RESERVE LEVEL DECLARATION GUIDELINES

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VERSION RELEASE HISTORY

Version	Effective date	Summary of changes
1.0	16 January 2018	First issue for *National Electricity Amendment (Declaration of lack of reserve conditions) Rule 2017*
2.0	6 December 2018	Update following consultation with changes to the definition of RXS, the inputs used to determine the prevailing conditions, and the confidence levels used to determine the FUM. The document style has been updated to the latest AEMO branding.
2.1	12 December 2018	AEMO delayed the deployment of the IT system changes to 12 December 2018 as a result of forecast conditions. A minor formatting correction in Table 2, Appendix C.

CONTENTS

1. INTRODUCTION

1.1. Purpose and scope

These are the *reserve level declaration guidelines* made under clause 4.8.4A of the National Electricity Rules (Guidelines).

These Guidelines have effect only for the purpose of declaring lack of reserve (LOR) conditions under clause 4.8.4 of the National Electricity Rules (NER). They describe the considerations and methodology *AEMO* applies in deciding to declare an LOR condition, and the levels of LOR conditions that may be declared.

An LOR declaration alerts *Registered Participants* to a probability of *capacity reserves* being insufficient to avoid *load shedding* (other than *interruptible load*) given reasonably foreseeable conditions and events.

The NER and the National Electricity Law prevail over these Guidelines to the extent of any inconsistency.

1.2. Definitions and interpretation

1.2.1. Glossary

Terms defined in the NER or the National Electricity Law have the same meanings in these Guidelines unless otherwise specified in this clause. Those terms are intended to be identified in these Guidelines by italicising them, but failure to italicise a defined term does not affect its meaning.

The words, phrases and abbreviations in the table below have the meanings set out opposite them when used in these Guidelines.

Term	Definition
Aggregate Energy Limited Capacity	Total aggregate contribution to supply from *scheduled generating units* in the *region* for which a daily *energy constraint* has been specified in ST PASA and PD PASA submissions. The value is determined by the *PASA* process and considers: • forecast *available capacity* specified by *Generators*; • forecast daily *energy constraint* specified by *Generators*; • optimisation of energy limited capacity through the *PASA* algorithm; and • network limitations as specified through *network constraint* equations.
Aggregate Non-Energy Limited Capacity	Total aggregate contribution to supply from *scheduled* and *semi-scheduled generating units* in the *region* for which no daily *energy constraint* has been specified in ST PASA and PD PASA submissions. The value is determined by the *PASA* process and considers: • forecast *available capacity* specified by *Generators*; • *network* limitations as specified through *network constraint* equations; and • forecasts for output of semi-scheduled generating units.
Aggregate Semi-Scheduled Output	The forecast output of *semi-scheduled generating units* in the *region*. The value is determined by the *PASA* process and considers: • *unconstrained intermittent generation forecast* determined by AWEFS and ASEFS; and • network limitations as specified through *network constraint* equations.
AWEFS	Australian Wind Energy Forecasting System
ASEFS	Australian Solar Energy Forecasting System

Term	Definition
BBN	Bayesian Belief Network
FUM	Forecast uncertainty measure
Interconnector Support	The maximum *energy* supply available to a *region* from adjacent *regions* after the demand to be met from *supply* is satisfied in adjacent *regions*. The value is determined by the *PASA* process and considers: • network limitations as specified through *network constraint* equations; and • demand to be met from *supply* in adjacent *regions* as determined by the *PASA* algorithm.
LCR	Largest credible risk – see clause 4
LCR2	Two largest credible risks – see clause 4
LOR	Lack of reserve (may be followed by a number corresponding with a reserve level defined in these Guidelines)
LOR assessment horizon	The period of time described in clause 2(a)
LOR Load Shedding	The reduction or *disconnection* of *load* (other than *interruptible load*).
LOR1 threshold	The level of *capacity reserves* below which AEMO may declare an LOR1 condition – see clause 2(d)
LOR2 threshold	The level of *capacity reserves* below which AEMO may declare an LOR2 condition – see clause 2(c).
MW	Megawatts
MWh	Megawatt hours
NER	National Electricity Rules
Operational Demand	A quantity (in MW) determined by AEMO representing the instantaneous demand of *load* (other than *scheduled load*) to be supplied by *sent out generation* of *scheduled generating units*, *semi-scheduled generating units*, and significant *non-scheduled generating units*. For further information about demand definitions see "AEMO Operational Demand Definition – Summary Document" on AEMO website
PD PASA	*PASA* in the *pre-dispatch* timeframe
RXS	Regional excess supply
RXS error	The expected difference between forecast RXS and actual RXS (see clause 3.2)
Scheduled Demand	The expected value of *regional* electricity demand (excluding *scheduled loads*) which will need to be met by supply from *scheduled generating units* and *semi-scheduled generating units* in the *region* or from other *regions*. The value is determined by AEMO forecasting systems and considers: • customer *load*; • output of major *non-scheduled generating units*; and • output of *embedded generating units* including rooftop solar generation.
ST PASA	*Short term PASA*

1.2.2. Interpretation

The following principles of interpretation apply to these Guidelines unless otherwise expressly indicated:

(a) These Guidelines are subject to the principles of interpretation set out in Schedule 2 of the National Electricity Law.

(b) References to time are references to Australian Eastern Standard Time.

(c) The following mathematical notations used in formulae and equations have these meanings:

   (i) MAX ( ) means the maximum (or highest) of two or more values within the brackets,

   (ii) '{ }', '( )' and '[ ]' indicates that all calculations between a pair of brackets are to be performed separately from expressions outside the brackets. Different forms of brackets are used only for ease of matching the opening bracket with the corresponding closing bracket.

1.3. Related documents

Title	Location
Reliability Standard Implementation Guidelines	www.aemo.com.au
Short Term PASA Process Description	www.aemo.com.au
Intervention, Direction and Clause 4.8.9 Instructions SO_OP3707	www.aemo.com.au
Procedure for the Dispatch and Activation of Reserve Contracts SO_OP3717	www.aemo.com.au
AEMO Operational Demand Definition – Summary Document	www.aemo.com.au

2. ASSESSMENT AND PUBLICATION

(a) AEMO assesses the probability of a shortfall in available *capacity reserves* leading to LOR Load Shedding in each *region* on a continuous basis, from the current time to the end of the period covered by the most recently *published short term PASA*. This is the LOR assessment horizon.

