National Electricity Market
Management Company Limited
ACN. 072 010 327

Methodology for Calculating Forward-Looking Transmission Loss Factors: Issues Paper

Prepared by: *Planning*

Version No: *V-08*

FINAL

Table of Contents

1. PURPOSE OF THIS DOCUMENT 1

2. CONSULTATION PROCESS 2

2.1 NOTICE 2
2.2 REVIEW SUBMISSIONS RECEIVED 3
2.3 MEETINGS AND PUBLIC FORUM 3
2.4 DRAFT DECISION SENT TO CONSULTED PARTIES 3
2.5 REVIEW SUBMISSIONS 4
2.6 FINAL DECISION 4

3. BACKGROUND 5

3.1 TREATMENT OF LOSSES IN THE NEM: LOCATIONAL PRICING 5
3.2 PRESENT METHODOLOGY FOR CALCULATING TRANSMISSION LOSS FACTORS 6
3.3 RIEMNS STAGE 1 CODE CHANGE PACKAGE 6
3.4 DEVELOPMENT OF A FORWARD-LOOKING METHODOLOGY 7
3.5 FORWARD-LOOKING LOSS FACTOR REFERENCE GROUP 7

4. ISSUES BEING CONSIDERED BY NEMMCO 9

4.1 PRINCIPLES FROM THE METHODOLOGY 9
4.1.1 Inter-regional Loss Factor Equations 9
4.1.2 Intra-regional Loss Factors 10
4.1.3 Load and Generator Data Forecasting and Modelling 11
4.1.4 Best Approximation to Full Nodal Pricing 11
4.1.5 Marginal Loss Factors 11
4.1.6 The Need to Represent Each Trading Interval 12
4.1.7 Historical Versus Market Simulation Basis 12
4.2 TRANSMISSION NETWORK MODEL 13
4.2.1 How many network configurations are required? 13
4.2.2 How are future network augmentations included? 14
4.2.3 How are future network augmentations verified? 14
4.3 FORECAST CONNECTION POINT LOADS 15
4.3.1 Historical Connection Point Load Data 15
4.3.2 Methodology for Scaling Connection Point Data 16
4.3.3 Scaling the Connection Point Load Forecasts 16
4.3.4 The Timing of the Connection Point Load Forecasts 17
4.3.5 Treatment of New Connection Points 17
4.3.6 Treatment of MVAr 17
4.4 FLOWS IN MARKET NETWORK SERVICE PROVIDERS NETWORKS 18
4.4.1 Determining Flows on Existing MNSP Interconnections 18
4.4.2 Determining Flows on New MNSP Interconnections 18
4.4.3 Basslink 19
4.5 ISSUES ASSOCIATED WITH FORECASTING GENERATION DATA 19
4.5.1 Historical Generation Data 20
4.5.2 General Approaches to Forecasting Generating Data 20
4.5.3 Creating Generating Data for New Generating Units 21
4.5.4 Verification of New Generating Unit Data 22
4.5.5 Existing Energy Limited and Seasonal Generating Units 23
4.5.6 Mothballed generation 23
4.5.7 Accounting Changes to Network Losses 23
4.5.8 Accounting for Interconnector Limits 23

4.5.9 Insufficient Generation Within a Region ... *24*
4.5.10 Out of Merit Order Dispatch ... *25*
4.5.11 Generator Planned and Forced Outages ... *25*
4.5.12 Generator MVAr and Voltage Profile ... *26*
4.6 VOLUME WEIGHTING THE INTRA-REGIONAL MLFS ... 26
4.6.1 Connection Point Load Weighting ... *26*
4.6.2 Pricing Weighting of Loss Factors ... *26*
4.6.3 Time Weighted Loss Factor for Infrequently Running Generation ... *27*
4.7 ESTIMATING INTER-REGIONAL MARGINAL LOSS FACTOR EQUATIONS ... 27
4.7.1 Regression Analysis ... *27*
4.7.2 Process ... *28*
4.7.3 Modelled Data ... *28*
4.8 OTHER METHODOLOGY ISSUES ... 29
4.8.1 Averaging Transmission Loss Factors ... *29*
4.8.2 Multiple Connection Points at the Same Physical Connection ... *29*
4.8.3 Pump Storage Plant ... *30*
4.8.4 New and Modified Connection Points ... *30*
4.8.5 Embedded Generators ... *31*
4.8.6 Maintaining a Nominal Voltage Profile ... *31*
4.8.7 Applying Loss Factors from 1 October rather than 1 July ... *31*

5. REFERENCES ... 33

6. APPENDIX A: TRANSMISSION LOAD CONNECTION POINT FORECAST LOAD PROFILE SCALING ... 34

6.1 REQUIREMENT FOR FORECAST LOAD PROFILES ... 34
6.2 PROCESS FOR PROVIDING FORECAST LOAD PROFILES ... 34
6.3 FACTORS TO BE CONSIDERED IN THE CHOICE OF AN APPROPRIATE SCALING TECHNIQUE 34
6.4 SUMMARY OF SCALING ALGORITHMS ... 35
6.4.1 Energy Only Scaling ... *35*
6.4.2 Linear Proportional Push-Pull ... *35*
6.4.3 Exponential Proportional Push-Pull ... *36*
6.4.4 Selective Peak Push-Pull ... *37*

7. APPENDIX B: FORECASTING THE GENERATING PROFILE FOR NEW UNITS FROM FIXED PROFILES ... 38

8. APPENDIX C: FORECASTING THE GENERATING DATA FOR NEW UNITS BASED ON INFORMATION FROM THE PROPONENTS ... 39

1. Purpose of this document

In March 2002 NECA submitted the Stage 1 of the Review of the Integration of the Energy Market and Network Services (RIEMNS) package of Code changes to the ACCC for authorisation. The ACCC are currently consulting on the package. This package includes the requirement for NEMMCO to consult on a forward-looking methodology for calculating loss factors for the transmission network[1]. In particular:

- the methodology for determining the inter-regional loss factor equations (clause 3.6.1(c)),
- the methodology for determining intra-regional loss factors (clause 3.6.2(d)); and
- the methodology for forecasting and modelling the load and generation data used to calculate the inter-regional loss factor equations and intra-regional loss factors (clause 3.6.2A(b))

NEMMCO is concerned that may be insufficient time to develop a methodology through consultation, implement changes to its systems, audit and test the new method in time to publish the new loss factors by 1 April 2003. In an effort to meet this deadline, NEMMCO is commencing the consultation on the methodology ahead of the ACCC authorisation of the Code changes and may also commence development of their Market Systems. The consultation and system modification work may be invalidated if material changes are required as part of the authorisation.

Therefore, the purpose of this document is to:

- describe the consultation process NEMMCO is following to fulfil the requirements of clauses 3.6.1(c), 3.6.2(d) and 3.6.2A(b);
- discuss the issues NEMMCO is considering when developing its loss factor methodologies; and
- describe the draft methodology that NEMMCO is initially proposing.

[1] This issues paper includes terms that are defined in the Code. Where this occurs the defined term is italicised.

2. Consultation Process

As discussed above clauses 3.6.1(c), 3.6.2(d) and 3.6.2A(b) require NEMMCO, in accordance with the Code consultation procedures, to develop, subsequently publish and maintain the methodology which is to apply to the calculation of transmission loss factors.

NEMMCO must perform the consultation in accordance with the Code consultation procedures described in clause 8.9 of the Code.

Figure 1 illustrates the Code consultation process.

Figure 1 Code Consultation Procedure defined in Clause 8.9

2.1 Notice

NEMMCO announced that the consultation commenced on 24 April 2002. The associated notice was sent to all *Code Participants*, *Intending Participants* and *interested parties*.

NEMMCO has invited submissions on the issues associated with the Code changes for the calculation of forward-looking transmission loss factors, particularly the proposed methodology for calculating the marginal loss equations and the static marginal loss factors for transmission connection points and the method used to establish the data sets used for these calculations.

To be valid, a submission must be received not later than 3 June 2002. This provides the consulted parties more than the 25 business days minimum requirement specified in clause 8.9(a).

2.2 Review Submissions Received

Unless a submission contains confidential information and the submitter requests that NEMMCO does not publish their submission, NEMMCO will publish submissions on the NEMMCO website and send a notice to the consulted parties.

Clause 8.9(f) requires that as the consulting party NEMMCO must consider all valid submissions within a period of not more than a further 20 business days after the close of the consultation period.

2.3 Meetings and Public Forum

Clause 8.9(e) states that "a written submission may state whether a consulted person considers that a meeting is necessary or desirable in connection with the matter under consultation, and if so, the reasons why such a meeting is necessary or desirable".

NEMMCO is holding a Public Forum to discuss the methodology for calculating forward-looking transmission loss factors in Sydney on 20 June 2002. NEMMCO invites the interested parties to attend this forum.

NEMMCO also invites the consulted parties to request an individual meeting in connection with the methodology for calculating forward-looking transmission loss factors . The consulted parties will need to provide reasons why such a meeting is necessary or desirable.

Clause 8.9(f) requires NEMMCO as the consulting party after having considered all valid submissions, to determine whether it is desirable or necessary to hold any meetings with the consulted parties. NEMMCO must use its best endeavours to hold such meetings with consulted persons within a further 25 business days.

