that this was being addressed through the Transparency of new projects rule change that takes effect from December 2019.

3.3 Commission analysis

The Commission recognises market participants' concerns in relation to MLFs: volatility, unpredictability and the associated costs of year-on-year changes in MLFs.

The discussion below sets out the Commission's considerations of the various issues stakeholders identified as driving the changes in MLF values as well as the impact that recent MLF values may be having on market participants. It includes the following aspects:

- transformation of the NEM
- accuracy of MLFs
- changes in MLF values
- impact of MLFs on investment
- impact of MLFs on the cost of capital.

3.3.1 Transformation of the NEM

The Commission outlined in its consultation paper that MLFs were previously reasonably predictable with little variability. This reflected the stability of the generation sector: much of the electricity supply in the NEM was provided by relatively few, large generators with reasonably consistent and forecastable dispatch patterns. In addition, many of these generators were securely connected (that is, connected with high voltage and low resistance transmission lines) to enable reliable supply to key demand locations.[60] Under these circumstances, market participants were better able to estimate future MLFs for a connection point. This allowed market participants to have more confidence of the impact of MLFs on their operational and investment decisions.

Stakeholders acknowledged a number of recent changes in the NEM are together contributing to the unprecedented change in the market as illustrated by changes in MLF values. In particular:

- new generation assets are being connected in remote parts of the NEM, that are a significant distance from demand centres, due to the location of certain fuel sources
- the new generation plants connecting often have correlated, rather than offsetting, dispatch characteristics
- co-location of new and often similar generation assets has been occurring
- the transmission infrastructure in those areas was not originally designed to support large-scale generation flows.

These fundamental changes are resulting in greater physical losses of electricity, which is not a function of economic theory but rather a function of physics. There are also additional factors, as indicated by stakeholder submissions, that do not directly create electrical losses

60 AEMC, *Transmission loss factors*, consultation paper, pp. 5-6.

but are market dynamics that are intensifying the variability and unpredictably of MLF values. Specifically:

- the rapid pace of investment and the related speed of construction with which new generation assets can be built relative to conventional assets (see Appendix D)
- a potential lack of coordination between generation project developers and the ultimate owners and operators of a facility
- information asymmetry for consultants to provide accurate advice to potential new investors in generation assets.

The changes identified above have created more real physical electrical losses, which is evident and represented through the increased losses embodied in AEMO's annual MLF publications. The Commission does not agree with Adani Renewables that there are "high inaccuracies" resulting from the use of a marginal and forward-looking calculation methodology. Instead, it notes that it is the factors noted above which are the fundamental cause of increased electrical losses, and the variability and unpredictably of MLF values.

3.3.2 Accuracy of MLFs

As part of its rule change request, Adani Renewables argued that MLFs are inaccurate[61] and that this inaccuracy results in the current variability in MLFs.[62]

The Commission has undertaken its own analysis to test if MLFs are inaccurate and to test the scale of variability in MLFs (section 3.3.3 below). On the first of these points, overall, the Commission's analysis indicates that MLFs have been reasonably accurate. The Commission also notes that MLFs are annual forecasts based on historical data and that any such forecast is likely to result in variances from actual, subsequent results.

Forecasts are generally considered efficient if they are unbiased. From the information illustrated below, the Commission could not detect a bias in MLF forecasts (Figure 3.1). The Commission notes that the objective of published MLFs is not to achieve an exact forecast of transmission losses but to provide efficient location and dispatch signals.

Figure 3.1 shows MLF values from published MLFs and a recalculated MLF value for the same year using backcast data. Data points are grouped into sub-region groups which have been given generic names. The difference between the two estimates represents the impact of additional information AEMO obtained between the time the MLF values were first published and actual generation data obtained later. For example, for region NSW-4, the published MLF was 0.03 points higher than the backcast MLF. Conversely, for region VIC-5, the published MLF was 0.06 points lower than the backcast MLF.

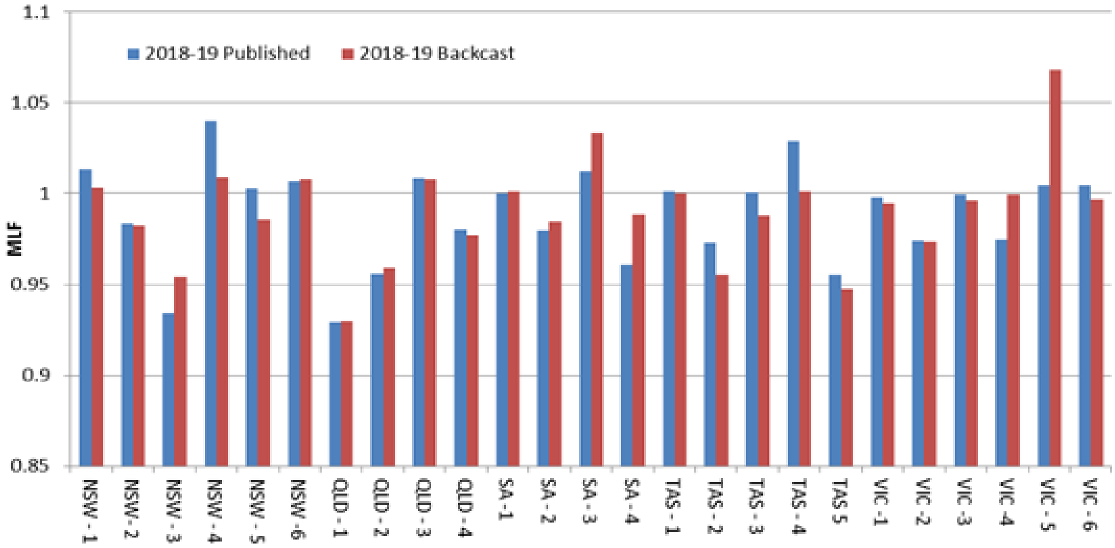
Figure 3.1 shows that there is no systemic difference between published MLFs and recalculated MLFs using backcast data. In some regions, the published MLF is higher than the backcast MLF while in other locations, the published MLF is lower than the backcast MLF. The chart also shows that the biggest difference between the published and backcast MLFs in

61 Adani Renewables, rule change request, 27 November 2018, covering letter; Adani Renewables, rule change request, 5 February 2019, covering letter.

62 Adani Renewables, rule change request, 27 November 2018, p. 3; Adani Renewables, rule change request, 5 February 2019, p. 3.

2018-2019 is 0.06 points for region VIC–5. This indicates that AEMO's MLF forecasts are efficient, unbiased forecasts.

Figure 3.1: Published and backcast MLFs for 2018-2019



Source: AEMO

Note: This graph shows the difference between published MLFs and backcast MLFs for the same year. This type of analysis shows that difference between forecast MLFs (the published MLF) and the updated MLF (backcast MLF), using actual data from the year the MLF is estimated for. The lower the difference between published and backcast MLF, the higher the accuracy of the forecast.

3.3.3 Changes in MLF values

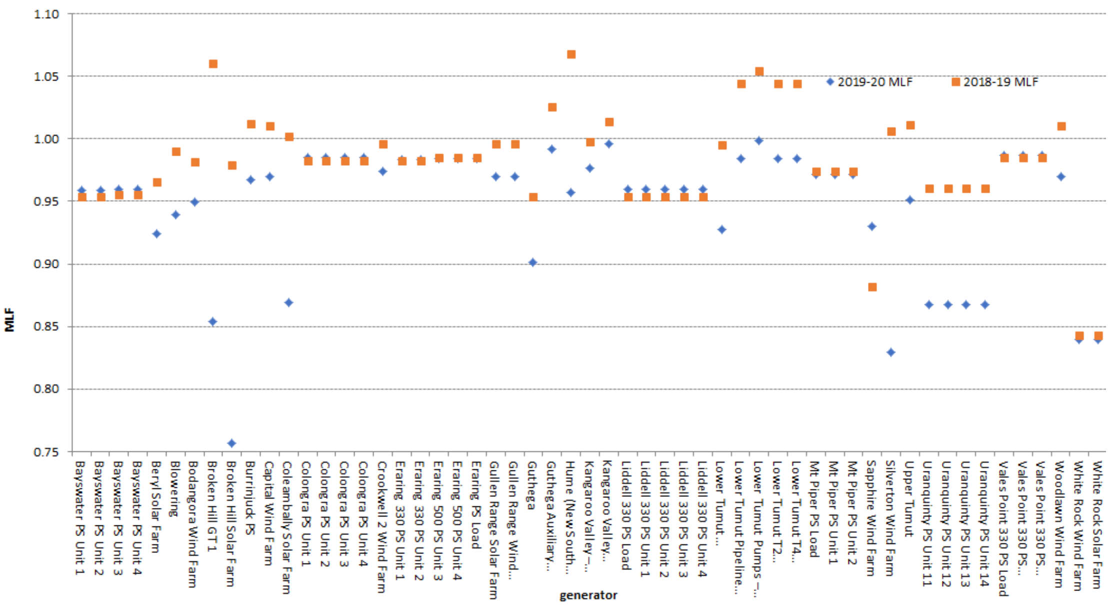
Some stakeholders submitted that they are concerned about declining and volatile MLFs that have not been predictable. In particular, they noted that declining MLFs affect revenue and consequently may have an impact on the cost of capital paid to fund investment in generation assets.

The Commission has tested these assertions against recent changes in MLF values in the NEM and found that while MLFs change, the larger declines are generally occurring in locations with significant network congestion. This is expected as MLFs have been designed to provide efficient locational signals for new assets (as well as achieve efficient dispatch).

Figure 3.2 shows the change in MLFs for NSW generators from 2018-2019 to 2019-2020. While most base load generators have stable MLFs, there have been significant declines for some generators (namely, Broken Hill GT1, Broken Hill Solar Farm, Coleambally Solar Farm, Hume and Silverton Wind Farm). Declining MLFs can affect new entrant generators as well as incumbents. For example, MLFs declined by 23 per cent for Broken Hill Solar Farm and 19 per cent for Broken Hill GT 1 between 2018-2019 and 2019-2020. However, there have also been increases in MLFs for renewable generators. For example, Sapphire Wind Farm's MLF increased by 5.4 per cent between 2018-2019 and 2019-2020. While the data in this figure focuses on NSW, the Commission's analysis has indicated similar trends have occurred in

Victoria and Queensland. Generation MLFs seem to have been more stable in Tasmania and South Australia.

Figure 3.2: Changes in MLFs in NSW, 2018-2019 to 2019-2020



Source: AEMO

Note: The graph shows the change in MLF values for NSW generators between 2018-19 and 2019-2020. The orange markers are the 2018-2019 MLFs and the blue markers are the 2019-2020 MLFs.

The Commission's analysis indicates that some generators have experienced a decline in MLF values. However, the analysis also indicates that many generators have not had this experience.

On 1 November 2019, AMEO published indicative MLFs for the 2020-2021 financial year.[63] The indicative MLFs are provided to provide an early indication to stakeholders of the potential direction and the extent of movement in MLFs across the NEM.

The indicative figures for 2020-2021 show that MLFs for some generators are continuing to decline, while the MLFs of other generators are increasing. For example, Broken Hill solar farm and Silverton wind farm in NSW are shown to continue their decline (4.2 per cent and 3.5 per cent respectively). Generators in North and Far North Queensland, on the other hand, are anticipated to experience increases in their MLFs. For example, Hughenden, Kidston and Ross River solar farms are expected to increase by 3.17 per cent and Daydream solar farm by 2.6 per cent. The Gannawarra Energy Storage System is a 25 MW/50 MWh Tesla Powerpack battery to be integrated with the 50 MW Gannawarra Solar Farm located west of Kerang in north-west Victoria. It is to become the first integrated solar and storage project in Victoria and among the largest of its kind in the world. Its generation and load

63 AEMO, *Indicative marginal loss factors: FY 2020-21*, November 2019.

MLFs are both forecast to improve by between four and six per cent, with its generation MLF forecast to be greater than 1.0.

The most efficient way to address the issue of volatile loss factor values is to move to dynamic marginal pricing with financial risk management tools. While this is not immediately possible, and not within the scope of this rule change process, the Commission does not consider that changing from MLFs to an alternative interim methodology would be likely to be consistent with the NEO. This is because an interim measure would be likely to introduce inefficiencies into the market (in regard to investment and operation of generation assets) and make any step change to dynamic pricing, if and when it were to occur, more significant.

In relation to the concerns about predictability of the movement in MLF values, the Commission notes that the changes made to the NER through the recent Transparency of new projects rule change are relevant. In addition, the Commission acknowledges AEMO's work plan to refine the MLF methodology through a forthcoming consultation process with stakeholders which may also assist stakeholders in managing changing MLF values in the future.

3.3.4 Impact of MLFs on investment

Stakeholders have submitted that the recent decline and volatility in MLFs could potentially result in a decline in investment in Australian generation assets.[64] To understand this further, the Commission has undertaken its own analysis using data published by AEMO and found that:

- committed generation investment has come down from relatively high levels in 2018 and 2019
- proposed investment was strong in July 2019
- proposed investment as at July 2018 was mostly in renewable generation (87 per cent of total proposed generation investment).

Committed and proposed investment in generation assets

Figure 3.3 illustrates the trend in committed and proposed generation investment in the NEM between August 2016 and July 2019. The graph shows that there was a substantial increase in committed investment between July 2018 and January 2019 which coincides with ramping up in the large-scale renewable energy target (LRET).[65] After January 2019, there is a significant drop in committed generation investment reflecting a combination of the renewable energy target (RET) being largely met, but also other factors, such as security output constraints, congestion risk and energy and emissions policy uncertainty.

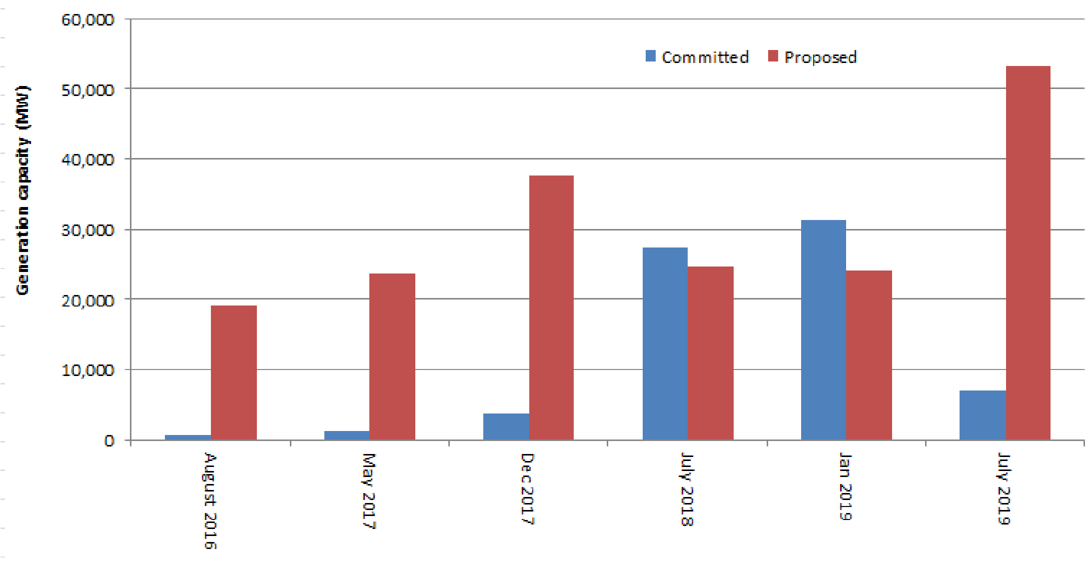
Nevertheless, proposed generation investment remains high in July 2019. The Commission notes that in July 2019, proposed investments were mostly in renewable generation assets with solar making up 46 per cent of proposed investment in July 2019, wind 31 per cent and

64 For example, submissions to the consultation paper: Investor Group, PARF, p. 5; CEC supplementary submission, p. 1.

65 The LRET was designed to incentivise investment in renewable energy generation assets to assist Australia in reaching its goal of 20 per cent of renewable energy by 2020.

water 10 per cent. Proposed investment in gas-fired generation plants is low at around three per cent.

Figure 3.3: Committed and proposed generation investment in the NEM



Source: AEMO
Note: The graph shows committed and proposed generation investment published by AEMO.

Recent investment in generation assets

Information on investment activity in the Australian electricity sector indicates that there is new debt capital entering the Australian capital market. For example, UK-based infrastructure and private equity investment manager Foresight Group has launched a new product, the Foresight Renewable Energy Income Fund, in Australia. The fund will target $150 million and will make loans of $5 million to $30 million, mainly to small-scale solar and wind and associated infrastructure projects.

According to the Foresight Group, small-scale solar in Australia is forecast to grow rapidly, faster than any other form of energy generation. And, unlike larger-scale renewable projects, smaller projects have lower connection costs and can be located close to demand centres, making them more efficient as electricity that is generated will travel shorter distances.[66] According to the Foresight Group, the fund will capitalise on the inefficiencies in the Australian debt market that have left small-scale renewables projects underserved.[67] It will target a 4.0-4.5 per cent yield margin over the Reserve Bank of Australia (RBA) cash rate. Assuming a yield of four per cent, this would mean a credit spread of 2.8 per cent (over the

66 https://www.foresightgroupau.com/foresight-renewable-energy-income-fund/ Accessed 28 October 2019.

67 https://www.foresightgroupau.com/foresight-renewable-energy-income-fund/, https://www.thefifthestate.com.au/business/investment-deals/foresight-group-launches-fund-for-small-scale-renewables/ Accessed 28 October 2019.

nominal risk free rate of 1.2 per cent as at July 2019). This is significantly higher than the current credit spread on BBB rated non-financial debt which was 1.41 per cent in July 2019.

The Foresight Group's Australian solar portfolio currently includes:

- Bannerton, Victoria (110 MW)
- Oakey 1, Queensland (30 MW)
- Oakey 2, Queensland (70 MW)
- Longreach, Queensland (17 MW)
- Barcaldine, Queensland (25 MW)

Asset valuations of investments

One consideration of investors is the value of the assets in which they invest and how this value holds over time. As a result, one of the factors to consider in addition to MLF risk and its impact on generation investment are asset valuations. Assets that are relatively over-valued would be relatively more affected by declining MLFs compared to assets that are valued closer to their intrinsic value. This is because an over-valued asset will require relatively higher cash flows to achieve the required rate of return of an investment made. For example, in a recent survey of renewable energy investors, Minter Ellison identified that the three most significant challenges investment in Australian renewables in the next 12 months are:[68]

- valuations (too high), 62 per cent of respondents
- complexities/uncertainties created in transitioning to renewables-based grid, 58 per cent of respondents
- instability around incentives, 57 per cent of respondents.

3.3.5 Impact of MLFs on cost of capital

A number of stakeholders have submitted that declining MLFs may result in an increase in the cost of capital. If this occurred, it is likely that this would lead to an increase in consumer prices for electricity. Alternatively, this could deter investors in committing new funds to Australian generation assets.[69]

In order to better understand the drivers of generators' cost of capital, the Commission has undertaken its own analysis and found that:

- equity betas of generators and generation asset developers are relatively low compared to other energy businesses and the financial market in general
- the cost of debt for BBB rated non-financial debt has been falling in Australia, resulting in a lower cost of capital generally implying that any relative decrease in the credit rating would have a relatively lesser impact on the cost of debt compared to a scenario where the cost of debt is stable or rising

68 Minter Ellison, *Australian renewable energy investment trends and outlook*, June 2019.

69 For example, submissions to the consultation paper: Investor Group, PARF, p. 5.

- a reduction in the gearing level (so that there is more equity funds invested compared to debt) will increase the cost of capital but overall, the cost of capital for renewable generation investments seems to be relatively low compared to the market
- overseas investors have, as recently as September 2019, committed substantial funds to invest in Australian generation assets.

Impact of MLFs on cost of equity

On the first of the points noted above, the Commission notes that on the equity-side, investors have expressed concerns that the decline in MLFs may impact on their ability to provide equity financing to Australian generation investment.

One of the main drivers of investors' returns is the equity beta. The equity beta signifies the systematic risk of an investment — the risk that cannot be diversified away by holding a portfolio of assets. All other things being equal, the riskier the investment compared to the overall market, the higher the equity beta and the required return.

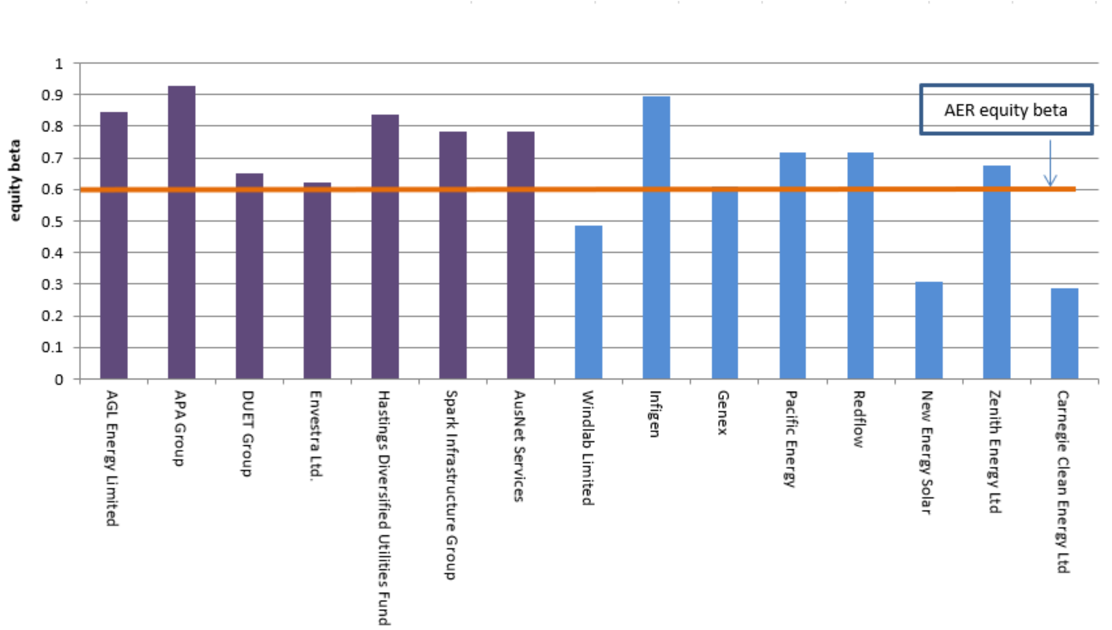
In addition, the gearing ratio of an investment also impacts on the equity beta. All other things being equal, including the level of systematic risk, the higher the gearing level of an investment (that is, the more equity funds are used compared to debt), the higher the equity beta.

These relationships[70] imply that a less debt financing for an investment would result in an increase in the cost of equity caused by an increase in the equity beta.

Figure 3.4 compares the equity betas (levered) of Australian energy companies; the AER's equity beta for regulated electricity distribution and transmission service providers and gas pipeline service providers; and the equity betas of developers, investors and owners of generation assets. The graph in Figure 3.4 shows that some of the generation assets or renewable energy equity betas (shown as blue bars) are lower than what the AER uses to estimate the cost of capital for regulated service providers. The equity betas for renewable generation assets are also similar or lower than most of the comparators set that the AER has used to estimate its equity beta range (purple bars). For example, Windlab (a member of the investor group) has an equity beta of 0.5, which is lower than the equity beta the AER uses (0.6) and lower than any equity beta in the set of comparators the AER used to estimate its equity beta range. Others, such as Infigen are higher than the AER's equity beta but lower than the market beta of one implying that they are less risky than the market.

70 The relationship between the levered equity beta, systematic risk and gearing. The unlevered equity beta (or asset beta) only takes into account systematic risk.

Figure 3.4: Equity beta comparison



Source: Bloomberg
Note: The graph shows equity betas for publicly traded energy business and developers. The orange line represents the equity beta the AER is using in its determinations for electricity and gas service providers. A gearing level of 60% is used by the AER for its levered equity beta estimate.

Impact of MLFs on cost of debt

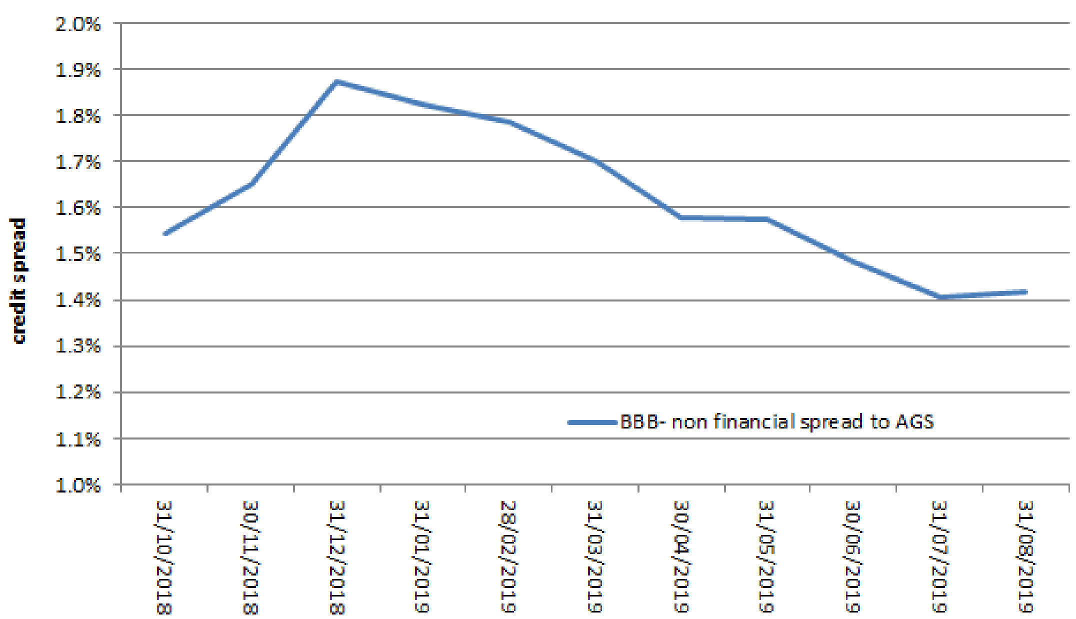
On the debt-side, investors have expressed concern that a decline in MLFs may trigger debt covenants.[71] This in turn could reduce the ability of those investors to refinance debt, resulting in a higher credit spread and lower gearing of investments.