(b) AEMO *publishes*, for each 30 minute period commencing on the hour and half-hour within the LOR assessment horizon, and for each *region*:

   (i) the expected *capacity reserves* (in MW);

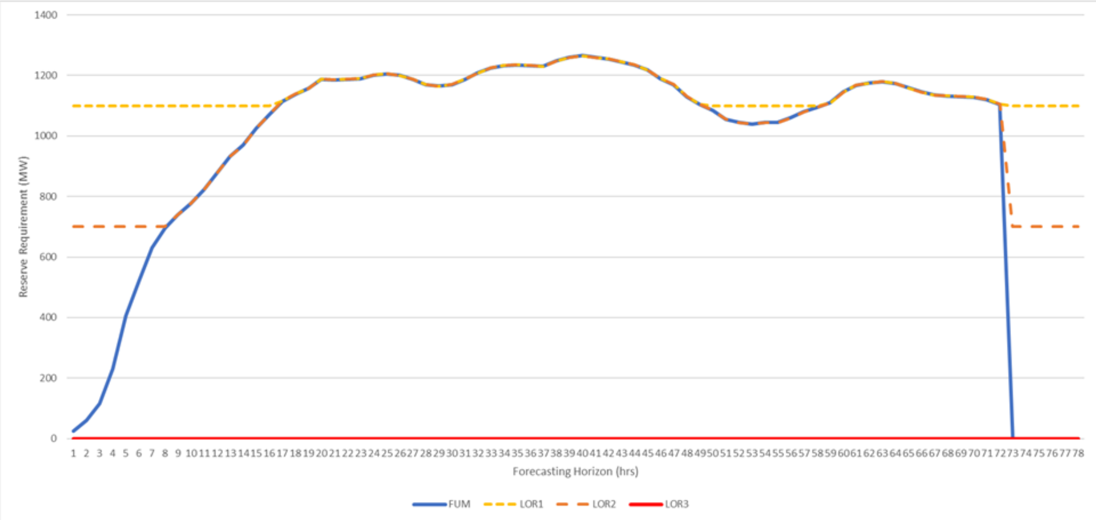
   (ii) the LOR2 threshold (in MW) – see paragraph (c); and

   (iii) the LOR1 threshold (in MW) – see paragraph (d).

(c) The LOR2 threshold within the LOR assessment horizon is MAX (LCR, FUM).

(d) The LOR1 threshold within the LOR assessment horizon is MAX (LCR2, FUM).

Figure 1 Schematic representation of LOR Formulation in circumstances of extreme FUM values. FUM reduces to 0 MW beyond 72 hrs forecast horizon



3. FORECAST UNCERTAINTY MEASURE

See also Appendix A for more detail.

3.1. Forecast regional excess supply (RXS)

3.1.1. Mainland regions

For the New South Wales, Queensland, South Australia and Victoria *regions* RXS is defined below.

(a) The following forecasts and measurements in each *region* for the LOR assessment horizon will be assessed in determining the value of RXS:

(i) aggregate capacity of *scheduled generation* in the *region* (C), calculated as:

(A) Aggregate Non-Energy Limited Capacity, plus

(B) Aggregate Energy Limited Capacity, less

(C) Aggregate Semi-Scheduled Output;

(ii) Interconnector Support (IS);

(iii) Aggregate Semi-Scheduled Output (SS); and

(iv) Scheduled Demand (D).

(b) Forecast RXS for any time in the LOR assessment horizon is determined by the formula RXS = C + IS + SS - D.

3.1.2. Tasmania

For the Tasmania *region* RXS is defined below.

(a) The following forecasts and measurements in each *region* for the LOR assessment horizon will be assessed in determining the value of RXS:

(i) *available capacity* of *scheduled generating units* (A);

(ii) *unconstrained intermittent generation forecast* (B); and

(iii) Scheduled Demand (C).

(b) Forecast RXS for any time in the LOR assessment horizon is determined by the formula RXS = A + B – C.

The RXS definition for Tasmania excludes components which are affected as an unintended consequence of a *network constraint* that requires Tasmania to export. When this condition occurs, it results in excessive errors in the Interconnector Support and Aggregate Non-Energy Limited Capacity components, which would cause erroneous RXS values if the RXS definition for Tasmania were to include these components.

3.2. Determining RXS error distribution

(a) RXS Error = Forecast RXS – Actual RXS for a particular forecast and a point in time.

(b) AEMO collects, stores and updates historical statistical data on RXS error, in different *power system*, ambient weather and other relevant conditions.

(c) At the time of assessment, AEMO applies the historical data and the conditions expected for the relevant period in the LOR assessment horizon, as illustrated in Appendix A, to determine a distribution of error (RXS error) across all forecasts within the first 72 hours of the LOR assessment horizon. The input states that will be taken into account in developing the distribution will be:

(i) forecast lead time;

(ii) forecast temperature at the reference weather station within the *region*[1];

(iii) forecast solar irradiance at the reference weather station within the *region*;

(iv) current demand forecast error for forecast lead times below 24 hours;

(v) forecast of Aggregate Semi-Scheduled Output; and

(vi) current supply mix by fuel type (coal, gas or hydro).

3.3. Forecast uncertainty measure (FUM) calculation

(a) The FUM for a *region*, point in time and set of expected conditions, is the number of MWs representing the quantity of RXS for which AEMO determines a specified confidence level of the RXS error not exceeding that number of MWs.

(b) Confidence levels are determined in accordance with clause 3.4 and are set out in Appendix B.

(c) FUM will be determined using the RXS error for the first 72 hours of the LOR assessment horizon. For the remainder of the assessment horizon a static value of 0MW will be used for FUM.

3.4. Confidence levels for determining FUM

(a) The confidence level used in determining FUM is to be set at a level that AEMO reasonably expects to achieve an appropriate balance between:

[1] For the reference weather stations refer to SO_OP_3703 – Short Term Reserve Management procedure: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Power-system-operation/Power-system-operating-procedures

(i) reducing the chance of a situation where LOR Load Shedding arises due to lack of action by AEMO as a result of reserve forecasting error; and

(ii) increasing the likelihood of unnecessary declarations due to an overly conservative confidence level.

(b) The confidence levels will also be selected to:

(i) decrease monotonically, where appropriate, with increasing forecasting horizon; and

(ii) be consistent across *regions* for the same forecasting horizon where this can be done whilst still reasonably satisfying the other selection criteria.

(c) To achieve this balance, different confidence levels may be required for each *region* and for each forecast timeframe within the LOR assessment horizon.

(d) The current confidence levels are specified in Appendix B.

(e) AEMO must review the confidence levels at least annually to determine whether or not they are still achieving the appropriate balance indicated in paragraph (a).

(f) AEMO must publish the results of its review and, if AEMO concluded that no change should be made to the current confidence levels, must include reasons for that conclusion.

Note: If AEMO proposes to change the confidence levels, it is required to consult on an amendment to these Guidelines in accordance with NER clause 4.8.4A(e).

3.5. Reasonability Limits for FUM Values

(a) Before the FUM value is used to calculate LOR levels (refer to clause 5), the calculated FUM value will be subject to a reasonability check, intended to prevent an unrealistic LOR level being determined due to mal-operation of AEMO systems.

(b) For this purpose AEMO will set upper/lower and delta raise/lower reasonability limits, which may vary between *regions* and forecasting timeframes, and will be revised as AEMO considers necessary. If AEMO revises the reasonability limits, AEMO must publish the revised limits and inform the market via a market notice.

(c) The upper/lower reasonability limits provide a cap or floor on the FUM value used to calculate LOR levels. The delta raise/lower reasonability limits implement a rate-of-change cap to limit the difference in FUM values for the same *trading interval* from consecutive runs.

(d) The current upper/lower and delta raise/lower reasonability limits are specified in Appendix C.

4. CREDIBLE CONTINGENCY SIZES

(a) AEMO determines the size of the two largest relevant *credible contingency events* that could affect the available *supply* of electricity for each *region* from time to time. These will generally be determined automatically, consistent with a list of relevant *credible contingency events* to be published by AEMO on its website alongside these Guidelines.