2.4 Draft Decision Sent to Consulted Parties

Following the consideration of all valid submissions and the completion of any meetings NEMMCO will publish a draft report on their website. Clause 8.9(g) requires that the draft report sets out:

- NEMMCO's conclusions and any determinations;
- its reasons for those conclusions;
- the procedure followed by NEMMCO when considering the matter; and
- summaries of each issue that NEMMCO reasonably considers to be material and the response to each such issue.

Once the draft report is published then NEMMCO will invite further submissions on the draft methodology for the calculation of forward-looking loss factors. To be valid, a submission must be received before the closing date. The consulted parties will be given at least the 10 business days minimum specified in clause 8.9(i).

2.5 Review Submissions

Clause 8.9(j) requires NEMMCO to consider all valid submissions within a period of not more than a further 30 business days.

2.6 Final Decision

Following the consideration of all valid submissions NEMMCO will publish a final report on their website. Clause 8.9(k) requires that the draft report sets out:

- NEMMCO's conclusions and any determinations on the matter under consultation;
- its reasons for those conclusions;
- the procedure followed by NEMMCO in considering the matter; and
- summaries of each issue that NEMMCO reasonably considers to be material and the response to each such issue.

NEMMCO will not publish their final report until NECA have gazetted the ACCC authorised RIEMNS Stage 1 Code changes.

3. Background

3.1 Treatment of Losses in the NEM: Locational pricing

The basic theory of efficient spot market pricing requires that marginal loss factors (MLFs) be applied to dispatch and settlements processes to provide:

- efficient dispatch of generators and scheduled loads taking into account the cost of losses; and
- correct locational signals for each connection point throughout the power system network.

MLFs reflect the change in losses that would occur for a very small (no more than 1 MW) change in load demand from the current operating level at each connection point on the power system. Theoretically the most rigorous approach to achieve this is to use full nodal pricing to continually calculate and update the MLFs at each dispatch interval. Full nodal pricing also incorporates the shadow price of transmission constraints into the optimal price of electricity at each connection point.

However using a fully dynamic marginal approach for the entire National Electricity Market (NEM) may be too complicated and could act as a barrier to entry for market participants. Indirectly, nodal pricing could deliver an economically less efficient outcome. The current Code design tempers a full marginal loss approach in the interests of simplicity by replacing it with one in which dynamic marginal loss factors apply for the transfer of electricity inter-regionally, static marginal loss factors apply intra-regionally for transmission connection points and loss factors based on average losses apply within a distribution area.

In effect the current design as adopted for the commencement of the NEM provides a zonal approximation to full nodal pricing. The approach taken has been to develop regions that:

- enclose areas where network losses are reasonably static over time; and
- locate major constraints that could impact on the dispatch of generation at region boundaries.

The first issue has been accounted for by separating the NEM into regions between which there are tidal flows of power, on the basis that these flows will produce large variations in MLFs. The variation in MLFs between these regions is accurately modelled by using dynamic inter-regional marginal loss factor equations to reflect this variation with respect to important power system variables.

Within each region the variation in MLFs over time should be significantly less than between regions. As such, using static values to represent the range of intra-regional MLFs at each connection point over a full financial year would provide acceptable accuracy.

The second issue has been accounted for by locating the region boundaries at the connection points where Transmission Network Service Providers (TNSPs) currently specify the limit on power flowing to and from other regions.

The location of the existing boundaries does not always coincide with the location of significant constraints.

The theory of marginal pricing and loss factors in the NEM is described in the NEMMCO document “Treatment of Loss Factors in the National Electricity Market” [1].

3.2 Present Methodology for Calculating Transmission Loss Factors

The current methodology for calculating the intra-regional transmission loss factors and the inter-regional loss factor equations is a backward-looking approach. That is, the loss factors are calculated using historical network flow data from the previous financial year. The present methodology can be summarised as follows:

(1) determine the half hourly transmission connection point metered load and generator data (including MVAr where available);

(2) define the network configuration and base load flow model of the transmission network;

(3) calculate the half hourly loss factors for each connection point using an automated load flow package (TPRICE)[2];

(4) calculate the static intra-regional loss factors as the volume weighted half hourly ratio of the loss factors for each connection point and its associate regional reference node (RRN); and

(5) perform regression analysis on the loss factors between regional reference nodes to specify dynamic inter-regional loss factor equations.

Schedule 3.2 of the Code also includes provisions for accounting for new connection points that have no historical data and for relocating connection points. The NEMMCO methodology will need to include similar provisions as schedule 3.2 is being deleted as part of the Stage 1 RIEMNS Code changes.

The present methodology is described in detail in the NEMMCO document “Treatment of Loss Factors in the National Electricity Market” [1].

3.3 RIEMNS Stage 1 Code Change Package

NECA is undertaking a review of the integration of the energy market and network Services (RIEMNS). The scope of RIEMNS includes:

- criteria for determination of region boundaries;
- managing market power;
- a redefined regional structure;
- beyond the initial refined regional structure;
- improved risk management;

[2] The TRPICE application calculates the loss factor for each connection point and regional reference node (RRN) referred to the load flow swing bus defined in the network model. The loss factor of connection point A referred to connection point B is defined as the ratio of their respective loss factors with respect to the swing bus.

- towards firmer access; and
- treatment of losses.

In August 2001 NECA published for consultation the RIEMNS Stage 1 package of Code changes that implemented some of the recommendations that emerged from RIEMNS. The proposed Code changes cover the development of a methodology to calculate forward-looking loss factors and the introduction of performance measures for transmission network service providers (TNSPs).

In December 2001 NECA published a revised package of RIEMNS Stage 1 Code changes for a second round of consultation.

In late March 2002 NECA submitted the RIEMNS Stage 1 Code change package to the ACCC for authorisation. The ACCC are currently consulting on the package.

3.4 Development of a Forward-Looking Methodology

The RIEMNS Stage 1 Code changes require NEMMCO to develop, publish and maintain, in accordance with the Code consultation procedures, methodologies for:

- the determination of *inter-regional loss factor* equations for a *financial year*, describing *inter-regional loss factors* between each pair of adjacent *regional reference nodes* in terms of significant variables (clause 3.6.1(c)),
- the determination of *intra-regional loss factors* to apply for a *financial year* for each *transmission network connection point* (clause 3.6.2(d)); and
- forecasting the *load* and *generation* data to be used in both the determination of *inter-regional loss factor* equations and *intra-regional loss factors*; and modelling additional *load* and *generation* data, where required, to be used in determining *inter-regional loss factor* equations (clause 3.6.2A(b)).

3.5 Forward-Looking Loss Factor Reference Group

In an effort to expedite the consultation and improve the quality of the consultation process, NEMMCO formed the Forward-Looking Loss Factor Reference Group (denoted as the Reference Group) to assist with the preparation of this consultation paper.

NEMMCO invited a representative cross-section of the NEM participants to be members of the Reference Group. The Reference Group consisted of:

- NEMMCO (as convenor);
- jurisdictional transmission planning entities (Powerlink, TransGrid, VENCorp, ESIPC and Transend)
- two representatives from the National Generator Forum
- one representative of the National Retailer Forum
- a customer representative

- an embedded generator representative

In addition NEMMCO has kept NECA informed of the Reference Group activities.

The operation of the Reference Group is now suspended as the consultation process has commenced. The members of the Reference Group are free to participate in the NEMMCO consultation, along with all other Code Participants, Intending Participants and interested parties. NEMMCO may decide to reconvene the Reference Group during the consultation process if additional complex issues are raised during the consultation process.

4. Issues being considered by NEMMCO

Sections 3.1 and 3.2 above provide a brief explanation of the treatment of losses in the NEM and the present backward-looking approach to the calculation of transmission losses factors using historical load and generator data.

This section discusses the issues NEMMCO is considering when developing the forward-looking loss factor methodology.

4.1 Principles from the Methodology

The RIEMNS Stage 1 Code changes require NEMMCO to consider the following principles when developing the forward-looking loss factor methodology. Some additional principles that NEMMCO believes are important are also included in this document.

4.1.1 Inter-regional Loss Factor Equations

Clause 3.6.1(d) requires NEMMCO to implement the following principles when developing the methodology for calculating inter-regional loss factor equations:

(1) Inter-regional loss factor equations are to apply for a financial year;

(2) Inter-regional loss factor equations must be suitable for use in central dispatch.

(3) Inter-regional loss factors are determined as part of central dispatch using inter-regional loss factor equations. The inter-regional loss factors must,

(i) as closely as is reasonably practicable, describe the marginal electrical energy losses for electricity transmitted through the relevant regulated interconnector between the 2 *relevant regional reference nodes* in adjacent *regions* in those trading intervals; and

(ii) aim to minimise the impact on the *central dispatch* of *generation* and *scheduled load* as compared to the *dispatch* of *generation* and *scheduled load* which would result from a fully optimised dispatch process taking into account the effect of losses.