However, the nominal risk free rate (as measured by 10-year nominal Australian Government bonds and credit spreads) has fallen significantly over the last 12 months or so. Figure 3.5 shows the trend in credit spreads for BBB rated non-financial debt, as measured by the RBA. It indicates that the timing of obtaining finance or refinancing can impact significantly on the cost of debt. For example, credit spreads for BBB rated non-financial debt was 1.87 per cent over the nominal risk free rate in December 2018, and 1.41 per cent in July 2019. Over the same period, the nominal risk free rate declined from 2.13 per cent in December 2018 to 1.2 percent in July 2019. Consequently, the cost of debt for a BBB rated non-financial investment would have been 4.0 per cent in December 2018 and 2.6 per cent in July 2019 based on the data we have gathered from the RBA and Bloomberg. This fall in the cost of debt would have an impact on the refinancing of assets. For example, an asset originally financed using BBB rated debt would see a significant fall in the cost of debt all other things being equal. Consequently, if the debt of a generation asset gets downgraded due to MLF risk, it is likely

71 A debt covenant is an agreement between a company and a creditor that sets out limits or thresholds for certain financial ratios that the company may not breach.

that the relative effect on the cost of debt will be dampened because of the general fall in the risk free rate and credit spreads.

Figure 3.5: BBB — non financial spread to risk free rate



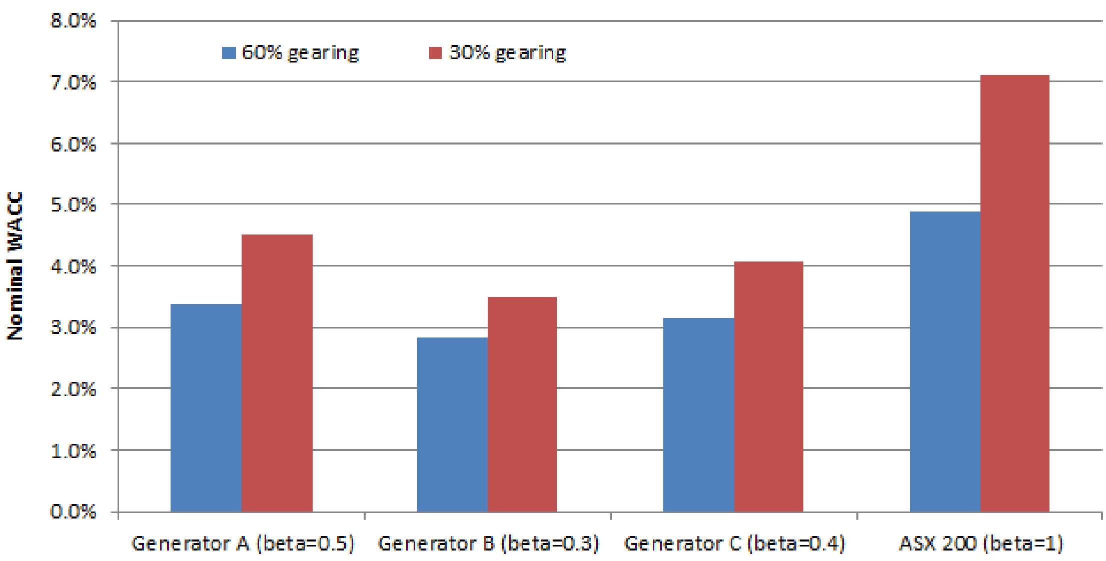
Source: RBA
Note: The graph shows the trend in BBB rated non-financial credit spreads (to the Australian Government securities - AGS) between October 2018 and August 2019.

If debt covenants were triggered, this would be likely to result in an increase in the cost of debt financing and a reduction in the gearing ratio as lenders reduce their exposure to the asset. All other things being equal, this would result in an increase in the WACC. While a change to an average loss factor methodology may delay this from occurring, it is likely to only shift the problem into the future, rather than resolving it. An increase in the WACC would also allocate risks efficiently, that is to the asset owner rather than to consumers and other generators as could be the case under an average loss factor methodology

Impact of MLFs on the gearing ratio

If lower MLFs result in a reduction in gearing, generators would require more equity capital, which all other things being equal, is more expensive than debt capital. Figure 3.6 shows that a reduction in the gearing ratio from 60 percent to 30 percent would result in an increase in the cost of capital (WACC). However, given that equity betas of generators seem to be relatively low compared to the market, the WACC for generators would still be considerably lower than that of the market after a change in the gearing ratio.

Figure 3.6: WACC and gearing



Source: AEMC
Note: The graph shows the WACC for generators with different equity betas (levered equity betas) and the market for gearing levels of 60 and 30 percent. Equity betas for stylised generators A, B and C have been chosen with reference to equity betas of traded energy generation and generation developer businesses obtained from Bloomberg in October 2019.

In summary, while stakeholders have expressed concern about refinancing the debt of existing generation assets that are experiencing declining loss factors, it is not clear if this is a temporary issue or whether this affects all assets in the generation sector. The market will provide financing to the most efficient investments at the best price. In terms of equity investment, it seems that:

- The equity betas of generation investments are lower than the market beta of one, and some are lower than the AER equity beta for distribution and transmission service providers and gas pipeline service providers.
- Some investment risk mentioned by stakeholders in submissions can be diversified away by holding a diversified portfolio of assets. For example, stakeholders holding a larger portfolio of generation assets generally submitted that they believe that in the absence of dynamic pricing, MLFs are the most efficient methodology to estimate loss factors and that portfolio diversification was a way to hedge MLF risk.

3.4 Other relevant work

The Commission considers that the most efficient solution to the problems identified above are the introduction of dynamic marginal pricing with financial risk management products. This would provide the most efficient locational signals, allow generators to hedge loss factor variability and in the long-run address network congestion issues. While dynamic pricing with financial risk management products can not be immediately implemented in the NEM, the

Commission considers that MLFs provide the most efficient, implementable solution available at present.

A number of stakeholders also considered that any changes to the transmission loss factor framework should be made holistically with broader market reform work. AEMO submitted that:

> ...any major change to the transmission loss factor framework must be considered with the broader market reform work underway. This should include the AEMC's work on COGATI, transparency of new projects rule change, and the ESB's work on post-2025 NEM market design.

The AER similarly submitted that "it is more desirable to make improvements through the other, more holistic, review and reform processes already in train, than through these isolated proposals".[72] The submissions by AEMO and the AER were echoed by a number of other stakeholders.[73]

Lighthouse Infrastructure submitted that:

> ...the trend toward higher system losses must be addressed by planning-led coordination of generation and transmission development. Market design improvements will not compensate for a sub-optimal underlying physical system. Ultimately unnecessary losses will increase the cost of electricity for consumers.

While noting these reform projects, some stakeholders submitted that the cost of retaining the status quo was too high and that the related projects will take too long to implement.[74] Canadian Solar considered that although any holistic design changes to MLF framework are best captured under the COGATI review, there is necessity for change through this rule change through transitional arrangements.[75]

However, the Commission notes that addressing the identified problems of variability and unpredictably of MLFs and increased physical electrical losses is best done through a broader more holistic market reform.

3.4.1 Transparency of new projects

The Commission initiated a rule change process on 18 April 2019, consolidating three rule change requests that were seeking to increase transparency of new generators connecting to the transmission network:

- the AEC sought to improve information provision in the NEM by codifying AEMO’s generation information page in the NER, reforming the intending participant category and clarifying the rules around disclosing confidential information

72 AER submission to the consultation paper, p. 2.

73 See also submissions to the consultation paper: Canadian Solar, p. 1; Stanwell, p. 1; CS Energy, attachment; Hydro Tasmania, p. 2; EUAA, p. 1; Mondo, p. 2.

74 Submissions to the consultation paper: CEC supplementary, Baringa report, p. 8; PARF, p. 5.

75 Canadian Solar submission to the consultation paper, p. 2.

- AEMO sought to allow developers that sell a grid scale resource prior to connection to register as intending participants, giving these developers access to important system data
- Energy Networks Australia sought to allow TNSPs to publish certain project information they have received from connection applicants.

The Commission published a final rule on the 24 October 2019 that will provide market participants better and more up-to-date information about what new generation projects are in the pipeline, which can help businesses make better investment decisions, such as where to locate.[76]

The Commission's final rule:

- facilitates greater access to relevant system information for developers that sell grid-scale assets prior to connection, while recognising that certain types of developers can already access this information by registering as intending participants
- codifies AEMO's generation information page in the NER, which is an information resource that provides regularly updated data on existing and proposed generation connections to the national grid
- requires TNSPs to share key connection information about new generation projects with AEMO, which AEMO must then publish on its generation information page.

The effect of these amendments is to provide better and more up-to-date information about what generation projects are in the pipeline, making it easier and quicker for developers to assess the viability of proposed projects, as the energy market transitions. As a result, market participants will be better informed, and therefore able to make more efficient decisions on where to invest in new generation, which could ultimately benefit consumers by promoting reliable supply at lower costs.

The Transparency of new projects rule change is closely related to the problems associated with the rule change requests from Adani Renewables. Submissions and stakeholder comments regarding recent year-on-year lowering of MLFs suggested that more information about forthcoming generation projects would allow investors to better forecast potential changes to MLFs that may arise.

3.4.2 COGATI review

The differences between transmission and generation decision-making processes are manifesting in a range of issues currently being experienced by investors, which includes MLFs. The Commission considers that changes to the transmission frameworks are needed so that the regulatory framework evolves to match the transition in the NEM. Transmission access reform is vital in order for the NEM to effectively evolve and transition to a lower emissions power sector, whatever this future may look like.

The Commission published a discussion paper for the COGATI review in October 2019. This set out further detail on its proposed approach to reforming the current access framework for

76 AEMC, *Transparency of new projects*, rule determination, 24 October 2019.

transmission networks across the NEM which involves changing three inter-related aspects of the current transmission access framework.

Reforms to transmission network access arrangements are likely to have significant implications for the appropriate approach to calculating MLFs. For example, in some overseas markets where there are locational marginal prices, MLFs are calculated dynamically at each location in real time. As a result, reforms to the loss factor framework will be considered in the COGATI review as part of the development of reforms to the access arrangements for transmission networks. The Commission is working with the ESB, AER, AEMO, as well as interested stakeholders, to progress the COGATI review. It will continue to consider the interactions between Adani Renewables' rule change requests and the COGATI review throughout both of these processes.

3.4.3 ESB post 2025 market design

The COAG Energy Council tasked the ESB with developing advice on a long-term, fit-for-purpose market framework to support reliability that could apply from the mid-2020s. The ESB recently released its market design issues paper. This paper provides advice on a long-term, fit-for-purpose market framework to support reliability, modifying the NEM as necessary to meet the needs of future diverse sources of non-dispatchable generation and flexible resources including demand side response, storage and distributed energy resource participation.[77]

The ESB post 2025 project relates to MLFs as it addresses a number of the issues which the Commission has identified above in this chapter. The ESB issues paper discusses five key challenges that will be material to the market design in 2025:[78]

- driving innovation to benefit the consumer
- investment signals to ensure reliability
- integration of distributed energy resources into the electricity market
- system security services and resilience
- integration of variable renewable energy into the power system.

3.5 Conclusion

The Commission acknowledges that the factors identified above are reflecting changes in actual electrical losses in the transmission system. This is leading to higher losses and lower MLF values for some generators. This has resulted in financial impacts for some generation asset owners and investors.

However, the Commission does not consider that Adani Renewables' claim that inaccuracies in forecasting MLFs are the root cause of some generators not being dispatched and increasing cost of generation to all market customers is the correct characterisation of the problem.

77 ESB website: http://www.coagenergycouncil.gov.au/publications/post-2025-market-design-issues-paper-%E2%80%93-september-2019

78 ESB, *Post 2025 Market Design*, Issues Paper, September 2019, p. 3.

The Commission considers that observed variability of the MLF values and the size of the IRSR are symptoms of more fundamental changes currently occurring in the NEM. Specifically, that investment in new generation assets is often occurring on the periphery of the electricity grid with limited reference to, or coordination with, investment needs for the transmission networks to support greater system use at such locations.

In addition, the Commission does not consider that the current arrangements of the allocation of IRSR is problematic. Given that it is customers who pay the cost of transmission investment not generators, it is appropriate for the residue to be allocated to customers.

The factors contributing to more electrical losses and the variability and unpredictability of annual MLF values are better addressed through other changes to the NEM. The new Transparency of new projects rule will address the information asymmetry issue that prospective and current owners of generation assets have identified. In addition, the COGATI review and the ESB post 2025 project are both relevant forums to develop solutions to address the fundamental causes of the issues arising in the current transition of the NEM to a different generation mix that meets the future needs of a low carbon economy.

4 INTRA-REGIONAL SETTLEMENT RESIDUES

This chapter outlines the rule change request related to IRSRs, and its rationale, lodged by Adani Renewables. It provides a summary of stakeholder submissions in relation to the proposed reallocation of IRSR. Furthermore, it provides the Commission's analysis of the request and provides its reasoning for the draft rule determination.

4.1 What are intra-regional settlement residues?

In the NEM the payments made by consumers of electricity (customers) do not match, and generally exceed, payments made to providers of electricity (generators). This occurs for a number of reasons including:

- Price separations between adjacent regions due to interconnector transfer limits.[79]
- Approximations in the representation of inter-regional loss factor equations.
- The use of intra-regional loss factors that are marginal loss factors.[80]

The inter-regional settlement residues are comprised of the residues due to price separation and the impact of inter-regional losses which are calculated for each interconnector and trading interval. Market participants can access the inter-regional settlements residues through an auction process and this can assist them to hedge their spot market exposure, especially for inter-regional trading.[81]

The remainder of the residues that accrue within a given region are the intra-regional settlement residues (IRSR).[82] As noted above, this tends to be positive but can be negative.

The IRSR are paid to (or recovered from) the TNSP for the associated region and used to decrease (or increase) TUOS charges. As IRSR is usually positive, this effectively results in the IRSR being returned to customers, as only customers (not generators) currently pay TUOS charges.

In addition, the IRSR are returned to customers on a postage stamp basis as part of the non-locational component of TNSP revenue.[83] As a result, there is no link between the accrual of IRSR and the manner in which it is distributed to customers. This has the advantage that it minimises the impact on real-time bidding behaviour of market participants (that is, bids from market loads). Consequently, the redistribution of IRSR does not distort the economic dispatch of the market.

79 When the flow on an interconnector is limited by a network constraint the electricity flow is generally from the lower priced region to the higher priced region. This means that electricity is paid for in the exporting region at a lower price than that paid by customers in the importing region, resulting in a settlement residue.

80 Marginal intra-regional loss factors are used in the NEM as this produces efficient signals for dispatch and longer-term investment. However, the use of marginal loss factors tends to recover more revenue from consumers than is paid to generators, contributing to settlement residues. A theoretical description of marginal loss factors is provided in AEMO, *Treatment of loss factors in the national electricity market*, available on AEMO's website.

81 Details of the calculation of inter-regional settlements residues and the auction process are available on the AEMO website.

82 NER clause 3.6.5(a)(3).

83 NER clauses 6A.23.3(e) and 6A.23.4(e).

4.2 Adani Renewables' views

On 27 November 2018, Adani Renewables submitted a rule change request to reallocate the IRSR to generators and market customers equally.[84]

Adani Renewables outlined three issues with the current approach and a fourth point articulating what it considered the result of a change would be:[85]

1. The current approach to the calculation and application of MLFs gives rise to loss factors that are approximations of actuals.
2. To the extent that high IRSRs represent cumulative error between forecast and actual losses, efficient dispatch of generation is undermined (through changing dispatch order and interfering with investment signalling).
3. Where MLFs are inaccurate, they can give rise to IRSRs. The existing approach of allocating these residues to customers via postage stamp TUOS then worsens the impact of any inaccuracy in loss factors, by funnelling this money away from generators.
4. Were IRSRs handed back to generators, some of the distortionary impact would be reduced.

Further, Adani Renewables stated that the current rules relating to transmission loss factors are resulting in high inaccuracies, which distorts the market through inefficiencies in operational and investment decision-making.[86] It considered that there are two factors within the NER causing these inefficiencies:[87]

1. Currently the generators do not receive any allocation of Intra-Regional Settlements Residue (IRSRs) that accrue due to MLF inaccuracies. IRSRs are returned only to one segment of market customers. A rule change to facilitate a reallocation of IRSRs to include generators will harbour savings that can be passed on to all market customers.
2. The inaccuracy in forecasting MLF for the following year/s results in generators assuming an artificially increased bid price as a result of an incorrect MLF. Hence generators are subject to an increased risk of not being dispatched, resulting in an increased cost of generation for all market customers.

The rationale for the reallocation of the IRSR provided by Adani Renewables is that it would result in "an improved effective MLF (less losses) for generators that have been subject to inaccuracies and therefore more competitive generation bidding, resulting in lower prices to market customers".[88] Specifically, it stated that redistributing half of the IRSR funds to generators would:[89]

84 Adani Renewables, rule change request, 27 November 2018, covering letter.
85 Adani Renewables, rule change request, 27 November 2018, p. 7.
86 Adani Renewables, rule change request, 27 November 2018, covering letter.
87 Adani Renewables, rule change request, 27 November 2018, covering letter.
88 Adani Renewables, rule change request, 27 November 2018, covering letter.
89 Adani Renewables, rule change request, 27 November 2018, pp. 7-8.

> …correct for any inaccuracies associated with the MLFs, and associated inefficiencies caused by these inaccuracies. While this change to the reallocation process will not directly address the cause of inefficiencies caused by inaccurate MLFs, it may go some way to reducing the impacts this inaccuracy has on the investment and operational efficiency of the NEM.

Adani Renewables summarised its rule change request by stating:[90]

> Adani Renewables proposes a rule change so that the process for the allocation of IRSRs be revised to include generation connection points and not only the network users who are subject to non-locational prescribed TUOS charges. The result of this rule change will be lower effective MLFs for generators that have been subject to inaccuracies and therefore more competitive generation bidding, resulting in lower prices to market customers.

4.3 Stakeholder views

Stakeholder submissions generally focused on whether there should be a change in the way transmission loss factors are calculated; a number of stakeholders did not provide any comment in relation to the request to reallocate the IRSR.

Additionally, no stakeholders provided direct comment that the current allocation of IRSR is problematic or will have a material impact on the long-term interest of consumers.

4.3.1 Allocation of IRSR

The ACT Government EPSDD stated that it did not consider that the current IRSR arrangements "necessarily represents a problem".[91]

Other stakeholders simply supported the proposed reallocation of part of the IRSR to generators without outlining specific reasons or identifying that the current IRSR arrangements are problematic.[92]

Although not explicit, it was apparent through the submissions that stakeholders who did address the proposed reallocation of IRSR did not necessarily consider the current distribution of the IRSR to customers only as problematic. Stakeholders who supported a reallocation of the IRSR were more focused on the accrual of the IRSR resulting from over-recovery of losses stemming from the perceived inaccuracies in the MLF calculation methodology.

Meridian Energy Australia and Powershop Australia (together, MEA Group) supported the proponent's request and suggested that a reallocation of IRSR would address the problem of inaccuracies. A reallocation of the IRSR would act as an effective hedge against a low MLF

90 Adani Renewables, rule change request, 27 November 2018, p. 3.

91 ESPDD submission to the consultation paper, p. 3.

92 Submissions to the consultation paper: Enel Green Power, p. 1; Engie, p. 2; Canadian Solar, p. 2; ERM Power, p. 2; Investor Group, p. 13.

and mitigate some of the 'cost' associated with inaccurate MLF calculations.[93] The Clean Energy Council (CEC) similarly commented that a reallocation of IRSR "would remove the current systematic IRSR surplus."[94]

There were a number of stakeholders who expressly rejected the claim that the market customers being the sole beneficiary of the IRSR is problematic or an unfair allocation. The Australian Energy Regulator (AER) reflected this sentiment and stated that:[95]

> …it remains appropriate that the IRSR continue to be allocated fully to customers because they bear the majority of costs and risks of transmission investment.

In addition, Intelligent Energy Systems (IES) stated:[96]

> The current distribution of the ISSR (sic) recognises that the IRSR is the outcome of marginal pricing methodology used to account for losses in the network. It aims to reduce the amount to be recovered in network charges generally without destroying the Individual MLF signal. This logic is appropriate for good efficiency. How network charges are distributed is another matter and is one of the subjects of the COGATI review.

Ergon Energy and Energex, and the Central Irrigation Trust (CIT) considered that the rule change request for IRSR itself was problematic and, if adopted would result in TUOS charges increasing and customers paying higher prices.[97] This point was also made by AEMO in its submission.[98] Similar submissions were received from stakeholders who found the premise of reallocating the residue away from customers to generators and customers as problematic:[99]

> …generators do not currently pay TUOS and hence it is inappropriate for them to receive the positive residues…

It was also noted by EnergyAustralia that generators do not pay for the use of the shared transmission network; rather customers pay for all new and ongoing transmission costs through TUOS charges. It further stated that Adani Renewables' solution of returning part of the IRSR to generators would not address the root cause of the problem.[100]

4.3.2 Calculation of IRSR

First Solar agreed with Adani Renewables and suggested that as there is an over-recovery resulting from inaccuracies and that this should be rectified through part of the IRSR being

93 MEA Group submission to the consultation paper, p. 2.

94 CEC supplementary submission to the consultation paper, p. 2.

95 AER submission to the consultation paper, p. 2. See similar comments from submissions to the consultation paper: CIT p. 4; Ergon Energy and Energex, p. 2; Energy Networks Australia, p. 4; EnergyAustralia, pp. 8-9.

96 IES submission to the consultation paper, p. 2.

97 Submissions to the consultation paper: CIT, p. 4; Ergon Energy and Energex, p. 2; Energy Networks Australia, p. 4; EnergyAustralia, pp. 8-9.

98 AEMO submission to the consultation paper, p. 6.

99 Energy Networks Australia submission to the consultation paper, p. 4. See also submissions to the consultation paper: AER, p. 2; Ergon Energy and Energex, p. 2; EnergyAustralia, pp. 8-9.

100 EnergyAustralia submission to the consultation paper, pp. 8-9.

reallocated to generators. First Solar submitted that this would be a fair reflection of a generator's contribution to transmission losses.[101]

AEMO noted that the proposal to reallocate IRSR would increase TUOS charges, and therefore considered that the benefits of the proposal must be assessed against the achievement of the NEO. AEMO also highlighted that South Australia's IRSR currently and predominately materialises in a negative amount.[102] AEMO stated that if the Commission reallocated the IRSR, generators in South Australia would consequently receive a bill, rather than a positive allocation.

AEMO also considered the impact on the IRSR if the Commission was to adopt an ALF calculation methodology. It stated:[103]

> ...a move to average loss factors would see a reduction in revenue collected from Market Customers, which may result in significant under-recovery and negative inter-regional settlement residue (IRSR) under some conditions. In the long run, and under circumstances where average loss factors could be calculated exactly, average loss factors would be expected to result in a zero average IRSR as prices would no longer reflect the marginal value of losses. However, in practice this may result in an increased risk of negative IRSR across the NEM and potentially lead to settlement periods when insufficient revenue is recovered from customers to pay generators.
>
> While AEMO acknowledges that average loss factors should result in higher pool payments which could offset the impact of negative residues, AEMO suggests that the risk of increased negative IRSR is considered by the Commission as part of its assessment of this aspect of the rule change request.

4.4 Commission analysis

The Commission has considered whether a change to the allocation of the IRSR would be likely to achieve the NEO. Its analysis below addresses Adani Renewables' rationale for the rule change and stakeholder submissions as summarised above.

The Commission does not agree with the proponent's characterisation that the way MLFs are calculated results in high inaccuracies in MLF values which create a high and undesirable positive accrual of IRSR. In addition, it does not agree that it is appropriate for the IRSR to be shared between customers and generators.

In forming this conclusion, there are two key aspects which the Commission has considered:

- settlement residues arise due to the marginal pricing framework
- that there is a need to allocate these residues and that they are most appropriately returned to customers to offset TUOS charges.

101 First Solar submission to the consultation paper, p. 3.

102 AEMO submission to the consultation paper, p. 6.

103 AEMO submission to the consultation paper, p. 6.

4.4.1 Marginal pricing framework

Marginal loss factors represent the additional losses that occur between a generator dispatching electricity and the delivery of that electricity to customers at the regional reference node for one additional unit (1 MW) of electricity. Losses increase with the square of the power flowing along the line. This means that marginal loss factors (the losses caused by an additional unit of flow along the line) are higher than the actual losses incurred. Thought of another way, the losses for the next unit of power flowing across the line are higher than the previous unit of power flowing across the line.

Marginal loss factors (as opposed to actual loss factors) send an appropriate price signal to market participants in both dispatch and investment timescales.

The use of marginal loss factors generally results in an over recovery of funds because generators are paid for electricity generated on a marginal basis. An IRSR for a jurisdiction resulting in a surplus amount is not due to "inaccuracies". Rather, it is a necessary and natural consequence of the appropriate decision to use the marginal pricing mechanism to calculate loss factors. The Commission therefore does not agree with Adani Renewables' characterisation that the calculation methodology of loss factors is itself inaccurate and results in high inaccuracies in the form of undesirable and significant IRSR.

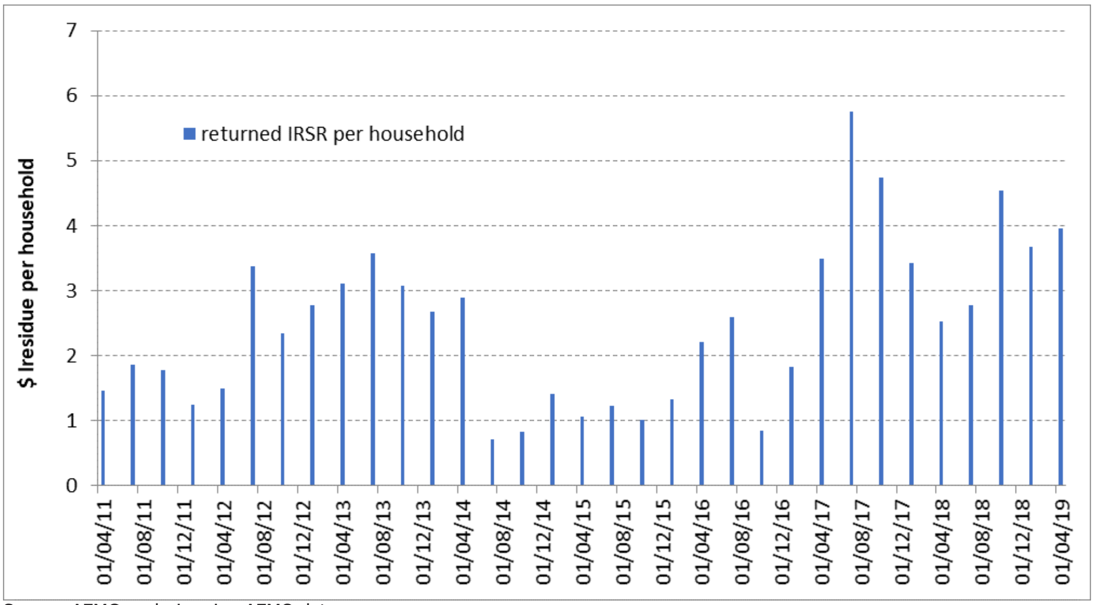
Therefore, including generators as recipients of IRSR would mean that generators are no longer being settled based on MLFs (assuming that the IRSR would be distributed in correlation with generator output rather than being allocated across generators in some other way). This would result in generators' revenues reflecting MLFs plus the IRSR amount (irrespective of being a negative or positive value). This would represent a move away from the principle of marginal pricing, and as a result, be an economically inefficient arrangement.