(b) AEMO then determines the reduction in *capacity reserves* expected to result in that *region* from the occurrence of:

(i) the single largest of those relevant *credible contingency events* (LCR) (in MW); and

(ii) both of the two largest *credible contingency events*, assuming they occur consecutively with sufficient time to return the *power system* to a *secure operating state* prior to the second event (LCR2) (in MW).

(c) The temporary reclassification of a *non-credible contingency event* may affect the size of the largest or second largest *credible contingency event* in a *region* at any time. In accordance with the NER and AEMO's normal procedures, AEMO issues a market notice when reclassification occurs.

(d) If other unusual temporary operating conditions result in situations that require manual specification of LCR and LCR2 levels, AEMO will inform *Market Participants* by issuing a market notice.

(e) On infrequent occasions the list of relevant *credible contingency events* may need to be revised if new classes of events need to be added or existing classes revised. If this occurs, AEMO will update the published list as soon as reasonably practicable.

5. DESCRIPTION OF RESERVE LEVELS

5.1. General

(a) AEMO will declare LOR conditions when it determines there is a non-remote probability of LOR Load Shedding due to a shortfall of available *capacity reserves* at a given time in the LOR assessment horizon, by reference to the criteria described in this clause for levels LOR3, LOR2 and LOR1. This is shown in Figure 1.

(b) In some cases where published forecast *capacity reserves* are below these LOR levels, AEMO may decide not to declare an LOR condition. Examples of such circumstances include:

(i) clearly incorrect PASA results due to software issues or incorrect performance of *network constraint* equations; or

(ii) situations where the shortfall is clearly transient and will be resolved through normal *dispatch* processes without presenting an ongoing threat to reliability of *supply*,

and in those circumstances AEMO will issue a market notice to explain why it has not declared an LOR condition.

5.2. LOR3

LOR3 will be declared for a *region(s)*:

(a) when LOR Load Shedding is occurring as a result of a shortfall of available *capacity reserves* (actual LOR3); or

(b) for a period within the LOR assessment horizon when the forecast of available *capacity reserves* in the *short term PASA* or *pre-dispatch schedule* is at or below zero (forecast LOR3).

5.3. LOR2

LOR2 will be declared for a *region(s)*:

(a) when the occurrence of the largest relevant *credible contingency event* would result in LOR Load Shedding as a result of a shortfall of available *capacity reserves* (actual LOR2); or

(b) for a period within the LOR assessment horizon when the forecast of available *capacity reserves* in the *short term PASA* or *pre-dispatch schedule* is less than LCR (forecast LOR2); or

(c) for a period within the LOR assessment horizon when the forecast of available *capacity reserves* in the *short term PASA* or *pre-dispatch schedule* is less than FUM for the relevant period and *region* (forecast LOR2).

5.4. LOR1

LOR 1 will be declared for a *region(s)*:

(a) when the consecutive occurrence of both the largest and the second largest relevant *credible contingency events* (as described in clause 4(b)(b)(ii)) would result in LOR Load Shedding occurring as a result of a shortfall of available *capacity reserves* (actual LOR1); or

(b) for a period within the LOR assessment horizon when the forecast of available *capacity reserves* in the *short term PASA* or *pre-dispatch schedule* is less than LCR2 (forecast LOR1); or

(c) for a period within the LOR assessment horizon when the forecast of available *capacity reserves* in the *short term PASA* or *pre-dispatch schedule* is less than FUM for the relevant period and *region* (forecast LOR1).

APPENDIX A. FORECAST UNCERTAINTY ERROR METHODOLOGY

This Appendix describes how the historical forecasting data is analysed under different prevailing conditions in order to estimate the combined forecasting error.

A.1 Sources of error

As described in clause 3.1, RXS error is determined using forecasts and measurements for:

- aggregate capacity of *scheduled generation* in the *region*, calculated as:
  - Aggregate Non-Energy Limited Capacity, plus
  - Aggregate Energy Limited Capacity, less
  - Aggregate Semi-Scheduled Output;
- Interconnector Support;
- Aggregate Semi-Scheduled Output; and
- Scheduled Demand.

In the case of the Tasmanian *region*, RXS error is determined using forecasts and measurements for:

- *available capacity of scheduled generating units*;
- *unconstrained intermittent generation forecast*; and
- Scheduled Demand.

A.1.1 Aggregate Non-Energy Limited Capacity

This value is the total aggregate contribution to supply determined by the *PASA* process from *scheduled generating units* and *semi-scheduled generating units* for which no daily *energy constraint* has been specified in ST PASA and PD PASA submissions. The calculation of this value considers the forecast available capacity as specified by *Generators*, the network limitations as specified by AEMO through *network constraint* equations, and AEMO-produced *unconstrained intermittent generation forecasts* for *semi-scheduled generating units*. Each of these components is a potential significant source of forecasting error.

A.1.2 Aggregate Energy Limited Capacity

This value is the total aggregate contribution to supply determined by the *PASA* process from *scheduled generating units* for which a daily *energy constraint* has been specified in *short term PASA* and *pre-dispatch PASA* submissions. The calculation of this value considers the forecast available capacity as specified by *Generators*, the forecast daily *energy constraint* as specified by *Generators*, the optimisation of energy limited capacity through the *PASA* algorithm, and the network limitations as specified by AEMO through *network constraint* equations. Each of these components is a potential significant source of forecasting error.

A.1.3 Aggregate Semi-Scheduled Output

This value is the total aggregate forecast output of *semi-scheduled generating units* in the *region* determined by the *PASA* process. The calculation of this value considers the AEMO-produced *unconstrained intermittent generation forecasts* for *semi-scheduled generating units*, and the network limitations as specified by AEMO through *network constraint* equations. Each of these components is a potential significant source of forecasting error.

A.1.4 Interconnector Support

This value is the maximum *supply* to the *region* available from adjacent *regions* after the demand to be met from *supply* is satisfied in the adjacent *region* as determined by the *PASA* process. The calculation of this value considers the *network* limitations as specified by AEMO through *network constraint* equations, and the demand to be met from *supply* in adjacent *regions* as determined by the *PASA* algorithm. Each of these components is a potential significant source of forecasting error.

A.1.5 Available capacity of scheduled generating units

Every *Scheduled Generator* is required to submit an estimate of *available capacity* of each *scheduled generating unit* for every *trading interval* for the next 8 days. This provides AEMO with an estimate of how much *generation* is available for *dispatch* and may be updated at any time up to the point of *dispatch*. This variation is a potential significant source of forecasting error.

A.1.6 Unconstrained Intermittent Generation Forecast

AEMO produces a *generation* forecast for every *semi-scheduled generating unit* and large *intermittent non-scheduled generating units* through its AWEFS and ASEFS forecasting systems. These forecasts are a potential significant source of forecasting error.

In some situations these *generating units* may be subject to *constraints*. This is a rare situation, and in *trading intervals* where this occurred, the relevant *generating units* were simply removed from the RXS calculation.

A.1.7 Scheduled Demand

AEMO currently produces Scheduled Demand forecasts at a *regional* level. The demand forecast considers customer *load*, the output of major *non-scheduled generating units* and the output of *embedded generating units* including rooftop solar generation. Each of these components is a potential significant source of forecasting error.