(4) Inter-regional loss factor equations are determined using forecast *load* and *generation* data and, if required, modelled *load* and *generation* data for the *financial year* in which the *inter-regional loss factor* equations are to apply. The forecast *load* and *generation* data and modelled *load* and *generation* data, if any, used must be that *load* and *generation* data prepared by *NEMMCO* pursuant to clause 3.6.2A;

(5) Inter-regional loss factor equations are determined by applying regression analysis to the *load* and *generation* data referred to in paragraph (4) above to determine:

(i) the variables which have a significant effect on the marginal electrical energy losses for electricity transmitted through each regulated interconnector for both directions of flow on those regulated interconnectors; and

(ii) the parameters that represent the relationship between each of those variables and the marginal electrical energy losses;

4.1.2 Intra-regional Loss Factors

Clause 3.6.2(e) requires NEMMCO to implement the following principles when developing the methodology for calculating intra-regional loss factors:

(1) Intra-regional loss factors are to apply for a financial year.

(2) 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 *regional reference node* in the same *region* for each *trading interval* of the *financial year* in which the *intra-regional loss factor* applies.

(2A) *Intra-regional loss factors* must aim to minimise the impact on the *central dispatch* of *generation* and *scheduled load* compared to that which would result from a fully optimised dispatch process taking into account the effect of losses.

(3) Forecast *load* and *generation* data for the *financial year* for which the *intra-regional loss factor* is to apply must be used. The forecast *load* and *generation* data used must be that *load* and *generation* data prepared by *NEMMCO* pursuant to clause 3.6.2A;

(4) The *load* and *generation* data referred to in paragraph (3) above must be used to determine *marginal loss factors* for each *transmission network connection point* for each *trading interval* in the *financial year* to which the *load* and *generation* data relates;

(5) The *intra-regional loss factor* for each *transmission network connection point* is determined using a volume weighted average of the *marginal loss factors* for the *transmission network connection poin*t;

(6) In determining the intra-regional loss factor for a transmission connection network point, flows in network elements that solely or principally provide market network services will be treated as invariant, as the methodology is not seeking to calculate the *marginal losses* within such *network element*s.

4.1.3 Load and Generator Data Forecasting and Modelling

Clause 3.6.2A(d) requires NEMMCO to implement the following principles when developing the methodology for forecasting and modelling the load and generator data required to calculate inter-regional loss factor equations and intra-regional loss factors:

(1) 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:

(i) actual *load* and *generation* data available for a 12 month period defined by the methodology with the objective to use the most recent *load* and *generation* data practicable;

(ii) projected *load* growth between each calendar month to which the actual *load* and *generation* data referred to in sub- paragraph (i) relates and the same calendar month in the *financial year* for which the forecast *load* and *generation* data is determined; and

(iii) the projected *network* configuration and projected *network* performance for the *financial year* in which the *inter-regional loss factor* equation or *intra-regional loss facto*r, as the case may be, is to apply

(2) Additional modelled *load* and *generation* data sets must only be used:

(i) in the determination of *inter-regional loss factor* equations under clause 3.6.1; and

(ii) where the range of *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 interconnecto*r.

4.1.4 Best Approximation to Full Nodal Pricing

As discussed in section 3.1, the most rigorous approach to achieve correct locational pricing and optimal dispatch is to use full nodal pricing.

In accordance with this view and 3.6.2(e)(2A), NEMMCO believes an appropriate approach when assessing alternatives in the methodology is to compare their outcomes with those anticipated under a regime of full nodal pricing. The option which gives the closest approximation would be preferred.

4.1.5 Marginal Loss Factors

The marginal loss factor and region boundary model adopted for the NEM is a zonal approximation to the implementation of full nodal pricing. In full nodal pricing, differentiation is used to determine the change in losses for an infinitely small change in load at each connection point.

To be consistent with this approach NEMMCO believes that marginal loss factors should be determined by the first derivative of the network loss function at a particular level of network flows. The use of the derivative in calculating marginal loss factors is supported by the RIEMNS Stage 1 principles above and the glossary definition of marginal electrical energy losses and marginal loss factors.

The TPRICE application used by NEMMCO takes the derivative terms from the Jacobian matrix [1] for each trading interval to calculate loss factors.

4.1.6 The Need to Represent Each Trading Interval

Clause 3.6.2(e)(4) requires NEMMCO to calculate the marginal intra-regional loss factors for each transmission connection point for each trading interval, prior to calculating the volume weighted average(clause 3.6.2(e)(5)). Similarly, clause 3.6.1(d)(3) requires the inter-regional loss factor equations to describe the marginal electrical energy losses as closely as practically for each trading interval.

Therefore, NEMMCO believes that it is necessary to represent each trading interval when calculating the intra-regional loss factors and the inter-regional loss factor equations, rather than considering a reduced set of representative periods (such as peak, off peak and shoulder) and applying them to financial year in which the loss factors are to apply.

4.1.7 Historical Versus Market Simulation Basis

As the methodology being developed is forward-looking it will be necessary to scale loads and energy to meet forecast values. Corresponding forecasts of future generation data and hence transmission network flows will also be required.

Broadly there are two possible approaches to forecasting future generation data and network flows. These are:

- simulations of market dispatch based on historical or SRMC bidding; and
- basing forecast load and generating data on historical dispatch behaviour with minimal changes to accommodate as load growth, new generating units and network augmentations.

In this document both approaches are discussed in more detail. However, NEMMCO's preference is that the methodology should be based as closely as possible on historical market behaviour because:

- the results of market simulations are very dependent on the detailed assumptions made about the bidding behaviour of existing and future market participants; and
- loss factors based on historical dispatch behaviour will be more deterministic.

4.2 Transmission Network Model

To calculate the loss factors and loss factor equations it is necessary to obtain a load flow representation of the NEM transmission network. Clause 3.6.2A(d)(1)(iii) of the RIEMNS Stage 1 Code changes states:

> ”the projected *network* configuration and projected *network* performance for the *financial year* in which the *inter-regional loss factor* equation or *intra-regional loss facto*r, as the case may be, is to apply”.

This raises the following questions.

4.2.1 How many network configurations are required?

To calculate the loss factors for each trading interval it is necessary to solve 17520 load flows (17568 for a leap year). This requires the use of an automated load flow package. It is not practical to develop a separate network model for each of the 17520 trading intervals.

At present NEMMCO uses a single network configuration described by a base case load flow with a fixed network configuration representing the entire financial year in which the loss factors will apply. This has been necessary because the automated load flow application TPRICE uses a single base case load flow to represent each trading interval studied.

NEMMCO has based this load flow on a high demand condition with all normally connected equipment in service. The switching arrangement for the Victorian 220 and 500 kV networks is selected to reflect normal operating conditions. The use of a high demand condition is necessary to ensure convergence of the load flow for each trading period.

In some parts of the network, special switching conditions may be modelled. For example, in Victoria, the power system will be modelled in radial mode and the special arrangements applying to Yallourn Unit 1 will be represented[3].

NEMMCO does not believe there is sufficient value in considering system conditions other than system normal as:

- the normal level of transmission outages, both planned and forced, is very low[4] and the incorporation of a number of such outages into the calculation would be disproportionately complex and difficult,
- the timing and location of the occasional major transmission outages that would materially affect loss factors are not predictable, and hence incorporation of these into a the calculation of forward-looking loss factors is not feasible.

Similarly, NEMMCO does not believe it is necessary to use multiple network configurations to represent high and low load conditions as the flows in the network are specified by the metered load and generator data.

[3] Yallourn unit 1 can be connected to either the 220 kV or 500 kV network. This can be represented by two generators, one for each point of injection. The generation profile for each injection would be based on the historical generation patterns of the unit.

[4] Typical targets for transmission availability are > 99.0% with forced outage rates of < 0.1%.

4.2.2 How are future network augmentations included?

It is not practicable to change the network configuration for each proposed network augmentation as:

- the commissioning dates of major network augmentations are usually uncertain at the time the loss factors are being calculated; and
- the automated load flow software used to calculate the loss factors requires a single base load flow case with a fixed network configuration, although for major network augmentations it would be possible to partition the data and use several network representations.

As stated in section 4.2.1 it is NEMMCO's opinion that only a minimum number of network configurations should be used for purposes of calculating loss factors.

The following procedure is suggested to ensure that the network configuration used to calculate marginal loss factors is compatible with the network configuration that will actually exist during the period when the marginal loss factors apply:

- where transmission augmentations are anticipated to be completed during the period July 1 – October 31, the modification be included in the network model for the entire financial year;
- where transmission augmentations are anticipated to be completed during the period November 1 – April 30, the modification be included in the network model for the last eight months of the financial year only; and
- where transmission augmentations are expected to be commissioned in the remainder of the financial year for which the marginal loss factors apply, the augmentation will not be included in the network configuration.

This three step approach should provide sufficient accuracy of the calculated marginal loss factors while avoiding the additional complexity and time that would be required to break the source data into a number of time periods consistent with the timing of each separate augmentation. The period November – April has been chosen to include those projects that are required for the summer and winter periods and as such are typically scheduled for commissioning in November and April respectively.

4.2.3 How are future network augmentations verified?

The impact of an augmentation to the transmission network may have a significant impact on the loss factors and loss factor equations. Therefore it is important that the characteristics and timing of augmentations are correct.