4.4.2 Consumers and the IRSR

Customers pay for transmission infrastructure through TUOS charges. This flows through to the electricity bills of end-use consumers. TNSPs who receive the IRSR in circumstances where there is a surplus are required to apply that directly to TUOS charges.[104] A positive IRSR therefore results in lower electricity bills, as illustrated in Figure 4.1 below.

104 NER clause 3.6.5(a)(6).

Figure 4.1: Quarterly IRSR returned to customer/per household NSW



Source: AEMC analysis using AEMO data

As noted, the existence of a settlements residue is a natural consequence of using a marginal pricing mechanism for loss factors. As customers pay for the transmission infrastructure being used, it is appropriate that customers' transmission costs are reduced where funds are available.

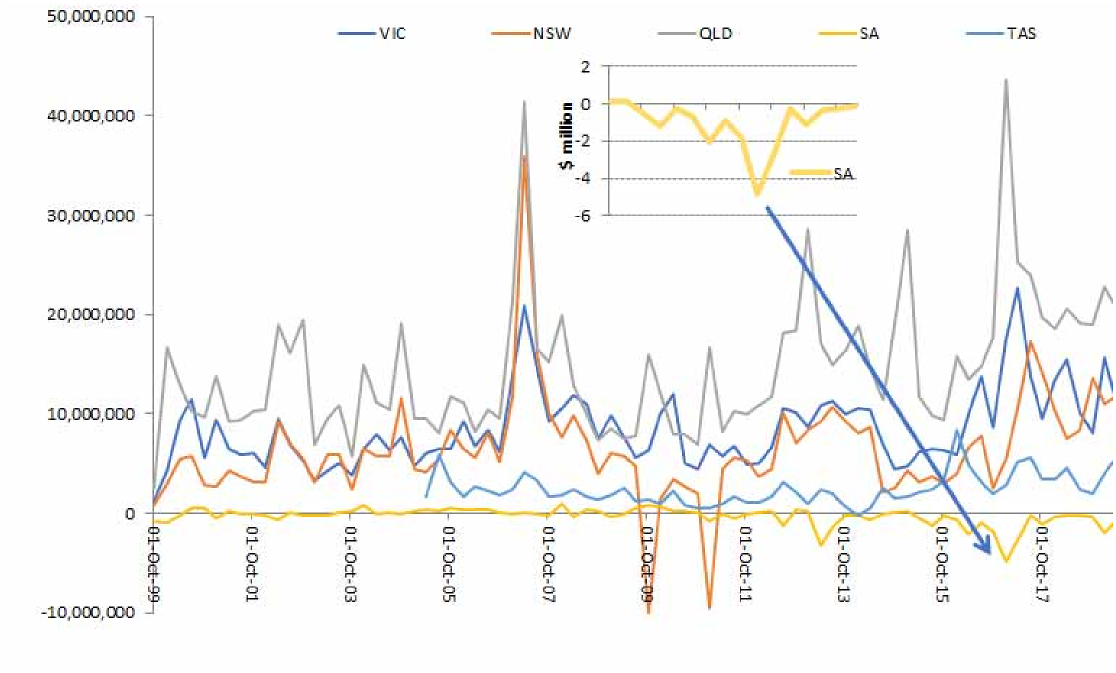
In its rule change request, Adani Renewables suggested that revising the allocation of IRSRs to include generation connection points would lower prices to market customers.[105] However, the Commission considers that the amount to which wholesale energy prices might be reduced would be uncertain and, in any event, would be unlikely to benefit customers to a greater extent than the existing arrangements. The current arrangements already directly reduce customers' electricity bills in circumstances of positive IRSR as specified by the NER. The Commission considers that a departure from this may result in a less efficient arrangement that may not as clearly or directly benefit customers.

While the use of MLFs tends to result in a positive accrued IRSR, under certain conditions the IRSR can be negative. The NER currently states that where the IRSR results in a negative pool, TNSPs are liable to reimburse that to AEMO.[106] Negative IRSR may occur in instances where there is a high spot price in combination with high temperatures and/or high load. This may lead to higher electrical losses in the system than the forecast annual MLFs accounted for, resulting in AEMO collecting less than what it must pay generators. Figure 4.2 below illustrates instances of negative IRSR occurring.

105 Adani Renewables, rule change request, 27 November 2018, p. 3.

106 NER clause 3.6.5(a)(4)(i).

Figure 4.2: Annual IRSR jurisdictions amounts from 1999-2017



Source: AEMO.
Note: This data has been aggregated by AEMO.

Adani Renewables did not consider jurisdictions where circumstances of negative IRSRs occur, as is the case for South Australia. If the Commission was to redistribute the IRSR between generators and customers, it would need to consider a framework where generators were also liable for the payment of IRSR in circumstances of negative amounts arising. This reallocation of the IRSR would likely result in higher electricity prices. This cost would likely be passed on to consumers through generators increasing their spot price.

4.5 Conclusion

Having regard to the purpose and operation of the IRSR, the Commission has considered Adani Renewables' rule change request and stakeholder views in regard to reallocating the IRSR equally (or otherwise) between generators and customers. It has concluded that the proposed change to the current allocation of the IRSR would not be likely to satisfy the NEO because it would:

- dampen the marginal pricing incentive for generators[107] and therefore negatively impact on the efficient operation of electricity services through distorting bidding behaviour
- result in increased TUOS charges, and likely overall higher costs, for consumers
- place costs on generators in regions where a negative IRSR occurs.

107 If the IRSR was distributed in correlation with generators' output.

The Commission does not agree with Adani Renewables' characterisation that the existence of positive IRSR represents an inaccuracy in the MLF calculation methodology for the reasons discussed above. Further, the Commission concludes that the proposed reallocation of the IRSR would not address the fundamental cause of the concerns raised by Adani Renewables.

5 AVERAGE LOSS FACTORS

This chapter outlines the rule change request on using an average loss factor methodology. It provides a summary of stakeholder submissions in relation to the proposal and provides the Commission's analysis on whether an average loss factor methodology would achieve the NEO better than MLFs.

5.1 Adani Renewables' views

In its rule change request, Adani Renewables proposed that the transmission loss factor methodology should be changed from marginal loss factors to average loss factors. Adani Renewables argued that the existing MLF calculation methodology is out-dated and no longer fit-for-purpose. This, in its view, subjects generators to increased risk of not being dispatched, resulting in increased cost of generation to all market customers.[108]

To address these concerns, Adani Renewables proposed to move from the current forward-looking MLF methodology to an average loss factor methodology. It asserted that this change "from MLFs (with IRSR reallocation to include generators) to an average loss factor methodology will be a further improvement as average loss factors can be calculated at the commencement of each year (rather than a wash up of IRSRs in arrears)".[109] Adani Renewables noted that requirements for the calculation of intra-regional loss factors are set out in clause 3.6.2 of the NER. It did not propose any specific amendments to these provisions. However, it did argue that AEMO must be required to calculate intra-regional loss factors according to an average loss factor methodology.

Adani Renewables did not provide a preferred methodology of how to calculate the average loss factor.

5.2 Stakeholder views

A number of submissions agreed with Adani Renewables that the current methodology of using static MLFs for intra-regional losses needs reforming. However, most stakeholders did not agree with Adani Renewables that a change to average loss factors would solve the underlying problem of why loss factors have been declining and become more volatile. Of these stakeholders, most agreed that dynamic loss factors implemented as part of wider market reforms, such as those under consideration in the COGATI review, would address the underlying problems of generators building at new fuel source locations where transmission capacity is insufficient better than a change to using average loss factors. Some stakeholders submitted that until these more substantial reforms are implemented, there are temporary remedies which could provide more investment certainty in the interim.

108 Adani Renewables, rule change request, 5 February 2019, covering letter.

109 Adani Renewables, rule change request, 5 February 2019, p. 3.

5.2.1 MLFs are economically efficient and provide correct locational signals

The AER submitted that MLFs are consistent with the marginal pricing on which NEM settlement is based. It also noted that using average loss factors would increase the risk that the overall settlement residue balance is negative. The shortfall would be allocated to TNSPs who in turn would collect higher TUOS charges from customers.[110]

The AEC did not support a move away from MLFs. It noted that the market requires all supply and demand be settled at a common clearing price set at their intersection. This means that a two-sided price must reflect the cost of supply, or the elasticity of demand, at the margin at that location and time. It noted that this is consistent with clauses 3.9.2(d) and 3.9.1(a)(6) of the NER.[111]

Energy Networks Australia (ENA) also submitted that any movement away from marginal loss factors to average loss factors would result in an inefficient price signal and redistribute the cost of losses from those responsible to others in the system.[112]

Similarly, Mondo did not support changing to a methodology based on average loss factors as this would deviate from the marginal pricing foundation of the NEM and therefore be less efficient and not meet the NEO.[113] Mondo based its preference on its own analysis showing that average losses need to be recognised as being a less accurate representation of losses for the purposes of marginal cost pricing, and therefore the NEM. It referred back to the fundamental economic principle that generally, the marginal cost of supplying one additional unit is greater than the average cost at any given operating point. This marginal value of trade principle is fundamental to ensuring that businesses operating in the market which are paid the clearing price, are able to also recover their fixed costs in the longer term. Mondo considered that if this principle is undone, it could undermine the business model for existing businesses, and weaken investment signals for new entrants.[114]

EnergyAustralia submitted that it is not convinced that there is any evidence to warrant a change from the current MLFs methodology to an ALF or that it is in the best interest of customers or consistent with the NEO.[115]

In its submission, SnowyHydro noted that MLFs are a key locational signal in the NEM that provides investors with an incentive to connect new generation close to the RRN and leverage efficiencies in the transport of energy across the system.[116] It considered that the proposal to address concerns with the current forward-looking MLF methodology by moving to an average loss factor methodology would not bring NEM-wide benefits and improvements to market participants' circumstances.[117]

110 AER submission to the consultation paper, p. 3.
111 AEC submission to the consultation paper, pp. 1-2.
112 ENA submission to the consultation paper, p. 2.
113 Mondo submission to the consultation paper, p. 1.
114 Mondo submission to the consultation paper, pp. 7-8.
115 EnergyAustralia submission to the consultation paper, p. 1.
116 SnowyHydro submission to the consultation paper, p. 1.
117 SnowyHydro submission to the consultation paper, p. 2.

AGL submitted that MLFs continue to provide the most efficient methodology for the assessment and application of transmission losses under current market conditions. It considered that this is because of the value it places on the marginal unit of electricity transmitted by individual generators (existing and new) across the network.[118]

Although MUFG Bank submitted that it is indifferent between average and marginal loss factors, it acknowledged that the current methodology is consistent with the clearing price mechanism which is set at the marginal cost of supplying the next unit of generation which is required in order to encourage efficient investment and dispatch.[119]

5.2.2 ALFs would help to address volatility and declines in MLFs

While a number of stakeholders expressed concern over the proposed change to using average loss factors, others were supportive of Adani Renewables' proposal.

For example, the CEC submitted that:[120]

> A higher level of certainty through an ALF approach reduces the risk of the investment, which translates to a lower cost of capital that can ultimately lead to more generation being developed under the same market conditions and therefore lower wholesale electricity prices and lower retail prices for consumers.

Further, the CEC stated that average loss factors would result in less variability in loss factors while still preserving locational signals, noting:[121]

> ...the ability for an AFL approach to improve investment certainty is likely to contribute to the NEO as it will improve the provision of information to assist investors and developers in making well-informed decisions on efficiency investment in generation capacity in the NEM.

The CEC's consultant, Baringa, provided modelling results indicating that customers could benefit from lower wholesale electricity prices under average loss and condensed loss factor methodologies.[122]

The Investor Group also suggested moving to an average loss factor methodology. This, in the group's opinion, will deliver the optimal balance between reduced volatility, continued locational price signalling and simplicity of calculation and implementation. The group also noted that the efficiency impact of moving to average loss factors will be lessened by the fact that MLFs are applied at the RRN and as such are an approximation anyway.[123]

Canadian Solar and Lighthouse Infrastructure also supported a change to an ALF based on the square root methodology. Lighthouse Infrastructure noted that the trend toward higher system losses must be addressed by planning-led coordination of generation and

118 AGL submission to the consultation paper, p. 2.

119 MUFG Bank submission to the consultation paper, p. 3.

120 CEC supplementary submission to the consultation paper, p. 2.

121 CEC supplementary submission to the consultation paper, p. 2.

122 CEC supplementary submission to the consultation paper, Bargina report, p. 28.

123 Investor Group submission to the consultation paper, p. 2.

transmission development. Market design improvements will not compensate for a sub-optimal underlying physical system. Ultimately unnecessary losses will increase the cost of electricity for consumers.[124]

Similarly, PARF focussed on investment of new infrastructure and supported average loss factors. In PARF's view, the ALF approach represents the optimal balance between restoring investor confidence (by making loss factors more stable) and retaining the locational signalling aspect of the existing approach to assist with grid planning objectives.[125] According to PARF, equity investors seek stable project returns, in particular for +20 year assets, and have similar concerns to debt investors regarding MLF revenue risk. PARF considered that the current variability and relative unpredictability of MLFs, if left unchecked, will not only lead to greater amounts of more expensive equity capital required (as lenders decrease total dollar debt available for generation projects), equity investors will also add additional risk premia for existing and new investments in renewable energy. It further noted that unlike exposures to spot wholesale prices, there are no financial instruments available for debt and equity investors to manage the MLF revenue risk. According to PARF, this MLF risk will inevitably increase the cost of re-contracting offtakes and/or re-financing existing generation assets and increase the cost of constructing new renewable energy generation, leading to higher electricity prices for consumers.[126]

Stakeholders also considered whether the current MLF calculation methodology or a change to an ALF methodology would have a material impact on the long-term interest of consumers. The Investor Group submitted that as there are material risks to current and future generation investment, this will ultimately impact the long-term interests of customers.[127] The Investor Group stated:

> From an investor perspective, the above escalating uncertainty has already, and will likely continue to, lead to a material reduction in existing asset values and therefore require and additional risk premium to be applied to any new investments. This additional risk premium could be applied by both equity and debt investors. Unlike risks associated with interest rates and wholesale electricity prices there are no financial instruments or hedges available to investors to hedge MLF risk and as a result investors will be required to make risk adjustments when considering future investment decisions. Potential risk adjustments include a margin of safety applied to all MLF forecasts and/or an additional risk premium added to cost of capital. This is expected to increase the cost of capital associated with future projects which will ultimately be passed on to customers through higher wholesale prices. The current MLF framework is therefore increasing the long-term cost to consumers through the future investment required to fund the 54GW of new capacity needed in the NEM by 2040.

124 Lighthouse Infrastructure submission to the consultation paper, p. 1.

125 PARF submission to the consultation paper, p. 1.

126 PARF submission to the consultation paper, p. 7.

127 Investor Group submission to the consultation paper, p. 1.

The Investor Group expanded on this point throughout its submission and stated that the current methodology inhibits effective revenue forecasts, introduces uncertainty and therefore increases investment risk sequentially resulting in reduced efficiency of electricity supply and increased costs through higher wholesale prices.[128] PARF also submitted that:[129]

> ...the recent variability and the inherent unpredictability of MLFs has had and will continue to have a material impact on the cost of capital for existing and new generation projects. This will inevitably flow through to electricity prices paid by the consumer and will therefore have a materially adverse effect on their long-term interests.

The CEC highlighted the same point with regard to the cost of capital adversely impacting on consumers:[130]

> Under the current MLF methodology, investors and developers have little certainty about loss factor trajectories, which in turn is introducing a risk premium to the cost of capital. A higher level of certainty through an ALF approach reduces the risk of the investment, which translates to a lower cost of capital that can ultimately lead to more generation being developed under the same market conditions and therefore lower wholesale electricity prices and lower retail prices for consumers.

Lighthouse Infrastructure echoed the same point that "a lower cost of capital will lead to more projects securing funding, ultimately benefiting customers".[131]

5.2.3 Changing to ALFs may not benefit the long-term interest of consumers

The ACT Government ESPDD submitted that inaccuracies in the current calculation methodology would only have a material impact on the long-term interest of consumers, and therefore contravene the NEO, if they are both significant in magnitude, and consistent in direction. It commented that it has seen "no evidence that the AEMO is consistently making the same error in its forecasts". [132]

Ergon Energy and Energex stated that the proposed change to the loss factor methodology would have a material impact on the long-term interest of consumers as it would result in more risk being taken by those who are least able to mitigate it, and less risk by those who can.[133]

EnergyAustralia similarly submitted that "there are appears to be no significant justification that moving from MLF to ALF is clearly in the best interest of the consumer".[134]

128 Investor Group submission to the consultation paper, p. 14.
129 PARF submission to the consultation paper, p. 9.
130 CEC supplementary submission to the consultation paper, covering letter p. 2, also Baringa report, p. 14.
131 Lighthouse Infrastructure submission to the consultation paper, p. 4.
132 ESPDD submission to the consultation paper, p. 3.
133 Ergon Energy and Energex submission to the consultation paper, attached table.
134 EnergyAustralia submission to the consultation paper, p. 7.

5.3 Commission analysis

Incorporation of electrical losses on transmission lines in an electricity grid into the operation of the NEM is important to enable the wholesale price of electricity to reflect the full cost of producing and delivering that electricity to its point of consumption.

MLFs represent the value of electrical energy that is lost when the next or marginal unit of electricity is transmitted across the transmission network. An MLF value specifically represents the losses between a generator or load connection point on the network and the regional reference node.

This marginal approach to calculating electrical losses is consistent with how other aspects of dispatch and pricing operate in the NEM. It has been used because marginal pricing is generally considered to lead to the most efficient outcomes.

Changing the loss factor methodology to an average methodology will, in the Commission’s view, introduce inefficiencies. In particular, it could change the merit order of dispatch. In addition, average loss factors are likely to provide a less clear and efficient locational signal to prospective generation investors, meaning that it is likely that more generators will locate in less efficient locations. This is likely to increase customers' prices in the long-term.

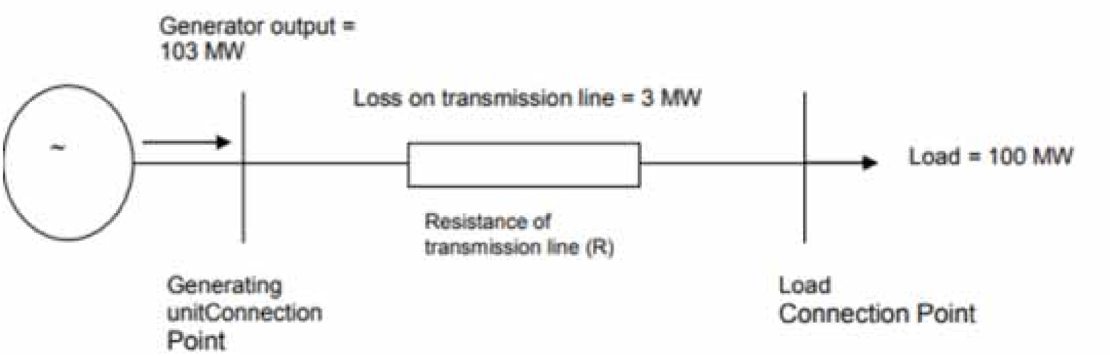
In addition, while potentially benefiting some investors, a change to an average loss factor approach would have a distributional impact from poorly located generators to consumers. The Commission's analysis also indicates that the IRSR (discussed in Chapter 4) is likely to reduce and therefore result in higher electricity prices (through a relative increase in TUOS charges).

The Commission has considered the submissions it received and, by applying the assessment framework outlined in the consultation paper, undertaken further analysis on the possible effects of a change to an average loss factor methodology.

5.3.1 Difference between marginal and average loss factors

When transmitting electricity from one point to another, a portion of the energy is lost in the form of heat due to electrical resistance. This occurs predominantly in transformers and transmission lines. These losses, which occur through electricity flows, are a function of physics and are unavoidable. This is illustrated in Figure 5.1.

Figure 5.1: Transmission line losses



Source: AEMO

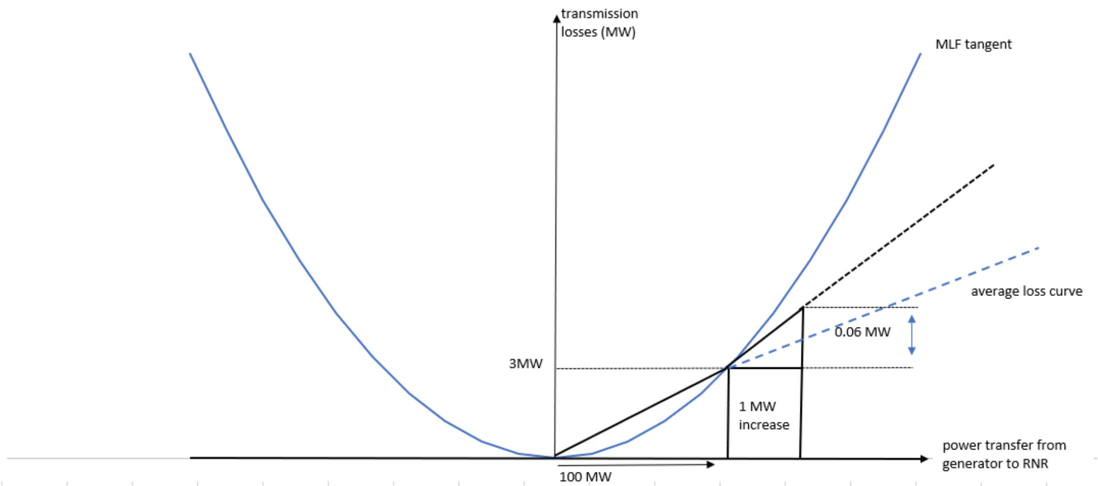
Note: The diagram above represents the loss of electricity when sending electricity from point A (generator) to point B (load). If the generator is to supply 100 MW of electricity to the load, then the generator has to generate 103 MW because of transmission losses of 3 MW.

Figure 5.2 below shows the transmission loss versus power flow characteristic for the simplified an example of a generator injecting 100 MW into a transmission line that supplies load at the regional reference node, with 3 MW of losses due to the flows in the transmission line. This loss characteristic is a quadratic with the losses on the transmission line being proportional to the square of the power transfer from the generator (to the RRN).

With 100 MW injected by the generator there is 3 MW of loss and hence the average losses are 3 per cent, or 0.03. Therefore, an average loss factor for a 100 MW injection is 0.97 (i.e. 1.00 – 0.03).

The marginal loss factors used to determine the efficient dispatch of generation are based on an incremental increase in generation. In this example, for an increase of 1 MW (from 100 MW to 101 MW) the losses would increase by 0.06 MW (from 3 MW to 3.06 MW). This would give a marginal loss factor of 0.94 (i.e. 1.00 – 0.06).

Figure 5.2: Difference between marginal and average loss factors



Source: AEMC graph, based on AEMO, *Treatment of loss factors in the National Electricity Market*, 1 July 2012, p. 17.

5.3.2 Impact on efficient operation of providing electricity services

Quantitative analysis provided to the Commission by the CEC suggested that using average loss factors would lead to a more efficient operation of electricity services. It further indicated that using the average loss factor approach could lead to the lowest baseload electricity prices when compared to MLFs and compressed MLFs, leading to the lowest total consumer payments.[135]

The Commission has reviewed the analysis and notes that only the impact on cash flows in a single year of switching to a set of higher generation loss factors was considered. Taking this analysis to its logical conclusion, it might suggest that customer outcomes could be improved by removing loss factors all together (that is, treating all generators with a loss factor of one). A model based on a loss factor of one might well show that consumer payments are lower under this scenario than under the ALF scenario. However, this would provide limited information about the long term impacts of such a change such as, what the efficiency loss associated with removing all price signals associated with losses would be. The analysis highlights the difficulty in modelling what the material impact on consumers would be under an ALF approach.

In order to assess the impact on market efficiency, the Commission has undertaken its own modelling of transmission loss factor methodologies to test the impact on consumer payments and the merit order of dispatch of generators.

135 CEC supplementary submission to the consultation paper, Baringa report, pp. 25-29.

A simple model was used that estimated an ALF value by the square root of the MLF. The model uses five hypothetical generators and a single-day load profile based on an average South Australian demand. Table 5.1 summarises the assumptions used for the stylised dispatch model.

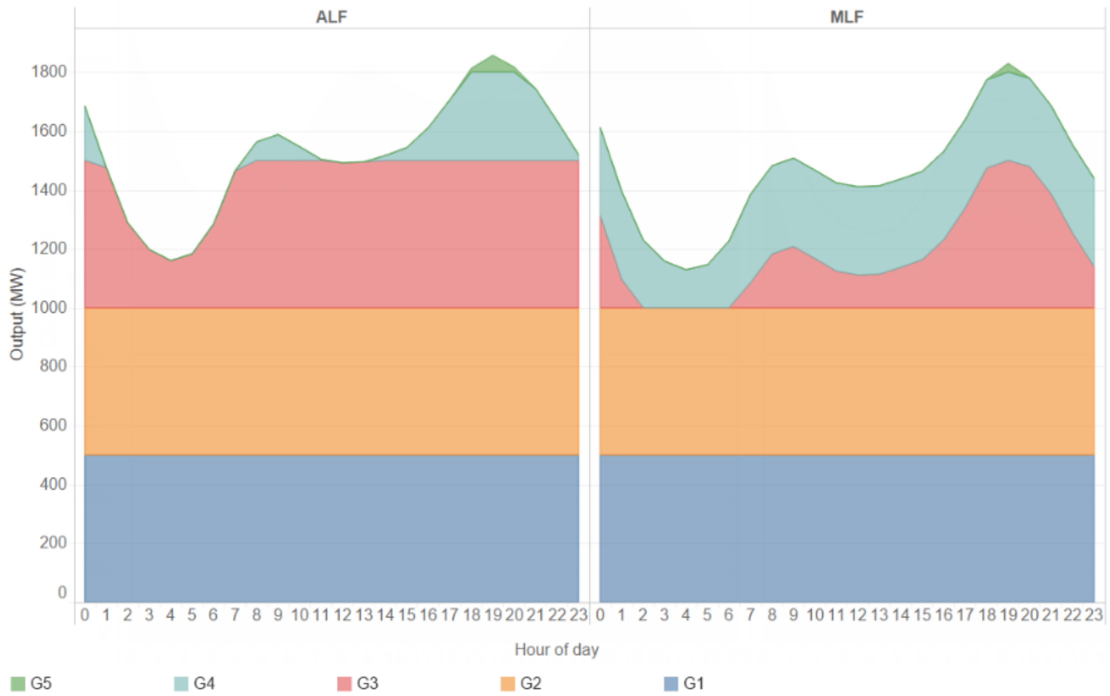
Table 5.1: Assumptions used for stylised dispatch model

	G1	G2	G3	G4	G5
SRMC	$25	$50	$160	$300	$1,000
MLF	0.99	0.98	0.500	0.950	0.900
ALF	0.995	0.990	0.707	0.975	0.949

Source: AEMC assumptions.