A.1.8 Preparation of data

(a) For every 30 minute trading interval since July 2011 AEMO calculated forecast RXS for the next 384 trading intervals (8 days ahead).

(b) Each 30 minute forecast was assessed against the actuals for each of the next 144 trading intervals. For example, a forecast run at 01-01-2017 01:00 would have forecasts for each 30 minute interval from 01-01-2017 01:30 to 04-01-2017 01:00 and an RXS error created for each of these.

(c) The known prevailing conditions that were present just prior to the forecast run were included to develop an understanding of how these conditions affect the forecasting error. Those prevailing conditions were:

  (i) current temperature at the reference weather station within the region;

  (ii) forecast temperature at the reference weather station within the region;

  (iii) current demand forecast error;

  (iv) forecast solar irradiance at the reference weather station within the region;

  (v) forecast output of *semi-scheduled generating units*;

  (vi) current supply mix by fuel type;

(vii) *regional reference price* ($/MWh); and

(viii) time of day (daytime / night-time forecast).

(d) Not all of the prevailing conditions were found to be significant to the RXS error distribution. The prevailing conditions which were deemed to be insignificant were discarded in order to simplify the calculation and enable the distributions to be built using a greater input sample size.

(e) This data was then used to train a Bayesian Belief Network to produce a RXS error distribution for each of the next 144 *trading intervals*. This is dynamic: the error distributions will update based on the current prevailing conditions when the forecast is produced.

(f) The data used for initial training of the BBN was from the period 1 July 2011 to 1 August 2017. The BBN will be retrained on quarterly basis; at the time of retraining, additional data available since the last retraining will be added to the training data set. Any changes to forecasting systems which result in a change in any of the error distributions (for example, an upgrade to the forecasting system resulting in an improvement to forecasting accuracy) will be reflected in the BBN (and subsequent FUM values) following the next scheduled retraining.

(g) The output of the BBN is a measure of the RXS error in MW for each of the next 144 *trading intervals*. As we are dealing with a forecasting error distribution, the "At Risk" MW (FUM) is associated with a confidence level. For example, a 6 hour ahead forecast that was run at 22:00 for 04:00 (overnight forecast) would have less uncertainty associated with the error than a forecast run at 10:00 for 16:00 (daily peak forecast). The BBN outputs a MW value for each of the forecasts, associated with a fixed confidence level. So for example in the 22:00 forecast run a typical FUM value for 6 hours ahead might be 200MW whereas for the 10:00 forecast run a typical FUM value for 6 hours ahead would be 300MW.

(h) Before the FUM value is used to calculate LOR levels (refer to clause 5), the calculated FUM value will be subject to a reasonability check (refer to clause 3.5).

A.2 Bayesian Belief Network

References and citations corresponding with the numbers in square brackets in this section are listed in Appendix D.

Bayesian Belief Networks (BBNs) [1], are probabilistic models used in artificial intelligence to deal with problems that are associated with uncertainty [2]. They can be used to investigate and present causal relationships between essential elements and output values of a system in a simple and understandable manner. They can be readily extended, modified, and incorporate missing data through the application of Bayes' theorem [3]. They are useful for calculating the impact of interventions such as examining alternative policies or decisions for optimizing a desired outcome. In addition, at the same time the uncertainties integrated with these causal relationships can be investigated.

BBNs are probabilistic graphical models based on directed acyclic graphs which are made of nodes connected by edges with a direction associated with them, and with no cycles [2]. The nodes in the networks depict a set of random variables, $V = V1,\ldots,Vi,\ldots,Vn$, and directed arcs connect pairs of nodes, $Vi \rightarrow Vj$, representing the dependencies between variables. In each pair of connected nodes, the parent node affect the child node and the direction of the arc between them shows the direction of the effect. The absence of an arc between two nodes denotes that those nodes are independent. The relationship between a child node and all its parents is described by a Conditional Probability Table (CPT). The CPT should be formed as follows:

(a) each row represents the probability of being within a state, given a combination of values of parent states;

(b) each row must sum to 1; and

(c) a node without parents has one row and it can be described probabilistically by a marginal probability distribution.

Once a problem and its uncertainty is modelled by a BBN, the BBN reasons about the problem through applying a flow of new information, evidence, i.e., a probabilistic inference system. Such an inference system is able to compute the posterior probability distribution for a set of query nodes, given values for some evidence nodes. The types of evidence can be categorized as follows:

(a) definite evidence, a definite information about that variable X has a specific value x;

(b) negative evidence, information about that variable Y is not in the certain state y1, however, may take any other values; and

(c) likelihood evidence, uncertain source of information.

The types of reasoning using BBNs can be categorized in to four categories:

(a) diagnostic, reasoning from indications to cause;

(b) predictive, reasoning from new knowledge about causes to new beliefs about results;

(c) inter causal, reasoning about the common causes of a predictable result; and

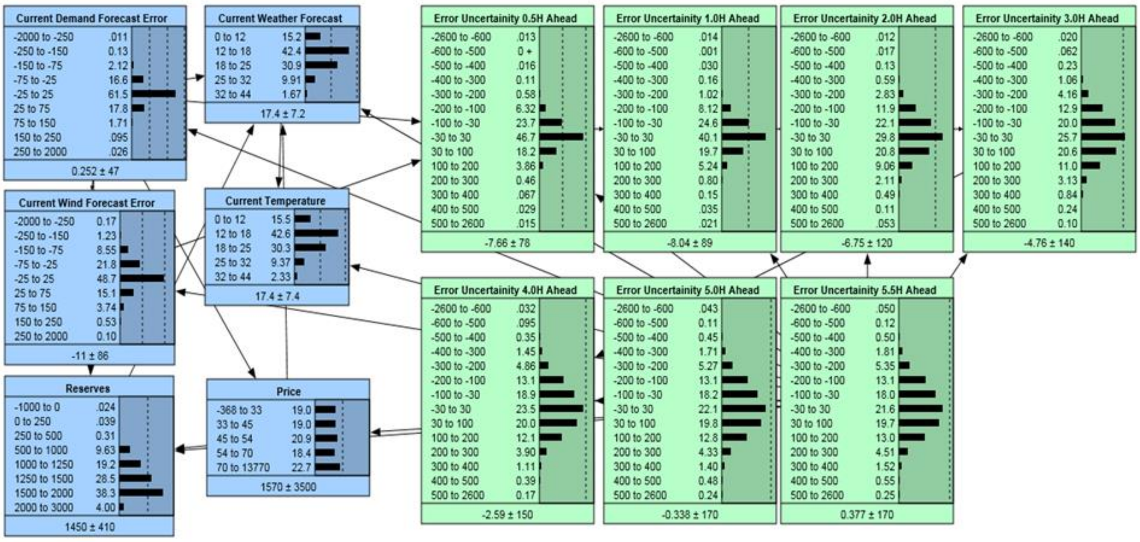
(d) mixed reasoning.

BBNs perform probabilistic updating by incorporating new information and evidence, provide a combination of predictive and diagnostic reasoning by incorporating new information and evidence through Bayes' theorem.