NEMMCO will require confirmation from the relevant TNSPs and DNSPs to ensure the correct network configuration is used. The TNSPs and DNSPs would be required to state that the augmentation projects in their network meet the commitment criterion in section 9.3 of the NEMMCO SOO [4], listed below:

1. the proponent has purchased/settled/acquired land[5] (or legal proceedings have commenced) for the construction of the proposed development;

2. contracts for the supply and construction of the major components of plant or equipment (such as generators, turbines, boilers, transmission towers, conductor, terminal station equipment) should be finalised and executed, including any provisions for cancellation payments;

3. the proponent has obtained all required planning consents, construction approvals and licences, including completion and acceptance of any necessary environmental impact statements;

4. the financing arrangements for the proposal, including any debt plans, must have been concluded and contracts executed; and

5. construction of the proposal must either have commenced or a firm commencement date must have been set.

Considering that the loss factor calculations will only require network developments within the next 12-18 months, there should be little difficulty meeting the criteria for commitment.

4.3 Forecast Connection Point Loads

The annual energy in the NEM may grow by several percent per year, and this will impact on transmission flows and the dispatch of generation throughout the interconnected power system. To include this effect in marginal loss factor calculations, historical load data should be scaled up to the demand and energy levels expected for the financial year for which the marginal loss factors apply.

Clause 3.6.2A(d)(1) requires load data that is representative of the expected load in the financial year in which the loss factors and loss factor equations are to apply, having regard to the most recent actual data available and the projected load growth.

4.3.1 Historical Connection Point Load Data

Clause 3.6.2A(d)(1)(i) requires the NEMMCO methodology to have regard for the 12 month period of actual load data available be used as the basis of the forecast connection point loads.

Connection point load and generator data is available to NEMMCO from their metering and settlement systems. Under clause 3.15.18(b) this data can be disputed within the period six months after the relevant billing period. Therefore, the settlements data can not be regarded as final until the later of 6 months or any relevant dispute is resolved. This introduces some potential practical issues.

5 Purchase of land or acquisition of easements, if required, do not imply by themselves a binding financial commitment but are a pre-requisite for commitment.

- The most recent data to become available by early January when NEMMCO would commence the loss factor calculation is from June the previous year. Therefore, effectively the most recent data is the data for the previous financial year.
- In the event that there are any unresolved settlement data disputes at 31 December, NEMMCO proposes to use the data as listed in the NEMMCO settlement systems at 31 December of the preceding year.

The Tasmanian network does not currently have connection point metering. Therefore, when Tasmania joins the NEM it may be possible that metered historical connection data will not be available. If this is the case the loss factors and loss factor equations would need to be calculated from SCADA data until sufficient metered historical connection data is available.

4.3.2 Methodology for Scaling Connection Point Data

The 12 months of actual load data needs to be modified to include the effects of load growth and any large known changes. These modifications include;

- large load changes (increase and decrease) at specific transmission connection points, including the anticipated timing as advised by the TNSPs and other participants
- scaling of the remainder of the load data to meet the forecast annual energy and the seasonal peak demands.

There are a number of possible algorithms that can be used to scale the historical connection point data to match the annual energy and seasonal maximum demand forecasts. Appendix A contains a discussion on some of the possible algorithms.

NEMMCO invites submissions on these algorithms.

4.3.3 Scaling the Connection Point Load Forecasts

The relevant TNSP could supply NEMMCO with the information necessary to scale the connection point data within their network. This forecast information should be consistent with the load forecasts prepared by the TNSPs in accordance with section 5.6 of the Code, published in the TNSP Annual Planning Review and the NEMMCO SOO [4]. NEMMCO would then apply the appropriate methodology described in Appendix A.

An alternative to NEMMCO performing the scaling is for the relevant TNSPs would supply NEMMCO with scaled load data for each connection point within their network for each trading interval. NEMMCO prefers this approach as the individual TNSPs have a detailed knowledge of the characteristics of each new connection point through their connection agreements with the DNSPs and large customers.

If the TNSPs provide the half hourly forecast of each of the connection points within their network then the TNSPs would be bound to follow the principles adopted in the NEMMCO methodology described in Appendix A.

NEMMCO is seeking comment on the process for scaling load data for each of the individual transmission connection points.

4.3.4 The Timing of the Connection Point Load Forecasts

The Network and Distributed Resources Code changes will require the NEMMCO SOO [4] to be published by 31 July each year, with an update by 31 January. The TNSPs will be required to supply NEMMCO with the relevant data, including regional load forecasts, by 30 April and 31 October. The regional load forecasts supplied by the TNSPs for the SOO will be prepared after the connection point load forecasts supplied by the TNSPs for the purposes of calculating the loss factors. Therefore, these forecasts may not be completely consistent as they are prepared at different times but the forecasts would otherwise be on the same basis.

This issue is discussed further in section 4.8.7.

4.3.5 Treatment of New Connection Points

Where the relevant TNSP indicates to NEMMCO that there is a new or modified transmission connection point that will be established in the financial year in which the loss factors will apply, a loss factor will be required. This includes:

- new directly connected customers;
- new or modified transmission substations; and
- relocating loads.

Confirmation of new or modified connection points by the end of January each year will allow NEMMCO sufficient time to include the modification in the loss factor calculations for the following financial year.

The profile for the new or modified load at each trading interval should be provided by the relevant TNSP.

Where the TNSP using reasonable endeavours is unable to provide an estimate of the profile by the end of January, a default load of not more than 1 MW would apply for each trading interval.

The timing advised by the relevant TNSP will be used to model the commencement of the new load.

4.3.6 Treatment of MVAr

The load data used to calculate the loss factors and the loss factor equations must include forecasts of the connection point reactive power in addition to the real power. Options for forecasting the reactive power include:

- applying an average annual power factor for each connection point calculated from the historical load data; and

- applying a separate power factor for each connection point from the equivalent trading interval from the historical load data.

NEMMCO believes that a separate power factor for each connection point and each trading interval is appropriate where the data exists. Average power factors would only be applied where the detailed data is not available.

Another approach to is consider if the associated TNSPs and DNSPs have committed capacitor banks at any of the transmission connection points. Additional capacitor banks planned for a connection power would improve the power factor and would offset the additional reactive power requirements due to load growth.

4.4 Flows in Market Network Service Providers Networks

4.4.1 Determining Flows on Existing MNSP Interconnections

When developing the methodology for calculating the intra-regional loss factors clause 3.6.2(e)(6) requires:

> "the intra-regional loss factor for a transmission connection network point, flows in network elements that solely or principally provide market network services will be treated as invariant."

The RIEMNS Stage 1 Code changes do not provide any guidance for determining the flows in MNSP interconnections when calculating the inter-regional loss factor equations. NEMMCO believes that the treatment of MNSP projects should be consistent for both intra-regional loss factors and inter-regional loss factor equations.

NEMMCO believes that the MNSP interconnector flows for the year in which the loss factors are to apply should be equal to the flows that occurred historically. That is, the MNSP flows would remain unchanged from the historical metered values corresponding to the trading periods associated with the historical transmission connection point load traces. This ensures that the relationship between the historical load traces and MNSP flows are maintained.

Alternative approaches could include:

- assuming zero flow for MNSP interconnectors;
- assume that the MNSP flows are in proportion to parallel flows in regulated interconnectors; or
- perform detailed market modelling assuming that the capability of the MNSP is offered at a bid of zero.

NEMMCO does not believe that there is a basis for these options.

4.4.2 Determining Flows on New MNSP Interconnections

NEMMCO does not believe there is a general basis for forecasting flows on new MNSP interconnections, such as Murraylink. Each case would be different and even where the direction of flow may seem obvious the size of the MNSP flow cannot be readily determined.

Therefore, NEMMCO believes that the most appropriate approach is to assume zero flow (not more than 1 MW) on a new MNSP interconnection in the year in which the loss factors and loss factor equations apply.

Where an MNSP has historical flow data for only part of the previous 12 months then it is proposed that the available data is used (as for an existing MNSP) and zero flow is assumed where no data is available (as for new MNSPs).

When historical actual flow data has been collected then NEMMCO would represent the new MNSP as an existing MNSP, as described in section 4.4.1.

4.4.3 Basslink

The forecast transfers on the Basslink project will have a significant impact on the loss factors in both Victoria and Tasmania. Also, unlike other MNSP developments, there are strong expectations that Basslink will transfer power north during the day and south during the night, with a zero net flow of energy in a typical year.

Therefore, NEMMCO believes that it is not adequate to simply forecast zero flows on the Basslink interconnector for the purpose of calculating loss factors before sufficient historical flows exist. Rather NEMMCO would propose that the following forecast of the Basslink flow:

- from 7:00 AM to 7:00 PM assume 300 MW north; and
- from 7:00 PM to 7:00 AM assume 300 MW south.

When historical actual flow data has been collected then NEMMCO would represent Basslink as an existing MNSP, as described in section 4.4.1.

If in the future a MNSP project is built where there is both a large impact on the network and there is a strong expectation on it behaviour then NEMMCO could consider undertaking a Code consultation to modify their methodology to include another special case for that interconnector.