The model calculates the revenue earned by each generator and the cost to customers, after accounting for the residue. To allow losses in the model, it was run twice. A first run to estimate the losses and a second to add the estimated losses to total generation. This is a simple model with the purpose to yield insights about the consequences of shifting to ALFs, not to forecast or measure actual outcomes.

Figure 5.3: Impact on dispatch



Source: AEMC

Note: Generators are stacked from highest to the lowest short-run marginal cost in $/MWh (SRMC). Generator 1 (G1) has the lowest SRMC and generator 5 (G5) has the highest SRMC. Compared to the MLF approach, generators with a lower SRMC are getting dispatched under the ALF approach. However, under the ALF approach more total energy is being generated and paid for by consumers because generator 3 has much higher losses than the other generators. Losses for the ALF scenario are roughly double those of the MLF scenario.

The graphs in Figure 5.3 demonstrate how a change in the loss factor methodology from a marginal to an average approach could alter the merit order of dispatch for generators in an electricity market. The right-hand side shows a merit order under a single-day load profile. On the left-hand side of the graph the same single-day load profile using average loss factors is shown. Under both examples, the merit order is the same until demand goes above 1,000 MW. To meet demand over 1,000 MW, there is a change in the merit order when an average loss factor methodology is used.

In the example in Figure 5.3:

- Generators are stacked from highest to the lowest short-run marginal cost in $/MW (SRMC).
- Generator 1 (G1) has the lowest SRMC and generator 5 (G5) has the highest SRMC.
- Under the ALF approach, generator 3 is dispatched more than generators 4 and 5, compared to under the MLF approach. Generator 3 has a lower SRMC than generators 4 and 5, this but generator 3 has much higher losses than those generators. In this example, the losses under the ALF approach are roughly double of those under the MLF approach.
- The result is that more energy needs to be generated and paid for by consumers under the ALF approach compared to the MLF approach, and in this example, this implies that the ALF approach could result in a higher cost dispatch compared to the MLF approach.

In particular, the graph shows that:

- the dispatch engine will prefer to dispatch generators with higher losses under an ALF approach
- the change in the merit order under ALFs will affect overall system losses as generators with higher losses are dispatched compared to the dispatch order under MLFs, resulting in operational inefficiencies more to supply
- the effect of moving from MLFs to ALFs on the merit order of dispatch will depend upon the level of demand, the bids of the generators and the loss factors themselves.

The Commission's analysis shows that changing to an ALF methodology has the potential to change the merit order of generators for dispatch. However, its impact in the NEM will ultimately depend on the specific situation, including which generators are online and which generator is marginal.

Depending on the spread of loss factor values, changing to an average loss factor methodology could result in a change in the dispatch merit order. As the merit order changes, the amount of electricity that needs to be generated will also change. This is because a change in the merit order from a state of more efficient dispatch to less efficient dispatch leads to losses and so more energy needs to be generated for a given level of final demand. As discussed in section 5.3.2., the reduced locational signal of ALFs is likely to result in more generators locating in locations with weaker transmission infrastructure. This would mean that even if the dispatch order changes to dispatch lower cost generation, more electricity will need to be produced as these generators will likely be located in areas with higher losses.

Under an ALF approach, generators with higher losses could potentially be dispatched ahead of generators with lower loss factors but higher SRMCs. While the ALF approach might provide more certainty to some investors, it comes at the expense of the potentially more efficient generators which do not get dispatched. This could ultimately result in higher electricity prices.

5.3.3 Impact on efficient investment

Marginal loss factors provide important investment signals with respect to the location of new generation assets. Investors in generation assets have some discretion in deciding where to locate an asset. For example, investors can potentially choose between locating closer to load or on a stronger part of the transmission network, both of which would likely result in a higher and more stable MLF relative to a new generation investment located far away from load centres and on a weak part of the transmission network. As part of these locational decisions, prospective investors should have considered the impact of current and future MLF values as one of the inputs for their revenue forecasts.

A change from marginal loss factors to average loss factors will therefore have an effect on dynamic efficiency. Dampening the locational signals would be likely to lead to more investment in parts of the power system with high losses. Over time, this would increase the amount of losses, and so the total dispatch cost. Ultimately, consumers would pay more for electricity to cover the cost of the additional electrical loses occurring as, overall, more electricity would have to be generated to meet the same level of demand.

Financial markets hedging products for loss factors, for example buying an insurance against MLF variability, are currently not available to investors in generation assets. However, loss factor risk could be managed by entering into long-term power purchasing agreements. In addition, some owners would be able to diversify loss factor risk by owning different types of generation assets and/or assets in different geographical locations.

A change from marginal to average loss factors would involve a transfer of risk from investors in new generation assets to consumers. However, consumers are not involved in the investment decision-making processes for new generation assets, and they would not be able to enter into long-term power purchasing agreements. Consequently, consumers are, in the Commission's view, the party least able to manage loss factor uncertainty and the resulting impact on consumer prices.

The Commission's COGATI review includes consideration of new hedging mechanisms for generators to increase the ability of investors in generation assets to manage risk associated with the impact of losses.

5.3.4 Risk allocation

The Commission's analysis described earlier also indicates that using an average methodology to calculate loss factors may result in a lower cost of capital for some generation assets compared to using the marginal methodology. This is largely a result of a reduction in revenue variability associated with more stable and less volatile loss factors.

However, the Commission also observes that the reduction in the cost of capital is only possible because some base risk of generation investment is transferred from generators to consumers. This section discusses how a change to an ALF could impact on the cost of debt, the cost of equity and what the distributional impacts would be.

Impacts on the cost of debt

One of the arguments made by stakeholders in submissions to the consultation paper was that the current volatility in MLFs results in an increase in the cost of capital for generation assets. PARF noted that this increase in the cost of capital applies to both debt and equity financing.[136]

This argument applies to both incumbent generators and new entrants as incumbent generation generally needs refinancing of debt every five years.

The variability in MLFs appears to be impacting the ability of some generator owners to service debt. As MLFs reduce (indicating higher losses):

- existing generators will earn less revenue but their costs remain unchanged
- new generation investment will require a higher rate of return as the probability of revenue variability and reduction means higher default risk.

Consequently, all other things being equal, the debt risk premium will increase and the gearing ratio will decrease. A decrease in the gearing ratio means that more equity capital will be required to finance the investment. As equity capital is more expensive than debt, this will impact the cost of capital of new generation investment and existing generation investment at refinancing. The same principle would also apply to owners of existing generators when refinancing their debt.

Impacts on the cost of equity

The ACIL Allen report submitted by PARF, noted that equity investors seek stable returns:[137]

> ...the current variability and relative unpredictability of MLFs, if left unchecked, will not only lead to greater amounts of more expensive equity capital required (as lenders decrease total dollar debt available for generation projects), equity investors will also add additional risk premia for existing and new investments in renewable energy.

The effect of increasing loss factor volatility on the cost of equity is two-fold.

First, reduced debt financing availability means a lower gearing ratio. The result is that more of the relatively more expensive equity finance would be required.

Second, volatility in loss factor values coupled with some significant reductions caused by new connections have increased generators' revenue volatility. All other things being equal, this would cause an increase in the cost of equity.

136 PARF submission to the consultation paper, p. 7.

137 PARF submission to the consultation paper, ACIL Allen report, p. 7.

The Commission also notes that investors submitted that loss factor risk is currently not hedgible. As observed by the CEC, loss factor variability is currently an unmanageable risk that cannot be hedged by industry.[138] Other stakeholders noted that while there are no hedging products available for loss factor risk, generator owners can manage this risk by entering into long term power purchasing agreements where possible. In addition, larger owners would be able to diversify away some loss factor risk through owning multiple generators in different locations.

Distributional impacts

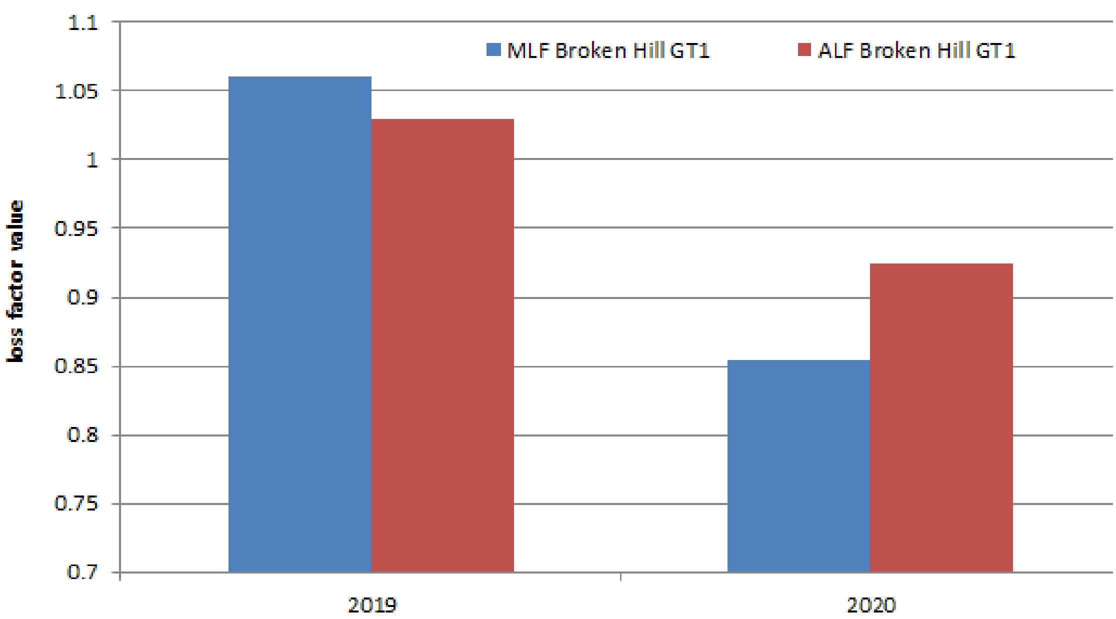
The Commission has also considered the impact of a change to an average loss factor methodology may have on generators. In particular, the Commission has recalculated loss factors of generators in the NEM using the square root of the MLF as an approximation of average loss factors. These calculations indicate that using an average methodology to calculate transmission loss factors would be likely to increase loss factors that had been lower than the average in a region and decrease loss factors that had been higher than the average in a region. This effect is likely to result in:

- a change in the dispatch order
- an increase in revenue for some generators and a decrease in revenue for other generators
- less efficient location signalling for future generation investment.

This is illustrated in Figures 5.4 and 5.5 which show marginal and average loss factors for generators in Broken Hill, New South Wales. The figures show than an average methodology could result in lower or higher loss factors compared to the MLF. Figure 5.4 shows that applying an average methodology in 2019 would result in a reduced loss factor value compared to the MLF value. This lower loss factor value would likely result in less revenue for the Broken Hill GT1 plant. Figure 5.5 shows that a change from MLF to ALF for Broken Hill solar farm would increase the loss factor values in both 2019 and 2020.

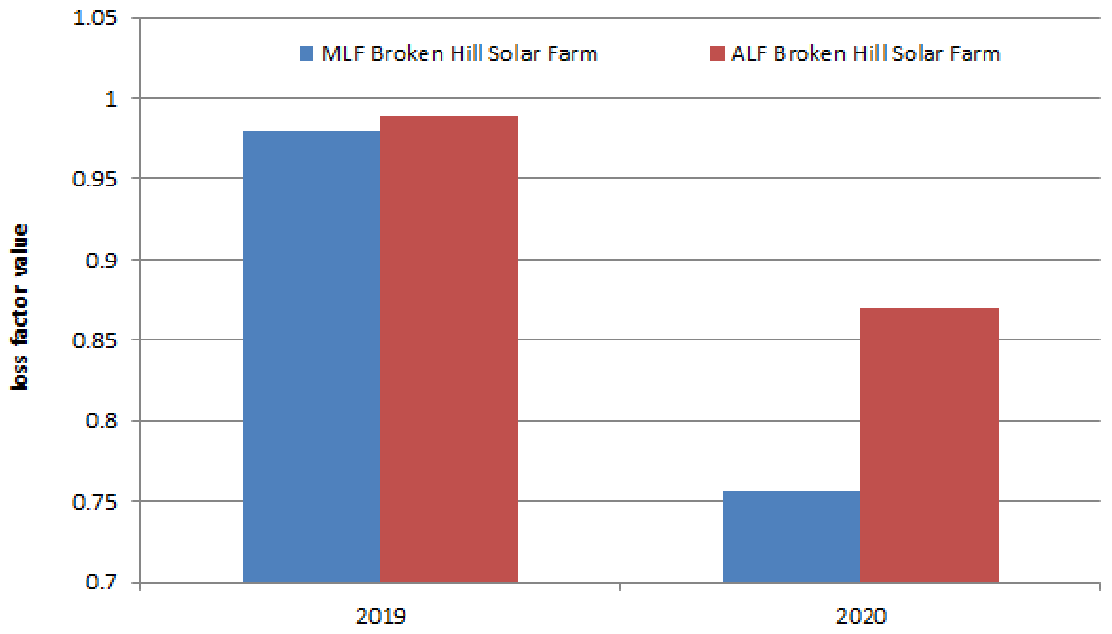
138 CEC submission to the consultation paper, p. 1.

Figure 5.4: Applying an average methodology — Broken Hill GT1



Source: AEMO, AEMC.
Note: ALF calculated using the square root of the published MLF.

Figure 5.5: Applying an average methodology — Broken Hill solar farm



Source: AEMO, AEMC.
Note: ALF calculated using the square root of the published MLF.

5.4 Conclusion

On balance the Commission has found that:

- Using average loss factors would be a move away from the economic framework of the NEM based on marginal pricing and could result in inefficient dispatch.
- Average loss factors would provide a dampened locational signal compared to marginal loss factors. This is likely to increase losses and congestion as new generators will be likely to locate in less efficient locations.
- Moving to an average methodology could provide more stable and predictable loss factor values. This would help reduce revenue volatility and lower the cost of capital for investors in some generation assets.
- However, an average loss factor methodology would also shift risk from the party best placed to manage it (investors in new generation assets) to consumers (who are least able to manage loss factor risk) resulting in further inefficiencies leading to higher costs for consumers.
- Average loss factors are likely to decrease the loss factors of generators with relatively high MLFs and increase loss factors of generators with relatively low MLFs.

For the above reasons, the Commission considers that the use of an averaging methodology for determining transmission loss factors in the NEM would not represent an improvement in the determination of loss factors and consequently would be unlikely to better meet the NEO than the current approach in the NER or the draft rule.

6 AEMO'S IMPROVEMENTS TO MARGINAL LOSS FACTORS

This chapter sets out and discusses the changes to the current MLF rules suggested by AEMO in its submission to the consultation paper.

In brief, the Commission has concluded that these suggested changes improve the MLF framework and are consistent with the NEO. These amendments to the NER form the basis of the draft rule.

6.1 AEMO's suggested rule changes

AEMO undertakes its own consultation process on the loss factor methodology with stakeholders.[139] It submitted that it will carry out a formal consultation on the methodology for determining MLFs to ensure that it remains fit for purpose after the AEMC's rule change process has been finalised.[140]

To provide greater flexibility to modify the calculation of MLFs as part of its own consultation process with stakeholders, AEMO identified three changes to the NER which, in its opinion, could assist it in providing more transparency on loss factor changes to help market participants better anticipate and manage changes in MLFs.

These changes to the NER are:[141]

1. Clause 3.6.1(d)(5) of the NER requires AEMO to use regression analysis to reflect inter-regional losses between nodes. AEMO submitted that flexibility to consult with stakeholders on techniques that are alternatives to regression analysis to reflect inter-regional losses could produce more optimal results. It therefore suggested that the relevant clause be removed.
2. Clause 3.6.2(e)(4) of the NER currently requires the MLF calculation to be performed on a 30-minute 'trading interval' basis. This means over 17,500 individual calculations are required to determine the MLFs each year. AEMO suggested that the 30-minute trading interval requirement be reconsidered as calculations using greater time intervals (for example, two hour intervals) may simplify the calculation process and better enable stakeholders to understand the loss factor calculations.
3. Clause 3.6.2(e)(6) of the NER requires that AEMO treat MNSPs as invariant in the MLF methodology. AEMO submitted that changing generation patterns between regions, for example due to new entrants, may require load balancing in the calculation. If this is the case, treating the MNSP flow as invariant may no longer be practical or appropriate. AEMO suggested that it may improve the accuracy of its modelling if it is able to better reflect actual flows and treat MNSPs (the only MNSP at present is Basslink) in a manner similar to other assets. AEMO therefore suggested that this clause be removed.

139 AEMC, *Transmission loss factors,* consultation paper, 6 June 2019, p. 13.

140 AEMO submission to the consultation paper, p. 1.

141 AEMO submission to the consultation paper, p. 5.

These changes, in AEMO's opinion, would allow it to work with stakeholders through formal consultation to modify the loss factor calculation.[142]

6.2 Commission analysis

The Commission has assessed AEMO's suggested changes to the NER that are outlined above. Each is discussed in turn in this section.

6.2.1 Removing the requirement to use regression analysis

Clause 3.6.1(d)(5) of the NER specifies that to determine the inter-regional loss factor equations, AEMO must use regression analysis to load and generation data to determine the variables that have a significant effect on marginal electrical losses and the relationships between those variables.

AEMO requested that clause 3.6.1(d)(5) of the NER be amended to allow it to use calculation methodologies other than regression analysis in determining inter-regional loss factor equations. However, it did not identify any specific alternatives to regression analysis that could be adopted.

On balance, the Commission does not see any issues with AEMO's suggestion as it would allow AEMO to consider alternative calculation methodologies to calculate the MLF as part of its own consultation with stakeholders.

The Commission notes that this change will still require AEMO to use an MLF methodology but it should provide more flexibility in the way the MLF values can be calculated. The removal of the requirement to use regression analysis would allow AEMO to continue using regression analysis until it has developed, following consultation, another methodology producing more optimal results. Making a change to clause 3.6.1(d)(5) of the NER now provides AEMO with future flexibility and enables the employment of a new calculation method without any further rule change process.

Making this change to the NER would be consistent with the NEO as it provides AEMO with the additional flexibility to implement any other, more efficient calculation methodology, should such a calculation methodology become available in the future.

6.2.2 Changing the 30-minute interval requirement

Clause 3.6.2(e)(2) of the NER requires the MLF methodology implemented by AEMO to enable an MLF value to:

> as closely as is reasonably practicable, describe the average of the *marginal electrical energy losses* for electricity transmitted between a *transmission network connection point* and the *regional reference node* in the same *region* for each *trading interval* of the *financial year* in which the *intra-regional loss factor* applies.

142 AEMO submission to the consultation paper, p. 5.

Relatedly, clause 3.6.2(e)(4) of the NER requires AEMO to calculate an MLF "for each *transmission network connection point* for each *trading interval* in the *financial year*". A NEM trading interval is currently 30 minutes.[143] This requirement means that a significant amount of calculation is required to produce each MLF value at each transmission connection point. This calculation complexity may mean that MLFs are difficult to reproduce, understand or estimate by market participants.

In discussions with AEMC staff, AEMO noted that the MLF calculation process could be made simpler and more likely to be replicable, without materially losing the level of accuracy of the MLF values, by allowing it to use less frequent data in the calculations. For example, AEMO may find that calculating MLFs on four hourly interval data may be sufficiently accurate but require fewer calculations and improve market participants' understanding of the methodology. Such an approach would still need to satisfy the requirement of clause 3.6.2(e)(2) of the NER to be as representative of the physical electrical losses in each trading interval as closely as reasonably practicable.

The Commission considers that this suggested change to clause 3.6.2(e)(4) of the NER has the potential to increase transparency and predictability of MLF values and in doing so, contribute to better investment decision-making and operations in the generation sector. For these reasons, the suggested change would be consistent with achieving the NEO.

6.2.3 Removing the requirement to treat MNSPs as invariant in the MLF methodology

In its submission AEMO also requested the removal of clause 3.6.2(e)(6) of the NER. This clause requires AEMO to treat MNSPs as invariant, or fixed, in the MLF methodology. The clause also notes that the MLF methodology does not seek to calculate marginal losses for MNSPs.

The Commission understands that the reason why this rule requires MNSPs to be treated as invariant is that is MNSPs bid strategically like a generator to maximise revenue. This would be difficult to model in the minimum extrapolation method because offering into one region also means bidding into the other region relevant to the MNSP. As a result, to aid modelling, the NER required MNSPs be treated as invariant so that the flows assumed in the calculations would follow historical flow patterns.

However, the Commission notes that market conditions have changed sufficiently to consider removing the requirement in clause 3.6.2(e)(6) of the NER. This would allow AEMO to use other assumptions and information in modelling the flows associated with MNSPs if it finds that an alternative approach better reflects actual behaviour and is still consistent with the MLF methodology. As BassLink is currently the only MNSP in the NEM, an alternative approach to the fixed flow assumption in the modelling for MLFs may be achievable.

143 Clause 3.6.2(e)(4) of the NER will be amended in the future to require the use of data for each 30-minute period (or a shorter period as specified in the methodology). See AEMC, *National Electricity Amendment (Five minute settlement and global settlement implementation amendments) Rule 2019, No. 7*, 8 August 2019.

6.3 Conclusion

The Commission has assessed the rule changes suggested by AEMO and considers that all three changes would meet the NEO and provide additional benefits to market participants with respect to simpler and more flexible calculations as well as less complex models.

As a result, the draft rule amendments will:

- remove the requirement that the inter-regional loss factors must be calculated using a regression analysis, enabling AEMO and stakeholders to consider and test the performance of alternative calculation techniques
- remove the requirement that MLF values must be based on a period of 30 minutes to allow other time periods to be used as the basis for calculating MLF values
- remove the requirement that MNSPs be treated as invariant in the calculation of MLFs so that AEMO would be able to forecast variable MNSP behaviour in its modelling.

In addition to these amendments, the draft rule also replaces "transmission loss factors" with "intra-regional loss factors" in clauses 3.6.2(b)(g) and (h) and Chapter 10 (for the terms "NMI Standing Data" and "virtual transmission node") of the NER. This clarifies and corrects these terms without changing any meaning.

7 OTHER IMPROVEMENTS TO MARGINAL LOSS FACTORS

As noted in the consultation paper, there are other possible actions that could be taken to address stakeholder concerns about the current volatility in MLFs. Some of these actions do not require amendments to the NER.

Many stakeholders commented on the measures included in the consultation paper. Some stakeholders provided alternative measures they thought could provide relief from loss factor volatility.

This chapter summarises stakeholder submissions and provides the Commission's analysis on:

- the measures the Commission identified in the consultation paper
- the alternative methodologies and measures suggested by stakeholders in their submissions.

7.1 More frequent publication of MLFs

Under clause 3.6.1(f) of the NER, AEMO is required to publish MLF values by 1 April for use over the 12-months commencing 1 July. As discussed in the public workshop on 4 July 2019, these requirements do not prevent AEMO publishing forecast MLF values at other times during the 12-month period for information purposes. However, more frequent mandatory publication of MLF values for the purpose of operating the NEM would require amendments to the NER. Consequently, the consultation paper sought feedback on how often loss factors should be calculated. In particular:

- the current arrangements of determining and publishing the MLFs once a year
- if the potential benefits of more frequently determined and published MLFs would be likely to outweigh the costs
- the appropriate frequency for determining and publishing MLFs.[144]

7.1.1 Stakeholder views

Stakeholders commented that more frequent publication of MLFs for market information could go some way in addressing MLF uncertainty. Some stakeholders went further, suggesting that AEMO should publish and use MLFs more frequently. Both options are discussed below.