Dynamic Bayesian Belief Networks (DBNs)*:* Most of the events that happen around us in everyday life cannot be depicted based on the fixed point in time, they should be explained through a sequence of observations that lead to the inference of one final event. Time is an important dimension in the field of artificial intelligence and reasoning. However, BBNs variables are time independent, in fact they are not able to model temporal relationships explicitly and they are a static model. In contrast, DBNs [4]–[5] consider how the variables change with time. Thus DBNs relate variables to each other over the sequences of time steps. Through this approach, a user is able to monitor and update the system continuously over the time steps. DBNs consist of a prior network, which comprises the prior probabilities for all of the variables in the network at time step t = 0, and a transition network, which encodes the probabilities for each variables conditioned on other variables for all time steps, t = 1, 2,…, n.

Figure 2 below provides an example of a Short Term (Less than 6 hours) BBN network for the South Australian *region*. The blue nodes are the parent nodes which represent the prevailing conditions that existed just prior to the forecast run and the green nodes represent the child node or forecasting error for each of the next 30 minute *trading intervals*. The black bars represent the probability associated with each of the corresponding bins. For example, below circled in red is the temperature recorded at the Adelaide Airport. It shows that 15.5% of the time the temperature recordings have been between 0 and 12 degrees.

Figure 2 Bayesian Belief Network



A.2.1 Sensitivity Analysis

Once a BBN network has been trained it is possible to statistically assess the impact that each of the prevailing conditions (input nodes) has on the forecasting errors. Using just the link structure of the net, you can determine which nodes are completely independent of other nodes. However, dependence is a matter of degree and once the net has been trained it can be used to assess how changes in the prevailing conditions change the probabilities or uncertainties in our forecasting error nodes (output nodes). From this analysis it was determined that the most significant prevailing conditions (the conditions that cause the largest change in forecasting uncertainty) are the following:

(a) Temperature forecast

(b) Solar irradiance forecast

(c) Forecast output of *semi-scheduled generating units*

(d) Current demand forecast error for forecast lead times below 24 hours.

(e) Current supply mix by fuel type (gas, coal or hydro)

Additional prevailing conditions that were assessed and determined to not cause a significant impact include:

(a) Price

(b) Current semi-scheduled forecasting error

(c) Current actual RXS

(d) Precipitation, humidity, wind speed forecasts

(e) Temperature forecast differential between different forecast providers

(f) Forecasts of reserve

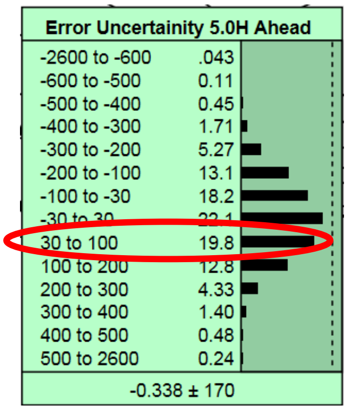
(g) Forecasts of interconnector support

Therefore the BBN includes the temperature forecast, solar irradiance forecast, forecast output of *semi-scheduled generating units*, the current demand forecast error and the current supply mix by fuel type as the input data for the BBN models.

A.2.2 Selection of Confidence Level

The final step is selecting the MW values associated with the confidence level. Figure 3 below is the forecasting error associated with the 5-hour ahead forecasts. This demonstrates the combined forecasting error from all three forecasting systems 5 hours after the forecast was run. The black bars are the probabilities associated with each of the bin ranges and the bins are in MW. For example 19.8% percent of the time AEMO produces a forecasting error of between 30-100 MW.

Figure 3 5 Hour Ahead Forecasting Error



In order to determine the associated MW value for the confidence level, all the probabilities are accumulated until they exceed the specified confidence interval and the associated MW value in that bin becomes FUM.

APPENDIX B. CONFIDENCE LEVELS

The confidence levels chosen for determination of FUM are as follows.

Table 1 Confidence levels for determination of FUM values

Region(s)	Forecastiong horizon (hours)	Confidence level
All	0.5 to 72	95%

APPENDIX C. REASONABILITY LIMITS

The reasonability limits chosen and applied as reasonability checks on the FUM value (section 3.5) are as follows.

Table 2 Reasonability limits

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
NSW1	0.5	0	759.2	142	19
NSW1	1	0	889.1	142	19
NSW1	1.5	0	1019	142	19
NSW1	2	0	1105.05	142	19
NSW1	2.5	0	1191.1	142	19
NSW1	3	0	1256.85	142	19
NSW1	3.5	0	1322.6	142	19
NSW1	4	0	1385.3	142	19
NSW1	4.5	0	1448	142	19
NSW1	5	0	1492.6	142	19
NSW1	5.5	0	1537.2	142	19
NSW1	6	0	1571.6	142	19
NSW1	6.5	0	1606	38	19
NSW1	7	0	1622.9	38	19
NSW1	7.5	0	1639.8	38	19
NSW1	8	0	1654.7	38	19
NSW1	8.5	0	1669.6	38	19
NSW1	9	0	1674.95	38	19
NSW1	9.5	0	1680.3	38	19
NSW1	10	0	1697.25	38	19
NSW1	10.5	0	1714.2	38	19
NSW1	11	0	1730.05	38	19
NSW1	11.5	0	1745.9	38	19
NSW1	12	0	1762.05	38	19
NSW1	12.5	0	1778.2	38	19
NSW1	13	0	1795.4	38	19
NSW1	13.5	0	1812.6	38	19
NSW1	14	0	1827.2	38	19
NSW1	14.5	0	1841.8	38	19
NSW1	15	0	1847.6	38	19
NSW1	15.5	0	1853.4	38	19
NSW1	16	0	1856.7	38	19
NSW1	16.5	0	1860	38	19

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
NSW1	17	0	1881.4	38	19
NSW1	17.5	0	1902.8	38	19
NSW1	18	0	1917.25	38	19
NSW1	18.5	0	1931.7	38	38
NSW1	19	0	1941.75	38	38
NSW1	19.5	0	1951.8	38	38
NSW1	20	0	1974.9	38	38
NSW1	20.5	0	1998	38	38
NSW1	21	0	2013.4	38	38
NSW1	21.5	0	2028.8	38	38
NSW1	22	0	2053.35	38	38
NSW1	22.5	0	2077.9	38	38
NSW1	23	0	2092.8	38	38
NSW1	23.5	0	2107.7	38	38
NSW1	24	0	2122.5	38	38
NSW1	24.5	0	2137.3	38	38
NSW1	25	0	2149.25	38	38
NSW1	25.5	0	2161.2	38	38
NSW1	26	0	2177.95	38	38
NSW1	26.5	0	2194.7	38	38
NSW1	27	0	2205.75	38	38
NSW1	27.5	0	2216.8	38	38
NSW1	28	0	2224	38	38
NSW1	28.5	0	2231.2	38	38
NSW1	29	0	2243.7	38	38
NSW1	29.5	0	2256.2	38	38
NSW1	30	0	2260.8	38	38
NSW1	30.5	0	2265.4	38	38
NSW1	31	0	2268.3	38	38
NSW1	31.5	0	2271.2	38	38
NSW1	32	0	2277.25	38	38
NSW1	32.5	0	2283.3	38	38
NSW1	33	0	2288.85	38	38
NSW1	33.5	0	2294.4	38	38
NSW1	34	0	2297.3	38	38
NSW1	34.5	0	2300.2	38	38