NEMMCO is seeking comment on:

- the proposal to have special treatment for the Basslink project;
- the proposed dispatch for Basslink; and
- the possibly other future MNSP projects as special cases.

4.5 Issues Associated with Forecasting Generation Data

Clause 3.6.2A(b) requires the development of a methodology for forecasting generation data for the year in which the loss factors and loss equations apply. The following issues need to be considered when forecasting the generation data. The methodology developed for the forecasting of generation data will need to address each of these issues while being internally consistent.

4.5.1 Historical Generation Data

The forecast generation data will be dependent on the historical generation data to some extent, depending on the forecasting methodology chosen. The historical generation data with be obtained from the same NEMMCO database for the same 12 month period as the connection point load data.

4.5.2 General Approaches to Forecasting Generating Data

Following the scaling of loads to account for load growth and the inclusion of new generation (discussed in section 4.5.3 below) and network augmentations, the generating data will no longer match the load and losses. Therefore it will be necessary to determine a procedure for modifying the generating data to restore the supply/demand balance.

As discussed in section 4.1.7, the two general approaches to forecasting generating data are to:

1. perform simulations of market dispatch; and
2. make minimal extrapolations in a prescribed manner from historical metered data.

<u>1. Simulation of Market Dispatch</u>

If market simulations are performed it is necessary to establish a merit order for the generators within a region and determine interconnector flows. The merit order can be estimated by a number of means but two possible options are:

- obtaining short-run marginal cost (SRMC) values for each dispatchable unit and assume that the forecast generator dispatch will not deviate from that predicted from SRMC bidding; and
- aggregating the offers for each dispatchable generator over the previous 12 months to produce an average historical offer.

It is not practicable to use SRMC bidding because of the difficulties in developing defensible SRMC data for each generator. Disputes over loss factors would inevitably include scrutiny of the uncertain SRMC data. Such a weakness in the methodology could potentially be exploited to an extent where the whole methodology becomes impractical.

Similarly, the future half hourly offers of some generating units may have no relationship to the half hourly generator dispatch that occurred in the previous year. Nevertheless, the historical approach is considered to be more defensible than the SRMC approach as there is an irrefutable source for the data used to determine the merit order. Adopting an approach based on historical bids would additionally require a method to include new generating units as no historical bidding data would be available.

<u>2. Minimal Extrapolation</u>

The alternative approach is to make minimal extrapolations from the historical generating data to restore the supply/demand balance.

Decreased generation can be achieved by scaling the historical output of each of the existing generating units in proportion to its offered capacity. Increased generation can be achieved by scaling the differences between the recorded output and the offered capacity of each existing generating unit. This approach would recognise the unit capabilities and would not attempt to scale generator output to above the offered capacity.

A variation is to treat base load, intermediate and peaking plant separately, with increased demand being met by raising base load plant output first and decreased demand by reducing peaking plant first. Similarly, another variation is to scale operating generating units (where the output is non zero) before scaling the remaining units.

The incremental approach also has some difficulties handling unusual and prolonged outages of generation, load and network plant, where these can distort the ‘expected’ dispatch patterns. This is discussed in more detail in section 4.5.11.

NEMMCO is seeking submissions that address all the issues related to the forecasting of generation data, including:

- the advantages and disadvantages of market simulations and the minimal extrapolation method; and
- whether the various categories of generation should be treated differently.

4.5.3 Creating Generating Data for New Generating Units

A forward-looking loss factor methodology will require a process for assigning a dispatch profile for each new generating unit. This can be achieved by assuming:

- a set of generating offers to be used in a market simulation;
- a fixed generation profile to be used in market simulations; or
- a fixed generation profile to be used in the minimal extrapolation approach.

The loss factors that would be calculated from this generating data will depend on the assumptions made, particularly the loss factor for the new generating unit. Therefore, the issue of who determines the operating parameters of new generating units is very important. If the proponent supplies NEMMCO with a set of offers or a generating profile then there is an incentive for them to supply information that will under estimate the utilisation of the unit in an attempt to the improve their loss factor. Conversely a dispute could easily arise if NEMMCO makes the necessary assumptions concerning the new generating unit’s operating parameters.

By way of example, a change of 0.001 in the loss factor of a 100 MW base load generator could change the pool revenue for a generator by more than $20k for an assumed average pool price of $25/MWh. Equally, using a simplified approach where there is no historical data (ie assuming a <1 MW profile for the year) would provide an advantage to the new plant for the first year, after which historical data will be available and loss factors will be more representative of actual operation.

NEMMCO and the Reference Group believe that it is not practicable to forecast the dispatch of a new generating unit by assuming a set of offers because it is based on information that cannot be easily verified and is likely to be difficult to defend in the event of a dispute. Rather, NEMMCO and the Reference Group believe that new generating units should be assigned a fixed profile. Possible processes for determining the profile would include:

1. NEMMCO, in consultation with the proponent, categorises the new unit into peaking, intermediate or base load and taking into account any energy limitations. Based on this, the unit would be assigned an agreed predefined profile;

2. the first method except that NEMMCO, in consultation with the proponent, categorises the new unit by fuel type and technology eg brown coal, black coal, CCGT gas, GT gas, distillate GT, hydro etc. An agreed, predefined profile would be assigned;

3. the proponent, in consultation with NEMMCO, defines the profile. The proponent would provide NEMMCO documentary justification to support the selection of a profile, as is the case in item 4, and this could remain confidential unless disputed;

4. the proponent provides NEMMCO with a detailed justification of the assumptions used to define the forecast generating data.

The first and fourth approaches are expanded in Appendix B and Appendix C respectively. The first two approaches have the advantage that they are transparent and deterministic. To maintain transparency, the third approach would require the dispatch profile provided by the proponent to be published. The Reference Group was undecided whether publishing the profile of a new generating unit would provide a sufficiently strong mechanism to ensure that the proponent provided a realistic profile.

NEMMCO is seeking submissions that address the process to obtain the information necessary to forecast the generating data for new units.

4.5.4 Verification of New Generating Unit Data

The inclusion of new generating units will affect the intra-regional loss factors of existing loads and generators, and could affect the inter-regional loss factor equations. Therefore, it is important that the commitment status, commissioning date, rating and classification are verified before the loss factors are determined.

NEMMCO believes that only the generating units that are included in the latest NEMMCO Statement of Opportunities (SOO) or an Addendum [4] should be included in the generating data.

NEMMCO is required to publish an addendum to the Statement of Opportunities by 31 January each year and this timing fits in well with the requirement to publish loss factors by 1 April. In addition, the SOO includes a rigorous criterion for determining if a generating unit should be regarded as committed.

4.5.5 Existing Energy Limited and Seasonal Generating Units

The dispatch of some generating units, such has hydro units and sugar mills, are energy limited. The methodology for forecasting generation data needs to consider these energy limits.

If the minimal extrapolation approach is used then the dispatch of energy limited units could be set to its historical values.

With the market simulation approach the historical dispatch can be used or the units can be dispatched to match energy targets derived from the historical generation data.

The loss factors that would be calculated when the energy limited units are dispatch to meet derived energy targets will depend on the algorithm used to allocate the available energy across the trading intervals. Therefore, it is NEMMCO's preference to set the dispatch of energy limited units to their historical values.

4.5.6 Mothballed generation

The opportunity also exists to set the output of generators that will be mothballed during the year for which the marginal loss factors apply to zero. The list of mothballed plant, and the associated timing, would be verified by the latest SOO or the latest Addendum to the SOO.

4.5.7 Accounting Changes to Network Losses

Scaling the load data, changing the dispatch of the generating units from the historical data and changes to the transmission network configuration will lead to changes in the transmission network losses. The net change in losses is seen in the load flow as a mismatch between the forecast generation and the load flow solution at the swing bus.

Conventional market simulation packages do not contain a network model that is sufficiently detailed to calculate the change in the network losses. Similarly, it would be difficult to accurately predict this change in losses when implementing a minimal extrapolation approach. For both approaches the change in network losses could be projected from the increase in demand.

If the swing bus mismatch is large this indicates that the generation data is not representative of anticipated dispatch and the mismatch should be reduced by rescheduling generation taking into account inter-regional transfer limits and generator offered capacity limits. The rescheduling needs to be consistent with the approach to interconnector limits, discussed in section 4.5.8.

4.5.8 Accounting for Interconnector Limits

Interconnector limits can readily be incorporated into conventional market simulation packages.

Under the minimal extrapolation approach the initial adjustment of the generating data may lead to trading periods where the interconnector transfer capabilities are exceeded and no longer representative of anticipated network flows. Therefore it will be necessary to develop a procedure to adjust the generation data to enforce the interconnector limits.

The issue of interconnector limits can be addressed by either:

1. treating each region separately and by adjusting the generation in a region to match the net load growth within that region; or

2. treat the NEM as a whole and re-adjust the generation where the flows exceed the interconnector transfer capability.

The first approach has the implicit assumption that the interconnector flows will be unchanged from the historical flows. While this approach is simpler it may not necessarily be representative of anticipated generator behaviour.