More frequent publication of MLFs for information only

Stakeholders suggested that a more frequent publication of forecast MLFs for information purposes, could greatly reduce the current level of uncertainty arising out of loss factor volatility.[145]

144 AEMC, *Transmission loss factors,* consultation paper, 6 June 2019, pp. 17-18.

145 For example, First Solar submission to the consultation paper, p. 8.

AEMO submitted that it intends to publish quarterly indicative MLF updates (for all regions in the NEM) which will provide trends of MLFs in the current year.[146] AEMO plans to base these quarterly indicative MLFs on the most recent information available, for example changes to the generator information page.[147] It has since published the first of these reports on 1 November 2019.[148]

Mondo submitted that more requirements could be placed on AEMO to improve the level of data and information available to participants. Once the ex-ante static yearly MLF has been applied, Mondo suggested that it would be useful if AEMO were to dynamically calculate and publish (but not use) in real time the dynamic MLF for each connection point. This would assist participants in understanding how a dynamic MLF would vary from their static yearly ex-ante MLF. As a final step, Mondo stated that it would also be useful if at the conclusion of the year, AEMO used the dynamically calculated and published half hourly MLFs to determine ex-post, what a static MLF would have been for each connection point using actual data rather than the forecast data used for the ex-ante calculation.[149]

ENA submitted that while it prefers a move to dynamic loss factors, in the meantime, more frequent updating would be an improvement.[150] The CEC also expressed support for AEMO's plan to publish more frequent guidance on MLFs.[151]

Stakeholders also noted that in addition to more frequent publication of loss factors, implementation of the rule change on the transparency of new projects will be able to provide additional certainty for generation investments.[152]

More frequent publication and use of MLFs

In its submission, MEA Group suggested that improvement to the current regime should focus on how often MLFs are calculated and the possible introduction of applying MLFs for different periods (for example, peak and off-peak periods).[153]

Similarly, EPSDD stated that the NER should be amended to remove the requirement that AEMO produce loss factors that apply for a whole financial year. According to EPSDD, AEMO should instead be required to publish one or more loss factors, and the associated time period(s) in which they apply, for the next financial year. This should require AEMO to ensure each connection point has a loss factor in place for the whole financial year. In EPSDD's opinion, this would allow, but not require, AEMO to implement dynamic loss factors. It would enable AEMO to strike an appropriate balance between the simplicity of having a small number of loss factors, with the accuracy of a larger number. This may result in loss factors

146 AEMO submission to the consultation paper. p. 1 and workshop presentation slides, Brisbane, 4 July 2019.
147 AEMO submission to the consultation paper, p. 4.
148 AEMO, *Indicative marginal loss factors: FY 2020-21*, November 2019.
149 Mondo submission to the consultation paper, p. 10.
150 ENA submission to the consultation paper, pp. 5-6.
151 CEC submission to the consultation paper, p. 2.
152 Submissions to the consultation paper: CEC, p. 2; AGL, p.2.
153 MEA Group submission to the consultation paper, p. 2.

applying for broad time periods such as "winter nights" or "summer days" and would not necessarily require a separate loss factor for every five minute interval.[154]

7.1.2 Commission analysis

The additional publication of loss factors for information purposes by AEMO should improve the predictability and certainty in regard to MLF changes for market participants in the NEM. It is likely that:

- a more frequent publication of loss factors on a quarterly basis, for information only, has the potential to provide valuable information to prospective investors and owners of generation assets
- a more frequent publication of loss factors, for information only, does not affect the efficiency of the operation of the NEM
- while creating some additional work for AEMO to resource, this is likely to be outweighed by the benefit of the additional information provided to the market
- more frequent MLF information will work in conjunction with the new rules on the transparency of new projects to enable market participants to make more fully informed decisions on investment in and operation of generators.[155]

For these reasons, the Commission supports AEMO's work to achieve greater transparency about the transmission loss factor framework.

However, the Commission does not support changes to mandate a more frequent publication and use of MLFs at this time. It understands the desire to address a perceived downside of the current methodology in the use of static values for a year. However, a greater number of values would be likely to result in additional uncertainties in times of MLF variability and potentially reduced notice to market participants of changes to MLF values.

For these reasons, the Commission considers that a move towards dynamic loss factors is best assessed in detail through its COGATI review. Under this review, the Commission and stakeholders are able to take a holistic view on the potential for wider market reforms to include the use of dynamic loss factors.

7.1.3 Conclusion

The Commission supports AEMO's plan to publish MLF data on a quarterly basis to the market for information purposes. Such action will not require any change to the NER and can be put in place as soon as practicable. Combined with the recent changes to the NER in regard to information on new investments, the Commission anticipates that market participants will be able to make better informed investment and operational decisions in the near future.

154 EPSDD submission to the consultation paper, p. 6.

155 The final rule on the transparency of new projects was made on 24 October 2019. AEMC, *National Electricity Amendment (Transparency of new projects) Rule 2019, No. 8.*

7.2 Amount of notice to market participants

Under the current arrangements AEMO is required to publish the MLF values each 1 April to apply for 12 months from 1 July. This provides market participants three months' notice of any changes to the intra-regional loss factor values and the inter-regional loss factor equations. In the consultation paper the Commission requested stakeholders consider if the NER should be amended to shorten or lengthen the notice period, taking into account:[156]

- the benefits for market participants and investors of increased notice of changes in loss factors
- the ability for transmission loss factors to reflect recent changes in generator behaviour and new generating units.

7.2.1 Stakeholder views

No stakeholders suggested that there is a need to change the amount of notice given by AEMO to market participants regarding the MLF values.

In particular, ERM Power submitted that it does not see any material benefit to altering the current publication timetable of transmission loss factors to apply from 1 July each year from the immediately preceding 1 April. It considered the three-month notification period allows final contracting level adjustments to be negotiated and concluded prior to the commencement of the financial year.[157]

Similarly, MEA Group submitted three months' notice consistent with quarterly publishing. Mondo and the Investor Group submitted that there is no reason to change this.[158]

7.2.2 Commission analysis

The Commission notes that all the submissions it received on the amount of notice AEMO has to give to market participants. It also considers that the current three months' notice is appropriate.

7.2.3 Conclusion

The Commission has decided that the draft rule make no change to the amount of notice provided by AEMO to market participants for the new MLF values.

7.3 Using a forward or backward-looking methodology

AEMO currently uses a forward-looking methodology to calculate MLFs based on forecasts of load and generation data consistent with the requirements specified by clause 3.6.2A(d) of the NER. This clause states that in preparing the methodology for forecasting and modelling load and generation data, AEMO must implement the following principles:

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156 AEMC, *Transmission loss factors,* consultation paper, 6 June 2019, p. 18.

157 ERM Power submission to the consultation paper, p. 4.

158 Submissions to the consultation paper: MEA Group, p. 3; Mondo, p. 10; Investor Group, p. 16.

- The forecast load and generation data must be representative of expected load and generation in the financial year in which the MLFs are to apply, having regard to:
    a. actual data from the previous 12-month period defined by the methodology
    b. projected load growth between the 12-month period of the actual data and the financial year for which the MLFs apply
    c. projected network configuration and performance for the financial year for which the MLFs apply.

As noted in the consultation paper, MLF values were initially calculated using a backward-looking method. The change to a forward-looking basis for the calculations was made in 2003 to reduce the two-year delay between changes in generation and the impact on the loss factor values inherent in the backward-looking method.

Given that both forward and backward-looking methodologies are feasible, stakeholders were requested to consider if a forward or backward-looking methodology should be used for loss factor calculations in the future.[159]

7.3.1 Stakeholder views

Submissions indicated that stakeholders support the continued use of the forward-looking methodology to calculate loss factors.

MEA Group submitted that it supported the forward-looking methodology which, in its opinion, allows generators to manage their revenue risk year-on-year.[160]

ERM Power also supported the ongoing use of the forward-looking loss factor calculation methodology. It considered that this approach ensures that forecast changes to account for commissioning of new generation sources or significant load can be included as well as forecast major generator planned outages as indicated in the Medium Term Projected Assessment of System Adequacy (MT PASA).[161]

The Investor Group, MEU and EPSDD all expressed support for the use of the forward-looking methodology.[162]

7.3.2 Commission analysis

The Commission notes that all the submissions it received on the use of the forward-looking methodology to calculate loss factors indicate that this is the preferred approach and no change is sought by market participants.

Changing to a backward-looking approach would be likely to result in less accurate forecasts and result in dampened locational and investment signals. In particular, a backward-looking approach would not include expected new investment in the modelling and calculations. This is particularly relevant in current market conditions, where rapid growth in new generation

159 AEMC, *Transmission loss factors,* consultation paper, 6 June 2019, pp. 18-19.

160 MEA Group, submission to the consultation paper, p. 3.

161 ERM Power submission to the consultation paper, p. 5.

162 Submissions to the consultation paper: Investor Group, p. 16; MEU, p. 3; EPSDD, p. 6.

connection are having a significant impact on MLF values. As a result, using a backward-looking approach is likely to increase uncertainty for market participants. For these reasons, the Commission concludes that MLFs should continue to be calculated based on the current forward-looking methodology.

7.3.3 Conclusion

The Commission considers that no change away from the forward-looking methodology to calculate loss factors is necessary. No changes to this effect are included in the draft rule.

7.4 Changing virtual nodes

This section discusses stakeholder suggestions that the loss factor framework should be amended with respect to the use of virtual nodes in general, and more specifically in regard to Berri in South Australia.

7.4.1 Stakeholder views

In its submission, the ACT Government EPSDD suggested that AEMO could start its determination of loss factors by calculating marginal loss factors for all generators using the current methodology and then define several virtual nodes for each state.[163] Then, according to EPSDD, AEMO could calculate the actual losses forecast to occur at each virtual node. This would then allow AEMO to calculate the forecast IRSR for each virtual node. With this information, AEMO would then be able to scale the loss factor for each generator within a virtual node such that the forecast IRSR for the virtual node would equal zero.[164]

In EPSDD's view, AEMO would be able to determine the size and location of the virtual nodes by balancing accuracy (which would be supported by smaller virtual nodes) and simplicity (which would arise from larger but few virtual nodes). It acknowledged that its suggested approach would not produce "exactly the correct answer". However, it did consider that its virtual node approach would be more accurate than the current method to calculating loss factors without being as complex.[165]

A different suggestion in relation to virtual nodes was made by CIT, an end use customer located near Berri in South Australia.[166]

CIT aims to resolve its particular concern regarding the recent changes it has experienced in relation to transmission loss values. It considers that the change and difference between Berri and Red Cliffs, 150 km apart, defy explanation.[167]

163 A virtual node is a non-physical node used for the purpose of market settlements, having a transmission loss factor determined in accordance with clause 3.6.2(b)(3) of the NER.

164 EPSDD submission to the consultation paper, p. 5.

165 EPSDD submission to the consultation paper, pp. 5-6.

166 CIT pumps water from the Murray River to 1,600 growers across different irrigation districts in South Australia. Water is supplied through fully automated pumping stations and pressurised pipeline systems.

167 The Berri node is a terminus for Murraylink, the high voltage connection between Berri, South Australia and Red Cliffs, Victoria. The Berri loss factors for 2016-17 and 2019-20 and 0.9379 and 1.1277 respectively.

CIT linked the changes in transmission loss factor values to the changing flow of power across the Murraylink interconnector rather than to changing load or generation in the area. There are a number of compounding features CIT submitted as possibly contributing to the increased loss values it is experiencing:[168]

- Losses are only apportioned to a few nodes close to the interconnector terminal.
- The use of a virtual transmission node (VTN) for South Australian small customers means that the losses are not individually attributable to small business customers supplied through the Berri node, but losses are attributed to large business customers at their connection point.
- The IRSR collection is on a regional loss basis but returned through TUOS reductions and applied on a postage stamp basis.

CIT identified four possible solutions to address its concerns. Of these four options, CIT indicated its preference for the AEMC to consider implementing either:[169]

- declaring Berri as a virtual node
- establishing another node which is the terminus node and then apportioning the losses across the state.

Other stakeholders expressed support in addressing the problem experienced by CIT.[170] EUAA specifically supported the establishment of another node with the terminus node and then apportioning losses across South Australia.[171] The SA Government submitted that the AEMC should consider mechanisms that could smooth the impacts of MLFs for connection points like the CIT's at Berri.[172]

7.4.2 Commission analysis

EPSDD's suggestion is to create a number of virtual nodes within a jurisdiction and determine generator loss factors such that the IRSR relevant to that virtual node balances to zero. This approach represents a significant change in the application of marginal loss factors to generation assets in the NEM. It also suggests that the IRSR represents an undesirable calculation error in marginal loss factors that should be corrected.

The Commission's concern is that the use of virtual nodes as suggested would move the transmission loss factor framework further away from dynamic regional pricing and dynamic loss factors and create more uncertainty in times of high MLF volatility.

In addition, the suggested approach does not recognise that IRSR arises from the wholesale market settlement process and reflects the use of MLFs to adjust prices between the RRN and the transmission connection point of a customer.[173] The settlements process generally tends to recover more from customers than is needed to pay generators because charging

168 CIT submission to the consultation paper, p. 2.

169 CIT submission to the consultation paper, p. 2.

170 Submissions to the consultation paper: MEU, p.2; South Australian Department for Energy and Mining, p. 2; EUAA, p. 3.

171 EUAA submission to the consultation paper, p. 3.

172 South Australian Department for Energy and Mining submission to the consultation paper, p. 2.

173 Metering inaccuracies are also captured in the IRSR.

customers marginal costs generally exceeds average costs. The remainder after paying generators is returned to customers through a decrease in TUOS charges.[174] That is, the IRSR is not designed to equal zero, it is a feature of using marginal pricing principles across the NEM. However, the end result is that customers will have paid generators for the electricity they have received.

As a result of these concerns, the Commission does not consider that the EPSDD's suggested changes to the transmission loss framework can be assessed further within this rule change process. Nor does the Commission consider that the changes would be likely to be consistent with achieving the NEO.

In regard to the concerns raised by CIT, the Commission notes these concerns have been acknowledged by AEMO:[175]

> You are correct that MLF volatility has significantly increased since the Murray Link has been commissioned in 2002. This volatility is an unfortunate side-effect of the way the MLF's are calculated in accordance with the national electricity rules.

The Commission also notes CIT's particular situation: Murraylink is the only interconnector associated with a very weak connection point. As a result, the variation of the Murraylink flow creates significant volatility for the Berri MLF. As previously noted, a key purpose of MLFs is to provide a locational signal to prospective investors. However, the influence of the Murraylink interconnector on MLF values for surrounding nodes like at Berri, may result in limited usefulness of these particular MLFs for long term investment signals.

Comparison between the Red Cliffs and Berri MLFs

CIT has noted the difference in the MLF values calculated for Berri and Red Cliffs. It regards the difference as inexplicable given the distance between the locations. However, such a comparison is likely to be misleading as the MLFs for the two locations are not calculated on the same basis. Specifically, the MLF for Berri is defined with respect to the price at Torrens Island (in Adelaide), while the MLF for Red Cliffs is defined with respect to the price at Thomastown (in Melbourne). As a result, the MLFs for the two locations would be expected to be different.

Also, with all other things held constant, an increase of the Murraylink flow from South Australia to Victoria will increase the MLF for Berri (that is, a larger value) but reduce the MLF for Red Cliffs (that is, a lower value). Over the last few years, AEMO data on flows experienced on the Murraylink indicate that the flow has been from Berri to Red Cliffs more of the time compared to the past.

Declaring Berri as a virtual node

CIT has suggested that forming a VTN at Berri would provide it with relief from high and variable MLF values. The Commission has considered this and concluded that declaring a VTN

174 The IRSR can be negative. In this case, customers will incur an increase in TUOS charges to enable generators to be correctly paid for the electricity generated.

175 CIT submission to the consultation paper, attachment 2 (letter from AEMO to CIT), p. 1.

for Berri would not provide any practical relief for the larger CIT loads at Berri. This is because the intra-regional loss factor (IRLF) for a VTN is a weighted average of the IRLF for the nodes that make up the VTN. As such, the IRLF for a Berri VTN would simply be the IRLF for Berri transmission connection points. That is, there would not be any difference in the MLFs applied to CIT's larger loads.

In addition, the Commission notes that the detail of specifying a VTN at Berri is not a matter for this rule change process. This process is defined by the scope of the problem set out in the rule change requests which did not refer to virtual nodes. Nevertheless, clause 3.6.2(b)(3) of the NER provides for assigning connection points to a VTN with the agreement of the AER.

Establishing a terminal node and apportioning losses across the state

CIT suggested that a node at the terminus of Murraylink could be established and the losses attributable to that location be shared across the whole state rather than the few nodes surrounding Berri (which is the current situation).

Currently, there is a node at the South Australian terminus of Murraylink. Adding another does not appear to provide a benefit. In addition, the Commission understands that establishing a new node would be a matter for the relevant TNSP and AEMO with the agreement of the AER under clause 3.6.2(b)(3) of the NER. The Commission also notes that clause 3.6.3(f)(2) of the NER allows the assignment of connection points on a distribution network to a transmission network connection point or VTN subject to the approval of the AER and informing AEMO. Other methods to establish a new terminal node are not a matter for this rule change process as the issues raised by CIT were not also identified in the rule change requests lodged by Adani Renewables.

7.4.3 Conclusion

The Commission considers that no additional changes arising out of stakeholders' issues in regard to virtual nodes are to be made to the NER through this rule change process.

The suggestion made by the EPSDD raises concerns for the Commission in that it represents a significant move away from the current underlying marginal approach embedded in the operation of the NEM. Any consideration of such changes are beyond the scope and time frame for this rule change process.

As set out above, the suggestions made by CIT do not resolve the underlying issues from the variability in the flows across Murraylink. The draft rule does not include rules to implement new nodes for Berri. Nor does it make changes to treat load MLFs differently to generator MLFs.

However, the Commission acknowledges CIT’s concerns and the unique position of the business. As a result, the Commission is engaging with AEMO directly to explore how the situation CIT is facing as an end use customer might be addressed through options outside this rule change process.

7.5 Other changes to AEMO's calculations

Stakeholders submitted a number of suggested changes that, in their view, could be readily made to improve the transmission loss factor framework. These are discussed below and include:

- AEMO's own review of the loss factor methodology
- AEMO's discretion to amend MLFs for revised outlook of generator availability
- AEMO sharing its model with selected consultants.

7.5.1 Stakeholder views

Stakeholders have provided a number of comments on other possible changes. These are summarised below.

AEMO's review of the loss factor methodology

AEMO has stated that it will conduct a formal stakeholder consultation process on the methodology for determining MLFs to confirm that it remains fit-for-purpose. It also noted that it is currently updating the tools and processes used to calculate MLFs to "better handle the increased calculation complexity associated with changing power system conditions."[176]

Origin noted and supported AEMO's current review of its methodology for forecasting MLFs.[177]

Revising MLFs

ENA suggested changes to the MLF framework to address the uncertainties arising out of the current volatility in MLFs. It submitted that the AEMC should make a more preferable rule which provides AEMO with discretion to amend MLFs to cater for a revised outlook of generator availability, republish the MLF values and provide a short notification period before the new MLF values take effect where the impacts are expected to be material.[178]

Sharing of AEMO's model

In relation to concerns expressed about the accessibility of the MLF calculations to market participants, AEMO has suggested that it could potentially share its model with a selected group of consultants.[179] The resulting model information could enable developers and investors in generation assets to obtain better MLF estimates as part of their due diligence processes.

Canadian Solar submitted that it supports the sharing of AEMO’s actual model parameters with a limited number of "super consultants" because it expects that this change would further minimise investor uncertainty and deliver lower cost renewable development.[180]

176 AEMO submission to the consultation paper, pp. 1 & 4.
177 Origin submission to the consultation paper, p. 1.
178 ENA submission to the consultation paper, p. 2.
179 AEMO, Transmission loss factor rule change workshop, Brisbane, 4 July 2019.
180 Canadian Solar submission to the consultation paper, p. 2.

Similarly, CEC supported AEMO's suggestion that it share its MLF model with "accredited" consultants.[181]

7.5.2 Commission analysis

The Commission has reviewed the various suggested changes to the MLF framework.

AEMO's review of the loss factor methodology

AEMO's review of the loss factor methodology provides an additional avenue for stakeholders to engage and discuss with AEMO what other improvements to the current methodology can be made within the existing rules. The Commission supports AEMO in this work and has made a draft rule to provide AEMO with greater flexibility in conducting consultation on the loss factor methodology.

Revising MLFs

ENA suggested that AEMO be able to adjust MLF values for revised forecasts. The Commission acknowledges that permitting such revisions would improve the accuracy of the forecast MLF values. However, this arrangement is likely to be complicated to implement and may result in additional variability and risk for market participants. This is because it will be uncertain to generators and investors as to if and when AEMO will change loss factors within the period between 1 April (when MLF values are initially published) and 1 July (when the MLFs take effect). The Commission also notes such arrangements would necessarily result in a very short notification period of the updated loss factor values for the market.

On balance, the Commission considers that under the current framework, permitting AEMO to make late adjustments to loss factor values would be unlikely to be beneficial for investors and owners of generation assets.

Sharing of AEMO's model

AEMO's suggestion to share its model with a selection of consultants has potential to improve transparency in the market and improve investment decision-making.

The Commission notes that this suggestion is in its early stages. In considering whether to implement a framework that enables loss factor modelling to be shared, the Commission observes that it is important that the level of competition in the market for consultants having access to the AEMO model is considered when the selection of the accredited consultants is made.

In particular, if the issue of providing the model only to a few selected consultants is because of the confidentiality of the information contained in the model, then AEMO should consider other ways of managing confidentiality concerns to enable a larger group of consultants to have access to the model. The Commission considers that a larger group of approved consultants would be likely to have greater benefit to market participants than only approving a few consultants.

181 CEC submission to the consultation paper, p. 2.

7.5.3 Conclusion

The draft rule provides changes to the loss factor methodology provisions of the NER that would support AEMO's anticipated review of the methodology in the near future. The Commission considers that no additional changes arising out of stakeholders' alternative proposals are required to be made to the NER at this time.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ALF	average loss factor/s
COGATI	Coordination of generation and transmission investment implementation review
Commission	See AEMC
ESB	Energy Security Board
IRSR	intra-regional settlement residue
MCE	Ministerial Council on Energy
MLF	marginal loss factor
MNSP	market network service provider
NEL	National Electricity Law
NEM	National energy market
NEO	National electricity objective
NER	National Energy Rules
RRN	regional reference node
TNSP	transmission network service provider
TUOS	transmission use of system
VTN	virtual transmission node

A LEGAL REQUIREMENTS UNDER THE NEL

This appendix sets out the relevant legal requirements under the NEL for the AEMC to make this draft rule determination.

A.1 Draft rule determination

In accordance with s. 99 of the NEL the Commission has made this draft rule determination in relation to the rule changes proposed by Adani Renewables.

The Commission’s draft determination is:

- it should not make a draft rule as proposed by Adani Renewables under the NEL
- to make a more preferable draft rule substantially as proposed by AEMO under the NEL.

The Commission's reasons for making this draft rule determination are set out in section 2.5.

A copy of the more preferable draft rule is attached to and published with this draft rule determination. Its key features are described in section 2.4.

A.2 Power to make the rule

The Commission is satisfied that the more preferable draft rule falls within the subject matter about which the Commission may make rules. The more preferable draft rule falls within s. 34 of the NEL as the framework in which intra-regional loss factors are calculated relates to the operation of the national electricity market and the activities of persons (including registered participants) participating in the NEM or involved in the operation of the national electricity system. Further, the more preferable draft rule falls within the matters set out in Schedule 1, item 34(a) of the NEL as it relates to settlement of transactions for electricity or services purchased or supplied through the wholesale exchange operated and administered by AEMO.

A.3 Commission's considerations

In assessing the rule change request the Commission considered:

- it's powers under the NEL to make the rules
- the rule change requests
- submissions and other information received during first round consultation
- information gathered from the stakeholder workshop held on 4 July 2019
- the Commission’s analysis as to the ways in which the proposal will, or is likely to, contribute to the NEO.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[182]

The Commission may only make a rule that has effect with respect to an adoptive jurisdiction if satisfied that the rule is compatible with the proper performance of AEMO's declared network functions.[183] The more preferable draft rule is compatible with AEMO's declared network functions because it is unrelated to them and therefore does not affect the performance of those functions.

A.4 Civil penalties

The Commission cannot create new civil penalty provisions. However, it may recommend to the COAG Energy Council that new or existing provisions of the NER be classified as civil penalty provisions.

The draft rule does not amend any clauses that are currently classified as civil penalty provisions under the NEL or National Electricity (South Australia) Regulations. The Commission does not propose to recommend to the COAG Energy Council that any of the proposed amendments made by the draft rule be classified as civil penalty provisions.

A.5 Conduct provisions

The Commission cannot create new conduct provisions. However, it may recommend to the COAG Energy Council that new or existing provisions of the NER be classified as conduct provisions.

The draft rule does not amend any rules that are currently classified as conduct provisions under the NEL or National Electricity (South Australia) Regulations. The Commission does not propose to recommend to the COAG Energy Council that any of the proposed amendments made by the draft rule be classified as conduct provisions.

182 Under s. 33 of the NEL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for energy. On 1 July 2011, the MCE was amalgamated with the Ministerial Council on Mineral and Petroleum Resources. The amalgamated council is now called the COAG Energy Council.

183 Section 91(8) of the NEL.

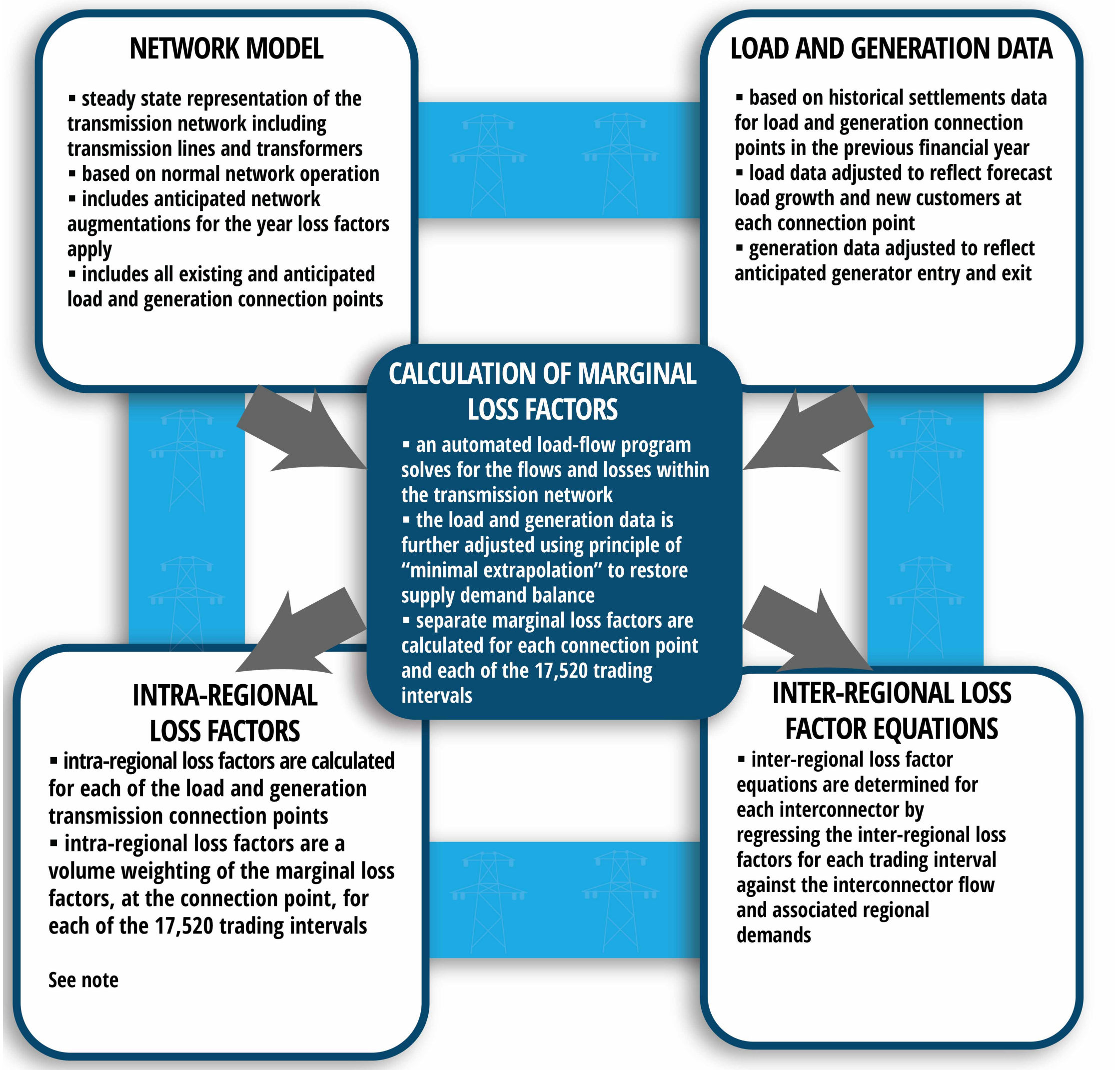
B CURRENT LOSS FACTORS FRAMEWORK

B.1 Current NER arrangements

The requirements in relation to the calculation of inter-regional and intra-regional loss factors for the NEM transmission networks are found in clauses 3.6.1, 3.6.2 and 3.6.2A of the National Electricity Rules (NER). In addition to these provisions, AEMO also publishes its calculation methodology.