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
NSW1	35	0	2303.75	38	38
NSW1	35.5	0	2307.3	38	38
NSW1	36	0	2311.75	38	38
NSW1	36.5	0	2316.2	38	38
NSW1	37	0	2316.5	38	38
NSW1	37.5	0	2316.8	38	38
NSW1	38	0	2317.05	38	38
NSW1	38.5	0	2317.3	38	38
NSW1	39	0	2314.9	38	38
NSW1	39.5	0	2312.5	38	38
NSW1	40	0	2324.9	38	38
NSW1	40.5	0	2337.3	38	38
NSW1	41	0	2343.65	38	38
NSW1	41.5	0	2350	38	38
NSW1	42	0	2362.85	38	38
NSW1	42.5	0	2375.7	38	38
NSW1	43	0	2384.15	38	38
NSW1	43.5	0	2392.6	38	38
NSW1	44	0	2399.4	38	38
NSW1	44.5	0	2628.2	38	38
NSW1	45	0	2632.2	38	38
NSW1	45.5	0	2635.7	38	38
NSW1	46	0	2639.2	38	38
NSW1	46.5	0	2644.15	38	38
NSW1	47	0	2649.1	38	38
NSW1	47.5	0	2650.75	38	38
NSW1	48	0	2652.4	38	38
NSW1	48.5	0	2652.4	38	38
NSW1	49	0	2652.4	38	38
NSW1	49.5	0	2652.4	38	38
NSW1	50	0	2652.4	38	38
NSW1	50.5	0	2652.4	38	38
NSW1	51	0	2652.4	38	38
NSW1	51.5	0	2652.4	38	38

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
NSW1	52	0	2652.4	38	38
NSW1	52.5	0	2652.4	38	38
NSW1	53	0	2652.4	38	38
NSW1	53.5	0	2652.4	38	38
NSW1	54	0	2652.4	38	38
NSW1	54.5	0	2652.4	38	38
NSW1	55	0	2652.4	38	38
NSW1	55.5	0	2652.4	38	38
NSW1	56	0	2652.4	38	38
NSW1	56.5	0	2652.4	38	38
NSW1	57	0	2652.4	38	38
NSW1	57.5	0	2652.4	38	38
NSW1	58	0	2652.4	38	38
NSW1	58.5	0	2652.4	38	38
NSW1	59	0	2652.4	38	38
NSW1	59.5	0	2652.4	38	38
NSW1	60	0	2652.4	38	38
NSW1	60.5	0	2652.4	38	38
NSW1	61	0	2652.4	38	38
NSW1	61.5	0	2652.4	38	38
NSW1	62	0	2652.4	38	38
NSW1	62.5	0	2652.4	38	38
NSW1	63	0	2652.4	38	38
NSW1	63.5	0	2652.4	38	38
NSW1	64	0	2652.4	38	38
NSW1	64.5	0	2652.4	38	38
NSW1	65	0	2652.4	38	38
NSW1	65.5	0	2652.4	38	38
NSW1	66	0	2652.4	38	38
NSW1	66.5	0	2652.4	38	38
NSW1	67	0	2652.4	38	38
NSW1	67.5	0	2652.4	38	38
NSW1	68	0	2652.4	38	38
NSW1	68.5	0	2652.4	38	38
NSW1	69	0	2652.4	38	38
NSW1	69.5	0	2652.4	38	38
NSW1	70	0	2652.4	38	38

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
NSW1	70.5	0	2652.4	38	38
NSW1	71	0	2652.4	38	38
NSW1	71.5	0	2652.4	38	38
NSW1	72	0	2652.4	38	38
QLD1	0.5	0	746.8	90	12
QLD1	1	0	838.85	90	12
QLD1	1.5	0	930.9	90	12
QLD1	2	0	981.35	90	12
QLD1	2.5	0	1031.8	90	12
QLD1	3	0	1054.6	90	12
QLD1	3.5	0	1077.4	90	12
QLD1	4	0	1108.9	90	12
QLD1	4.5	0	1140.4	90	12
QLD1	5	0	1156.2	90	12
QLD1	5.5	0	1172	90	12
QLD1	6	0	1178.45	90	12
QLD1	6.5	0	1184.9	24	12
QLD1	7	0	1182.3	24	12
QLD1	7.5	0	1179.7	24	12
QLD1	8	0	1163.1	24	12
QLD1	8.5	0	1146.5	24	12
QLD1	9	0	1121.7	24	12
QLD1	9.5	0	1096.9	24	12
QLD1	10	0	1103.3	24	12
QLD1	10.5	0	1109.7	24	12
QLD1	11	0	1120.8	24	12
QLD1	11.5	0	1131.9	24	12
QLD1	12	0	1143	24	12
QLD1	12.5	0	1154.1	24	12
QLD1	13	0	1163.2	24	12
QLD1	13.5	0	1172.3	24	12
QLD1	14	0	1178	24	12
QLD1	14.5	0	1183.7	24	12
QLD1	15	0	1191.5	24	12
QLD1	15.5	0	1199.3	24	12
QLD1	16	0	1206.6	24	12
QLD1	16.5	0	1213.9	24	12

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
QLD1	17	0	1218	24	12
QLD1	17.5	0	1222.1	24	12
QLD1	18	0	1231.3	24	12
QLD1	18.5	0	1240.5	24	24
QLD1	19	0	1249.15	24	24
QLD1	19.5	0	1257.8	24	24
QLD1	20	0	1265.5	24	24
QLD1	20.5	0	1273.2	24	24
QLD1	21	0	1272.05	24	24
QLD1	21.5	0	1270.9	24	24
QLD1	22	0	1276.55	24	24
QLD1	22.5	0	1282.2	24	24
QLD1	23	0	1286.85	24	24
QLD1	23.5	0	1291.5	24	24
QLD1	24	0	1294.25	24	24
QLD1	24.5	0	1297	24	24
QLD1	25	0	1299.6	24	24
QLD1	25.5	0	1302.2	24	24
QLD1	26	0	1305.75	24	24
QLD1	26.5	0	1309.3	24	24
QLD1	27	0	1313.8	24	24
QLD1	27.5	0	1318.3	24	24
QLD1	28	0	1323.65	24	24
QLD1	28.5	0	1329	24	24
QLD1	29	0	1338.8	24	24
QLD1	29.5	0	1348.6	24	24
QLD1	30	0	1351.25	24	24
QLD1	30.5	0	1353.9	24	24
QLD1	31	0	1358.7	24	24
QLD1	31.5	0	1363.5	24	24
QLD1	32	0	1366.95	24	24
QLD1	32.5	0	1370.4	24	24
QLD1	33	0	1371.75	24	24
QLD1	33.5	0	1373.1	24	24
QLD1	34	0	1373.95	24	24
QLD1	34.5	0	1374.8	24	24
QLD1	35	0	1378.25	24	24