Under the second approach the generation would need to be increased in the region that is importing beyond the interconnector capabilities with a corresponding reduction in generation in the associated exporting region.

The second approach may be difficult to apply in the future if interregional loop flows exist[6]. In this case the relationship between generation in the importing region and the interconnector flows may be more complicated and an iterative method would be required to enforce the interconnector limits.

In the NEM the interconnector limits depend on the power system operating conditions and would be too complicated to represent in detail. NEMMCO believes that fixed interconnector limits would be adequate for the calculation of loss factors. Further, NEMMCO recommends that the same interconnector capabilities used in the supply/demand analysis in the SOO should be used for the calculation of forward-looking loss factors.

4.5.9 Insufficient Generation Within a Region

It is theoretically possible that there will be insufficient generation within a region for some trading intervals, although this is very unlikely. If all generating sources within a region have been fully dispatched to their offered capacity, including energy limited units, then the methodology needs to include a provision to allow loads in a region to reduced to restore the supply demand balance.

Conventional market simulation package can represent this approach to a shortfall in generation. A minimal extrapolation approach would need to explicitly include a mechanism to reduce the loads during a period of shortfall.

6 The present regional representation of the NEM is linear as it does not include loop flows. This means that the interconnector flows can be uniquely calculated from a set of regional demands and regional generation. If one or more loops are introduced into the NEM then the interconnector flows will depend on the load and generation distribution and the impedance of each interconnector.

4.5.10 Out of Merit Order Dispatch

Out of merit order dispatch occurs when the presence of external factors such as network support and financial contracts cause the dispatch of some generating units to differ from that expected from a dispatch based on a merit order. Therefore, it is not possible to include out of merit dispatch in a market simulations as network support and financial contracts are normally confidential.

The minimal extrapolation approach does readily include the effects of out of merit order dispatch if it is assumed that the best estimate of the contractual behaviour of the NEM generating units is its behaviour from the previous year.

NEMMCO believes that out of merit order dispatch does occur regularly in the NEM and, therefore, NEMMCO prefers the minimal extrapolation approach to forecasting the generation data for the loss factor calculations.

4.5.11 Generator Planned and Forced Outages

The generating units in the NEM are unavailable for significant periods for planned and, to a lesser extent, forced outages. Ignoring these outages in the calculation of the loss factors may have a considerable impact on the calculation of the loss factors.

The Reference Group considers that outages can be considered by either:

1. applying a typical combined outage rate of say 6 %; or
2. assuming that the previous years pattern of outages is typical and is the best estimate of the pattern in the year the loss factors apply.

Applying typical outage rates would require NEMMCO making arbitrary decisions for the timing of such maintenance and is therefore not a desirable approach. By contrast, assuming the previous years outage pattern would be expected to give the best allocation of outages in the long run.

The Reference Group did note that outage periods are generally less than nine weeks but occasionally a generating unit may undergo a prolonged outage due to a major component failure. Under these circumstances it is arguable that it is reasonable to assume that an identical outage would not occur in the next year and that the typical generating data be estimated for the year the loss factors apply. A market simulation approach would readily estimate the missing generator data while for a minimal extrapolation approach the estimated generator data could be obtained by averaging other units at the same station or from a previous year for a single unit station.

NEMMCO is seeking submissions on the treatment of generator outages when calculating loss factors.

4.5.12 Generator MVAr and Voltage Profile

The transmission losses and hence the loss factors also depend on the flow of reactive power and the resulting transmission network voltage profile. At present a backward-looking methodology is used to calculate the loss factors and the historical connection point reactive power flows are available from the NEMMCO settlements system.

Modelling an automatic voltage controller on each generating unit is considered essential to obtain convergence of the load flow under the full range of system loadings. It is not considered practical to rely on historical output of generators as this is likely to distort voltage profiles when forecast loads are applied.

NEMMCO and Reference Group therefore recommend allowing the reactive output of generators to be determined automatically as part of the load flow solution.

4.6 Volume Weighting the Intra-regional MLFs

Clause 3.6.2(e)(5) of the RIEMNS Stage 1 Code changes specifies a volume weighted average of the regional marginal loss factors for the transmission network connection points.

4.6.1 Connection Point Load Weighting

The Network Losses Working Group (NLWG) considered three forms of weighting [5]:

- time weighting where each loss factor has the same weighting.
- region weighting where each loss factor is volume weighted by the regional demand for the same trading interval.
- connection point load weighting where each loss factor is volume weighted by the connection point load for the same trading interval.

The NLWG determined that connection point load weighting provides the closest zonal approximation to full nodal pricing [5]. This is the recommended approach and is consistent with the approach adopted in the current historic approach.

4.6.2 Pricing Weighting of Loss Factors

Connection point load weighting does not return exactly the same revenues as would result if marginal loss factors were updated each trading interval. To achieve an exact match the marginal loss factors would also have to be weighted against the spot price in each trading interval. Weighting by price is excluded by the requirement in the Code for volume weighting.

While marginal loss factors are directly correlated with generator and load levels, the same physical relationship does not exist between marginal loss factors and the spot price. As such, including the spot price in the weighting process could lead to perverse outcomes. Also, for a forward-looking methodology the loss factors would need to be weighted by future prices.

For these reasons, as well as the additional complexity required, NEMMCO and the NLWG believes that price weighting of marginal loss factors is not appropriate.

4.6.3 Time Weighted Loss Factor for Infrequently Running Generation

It can be argued that where a generator or load is dispatched for short periods, say less than 50 hours in a year, the loss factor should be time weighted over the full year. This will minimise the likelihood of large changes in loss factor from one year to the next.

However, NEMMCO does not believe that time weighting of loss factors meets the requirement in the Code for volume weighting.

4.7 Estimating Inter-regional Marginal Loss Factor Equations

A single static loss factor between adjacent RRNs does not adequately define the loss factors between regions because of the large variability of inter-regional flows and the associated loss factors. Therefore, the inter-regional loss factors are represented by equations, known as inter-regional loss factor equations, which are solved for each dispatch interval using key power system variables.

4.7.1 Regression Analysis

Clause 3.6.1(d)(5) of the RIEMNS Stage 1 Code changes requires the coefficients of the inter-regional loss factor equation parameters to be estimated using regression analysis. The statistical significance of the regression statistics can be assessed using the R^2 and standard error of the regression. NEMMCO currently publishes this statistical information with the inter-regional loss factor equations.

The inter-regional loss factor equations include a number of variables which have a significant impact on inter-regional losses. The NEMMCO Scheduling, Pricing and Dispatch (SPD) system determines dispatch instructions for generators and scheduled loads, and the spot price in the NEM. In setting up SPD for the Australian market, it was necessary to limit the choice of variables that can be used in the inter-regional loss factor equations to the following:

- linear terms only;
- the inter-regional transfer flow between the adjacent reference nodes for which the loss factor equations are being determined;
- region demands.

Other variables such as generator outputs are not currently permitted, in part because a proper treatment would implicitly re-introduce a dynamic, and site specific, treatment of inter-regional losses.

4.7.2 Process

The process for estimating the coefficients of the inter-regional marginal loss factor equations is as follows:

1. Apply the forecast MW and MVAr data for each trading interval to the TPRICE program which calculates marginal loss factors for all load and/or generator connection points for all trading intervals. The loss factors are referenced to the loadflow case swing bus (normally Murray); i.e. the swing bus is effectively used as the regional reference node for all connection points in the loadflow case.

2. Obtain inter-regional transfer MW flows (at the region boundary) and region demands for each trading interval.

3. Select the appropriate pair of regional reference nodes. (For example the Murray 330 kV and Sydney West 330 kV connection points for the Snowy – NSW loss factor equation.)

4. Divide the loss factor of one RRN by the other for all trading periods (the loss factor equation will refer the loss factor of this RRN to the other RRN). For example by dividing the Sydney West 330 kV loss factor by the Murray 330 kV loss factor the inter-regional loss factor equation will refer the Sydney West loss factor to the Murray 330 kV RRN.

5. Use regression analysis to obtain the “best fit” equation describing the variation of MLFs against inter-regional transfer flows and region demands.

6. Record correlation factors and associated variances to be published in conjunction with the inter-regional loss factor equation.

7. Repeat steps 2 to 6 for each pair of adjacent RRNs.

4.7.3 Modelled Data

Clauses 3.6.1(d)(4) and 3.6.2A(d)(2) of the RIEMNS Stage 1 Code changes provides for the use of an additional modelled load and generation data sets for the calculation of the inter-regional loss factor equations, where required.

Modelled data should be distinguished from forecast data. Forecast data represents the best estimate of the anticipated load and generator data for the year in which the loss factor applies. Modelled data is used when the range of historical load and generation data available for the regulated interconnector is not sufficient to derive inter-regional loss factor equations to apply over the full range of transfer capability for the regulated interconnector.

The objective of modelled data is to modify the interconnector flow to cover their complete range with minimal distortion of the distribution of flows in the transmission network. This can be achieved by scaling the generation in the associated region to promote a change in the interconnector flow.

Where the forecast interconnector flow does not reach the transfer capability in a given direction a random sample of 1 % of trading intervals are modified so that the interconnector flow equals the interconnector transfer capability. If the forecast interconnector flow does not reach the transfer capability in the reverse direction then a further of 1 % of trading intervals are modified.