Figure A.1 below illustrates the process for calculating the intra-regional and inter-regional loss factors.

Figure B.1: Loss factor calculation process



Source: AEMC

Note: The intra-regional loss factors are also often referred to as marginal loss factors (MLFs), transmission loss factors or static/single loss factors.

B.1.1 Intra-regional loss factors

Intra-regional loss factors notionally describe the marginal impact of electrical energy losses for electricity transmitted between a RRN and a transmission connection point in the same region for a defined time period and associated set of operating conditions.[184] Intra-regional loss factors are also commonly referred to as marginal loss factors (MLFs), transmission loss factors and static loss factors.[185]

AEMO must determine, publish and maintain a methodology for the determination of intra-regional loss factor equations for a financial year.[186] Publication of the intra-regional loss factors it determines by 1 April prior to the financial year in which they are to apply.[187]

When preparing this methodology, AEMO must implement a set of principles that can be summarised as follows:[188]

- the intra-regional loss factors are to apply for a financial year
- an intra-regional loss factor must, as closely as is reasonably practicable, describe the average of the marginal electrical energy losses for electricity transmitted between a transmission network connection point and the RRN in the same region for each trading interval of the financial year in which the intra-regional loss factor applies
- the intra-regional loss factors must aim to minimise the impact on the central dispatch process of generation and scheduled load compared to that which would result from a fully optimised dispatch process taking into account the effect of losses
- the intra-regional loss factors are determined using forecast load and generation data, as described in clause 3.6.2A
- the intra-regional loss factor for a transmission network connection point is determined using a volume weighted average of the marginal loss factors for the transmission network connection point for the financial year in which the intra-regional loss factor applies
- flows in network elements that solely or principally provide market network services will be treated as invariant.[189]

Generally a single intra-regional loss factor applies for each transmission connection point for a financial year. However, two intra-regional loss factors can be applied when AEMO determines, in accordance with its loss factor methodology, that one intra-regional loss factor does not, as closely as is reasonably practicable, describe the average of the marginal electrical energy losses for electricity transmitted between a transmission network connection point and the RRN.[190] Two intra-regional loss factors may be required for storage facilities

184 NER clause 3.6.2(b)(1).

185 Intra-regional loss factors are commonly called marginal loss factors because the marginal impact on losses is considered when determining the value, transmission loss factors because they apply to transmission connection points and static loss factors because a single static values applies for a whole financial year.

186 NER clause 3.6.2(d).

187 NER clause 3.6.2(f1).

188 NER clause 3.6.2(e).

189 The losses within market network services are treated separately.

190 NER clause 3.6.2(b)(2)(i)

(e.g. pump storage or batteries) when the energy at the transmission connection point is both positive (generating) and negative (load) to prevent the volume weighting process from determining a meaningless single static intra-regional loss factor.[191]

Intra-regional loss factors may, with the agreement of the AER, be averaged over an adjacent group of transmission network connection points within a single region to define a virtual transmission node (VTN) with an intra-regional loss factor calculated as the volume weighted average of the intra-regional loss factors of the constituent transmission network connection points.[192] VTNs are currently defined in New South Wales, South Australia and Tasmania.[193]

Intra-regional loss factors are used as price multipliers that are applied to the regional reference price to determine the local spot price at each transmission network connection point and VTN.[194]

In addition, AEMO determines intra-regional loss factors for new and modified connection points in the financial year in which an intra-regional loss factor is to apply if it did not determine an intra-regional loss factor in the preceding financial year.[195] AEMO must, as far as practicable, follow its methodology when determining these intra-regional loss factors.[196]

B.1.2 Inter-regional loss factors

Under clause 3.6.1 of the NER, inter-regional loss factors describe the marginal impact of electrical energy losses for electricity transmitted from a regional reference node (RRN) in one region to the RRN in an adjacent region.[197]

AEMO must determine, publish and maintain a methodology for the determination of inter-regional loss factor equations for a financial year,[198] in accordance with the rules' consultation procedures.[199]

When preparing this methodology, AEMO must implement the principles pursuant to clause 3.6.1(e) of the NER:[200]

- replace the original principles

AEMO must publish the inter-regional loss factor equations it determines by 1 April prior to the financial year in which they are to apply.[201]

191 A volume weighted loss factor can become meaningless when the total energy at a connection point is close to zero; that this the sum of the generation is approximately equal to the sum of load over the financial year. When this occurs both the numerator and the denominator in the calculation approach zero and the ratio becomes poorly defined. This is discussed further in section 5.6.1 of version 7 of AEMO's "Forward-looking transmission loss factors" methodology.

192 NER clause 3.6.2(b)(3).

193 Regions List and Draft Marginal Loss Factors: FY 2019-20, published by AEMO on 1 April 2019.

194 NER clause 3.6.2(c).

195 NER clause 3.6.2(i).

196 NER clause 3.6.2(j).

197 NER clause 3.6.1(b)(1).

198 NER clause 3.6.1(c).

199 The rules' consultation procedures are defined in rule 8.9 of the NER.

200 NER clause 3.6.2(e).

201 NER clause 3.6.1(f).

B.1.3 Load and generation data used to determine inter-regional loss factor equations and intra-regional loss factors

Clause 3.6.2 of the NER obligates AEMO, in accordance with the rule consultation procedures, to determine, publish and maintain a methodology for determining the load and generation data to be used to determine the inter-regional loss factor equations and intra-regional loss factors for each financial year. This methodology includes:[202]

- forecasting the load and generation data to be used to determine the inter-regional loss factor equations and the intra-regional loss factors. This includes new or revised intra-regional loss factors for connection points that are established or modified during the financial year in which the intra-regional loss factors apply
- modelling any additional load and generation data, where required
- the collection of relevant data from registered participants.

In preparing the methodology for forecasting and modelling load and generation data, AEMO must implement the following principles:[203]

- the forecast load and generation data must be representative of expected load and generation in the financial year in which the inter-regional loss factor equations or intra-regional loss factors are to apply, having regard to;
  - actual data from the previous the -month period defined by the methodology
  - projected load growth between the 12-month period of the actual data and the financial year for which the inter-regional loss factor equations and intra-regional loss factors apply
  - the projected network configuration and projected network performance for the financial year in which the inter-regional loss factor equations and intra-regional loss factors apply.
- additional modelled load and generation data sets must only be used in the determination of inter-regional loss factor equations where the range of forecast load and generation data is not sufficient to derive inter-regional loss factor equations to apply over the full range of transfer capability of the regulated inter-connector.

In addition, registered participants are required to provide the information set out in the methodology developed and published by AEMO. This information includes the deadlines for the provision of that information and any other obligations with respect to the provision of that information are required to be included in AEMO's published methodology.[204]

B.1.4 Application of the intra-regional loss factors

The intra-regional loss factors determined by AEMO are applied in the AEMO market systems. This occurs in the following ways:

202 NER clause 3.6.2A(b).

203 NER clause 3.6.2A(d).

204 NER clause 3.6.2A(e).

- semi-scheduled and scheduled generators' dispatch offers are divided by the intra-regional loss factor (to refer the offer to the RRN)[205]
- scheduled loads' dispatch bids are divided by the intra-regional loss factor (to refer the offer to the RRN)[206]
- the local spot price at each transmission network connection point is the spot price at the assigned regional reference node multiplied by the relevant intra-regional loss factor applicable to that connection point (the local spot price is not actually used further in the NER)[207]
- being used in the calculation of compensation in relation to AEMO directions[208]
- when determining the settlements payments (paid by market customers and paid to generators) by multiplying the measured energy in the trading interval, the regional spot price and the relevant intra-regional loss factor.[209]

B.2 AEMO's role in determining intra-regional loss factors

As discussed earlier, the NER provides a number of key principles that AEMO must follow when it determines the inter-regional loss factor equations and the intra-regional loss factors each financial year. In addition, AEMO is required to produce and publish its methodology for determining the loss factors. This methodology is available on the AEMO website.[210]

AEMO uses an automated load flow program to calculate the loss factors for the financial year on which the inter-regional and intra-regional loss factors apply.[211] This program requires a network model that represents the region's transmission network plus the connection energy flows for each trading interval for the generators and loads connected to the transmission network.

The following discussion summarises AEMO's forward-looking intra-regional loss factor methodology and its application and includes:

- network model
- load forecast data
- controllable network element flow data
- generation data
- restoring the supply and demand balance
- intra-regional loss factors
- inter-regional loss factor equations

205 NER clause 3.8.6(h)(3).

206 NER clause 3.8.7(f).

207 NER clause 3.9.1(c).

208 NER clause 3.12.2(a)(2).

209 NER clause 3.15.6(a).

210 http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Loss_Factors_and_Regional_Boundaries/2017/Forward-Looking-Loss-Factor-Methodology-v70.pdf

211 AEMO uses the TPRICE program for calculating the NEM loss factors.

- publication of the loss factors.

B.2.1 Network model

The inter-regional and intra-regional loss factors are determined from the losses that occur for energy flows within the region's transmission network. Therefore, an important input when determining the loss factors is a suitable model of the NEM transmission network.[212]

The network model AEMO uses is a single network representation to represent the normal network configuration that is anticipated for the financial year in which the inter-regional and intra-regional loss factors will apply. This model is based on the existing network plus any network augmentations that are expected to be commissioned during that year. Information on expected network augmentations are those which have been determined in consultation with the transmission network service providers (TNSPs) who supply relevant network data regarding these augmentations.

In addition, AEMO must ensure that the network model includes all existing connection points and those that are anticipated to be established before the end of the financial year which the inter-regional and intra-regional loss factors will apply.

B.2.2 Load forecast data

The automated load flow program used to calculate the inter-regional and intra-regional loss factors requires estimates of the energy consumed at each load connection point for each trading interval. This load energy information is provided to AEMO by TNSPs. AEMO performs due diligence on the provided data to ensure the forecasts are consistent with the most recent load forecasts used in its electricity statement of opportunity (ESOO) document.

The connection point load forecasts provided by the TNSPs:

- are based on reference year connection point data (retaining the same weekends and public holidays)[213]
- are consistent with the latest annual regional load forecasts prepared by AEMO or the TNSP
- are based on 50 per cent probability of exceedance and medium economic growth conditions
- include any known new loads
- include existing and committed generation that is embedded in the distribution network
- are an estimate of the active and reactive power at each connection point for each trading interval.

212 AEMO bases the network model on the PSSE load flow models it uses for contingency analysis and for the initial conditions for the more detailed stability studies it performs to assess system security.

213 The reference year is previous financial year to the year when the loss factors are determined. For example, the 2019-20 loss factors are determined in the 2018-19 year and the reference year is 2017-18.

B.2.3 Controllable network element flow data

Energy flows in a transmission network from generators to load centres and are generally passively distributed throughout the transmission network. The distribution of flows is predominantly determined by the impedances of the transformers and transmission lines, plus their topology. The exceptions to this are the Murraylink, Terranora and Basslink controllable network elements (DC links) where the flows on these links can be actively controlled through the AEMO dispatch process.

The Murraylink and Terranora network elements are regulated interconnections that operate in parallel with the Heywood and QNI[214] interconnectors respectively. In these cases the automated load flow program will determine the flows on these elements as a proportion of the Heywood and QNI flows.[215]

In contrast, the Basslink interconnector is an unregulated interconnector that operates as a market network service. To determine the flows on Basslink AEMO assumes that its flows are unchanged from the reference year (as required by the current provisions of the NER).

B.2.4 Generation data

In addition to the network model, the load data and the flows on controllable network elements, the automated load flow requires a set of generation data by connection point for each trading interval.

For the existing generating units, AEMO uses the generation data from the reference year.

For new generating units AEMO estimates generation data from similar existing generating units that have a known generation profile. In addition, AEMO assumes the dispatch of new committed generating units to be zero for trading intervals prior to the commissioning date reported in the latest ESOO.[216]

Once commissioned, AEMO estimates the output of new generating units by shaping and scaling generation data from similar generating units that operated in the reference year data by:

- identify generating units in the NEM that use similar technology and fuel type (AEMO tries to only use data from generating units that are up to five years old, but does relax this to 10 years if no suitable data is otherwise available)
- find the average output of the similar generating units as a percentage of their winter rating from the reported in the latest ESOO
- determine the output of the new generating units by scaling the average output profile by the nameplate rating of the new generating unit.

Once a generating unit has been operating for two years AEMO will have sufficient actual data included in the relevant reference year.

214 QNI is the Queensland to New South Wales interconnector.

215 See section 5.5.3 of the AEMO forward-looking loss factor methodology.

216 The Commission understands AEMO sough subsequent commissioning updates from all committed generation proponents for this year's MLF determination.

Hydro and wind generating systems are rated differently as their output is energy constrained or intermittent. AEMO consults with the proponents of new hydro or wind generating units to determine an anticipated generation profile. Where the proponent is unable to provide a suitable profile, then AEMO uses a flat generation profile equal to the product of the anticipated utilisation factor and the nameplate rating of the generating unit. AEMO's methodology also includes a general approach to estimating the generation profile for new generating units that utilise a new technology or fuel type.

AEMO's determination of the generation data also needs to account for retiring generating units. Thus, AEMO sets the output to zero for generating units that are identified as retiring in the latest ESOO.

Finally, AEMO will also modify generation data when either AEMO or the associated generator considers that the operation during the reference year is unlikely to be representative of generation expected from a generating unit during the year that the inter-regional and intra-regional loss factors apply. This may occur for a number of reasons including significant droughts that limit the output of the generating unit, or prolonged outages for maintenance etc.[217]

B.2.5 Restoring the supply and demand balance

In the reference year the energy supplied by generation balances the energy consumed by the loads plus the losses in the network. However, this supply-demand balance will no longer occur for the year in which the inter-regional and intra-regional loss factors are being determined. This is because demand has been adjusted to account for load growth and new loads, and supply has been adjusted to account for new generation and generator retirement. In addition, network augmentations have been included and these may also affect the losses in the transmission network.

This supply-demand balance needs to be restored for the network flows to be representative of the flows in transmission network to be representative of the future financial year when the inter-regional and intra-regional loss factors will apply. To restore the supply-demand balance AEMO uses a process it calls the minimal extrapolation principle. This is done by adjusting the output of all the dispatchable generating units that are operating in that trading interval.

For periods of excess generation, where load has increased by less than the initial forecast of the output of the new generating units, AEMO reduces the net generation by scaling the output of all the generating units in proportion to their output in the reference year. AEMO does not adjust the output of energy limited generating units such as pump storage schemes.

For periods of insufficient generation, where load has grown by more than the initial forecast of the additional generation or due to generation retirement, AEMO increases the net generation. This is a more complex process than reducing the output of the generation as it

217 Additional details are available in section 5.5.6 of its forward-looking loss factor methodology.

needs to consider output limits on generating units and which units could have potentially operated at that time.[218]

When adjusting the generation to restore the supply-demand balance, the minimal extrapolation principle also needs to consider interconnector limits. Failure to consider interconnector limits could potentially result in flows that are beyond the secure limit of the interconnector and would not be representative of the network flows that could occur. Therefore, AEMO implements interconnector limits that are representative of the limits it expects to apply for summer and winter, and for peak and off-peak periods, for the financial year that the inter-regional and intra-regional loss factors will apply. AEMO consults with TNSPs when developing these representative limits. Considering the interconnector limits means that AEMO may need to adjust generation differently in different regions to maintain inter-regional flows within the respective transfer capabilities.

B.2.6 Intra-regional loss factors

The automated load flow program solves for the network flows, and the associated loss, for each trading interval using the generation and load data described above. The loss factors for each load and generation connection point, with respect to their RRN, are extracted from the load flow solution for each trading interval. This results in 17,520 marginal loss factor values for each transmission connection point in the NEM.[219]

The intra-regional loss factor value for a given transmission connection point is the volume weighted average of the 17,520 intervals, where the weights are the energy generation and/or consumption values for each trading interval.

The use of volume weights to average the marginal loss factors for the trading intervals means that the resulting single intra-regional loss factor value is representative of periods of either high generation or consumption, for a generating unit or load connection point respectively.

Following the determination of the intra-regional loss factors for each of the transmission connection points, AEMO also calculates the loss factors for any VTNs.[220]

B.2.7 Inter-regional loss factor equations

In addition to providing intra-regional loss factors for each trading interval, the automated load flow solution provides the inter-regional loss factors between the adjacent RRN.

Inter-regional loss factor equations are then determined for each interconnector by regressing the inter-regional loss factors for each trading interval against the interconnector

218 Additional details on the process AEMO uses for period in insufficient generation are available in section 5.5.2 of its forward-looking loss factor methodology.

219 In a leap year there are 17,568 trading intervals due to the presence of 29 February.

220 Clause 3.6.2(b)(3) of the rules allows, with the agreement of the AER, for intra-regional loss factors to be averaged over an adjacent group of transmission network connection points. If averaging is used, the relevant transmission network connection points will be collectively defined as a VTN. The intra-regional loss factor for the VTN is calculated as the volume weighted average of the intra-regional loss factor loss factors of the constituent TNIs. AEMO's forward-looking transmission loss factors methodology explains the specific method that it uses. VTNs are used for some connection points in New South Wales, South Australia and Tasmania.

flows by trading interval. The quality of the regression is improved by also including the regional demand values in the associated regions into the regression models.

C OTHER METHODOLOGIES CONSIDERED

This appendix summarises additional loss factor methodologies provided in submissions by stakeholders, outlines stakeholder views and provides the Commission's analysis on whether they would achieve the NEO better than the current MLF methodology. This chapter includes discussion on:

- cap and collar approach to loss factors
- grandfathering of MLFs
- the Irish compression model
- the Italian model to treat transmission losses
- dynamic loss factors.

C.1 Cap and collar

In its consultation paper the Commission identified the cap and collar methodology as a potential approach to loss factors. Some stakeholders suggested that this could address the issues identified by Adani Renewables. The Commission provided an outline of how a cap and collar approach for loss factors could be implemented in the NEM. It noted that one such approach could be to apply a band within which all intra-regional loss factors must sit. For example, all loss factors must be between 0.8 and 1.1. Another approach to cap and collar identified was to apply a constraint to the change made to an intra-regional loss factor value by AEMO. For example, the maximum change to a loss factor is +/- five per cent.

Generally, the rationale for a cap and collar approach is that setting a limit within which loss factor values would sit would provide transmission connected market participants with a degree of certainty about how high or low their loss values would be. However, using a cap and collar may result in transmission loss factors that may not accurately reflect the loss of electricity from a transmission connection point to the RRN at all times or for all locations. As losses must always be accounted for, such a result would pass the cost of the lost electricity to consumers.[221]

C.1.1 Stakeholder views

Submissions indicated that there is almost no stakeholder support for changing the loss factor methodology to a cap and collar approach. While Origin noted that a cap and collar method would reduce variability of loss factors, it also acknowledged that the methodology would result in a shifting of risks and costs from new generation investment to consumers.[222]

Other stakeholders also noted that moving to a cap and collar methodology would:

- imply a move away from the current open access approach to transmission[223]

221 AEMC, *Transmission loss factors* consultation paper, 6 June 2019, pp. 18-19.

222 Submissions to the consultation paper: Origin, p. 5; EUAA, p. 3.

223 AEC submission to the consultation paper, p. 5.

- socialise losses (or avoided losses) across consumers[224]
- blunt locational signals currently provided by MLFs.[225]

The Commission received one submission supporting the cap and collar approach as a viable option. QIC Global Infrastructure submitted that cap and collar could provide a higher degree of certainty to market participants.[226]

PIAC suggested a methodology it called the insurance model. This model offers generators the option to purchase an insurance product in the form of an annually fixed MLF schedule with a ceiling and a floor.[227] In this respect the suggested model is similar to a cap and collar although it requires a counterparty to sell this type of insurance product. PIAC submitted that its suggested methodology would equalise the level of risk between participants compared to current arrangements where early connectors to the transmission system face significantly more risk. PIAC noted that under this model, AEMO would apply unbounded MLFs to determining the dispatch order for generators.[228]

C.1.2 Commission analysis

The Commission has considered stakeholder comments in regard to changing the loss factor methodology to a cap and collar approach. It has drawn similar conclusions to some stakeholders that, if implemented, a cap and collar methodology would be likely to:

- result in increased costs to all consumers in the NEM
- reduce locational signals provided by loss factors
- shift risk from new generation investment to consumers.

Impact on efficient investment

By limiting the up and down-side of MLF, the cap and collar would reduce volatility in MLFs. This would be likely to lead to more stable and predictable revenue and, all other things being equal, lead to a stable, if not lower, cost of capital.

However, applying a cap and collar to MLFs may be likely to induce additional investment in locations with relatively weak transmission infrastructure, increasing losses and congestion for the transmission network in the long run. These inefficient locational decisions could result in more losses which would flow through as higher costs to consumers.

Impact on efficient operation of providing electricity services

Similar to the analysis provided for average loss factors, the changing to a cap and collar would likely introduce inefficiencies into the provision of electricity services:

- Using marginal pricing for dispatch and a cap and collar for MLFs will result in some market distortion. Similar to the analysis provided on the ALF approach, a cap and collar

224 Infigen submission to the consultation paper, p. 3.

225 EnergyAustralia submission to the consultation paper, p. 9.

226 QIC Global Infrastructure submission to the consultation paper, p. 4.

227 PIAC submission to the consultation paper, p. 3. This methodology was also suggested to the AEMC in the context of the COGATI review.

228 PIAC submission to the consultation paper, p. 4.

could impact on the merit order of dispatch resulting in generators with higher losses being dispatched.

- The ultimate impact on the merit order of dispatch will depend on which generators are online and which generator is marginal.

Risk allocation

The Commission's analysis indicates that applying a cap and collar to MLFs may result in a reduction in revenue volatility and result in a more stable and potentially lower cost of capital for owners of generators and prospective investors.

However, as stakeholders noted, a cap and collar would result in a shifting of risks and costs from new generation investment to consumers.[229]

The Commission acknowledges PIAC's insurance model aims to address risk allocation. However, the purpose of PIAC's insurance model seems to be to provide increased certainty for investors in generation projects in individual energy zones, with the option to applying the same methodology to the NEM. According to PIAC, this can be conceptualised as "smoothing within the generation fleet in the energy zone, so that the risk is somewhat equalised between participants.".[230] By placing a cap and collar on the MLF values, PIAC's suggested approach effectively transfers risk from some generators to others. This is because the returns of some generators are likely to be capped, while the potential losses of other generators would be limited by the floor on MLFs. It is also not clear how applying such an approach would impact on the IRSR.

On balance, the Commission considers that while a cap and collar approach to MLFs may provide a stable (and potentially reduced) cost of capital, this would come at the expense of consumers. Applying a cap and collar would transfer some loss factor risks from generators to consumers, who are not well-placed to manage them. This would result in inefficiencies and higher costs to consumers.

C.1.3 Conclusion

While a cap and collar would reduce variability in loss factors which could provide benefits to debt and equity investors, in terms of more funding availability and a reduced cost of capital, it would lead to less efficient investment, dispatch and risk allocation.

On balance, the Commission considers that the use of a cap and collar for determining transmission loss factors in the NEM would not represent an improvement in the transmission loss factor framework and be consistent with the NEO.

C.2 Grandfathering

In its consultation paper, the Commission asked stakeholders if grandfathering of MLFs year-on-year could address the current volatility in MLFs. In doing so, it noted:

229 EUAA submission to the consultation paper, p. 3.

230 PIAC submission to the consultation paper, p. 4.

- Locking in the MLF value for a generator would allow generators and their investors to better predict and manage the financial risk of MLF variability.
- Lower MLFs, capturing the full effect of the additional losses resulting from the connection of a new generator, would apply to new transmission connections.
- Grandfathered MLFs may not lead to efficient investment decisions and may create barriers to entry for new generators.[231]

C.2.1 Stakeholder views

Submissions from stakeholders indicated little interest in applying grandfathering to loss factors. One stakeholder, PIAC, suggested a modified model of grandfathering which could be used to provide stronger investment signals. Other submissions opposed grandfathering on the basis that it would result in an inefficient wholesale market.

Origin submitted that, in its opinion, grandfathering would result in inefficient dispatch.[232] Similarly, ERM Power submitted that while grandfathering of loss factors for existing generators could sharpen locational signals for new generators to more accurately calculate their true marginal impact on overall system losses, the use of grandfathered losses could also act as a barrier to the efficient entry of new generation or retirement of existing generation.[233] EnergyAustralia and Baringa also noted that grandfathering would result in absolute certainty in MLFs (depending on length of grandfathering) but would come at the expense of any accuracy or potentially locational signals.[234]

The Investor Group did not support grandfathering, noting that this would have the potential to "...distort investment signals and discourage future investment signals and discourage future investment in generation."[235] MUFG Bank submitted that it considered that setting a floor for MLFs would provide a better model than grandfathering.[236]

However, QIC Global Infrastructure stated that the application of grandfathering principles could contribute to a higher degree of confidence for market participants.[237]

PIAC suggested a variant of the grandfathering model which locks-in particular MLFs for a set period-of-time.[238] It claimed that this model would provide a stronger investment signal for generator connection through the MLF by allowing connecting parties to have their MLF 'locked in' by AEMO for a standard period-of-time, allowing the owner of the generator greater certainty of its future revenue. The necessary design decisions would include determining an appropriate sunset period for this. If a new party were to connect nearby and affect the local MLF, this change would be borne by the second party alone rather than being spread across both parties. In PIAC's opinion, this approach provides a much stronger signal

231 AEMC, *Transmission loss factors,* consultation paper, 6 June 2019, p. 19.

232 Origin submission to the consultation paper, p. 5.

233 ERM Power submission to the consultation paper, p. 5.

234 Submissions to the consultation paper: EnergyAustralia, p. 9; CEC supplementary submission: Baringa report, p. 24.

235 The Investor Group submission to the consultation paper, p. 17.

236 MUFG Bank submission to the consultation paper, p. 4.

237 QIC Global Infrastructure submission to the consultation paper, p. 4.

238 Baringa also noted that grandfathering could be for a set period. CEC supplementary submission to the consultation paper: Baringa report, p. 24.

to each connecting generator to minimise their impact on overall loss factors, such as by incorporating storage. Once the determined period-of-time has elapsed, the MLFs are no longer 'locked in' and the revised loss factor at the connection point is applied to both parties.[239]

C.2.2 Commission analysis

The Commission considers that applying grandfathering to loss factors would be likely to:

- act as a barrier to entry for new generation
- reduce accuracy of loss factor values
- distort locational signals of loss factors
- result in inefficient dispatch of generators in the NEM.