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
QLD1	35.5	0	1381.7	24	24
QLD1	36	0	1383.75	24	24
QLD1	36.5	0	1385.8	24	24
QLD1	37	0	1388.05	24	24
QLD1	37.5	0	1390.3	24	24
QLD1	38	0	1393.15	24	24
QLD1	38.5	0	1396	24	24
QLD1	39	0	1404.8	24	24
QLD1	39.5	0	1413.6	24	24
QLD1	40	0	1423.2	24	24
QLD1	40.5	0	1432.8	24	24
QLD1	41	0	1438.75	24	24
QLD1	41.5	0	1444.7	24	24
QLD1	42	0	1446.7	24	24
QLD1	42.5	0	1448.7	24	24
QLD1	43	0	1450.35	24	24
QLD1	43.5	0	1452	24	24
QLD1	44	0	1452.9	24	24
QLD1	44.5	0	1453.8	24	24
QLD1	45	0	1455.4	24	24
QLD1	45.5	0	1457	24	24
QLD1	46	0	1458.6	24	24
QLD1	46.5	0	1460.2	24	24
QLD1	47	0	1465.55	24	24
QLD1	47.5	0	1470.9	24	24
QLD1	48	0	1472.45	24	24
QLD1	48.5	0	1474	24	24
QLD1	49	0	1476.25	24	24
QLD1	49.5	0	1478.5	24	24
QLD1	50	0	1480.95	24	24
QLD1	50.5	0	1483.4	24	24
QLD1	51	0	1485.65	24	24
QLD1	51.5	0	1487.9	24	24
QLD1	52	0	1492.85	24	24
QLD1	52.5	0	1497.8	24	24
QLD1	53	0	1501.8	24	24
QLD1	53.5	0	1505.8	24	24

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
QLD1	54	0	1509.9	24	24
QLD1	54.5	0	1514	24	24
QLD1	55	0	1516.7	24	24
QLD1	55.5	0	1519.4	24	24
QLD1	56	0	1520.1	24	24
QLD1	56.5	0	1520.8	24	24
QLD1	57	0	1523.95	24	24
QLD1	57.5	0	1527.1	24	24
QLD1	58	0	1528.9	24	24
QLD1	58.5	0	1530.7	24	24
QLD1	59	0	1533.3	24	24
QLD1	59.5	0	1535.9	24	24
QLD1	60	0	1538.15	24	24
QLD1	60.5	0	1540.4	24	24
QLD1	61	0	1545.25	24	24
QLD1	61.5	0	1550.1	24	24
QLD1	62	0	1551	24	24
QLD1	62.5	0	1551.9	24	24
QLD1	63	0	1551.1	24	24
QLD1	63.5	0	1550.3	24	24
QLD1	64	0	1553.95	24	24
QLD1	64.5	0	1557.6	24	24
QLD1	65	0	1559.85	24	24
QLD1	65.5	0	1562.1	24	24
QLD1	66	0	1562.55	24	24
QLD1	66.5	0	1563	24	24
QLD1	67	0	1565.85	24	24
QLD1	67.5	0	1568.7	24	24
QLD1	68	0	1569.65	24	24
QLD1	68.5	0	1570.6	24	24
QLD1	69	0	1571.9	24	24
QLD1	69.5	0	1573.2	24	24
QLD1	70	0	1574.6	24	24
QLD1	70.5	0	1576	24	24
QLD1	71	0	1577.3	24	24
QLD1	71.5	0	1578.6	24	24
QLD1	72	0	1578.6	24	24

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
SA1	0.5	0	311.2	48	6
SA1	1	0	356.45	48	6
SA1	1.5	0	401.7	48	6
SA1	2	0	422.4	48	6
SA1	2.5	0	443.1	48	6
SA1	3	0	463.15	48	6
SA1	3.5	0	483.2	48	6
SA1	4	0	492.6	48	6
SA1	4.5	0	502	48	6
SA1	5	0	510.5	48	6
SA1	5.5	0	519	48	6
SA1	6	0	523.75	48	6
SA1	6.5	0	528.5	13	6
SA1	7	0	536.2	13	6
SA1	7.5	0	543.9	13	6
SA1	8	0	555.35	13	6
SA1	8.5	0	566.8	13	6
SA1	9	0	571.95	13	6
SA1	9.5	0	577.1	13	6
SA1	10	0	576.1	13	6
SA1	10.5	0	575.1	13	6
SA1	11	0	578.6	13	6
SA1	11.5	0	582.1	13	6
SA1	12	0	587.6	13	6
SA1	12.5	0	593.1	13	6
SA1	13	0	600.2	13	6
SA1	13.5	0	607.3	13	6
SA1	14	0	610.8	13	6
SA1	14.5	0	614.3	13	6
SA1	15	0	616.2	13	6
SA1	15.5	0	618.1	13	6
SA1	16	0	620.2	13	6
SA1	16.5	0	622.3	13	6
SA1	17	0	627	13	6
SA1	17.5	0	631.7	13	6
SA1	18	0	635.05	13	6
SA1	18.5	0	638.4	13	13

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
SA1	19	0	642.85	13	13
SA1	19.5	0	647.3	13	13
SA1	20	0	651.45	13	13
SA1	20.5	0	655.6	13	13
SA1	21	0	662	13	13
SA1	21.5	0	668.4	13	13
SA1	22	0	675.65	13	13
SA1	22.5	0	682.9	13	13
SA1	23	0	688.85	13	13
SA1	23.5	0	694.8	13	13
SA1	24	0	701.05	13	13
SA1	24.5	0	707.3	13	13
SA1	25	0	711.6	13	13
SA1	25.5	0	715.9	13	13
SA1	26	0	718.65	13	13
SA1	26.5	0	721.4	13	13
SA1	27	0	724.45	13	13
SA1	27.5	0	727.5	13	13
SA1	28	0	729.45	13	13
SA1	28.5	0	731.4	13	13
SA1	29	0	733.55	13	13
SA1	29.5	0	735.7	13	13
SA1	30	0	736.65	13	13
SA1	30.5	0	737.6	13	13
SA1	31	0	738.35	13	13
SA1	31.5	0	739.1	13	13
SA1	32	0	742.9	13	13
SA1	32.5	0	746.7	13	13
SA1	33	0	748.95	13	13
SA1	33.5	0	751.2	13	13
SA1	34	0	753.6	13	13
SA1	34.5	0	756	13	13
SA1	35	0	759.7	13	13
SA1	35.5	0	763.4	13	13
SA1	36	0	766.35	13	13
SA1	36.5	0	769.3	13	13
SA1	37	0	772.85	13	13

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
SA1	37.5	0	776.4	13	13
SA1	38	0	778.65	13	13
SA1	38.5	0	780.9	13	13
SA1	39	0	794.55	13	13
SA1	39.5	0	808.2	13	13
SA1	40	0	810.35	13	13
SA1	40.5	0	812.5	13	13
SA1	41	0	814.3	13	13
SA1	41.5	0	816.1	13	13
SA1	42	0	816.85	13	13
SA1	42.5	0	817.6	13	13
SA1	43	0	820.65	13	13
SA1	43.5	0	823.7	13	13
SA1	44	0	824.9	13	13
SA1	44.5	0	826.1	13	13
SA1	45	0	827.2	13	13
SA1	45.5	0	828.3	13	13
SA1	46	0	829.35	13	13
SA1	46.5	0	830.4	13	13
SA1	47	0	830.25	13	13
SA1	47.5	0	830.1	13	13
SA1	48	0	830.95	13	13
SA1	48.5	0	831.8	13	13
SA1	49	0	831.9	13	13
SA1	49.5	0	832	13	13
SA1	50	0	821.05	13	13
SA1	50.5	0	810.1	13	13
SA1	51	0	824.8	13	13
SA1	51.5	0	839.5	13	13
SA1	52	0	840	13	13
SA1	52.5	0	840.5	13	13
SA1	53	0	842	13	13
SA1	53.5	0	843.5	13	13
SA1	54	0	845.3	13	13
SA1	54.5	0	847.1	13	13
SA1	55	0	846.9	13	13
SA1	55.5	0	846.7	13	13