Note that the modelled data is not to be used for the calculation of the static intra-regional loss factors.

The limits used for the interconnector range should be consistent with the limits used for forecasting the generator data in section 4.5.8.

4.8 Other Methodology Issues

4.8.1 Averaging Transmission Loss Factors

Clause 3.6.2(g) requires NEMMCO to develop a methodology for averaging transmission loss factors. This has been the subject of a separate NEMMCO consultation [3].

4.8.2 Multiple Connection Points at the Same Physical Connection

A *transmission network connection point* is defined in the Code as a *connection point* on a *transmission network*. A *connection point* is further defined as "The agreed point of supply established between Network Service Provider(s) and another Code participant, Non-registered Customer or franchise customer". A Code Participant includes a Generator, a Customer, a Market Participant and a Market Network Service Provider. The Code therefore requires a marginal loss factor to be calculated for each of these Participants.

Where a number of customers are connected at the same transmission network node NEMMCO has calculated a single intra-regional marginal loss factor on the basis that the resultant "volume weighted" marginal loss factor would be identical even if calculated for each Customer individually. However should scheduled load(s) be connected at the same node as non-scheduled loads, or large industrial loads with quite different load profiles, it is proposed that separate marginal loss factors be calculated for each scheduled load, and the non-scheduled load as a whole. This is considered appropriate, as the scheduled loads will participate in the dispatch process.

NEMMCO is seeking comment on whether it is appropriate to have separate loss factors where a number of customers are connected at the same transmission connection point.

Where a generator and load are connected to the same node, and the generator is dispatched in a different pattern to the load, a single marginal loss factor may not lead to the same financial outcome for the load and generator as would result if nodal pricing was applied. However, the overall financial outcome (ie. generator and load combined) will be the same. An example of this is provided in Appendix A of the NLWG report

[5]. A similar outcome will result if two or more generators with different dispatch patterns are located at the same transmission network node.

To maintain consistency with the outcomes that would result if nodal pricing was employed, it is recommended that where loads and generators, or generators with different dispatch patterns are connected to the same transmission network node, separate marginal loss factors will be calculated for:

- each generator,
- each scheduled load, and
- the remaining non-scheduled load

To avoid undue complexity it is proposed that separate marginal loss factors will not be calculated where a number of generators of the same type are located at the same node. For example separate marginal loss factors would not be calculated for each Bayswater generating unit.

4.8.3 Pump Storage Plant

A pump-storage hydro generator can either operate as a generator or as a pump (load). At present some pump-storage generators in the NEM operate with a single loss factor for both pumping and generating while others have separate loss factors for pumping and generating. Operating a pump-storage generator with separate loss factors for operation as a pump or generator produces a dispatch that is closer to that would result from a fully optimised dispatch process.

NEMMCO is seeking submissions on the need to have separate loss factors for pump and generator operation of a pump-storage generator.

4.8.4 New and Modified Connection Points

The Code requires NEMMCO to publish the loss factors for the NEM by 1 April prior to the year in which they are apply. However, the loss factor methodology will need to include provisions for new connection points (loads or generators) that are defined after 1 April as new connection points can be defined at anytime and often only a few months before they are utilised.

Clauses 3.6.2(h)(1) and (2) require NEMMCO to determine an additional loss factor for a transmission connection point that is established during a year (or after the publication of the loss factors by 1 April) or for a material modification of a transmission connection point.

Clause 3.6.2(j) requires that the load and generator data used to calculate the additional loss factor should be the same data used to calculate the loss factors for the year adjusted to include the effects of the new connection. The following approaches would be used:

- a new generating unit, either at an existing or new power station, is included using the profiles described in 4.5.3. The remaining generating units are adjusted using the approach in section 4.5.

- a new load is included using a demand profile specified by the associated TNSP and the generating units adjusted using the approach in section 4.5.
- a load where the future profile cannot be estimated by the TNSP or proponent using reasonable endeavours should be treated as a load of not more than 1 MW for each trading interval.
- a material change to the connection point network, such as reinforcement of connection assets or a relocation similar to that of the Yallourn unit in 2000, is considered by modifying the base load flow case and re–running TPRICE to generate a new loss factor.

There is no provision in the RIEMNS Stage 1 Code changes to recalculate loss factors following a material change to the network that is unknown when the loss factors are being calculated.

4.8.5 Embedded Generators

Embedded generators are generally smaller than those connected directly to the transmission network. The Code requires an average distribution loss factor to be calculated for these generators unless, in NEMMCO's opinion, the generator may have a significant impact on the central dispatch of generation.

Because embedded generators are typically small, a suitable option may be that where an average loss factor is to apply a nominal output (no more than 1 MW) be assumed for the embedded generator for each trading interval.

4.8.6 Maintaining a Nominal Voltage Profile

The loss factor and loss factor equations need to calculated using an appropriate voltage profile on the transmission network that is based on typical operating conditions.

4.8.7 Applying Loss Factors from 1 October rather than 1 July

The Reference Group is concerned that the TNSPs will need to supply NEMMCO with load forecasts by about 1 January to meet the NEMMCO publication date of 1 April. The TNSPs, and DNSPs, perform an annual update of the load forecast for publication in their APR and the NEMMCO SOO following the previous summer period. The implications of this is that the connection point load forecasts supplied to NEMMCO to calculate the loss factors will be based on load forecast information that is nearly a year out of date[7].

The Reference Group believes that it is very desirable to calculate the loss factors after the annual revisions of the load forecasts as failing to do so would compromise the benefits of adopting forward-looking loss factors. Waiting to after the summer would mean that the TNSPs would supply the connection point forecasts by about 1 June, NEMMCO would

[7] Even if the TNSPs and DNSPs were to must produce a second detailed load forecast each year it would not be based on behaviour from the most recent summer.

then publish the loss factors at the end of July and the loss factors would take effect on 1 October.

The Reference Group acknowledges that applying the loss factors from 1 October to 30 September, rather than the present financial year, would have a number of implications including:

- additional Code changes to align the application of new transmission loss factors, distribution loss factors and, if required, revised region boundaries;
- possible Code changes to align loss factors to the Transmission and Distribution Pricing arrangements; and
- impacts on the trading and financial arrangements of the market participants.

Therefore, a general review of the Code and market arrangements would need to be performed if the proposal to change from applying loss factors for a financial year.

NEMMCO invites the consulted parties to comment whether the advantages out weigh the difficulties of applying loss factors for a year from 1 October rather than the financial year. If there is general support for such a change NEMMCO would consider pursuing appropriate Code changes.

5. References

[1] “Treatment of Loss Factors in the National Electricity Market”, November 1999, published by NEMMCO on their internet site.

[2] “Stage 1 of the integrating the energy market and network services”, Code Change Panel Consultation Paper, December 2001, published by NECA on their internet site.

[3] “Methodology for the Averaging Transmission Loss Factors: NEMMCO Draft Decision”, published by NEMMCO on their internet site.

[4] “Statement of Opportunities”, published by NEMMCO each year in accordance with clause 5.6.4, ISSN 1443-9050. Information to obtaining the latest version of the SOO or Addendum is available on the NEMMCO internet site.

[5] “Forward-Looking Method for Calculating Marginal Loss Factors in the NEM”, prepared by the Network Losses Working Group and submitted to NECA in January 2000, and resubmitted in June 2001 following minor revision.

6. Appendix A: Transmission Load Connection Point Forecast Load Profile Scaling

6.1 Requirement for Forecast load Profiles

For the determination of forward-looking transmission marginal loss factors it is necessary to provide new forecast half-hourly loading profiles for each load connection point.

As outlined in section 4.3 these profiles must fairly represent the expected loading throughout the year in which the loss factors will be applied. Accordingly, they should be based on the typical historical load shape for that connection point as it varies throughout a year and should then be scaled to reflect the energy and demand forecasts and any expected net load shape changes for the forecast year.

6.2 Process for Providing Forecast Load Profiles

The provision of forecast transmission connection point load profiles shall generally be in accordance with the following procedure.

1. The actual historical revenue metering based loading profile for the recent twelve month period, as defined in section 4.3.1, shall be established as a starting point.
2. These historical profiles should be corrected for any significant distortion which occurred due to extensive load transfers between different connection points, provided that reciprocal corrections are applied to the other relevant connection points.
3. These historical profiles should also be corrected for any significant distortion which occurred due to a period of unsupplied load or managed load reduction for any reason.
4. These historical profiles should also be corrected for significant distortion which occurred due to an atypical reduction in an embedded non-scheduled generator's dispatch.
5. The equivalent forecast energy, summer maximum demand and winter maximum demand growth rates between the timing of historical corrected data and the forecast year, shall then be applied to scale the profile, using the most appropriate scaling technique for the particular connection point.
6. For connection points where substantial committed change to the character and/or level of loading is expected, it could be more appropriate for an entirely new loading profile to be determined by agreement.