The Commission considered PIAC's suggested methodology of a time-limited lock-in model for MLFs. The Commission understands that connecting parties would have their MLFs locked in for a standard period-of-time and that:

- New entrants that connect to the transmission network and affect the local MLF would bear the full change in the MLF at that location. For example, an incumbent generator with a locked-in MLF of one would retain its MLF, and the newly connected generator would have its MLF value calculated based on the losses associated with its own generator and the incumbent generator until the incumbent's MLF is unlocked.
- Once the determined period-of-time for generator one has expired, the MLF at the connection point would be unlocked and generators one and two would receive revised MLFs reflecting forecast marginal losses.

PIAC's suggested limited period for grandfathering MLFs is an advantage over the lifetime approach to grandfathering. However, the likely implications of applying limited period grandfathering to MLFs, including inefficient dispatch, barriers to entry for new generation and distorted locational signals, are just as relevant as they are for long term grandfathering. On balance, these effects outweigh the positive impacts that may arise for investors in new generation.

As part of considering whether loss factor methodology should include grandfathering, the Commission has applied the assessment framework outlined in the consultation paper.

Impact on efficient investment

The grandfathering of MLFs would be likely to result in inefficient investments, because owners of new generation may be deterred by the higher losses attributed to them compared to incumbent generators holding grandfathered MLFs. Incumbent generators would benefit from a lower cost of capital arising from certainty in MLF values. However, new entrants will bear the costs of a higher cost of capital.

239 PIAC submission to the consultation paper, pp. 5-6.

Impact on efficient operation of providing electricity services

Grandfathering may act as a barrier to entry for new generators. As a result, the operation of the NEM would be less efficient because it could prevent more efficient lower cost generators from entering the market.

Risk allocation

Grandfathering of MLFs would be expected to shift the risk of high or variable loss factors from incumbent generators to new entrants and ultimately to consumers. The effect of this would likely be that:

- consumers would pay more as less efficient generation assets supply the market in response to less accurate MLFs
- more efficient lower cost generation would be deterred from entering the market because they are facing the full loss factor risk on a transmission line when connecting.

C.2.3 Conclusion

Overall, the Commission has concluded applying grandfathering to MLFs may create some benefits to investors and owners of existing generation assets but the approach would be likely to create undesirable distortions in the NEM. In particular, prospective investors and owners of new, more efficient, generators may be deterred from entering the market because of the lower MLF values that would be allocated to them. As a result, grandfathering MLFs would be unlikely to promote the NEO.

C.3 The Irish compression model

The single electricity market (SEM) in Ireland and Northern Ireland uses a unique approach to transmission loss factors, which has become known as the "compression" model. The Investor Group suggested the Irish compression methodology could be used to determine loss factors in the NEM, although noted that it was not their preferred model.

The Irish compression approach is to derive a single volume-weighted marginal loss factor value for a financial year for a given transmission connection point. The single electricity market operator (SEMO) then applies a compression factor which has the effect of limiting the spread of values for loss factors assigned to connection points. Figures C.1 and C.2 set out how the Irish compression model is computed.

Firstly, the MLF value for each transmission point is calculated using the formula in Figure C.1. The algorithm is then normalised around the normalisation number (NN) as shown in Figure C.2. A NN is calculated for each scenario. The NN is a point of reference for the loss factors to be compressed around. The NN is chosen so that, after compression is applied, the compressed losses are equal to the uncompressed losses (the forecast transmission losses for a month). In the SEM, the NN is approximately 0.98, but varies depending on the losses for each month and day and night. The effect of applying a compression factors are to reduce the range of the loss factors, such that the effects of volatility are reduced by approximately 50%.

Figure C.1: Irish compression model - calculating the MLF

$$\frac{\Delta\, total\ system\ demand}{average\ of\ absolute\ value\ of\ +\Delta G\ and\ -\Delta G}$$

Source: EirGrid and SONI, *Explanatory Paper for Transmission Loss Adjustment Factor Calculation Methodology (TLAF)*, September 2012.

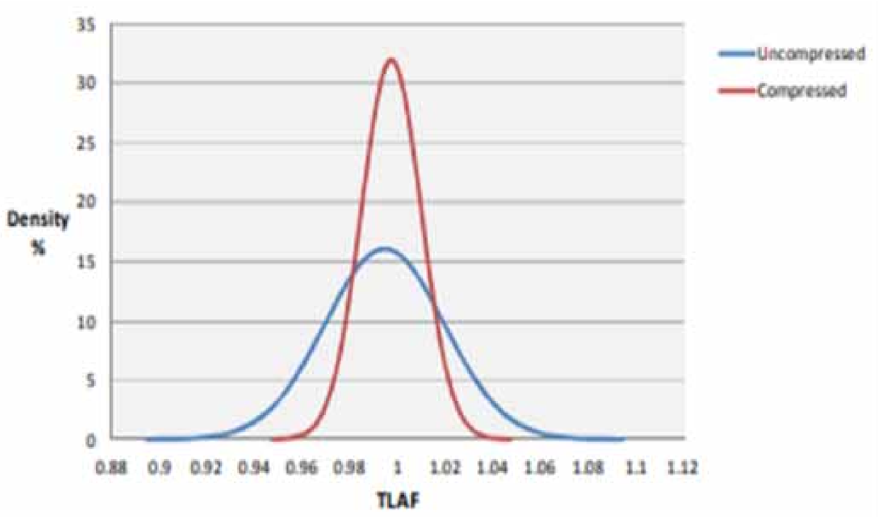
Figure C.2: Irish compression model - compressing the MLF

$$if\ X < NN,\ \frac{NN-X}{2*NN}+X;\quad if\ X > NN,\ X-\frac{X-NN}{2*NN}$$

Source: EirGrid and SONI, *Explanatory Paper for Transmission Loss Adjustment Factor Calculation Methodology (TLAF)*, September 2012.
Note: X=the uncompressed loss factor (MLF) and NN=normalisation number.

EirGrid and SONI (the system operator for Northern Ireland) have illustrated the effect of applying the transmission adjustment loss factor (TLAF) in the graph below. It shows how the distribution of loss factors under the compressed methodology moves closer to unity resulting in less volatility. On the other hand, the graph also shows that by compressing the loss factors, locational signalling is likely to be reduced.

Figure C.3: Effect of applying the compression model (TLAF)



Source: EirGrid and SONI, *Explanatory Paper for Transmission Loss Adjustment Factor Calculation Methodology (TLAF)*, September 2012.

C.3.1 Stakeholder views

The Investor Group submitted that the Irish compression model was their second option to change the MLF framework in the NEM.[240] PARF made similar comments in its submission.[241] The Investor Group considered that the Irish compression model would be likely to:

- reduce volatility of revenue for existing generators
- reduce over-recovery of IRSR
- increase investment certainty and bankability of future renewable energy projects
- mitigate the risk of cost of capital risk premia to compensate for increased loss factor volatility.

While the Investor Group found this option to have a similar impact as the average loss factor, the group preferred the average methodology because using the Irish compression model would be:

- relatively complex to understand and implement
- less reflective of actual losses
- sensitive to the value assumed for the normalisation value.[242]

In its submission, Hydro Tasmania noted that a loss factor methodology which more closely than the marginal methodology aligns loss factors to reflect actual losses deserves attention. It suggested that one of such a methodology could be the Irish compression model.[243]

The CEC's consultant, Baringa, suggested that both compressed MLFs and average loss factors would reduce the cost of capital for new investment and enable more projects to be financially viable. Baringa stated that according to its analysis, both options, compressed MLFs and average loss factors, could support the development of new generation capacity at least cost by providing generators stronger revenues and maintaining more favourable loss factors as the capacity of new build increases. The effects of using a compression MLF model, according to Baringa, include:

- greater certainty because compressed MLFs are likely to vary less
- dampened locational signal
- dispatch efficiency preserved albeit less marginal losses are factored in
- reduced forecast error
- reduced IRSR.[244]

C.3.2 Commission analysis

One benefit of the Irish compression model is that it would be likely to result in more stable and, for some generators higher, loss factors compared to MLFs. However, it would also be

240 Investor Group submission to the consultation paper, p. 11.

241 PARF submission to the consultation paper, p. 12.

242 Submissions to the consultation paper: Investor Group, p. 12.

243 Hydro Tasmania submission to the consultation paper, p. 2.

244 CEC supplementary submission to the consultation paper, p. 18.

likely to create reductions in the locational signal, which could result in higher costs to consumers in the long-term. This is the case, because:

- there would be at least some risk transferred from remote generators to generators located closer to load centres
- dampening the locational signal may incentivise new entrant generators to locate further away from load, increasing total losses.

Impact on efficient operation of providing electricity services

The Commission understands that the compression model is intended to result in the same merit order of dispatch as would be the case as using uncompressed MLFs, even as the absolute range of loss factors is reduced. However, it is not clear that this would be the result in all circumstances and, as such, the Commission considers that the impact of the compression model on the efficient operation of generators is uncertain.

Impact on efficient investment

While the Irish compression model might aim to preserve the merit order as under a pure MLF approach, the absolute values of the loss factors would be altered, reducing their effectiveness as signals to incentivise efficient investment in transmission. Similar to a cap and collar approach, the compression model would be likely to induce extra investment in locations with weaker transmission infrastructure, increasing losses and resulting in higher costs to consumers in the long run.

The Irish Single Electricity Market Committee (SEMC), published its decision on the treatment of losses in the SEM in June 2012.[245] As part of its consultation process, the SEMC published a proposed decision paper (SEMC, proposed decision paper for consultation, SEM-12-024, April 2012) and invited stakeholder comment.

The SEMC received seven submissions from generators and retailers. None of the submissions favoured the compression model. Submissions argued that all that compression achieves is the removal of extremities of the existing loss factor methodology (TLAFs) and that maintaining the compression methodology on an ongoing basis perpetuates the methodology which had been under scrutiny in the first place.[246] Submissions argued for locational signals (the TLAF methodology) or fixed loss factors.

Risk allocation

The Irish compression model would be likely to shift risk, both between generators and customers and between different generators. As noted by the CEC in its supplementary submission, applying a compression model would be likely to result in:

- a reduction in the settlement residue and therefore a smaller reduction in TUOS charge passed through to consumers, resulting in relatively higher bills[247]

245 SEMC, *Treatment of losses in the SEM*, decision paper, 26 June 2012.

246 SEMC, *Treatment of losses in the SEM*, decision paper, 26 June 2012 p. 5.

247 CEC supplementary submission to the consultation paper, p. 18.

- reduction of loss factors for MLFs that are larger than the compression number[248]

The compressed loss factor values would be likely to lead to:

- more stable and higher loss factors for some generators, which might reduce their cost of capital
- lower compressed loss factors for some generators (those having an MLF greater than the compression factor), which could result in less revenue and potentially a higher cost of capital

The Commission has carried out some analysis to estimate the impact of a change to a compression methodology on generators. In particular, it recalculated loss factors of generators in the NEM using the Irish compression model and using a compression number of 0.97.[249] The Commission's analysis indicated that a change to the use of a compression model to determine transmission loss factors would be likely to result in some generators enjoying a relatively higher loss factors (compared to under the current MLF methodology) and therefore higher revenue. However, other generators would experience a reduction in their MLF and hence revenue. That is, the change from the current MLF methodology to a compression model has the effect of redistribution revenues between generators.

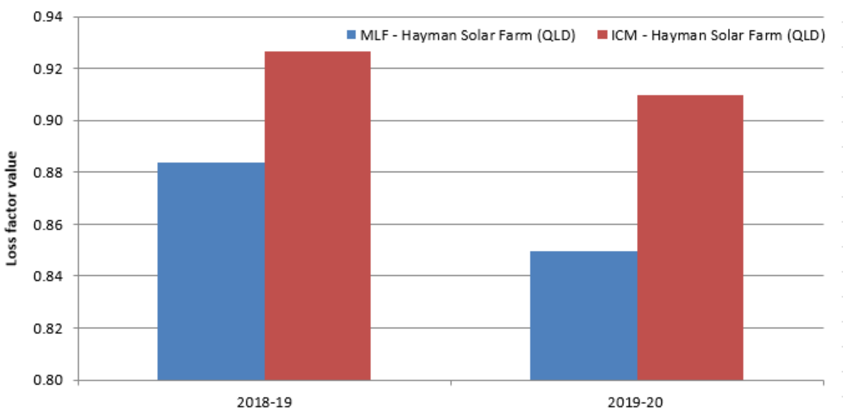
For example, Figure A.4 shows the marginal and compressed loss factors for Hayman solar farm in Queensland and Figure A.5 shows the marginal and compressed loss factors for Sun Metals solar farm, also in Queensland. Figures A.4 and A.5 demonstrate how applying a compression model can increase the loss factor of generators with an MLF lower than the compression factor and reduce the loss factor of generators with an MLF higher than the compression factor. In 2019 and 2020, applying a compression model would:

- increase the loss factor for Hayman solar farm by five and seven percent respectively
- decrease the loss factor for Sun Metals solar farm by two percent in both years.

248 CEC supplementary submission to the consultation paper, p. 19.

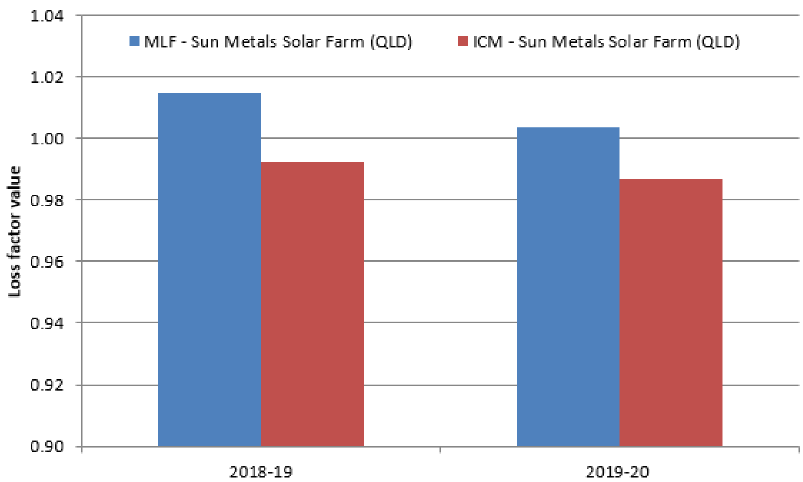
249 This number was used as CEC proposed a compression number of 0.97-0.98 based on 2019-2020 MLFs for all generation and load. CEC supplementary submission to the consultation paper, p. 20.

Figure C.4: Applying a compression model Hayman solar farm Queensland



Source: AEMO, AEMC.
Note: Compressed loss factors calculated using a compression factor of 0.97.

Figure C.5: Applying a compression model Sun Metals solar farm Queensland



Source: AEMO, AEMC.
Note: Compressed loss factors calculated using a compression factor of 0.97.

C.3.3 Conclusion

On balance, the Commission considers that the use of the Irish compression model for determining transmission loss factors in the NEM would be unlikely to be an improvement in the MLF framework and so be unlikely to be consistent with the NEO. This is the case, because:

- there would be at least some risk transferred from remote generators to generators located closer to load centres

- dampening the locational signal may incentivise new entrant generators to locate further away from load, increasing total losses
- compressed loss factors are likely to result in higher costs for consumers.

C.4 The Italian model

Enel Green Power suggested that the Commission have regard to the Italian approach to determining loss factors. The key principle for this approach is that the "end-user of electricity or their Retailers should bear the full cost for losses, while the Network operators buys the extra-energy needed to front the losses".[250] Enel noted that the Italian market is relevant because it faced a rapid renewables penetration over the last 10 years, similar to what is currently occurring in Australia.[251]

> **BOX 1: TRANSMISSION LOSSES IN THE ITALIAN ELECTRICITY MARKET**
>
> The Italian wholesale market operates using a power exchange and bilateral contracts. The treatment of losses is based on the principle that "load" (end-users of electricity or the suppliers representing them) should bear the cost for the losses.
>
> Customers pay for a quantity of electricity that includes what is used as well as the loss incurred to transport that electricity and an error factor.
>
> With respect to cost allocation of transmission losses:
>
> - In the day-ahead market, losses are priced at the energy clearing price.
> - The difference between the day-ahead estimation of losses and the actual level of losses is paid by the Italian transmission service operator (TERNA) at the balancing price in real time and recovered by all customers through network tariffs.

Source: INOGATE, *EU practice in treatment of technical losses in the high voltage grid*, January 2012.

C.4.1 Stakeholder views

No stakeholder other than Enel Green Power suggested or commented on the Italian approach to transmission loss factors.

In its submission, Enel Green Power agreed with Adani Renewables that the loss factor methodology should be changed. It suggested that the AEMC look at a European example, in particular the Italian model, to calculate loss factors.[252] The Italian model uses ex-ante loss factors and the transmission company is pays for the difference between estimated and actual losses.[253]

250 Enel Green Energy submission to the consultation paper, p. 5.

251 Enel Green Energy submission to the consultation paper, p. 1.

252 Enel submission to the consultation paper, p. 1.

253 Enel submission to the consultation paper, p. 5.

Enel commented that the Italian model of regulating transmission infrastructure has been in place for a long-time and has proven to be effective in facilitating rapid renewable penetration. It also noted that in Italy:

- ex-ante loss factors are periodically updated by the Italian Regulation Authority.
- the difference between estimated and actual losses is paid by transmission system operator at the market price and passed through to all customers
- a liability is periodically computed as the difference between actual and estimated costs
- this difference is owed to or by the distribution network operator.

Enel Green Energy suggested that because generators are excluded from the risk of transmission losses, they are able to provide electricity at the cheapest price.[254]

C.4.2 Commission analysis and conclusion

The Commission has considered the Italian model as suggested by Enel. It considers that it wouldn't be possible to adopt a similar model in Australia without undertaking other substantial changes to the NEM which are outside the scope of this rule change process and which would have significant impacts on the operation of the NEM.

In addition, the Commission considers that a significant drawback of the approach is that it does not provide locational signals to site new generators. As discussed in the COGATI review, the Commission considers this is a desirable feature for the NEM.

C.5 Dynamic loss factors

The Commission's COGATI review is seeking to determine how best to coordinate generation and transmission investment in the NEM. This project is broader in scope than this rule change process and includes considering significant market reforms such as the introduction of dynamic loss factors and financial hedging arrangements. The Commission notes that in some overseas markets where there are locational marginal prices, MLFs are calculated dynamically at each location in real-time. As a result, significant reforms to the loss factor framework, including consideration of moving to the more efficient dynamic loss factor approach, are best considered along-side the development of reforms to the access arrangements in place for the transmission system.[255]

C.5.1 Stakeholder views

Several stakeholders expressed an interest in further consideration of dynamic loss factors. Engie suggested that the Commission should provide analysis of the multiple MLFs approach and five-minute dynamic loss factors in terms of cost, dispatch efficiency and risk management to inform stakeholders in their assessment of various approaches.[256]

IES submitted that while it does not support Adani's proposal to use average loss factors, it considered that the current MLF arrangement does need to be upgraded. In its view, the

254 Enel submission to the consultation paper, p. 5.

255 AEMC, *Transmission loss factors*, consultation paper, 6 June 2019, p. 14.

256 Engie submission to the consultation paper, p. 3.

analytical market design constraints that existed when MLFs were developed no longer apply and that the best way forward is to calculate and apply MLFs in real time.[257] IES further submitted that "realistic MLFs would sharpen operational and investment signals by lowering off-peak prices and increasing peak prices."[258] As a result, IES considered that the NEM should move towards implementing dynamic marginal losses in real time as this would better achieve the NEO and remove AEMO from direct involvement in the market.[259]

Similarly, supporting a change to dynamic loss factors, EPSDD submitted that the NER should be amended to remove the requirement that AEMO produce loss factors that apply for a whole financial year. AEMO should be instead required to publish one or more loss factors, and the associated time period(s) in which they apply, for the next financial year. This should require AEMO to ensure each connection point has a loss factor in place for the whole financial year. In EPSDD's opinion, this would allow, but not require, AEMO to implement dynamic loss factors. Such changes would enable AEMO to strike an appropriate balance between the simplicity of having a smaller number of loss factors, with the accuracy of a larger number. This may result in loss factors applying for broad time periods such as 'winter nights', 'summer days' and would not necessarily require a separate loss factor for every five minute interval.[260]

ENA submitted that it prefers a move to dynamic loss factors, and in the meantime, more frequent updating and publication of the loss factor values would be an improvement.[261]

AusNet Services submitted that while supporting a move to universally applied dynamic MLFs, it would also see value in allowing generators and market customers to opt-in to dynamic MLFs as an interim step. Under this approach the opting-in market participant is allocated a dynamic MLF for each trading interval, within a week of the trading interval.[262]

In contrast, Mondo submitted that it does not support moving to a dynamic MLF framework. It noted that it seems inevitable that to manage a volatile MLF, market participants would need to come to some agreement in advance of the likely average MLF over the period, and then agree on a calculation to deal with the 'unders' and 'overs' introduced by the dynamic MLF. Mondo noted that if its observation is correct, then it raises the question of what is the value of the dynamic MLF, if it then needs to be effectively 'averaged away' by market participants.[263]

C.5.2 Commission analysis

The Commission has considered stakeholder submissions on dynamic loss factors and maintains its position that a potential change to dynamic marginal loss factors is best

257 IES submission to the consultation paper, p. 1.
258 IES submission to the consultation paper, p. 2.
259 IES submission to the consultation paper, p. 6.
260 EPSDD submission to the consultation paper, p. 6.
261 ENA submission to the consultation paper, pp. 5-6.
262 AusNet Services submission to the consultation paper, p. 1.
263 Mondo submission to the consultation paper, p. 9.

considered along-side broader reforms to transmission access arrangements which are currently being considered as part of its COGATI review.[264]

The Commission acknowledges that it is theoretically possible to compute dynamic loss factors, and that this could achieve market efficiencies. However, it considers that substantial changes such as this are best considered with other changes to wholesale electricity pricing, such as those being considered through the COGATI review. Regard should also be had to the ESB's work on actioning the Integrated System Plan and the post-2025 market design for the NEM.

The introduction of dynamic loss factors would be likely to also require significant, costly changes to AEMO's systems. Accordingly, such a change is unsuitable as a short-term change that could be made before the introduction of further, more fundamental changes that may be made through the implementation of reforms identified in the COGATI review.

While dynamic marginal loss factors are likely to achieve market efficiencies, their use also introduces a higher level of variability. In the absence of any appropriate hedging mechanism being introduced at the same time (for example, financial risk management options as being contemplated under the COGATI review), this could, all other things being equal, lead to unintended consequences. These important flow-on effects warrant further consideration.

C.5.3 Conclusion

While the use of dynamic loss factors for determining transmission loss factors in the NEM could represent an improvement in efficiency, the adoption of dynamic loss factors on their own would introduce additional variability. The introduction of dynamic loss factors should therefore be accompanied by complementary reforms, such as financial risk management options.

Consequently, the introduction of dynamic loss factors would require wider changes to be made, which are beyond the scope of this particular rule change process. Such changes should be considered holistically, and the broader reforms to the transmission access framework being considered by the ESB and by the Commission in its COGATI review represent the appropriate vehicles for this.

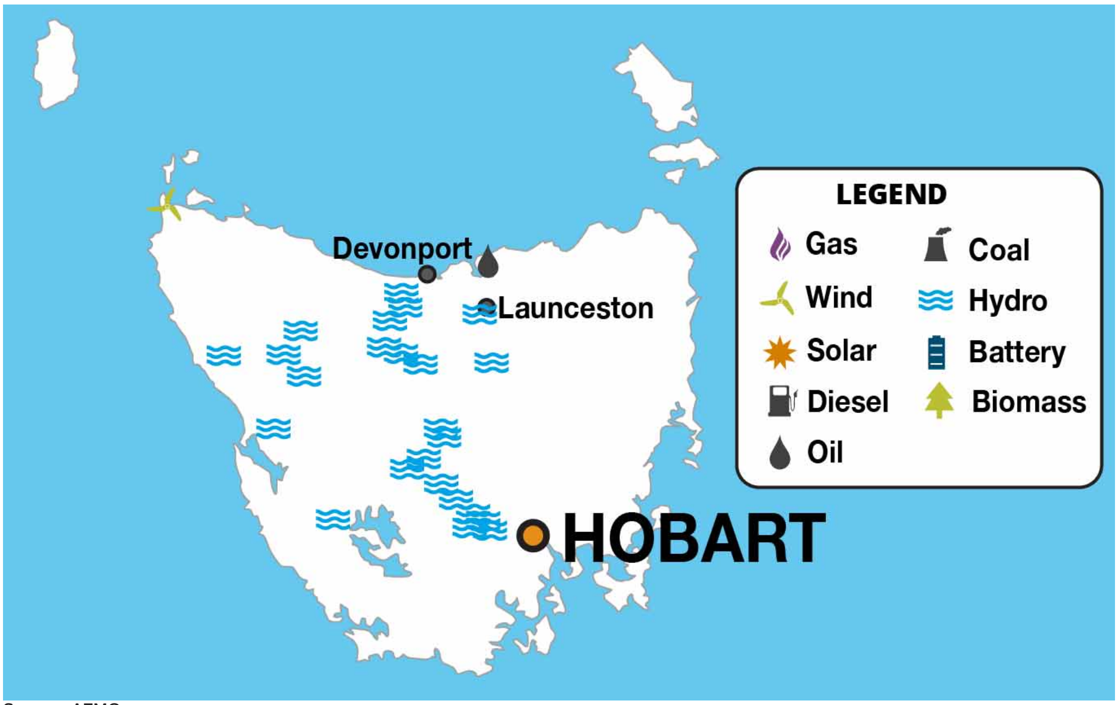
264 AEMC, *COGATI directions paper*, 27 June 2019, pp. 25-34.