6.3 Factors to be Considered in the Choice of an Appropriate Scaling Technique

The purpose in choosing an appropriate scaling technique is to provide the fairest possible marginal loss factor determination for each individual connection point. Accordingly, based on the factors which influence the volume weighting of half hourly loss factors over the year, the most important outcomes of the scaling process are in order of preference:

1. Incorporate the correct forecast total annual energy.
2. Incorporate any appropriate energy split between seasons of the year, reflecting any gradual shifts in those proportions which are expected to continue or to reflect any other expected changes.
3. Avoid any significant distortion of the appropriate proportioning of load between network high and low loading periods on a daily basis.
4. Have an appropriate level of summer and winter peak demands and number of days on which relatively high daily peak demands occur.

6.4 Summary of Scaling Algorithms

Scaling algorithms refer to the scaling of historical connection point profiles to meet all three forecasts of annual energy, summer peak and winter peak demand.

If the energy and either of the peak demand forecast growth ratios are different, then scaling will change the fundamental shape of the profile to varying degrees dependent on the scaling algorithm chosen.

For example, if the peak demand is growing faster than the energy, the resultant scaled profile will be "peakier" than the historical base profile. Conversely, if the energy is growing faster, this will tend to "flatten" the future load shape.

If summer and winter demand growth rates differ significantly and/or the proportion of annual energy between summer and winter half year periods is expected to change, it may be necessary to apply a scaling algorithm in two parts for those periods.

The following sections discuss four different scaling algorithm.

6.4.1 Energy Only Scaling

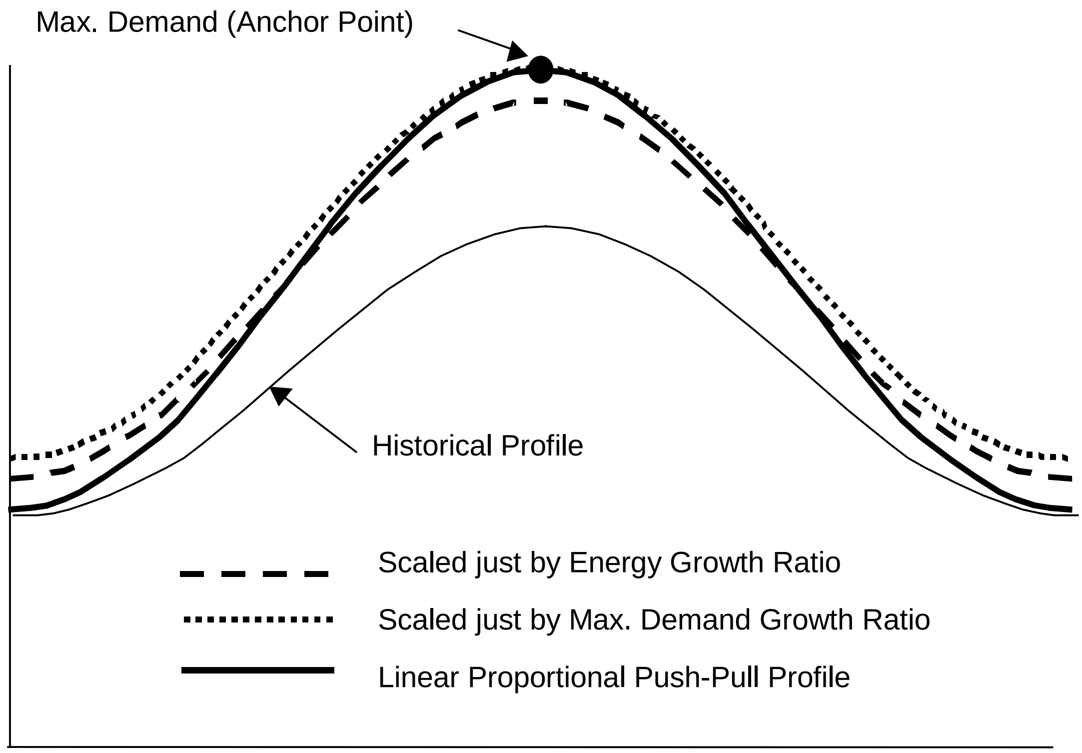
This algorithm just scales the entire historical profile by the energy growth ratio, ignoring peak demand forecasts.

It is suitable for profiles with non-typical load shapes, such as smelters, railways, and connection points with high component of embedded generation or regular load transfers.

When other algorithms produce significant distortions, this method should be used as a default.

6.4.2 Linear Proportional Push-Pull

Where demand growth rates differ from the energy growth rate, energy only scaling will produce peak demands greater or lower than the forecast levels. This method corrects the peak demands by then reallocating energy over all half hours according to the linear difference between each half hour's demand and the peak demand. A simplified illustration of this technique is shown below.



The method is equivalent to multiplying the entire profile by a derived ratio then adding or subtracting a derived fixed correction to each half hour. If the fixed correction amount is substantial ratio of the minimum loading level then this algorithm can produce significant distortion of the profile at low loading levels.

Accordingly, this method may trim too much off low loading levels when creating peakier loads shapes, but it is generally well suited for creating flatter load profiles.

6.4.3 Exponential Proportional Push-Pull

This method is similar to the linear proportional push pull method. It also seeks to scales profiles by the energy growth ratio, but then corrects to the forecast demands by reallocating energy by adding or subtracting in each half hour in accordance with an exponential (or bell curve) proportion based on the difference from maximum and minimum demands. It is necessary to specify both maximum and minimum demand growth ratios.

This method avoids trimming too much off low loading levels when creating peakier load shapes, but is not as suited for creating flatter load profiles.

6.4.4 Selective Peak Push-Pull

This method applies to energy growth ratio, then seeks to correct a small number of days on which the highest demands occur (eg 10 days), and then redistributes the small energy change on those days over the remainder of the year. The correction on the chosen days can be made by an equivalent daily linear or exponential push pull algorithm.

This method is more complex but is well suited for making minor adjustments to profiles, both peaking and flattening, for loads where the highest maximum demands are highly sensitive to weather conditions.

7. Appendix B: Forecasting the Generating Profile for New Units from Fixed Profiles

This appendix contains a possible generating profile for new generating units. It is based on the assumption that new generating units can be classified as peaking, intermediate, base load and energy limited.

Peaking Generator

The generator will be dispatched to offered capacity for 3 hours per working day (approximately 10% capacity factor), covering the half-hour periods 7:30 AM to 9:00 AM, and 5:00 PM to 6:30 PM. For each half-hour, all other generators that are generating in the same region will be reduced in proportion to their capacity, to compensate for the additional output from the new generator.

Intermediate generator

The generator will be dispatched to offered capacity for 12 hours per working day (approximately 35% capacity factor). The generator will be dispatched for half-hour periods from 7:30 AM through to 7:30 PM. For each half-hour, all other generators that are generating in the same region will be reduced in proportion to their capacity to compensate for 60% of the additional output from the new generator. The remaining 40% to be allocated to the remaining generators in the NEM in proportion to their capacity. This proportioning may need to be modified to ensure inter-regional transfer limits are enforced, as discussed in section 4.5.8.

Base load generator

The generator will be dispatched 24 hours per day. The generator will be dispatched to full output for the half-hour periods from 7:00 AM through to 8:00 PM and to the minimum output level of the generator (as advised by the proponent) for the remainder of the day. For each half-hour, all other generators that are generating in the same region will be reduced in proportion to their capacity to compensate for 40% of the additional output from the new generator. The remaining 60% to be allocated to the remaining generators in the NEM in proportion to their capacity. This proportioning may need to be modified to ensure inter-regional transfer limits are enforced, as discussed in section 4.5.8.

Energy Limited Plant

New energy limit plant would be classified as peaking until generation data before 12 consecutive months has been recorded.

Variations on this algorithm include:

- to apply the same generating profiles to the new generating units without reducing the output of existing generators prior to restoring the supply demand balance; and
- classify the generators on their fuel type and technology.

8. Appendix C: Forecasting the Generating Data for New Units Based on Information from the Proponents

This appendix contains a description of a process where the proponents of a new generating unit provides NEMMCO the information necessary for NEMMCO to determine the forecast generating data. The process contains mechanism that are intended to ensure that the proponents provide NEMMCO with realistic information. The process is:

- Each new generator is assumed to operate continuously at full load from its installation date, subject to NEMMCO receiving credible advice from the operator of reductions due to:
    - forced outages
    - planned outages
    - an energy limit
    - an intent to operate only when the relevant regional reference node price exceeds a stated value, or
    - generation being determined by factors outside the control of the participant such as the seasonal nature of the fuel source.
- No other grounds shall be accepted, and these restrictions shall be accepted only if NEMMCO, acting reasonably, accepts them as valid.
- Any specified reductions due to forced outage shall be incorporated as a uniform reduction in availability.
- Any specified reduction due to planned outage will be applied during periods specified by the participant.
- Any specified energy limit shall be applied by distributing generation from the highest price settlement period from the previous financial year to lower-priced periods until the specified energy is exhausted.
- Where an intent to operate only above a specified price is applied then the generation profile will comprise full-load when the corresponding historical price exceeded the specified value, and zero at other times.
- Where an external factor is limiting production, then the generation profile shall be as specified by the generator, provided this is accepted as reasonable by NEMMCO.