D CHANGE IN GENERATION MAPS

The information contained in these maps, including the location and generation type, has been prepared by the AEMC as a general guidance and for information purposes only. The information is based on publicly available sources, and has not been independently verified by the AEMC, and therefore, may not be complete, accurate or up to date.

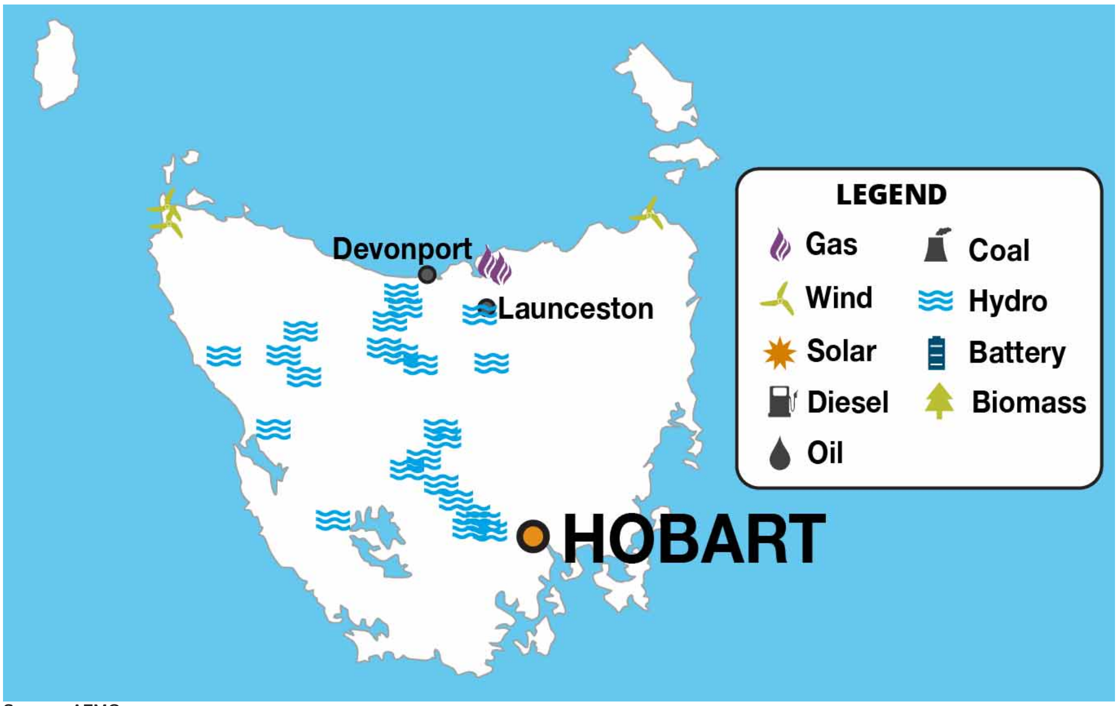
D.1 Tasmania

Figure D.1: Location of generation in Tasmania 2002



Source: AEMC

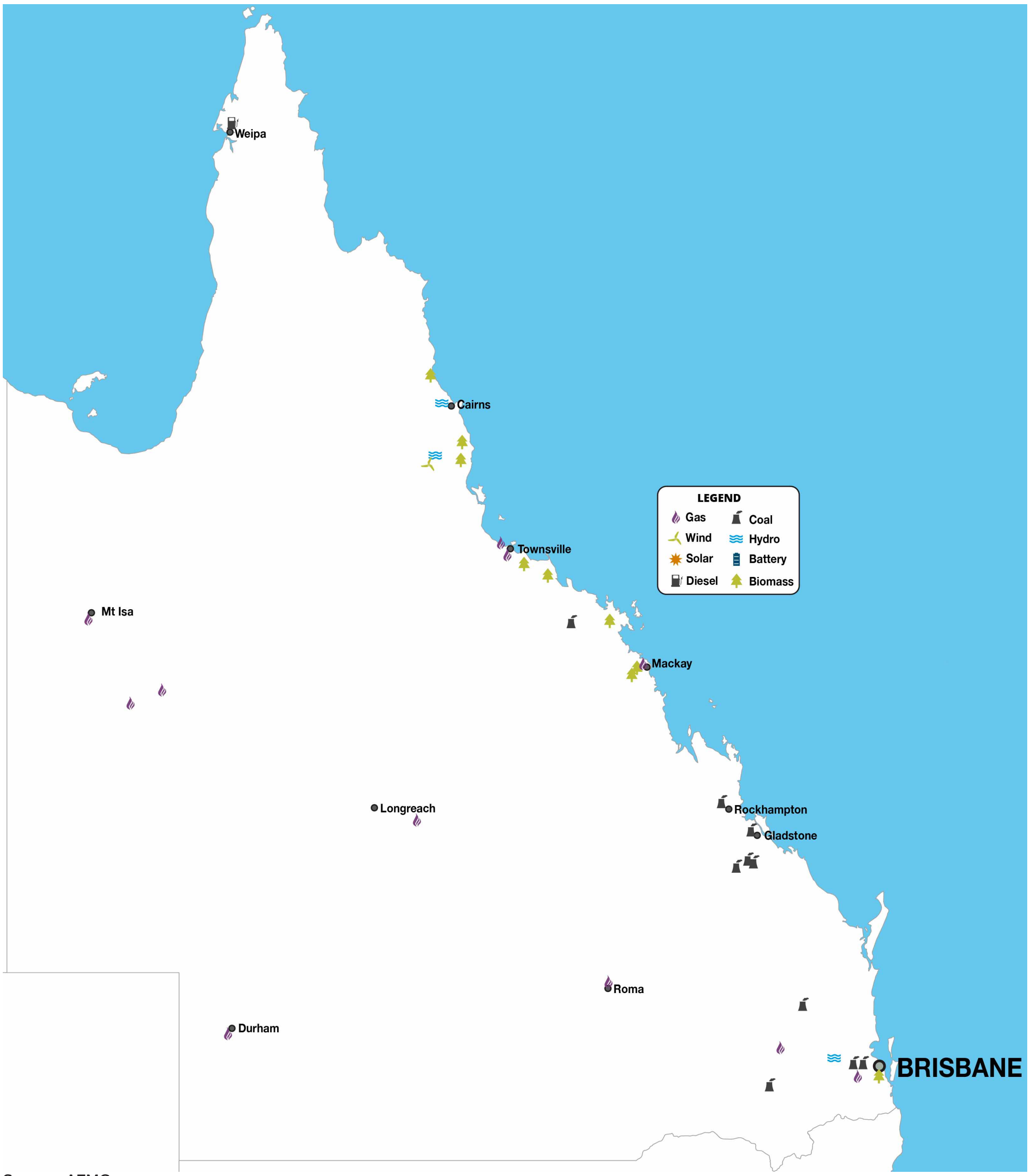
Figure D.2: Location of generation in Tasmania 2019



Source: AEMC

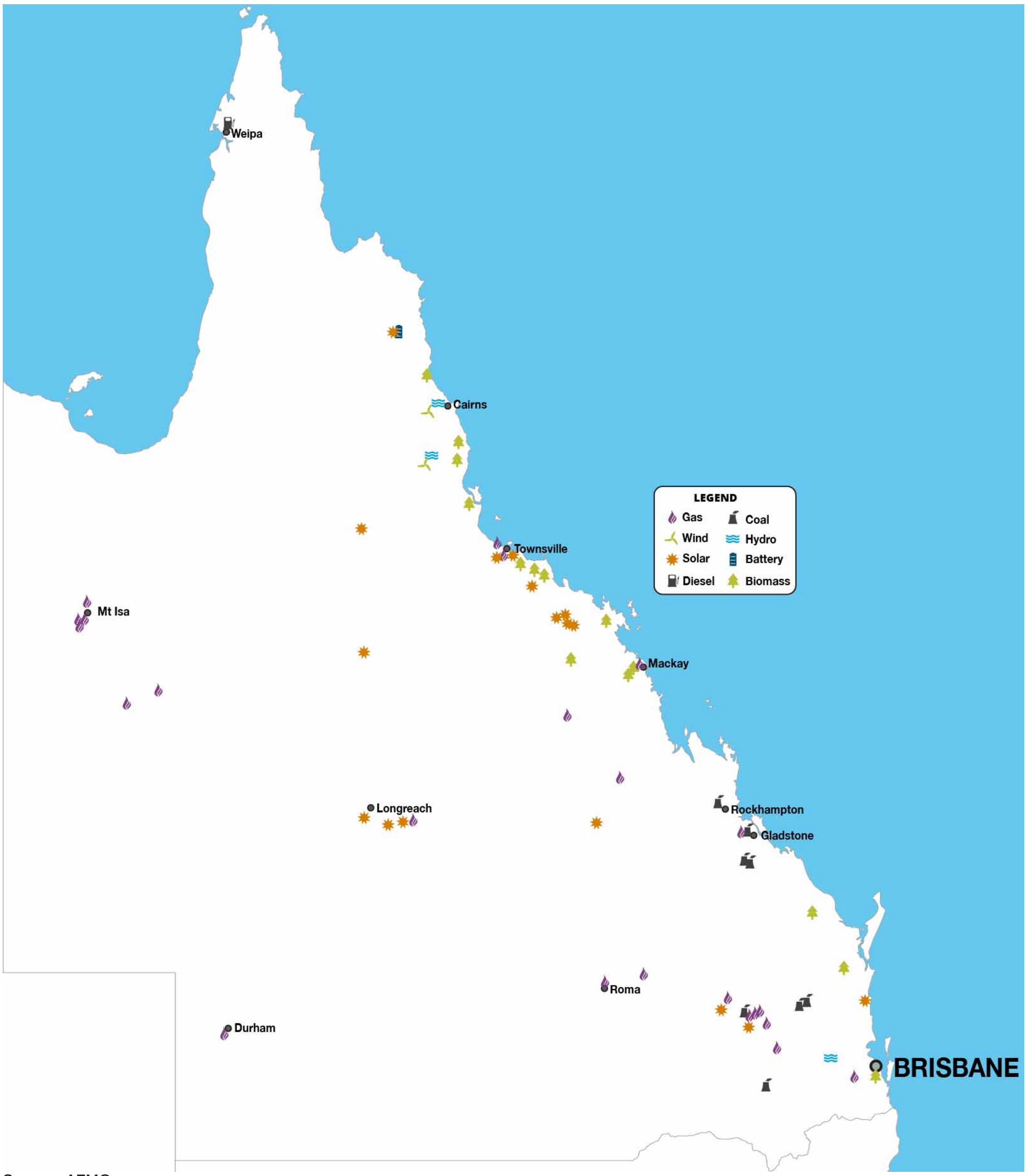
D.2 Queensland

Figure D.3: Location of generation in Queensland 2002



Source: AEMC

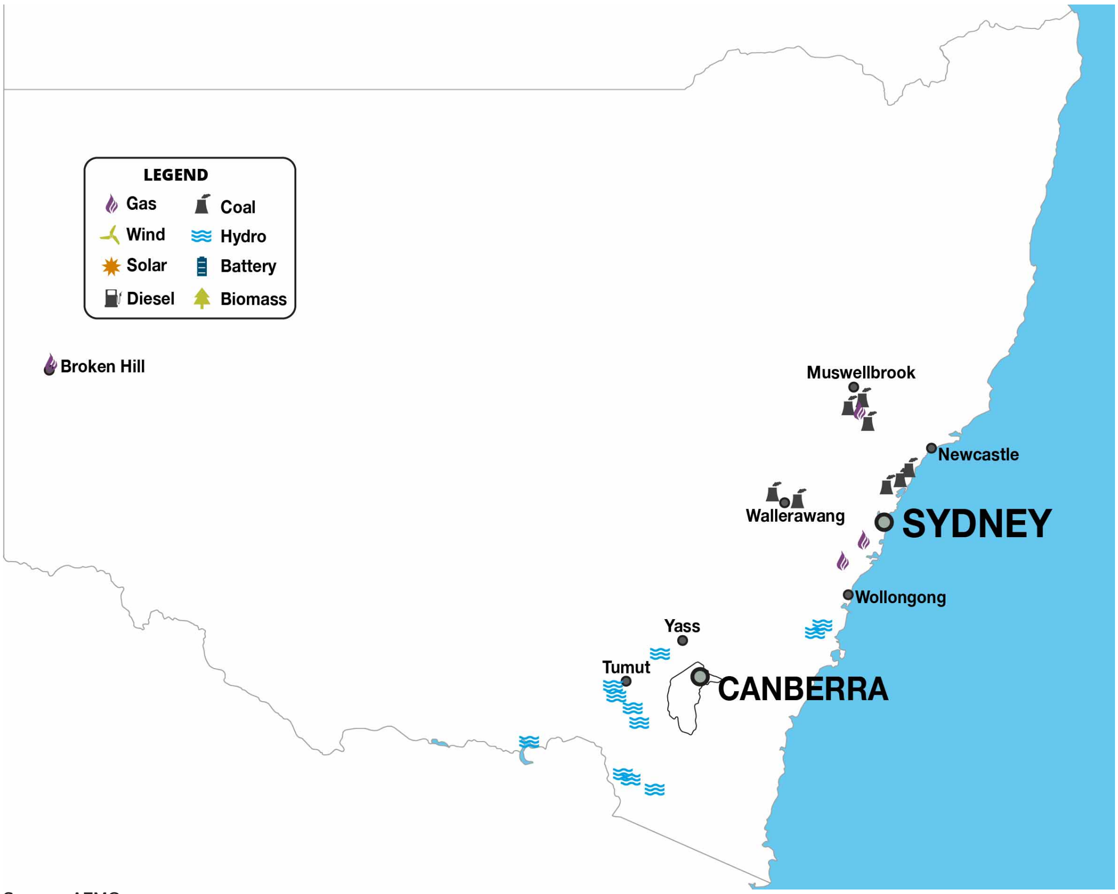
Figure D.4: Location of generation in Queensland 2019



Source: AEMC

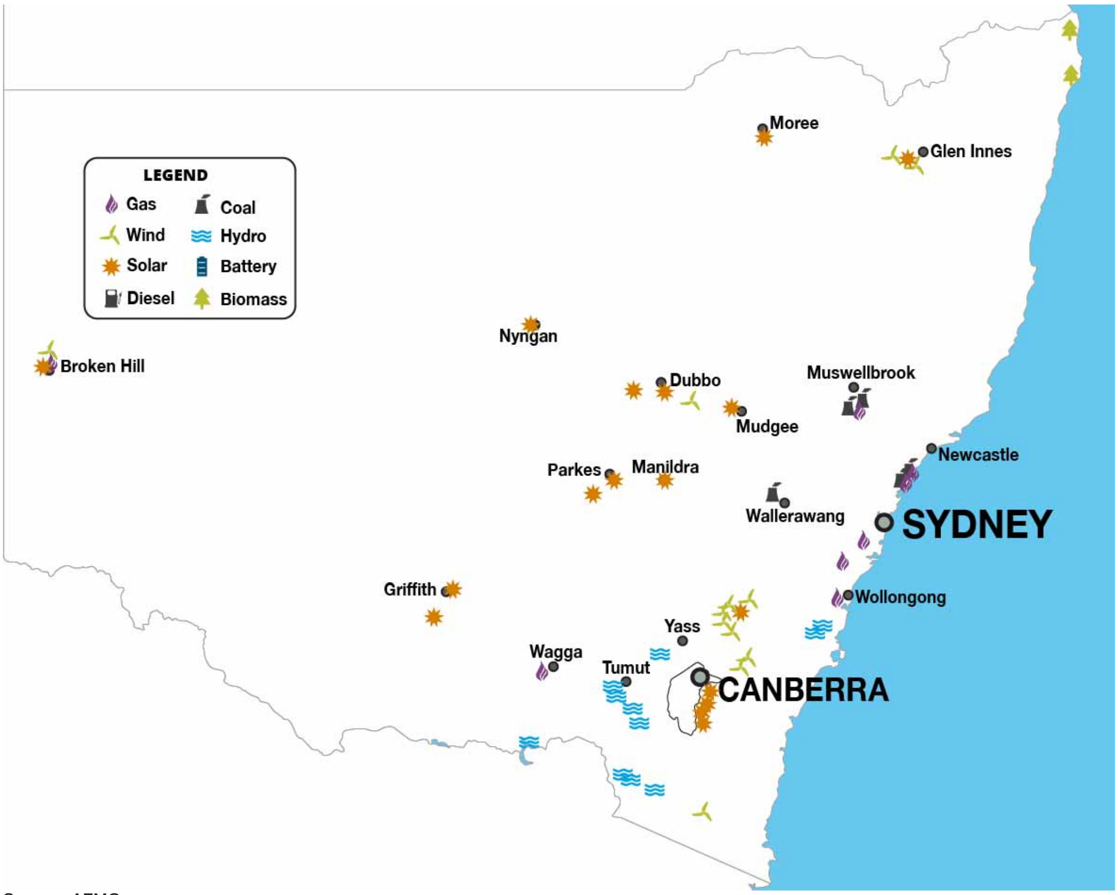
D.3 New South Wales

Figure D.5: Location of generation in New South Wales 2002



Source: AEMC

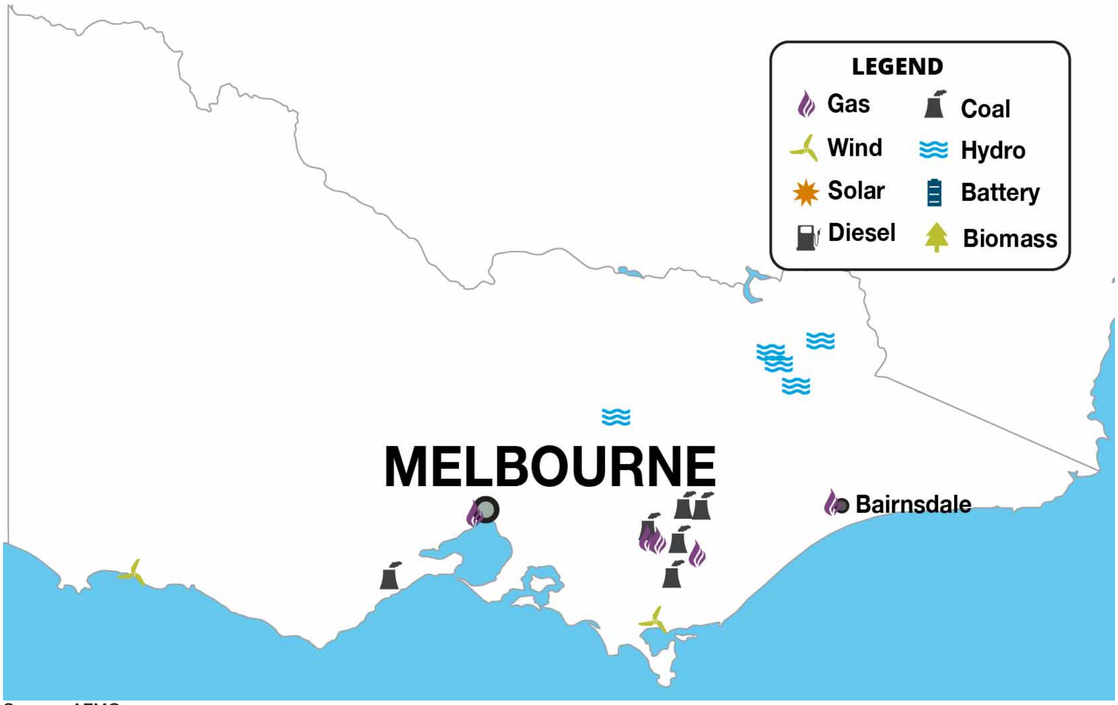
Figure D.6: Location of generation in New South Wales 2019



Source: AEMC

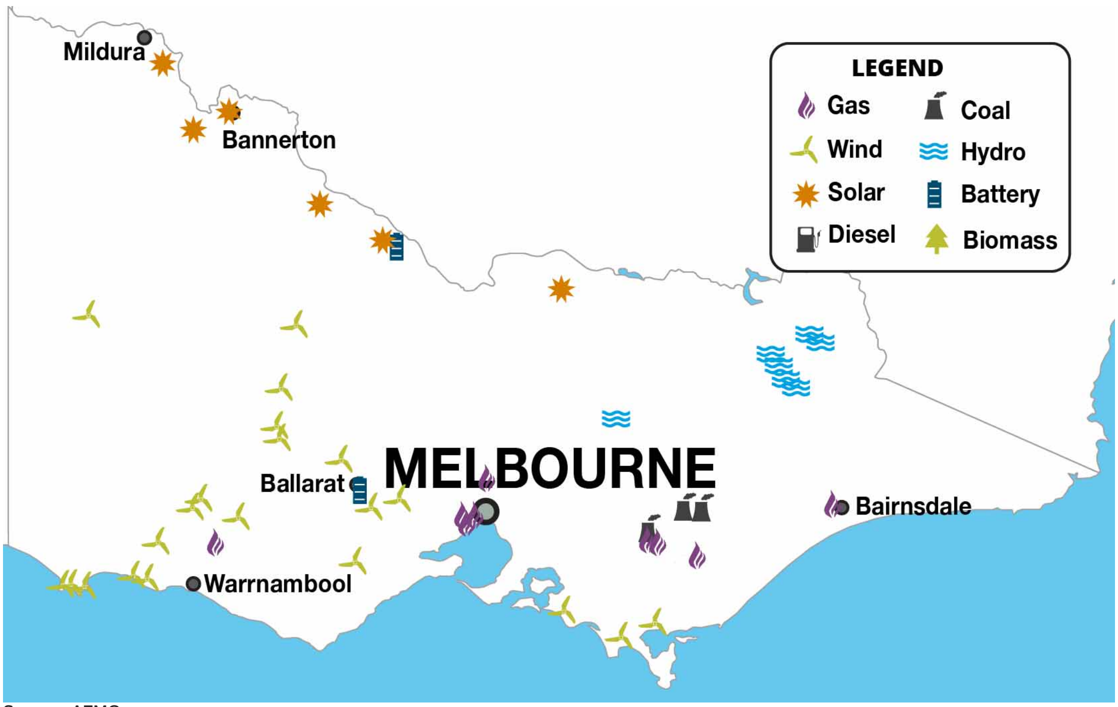
D.4 Victoria

Figure D.7: Location of generation in Victoria 2002



Source: AEMC

Figure D.8: Location of generation in Victoria 2019



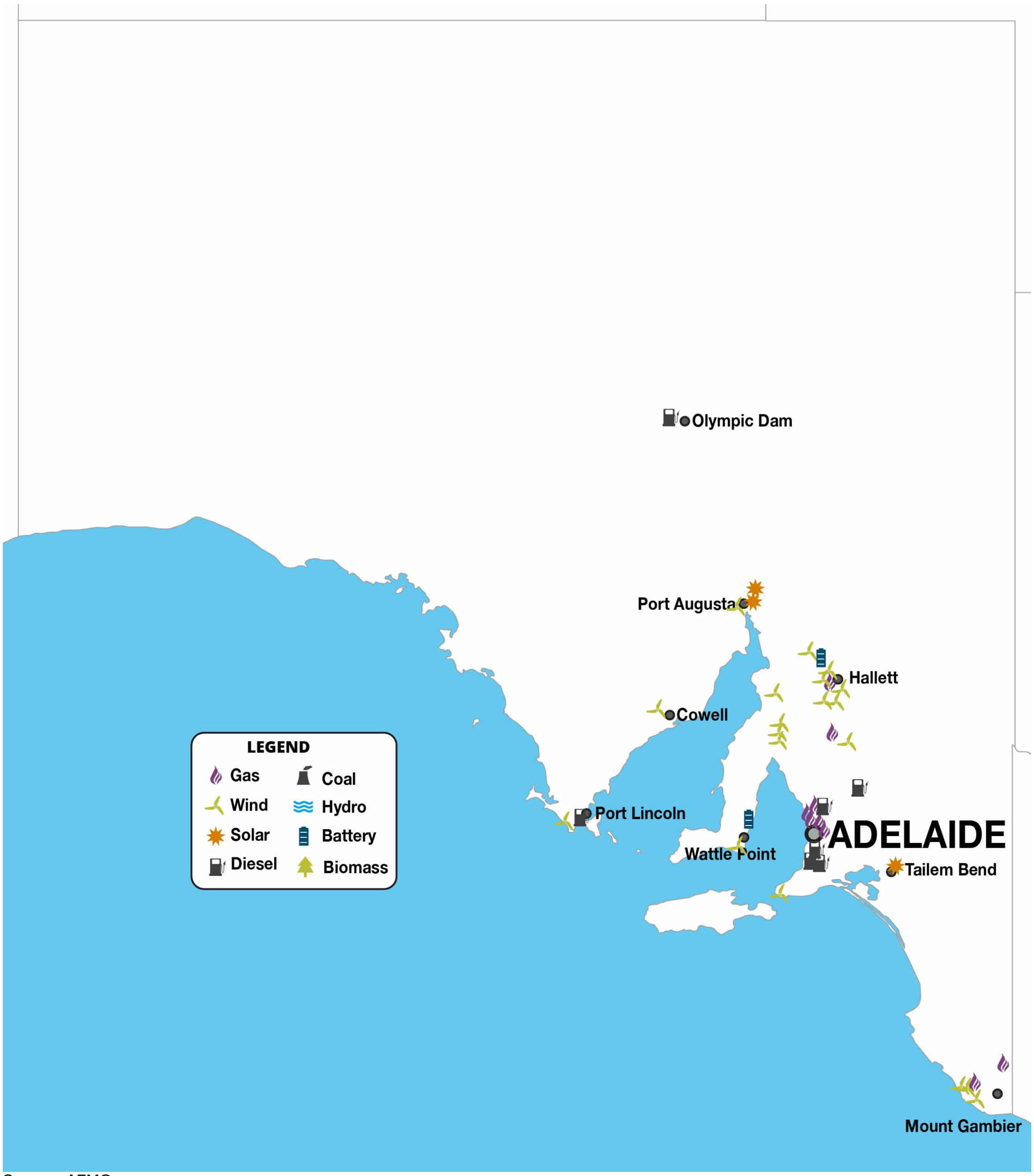
Source: AEMC

D.5 South Australia

Figure D.9: Location of generation in South Australia 2002

Source: AEMC

Figure D.10: Location of generation in South Australia 2019



Source: AEMC