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
SA1	56	0	846.55	13	13
SA1	56.5	0	846.4	13	13
SA1	57	0	846.95	13	13
SA1	57.5	0	847.5	13	13
SA1	58	0	846.3	13	13
SA1	58.5	0	845.1	13	13
SA1	59	0	842.9	13	13
SA1	59.5	0	840.7	13	13
SA1	60	0	841.75	13	13
SA1	60.5	0	842.8	13	13
SA1	61	0	844.1	13	13
SA1	61.5	0	845.4	13	13
SA1	62	0	846.75	13	13
SA1	62.5	0	848.1	13	13
SA1	63	0	852.6	13	13
SA1	63.5	0	857.1	13	13
SA1	64	0	860.95	13	13
SA1	64.5	0	864.8	13	13
SA1	65	0	869.3	13	13
SA1	65.5	0	873.8	13	13
SA1	66	0	874.95	13	13
SA1	66.5	0	876.1	13	13
SA1	67	0	878.25	13	13
SA1	67.5	0	880.4	13	13
SA1	68	0	881.5	13	13
SA1	68.5	0	882.6	13	13
SA1	69	0	884.9	13	13
SA1	69.5	0	887.2	13	13
SA1	70	0	888.5	13	13
SA1	70.5	0	889.8	13	13
SA1	71	0	890.15	13	13
SA1	71.5	0	890.5	13	13
SA1	72	0	890.5	13	13
TAS1	0.5	0	199.1	37	5
TAS1	1	0	216.1	37	5
TAS1	1.5	0	233.1	37	5
TAS1	2	0	244.9	37	5

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
TAS1	2.5	0	256.7	37	5
TAS1	3	0	262.15	37	5
TAS1	3.5	0	267.6	37	5
TAS1	4	0	270.95	37	5
TAS1	4.5	0	274.3	37	5
TAS1	5	0	277	37	5
TAS1	5.5	0	279.7	37	5
TAS1	6	0	282.1	37	5
TAS1	6.5	0	284.5	10	5
TAS1	7	0	284.55	10	5
TAS1	7.5	0	284.6	10	5
TAS1	8	0	286.3	10	5
TAS1	8.5	0	288	10	5
TAS1	9	0	289.9	10	5
TAS1	9.5	0	291.8	10	5
TAS1	10	0	292.5	10	5
TAS1	10.5	0	293.2	10	5
TAS1	11	0	293.7	10	5
TAS1	11.5	0	294.2	10	5
TAS1	12	0	295.4	10	5
TAS1	12.5	0	296.6	10	5
TAS1	13	0	297.25	10	5
TAS1	13.5	0	297.9	10	5
TAS1	14	0	298.75	10	5
TAS1	14.5	0	299.6	10	5
TAS1	15	0	302.45	10	5
TAS1	15.5	0	305.3	10	5
TAS1	16	0	306.1	10	5
TAS1	16.5	0	306.9	10	5
TAS1	17	0	307.6	10	5
TAS1	17.5	0	308.3	10	5
TAS1	18	0	310.55	10	5
TAS1	18.5	0	312.8	10	10
TAS1	19	0	320.9	10	10
TAS1	19.5	0	329	10	10
TAS1	20	0	330.75	10	10
TAS1	20.5	0	332.5	10	10

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
TAS1	21	0	334.3	10	10
TAS1	21.5	0	336.1	10	10
TAS1	22	0	337.05	10	10
TAS1	22.5	0	338	10	10
TAS1	23	0	339.7	10	10
TAS1	23.5	0	341.4	10	10
TAS1	24	0	342.05	10	10
TAS1	24.5	0	342.7	10	10
TAS1	25	0	343.35	10	10
TAS1	25.5	0	344	10	10
TAS1	26	0	345.35	10	10
TAS1	26.5	0	346.7	10	10
TAS1	27	0	347.6	10	10
TAS1	27.5	0	348.5	10	10
TAS1	28	0	348.85	10	10
TAS1	28.5	0	349.2	10	10
TAS1	29	0	350.05	10	10
TAS1	29.5	0	350.9	10	10
TAS1	30	0	351.05	10	10
TAS1	30.5	0	351.2	10	10
TAS1	31	0	352	10	10
TAS1	31.5	0	352.8	10	10
TAS1	32	0	354.05	10	10
TAS1	32.5	0	355.3	10	10
TAS1	33	0	356.7	10	10
TAS1	33.5	0	358.1	10	10
TAS1	34	0	359	10	10
TAS1	34.5	0	359.9	10	10
TAS1	35	0	361.25	10	10
TAS1	35.5	0	362.6	10	10
TAS1	36	0	364.6	10	10
TAS1	36.5	0	366.6	10	10
TAS1	37	0	368.05	10	10
TAS1	37.5	0	369.5	10	10
TAS1	38	0	370.1	10	10
TAS1	38.5	0	370.7	10	10
TAS1	39	0	368.6	10	10

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
TAS1	39.5	0	366.5	10	10
TAS1	40	0	369.3	10	10
TAS1	40.5	0	372.1	10	10
TAS1	41	0	372.15	10	10
TAS1	41.5	0	372.2	10	10
TAS1	42	0	370.7	10	10
TAS1	42.5	0	369.2	10	10
TAS1	43	0	369.75	10	10
TAS1	43.5	0	370.3	10	10
TAS1	44	0	370.8	10	10
TAS1	44.5	0	371.3	10	10
TAS1	45	0	371.85	10	10
TAS1	45.5	0	372.4	10	10
TAS1	46	0	373	10	10
TAS1	46.5	0	373.6	10	10
TAS1	47	0	374.55	10	10
TAS1	47.5	0	375.5	10	10
TAS1	48	0	375.25	10	10
TAS1	48.5	0	375	10	10
TAS1	49	0	374.4	10	10
TAS1	49.5	0	373.8	10	10
TAS1	50	0	374.3	10	10
TAS1	50.5	0	374.8	10	10
TAS1	51	0	374.35	10	10
TAS1	51.5	0	373.9	10	10
TAS1	52	0	373.75	10	10
TAS1	52.5	0	373.6	10	10
TAS1	53	0	374.05	10	10
TAS1	53.5	0	374.5	10	10
TAS1	54	0	373.9	10	10
TAS1	54.5	0	373.3	10	10
TAS1	55	0	376.85	10	10
TAS1	55.5	0	380.4	10	10
TAS1	56	0	380.2	10	10
TAS1	56.5	0	380	10	10
TAS1	57	0	380.6	10	10
TAS1	57.5	0	381.2	10	10

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
TAS1	58	0	381.5	10	10
TAS1	58.5	0	381.8	10	10
TAS1	59	0	381.3	10	10
TAS1	59.5	0	380.8	10	10
TAS1	60	0	380.75	10	10
TAS1	60.5	0	380.7	10	10
TAS1	61	0	379.8	10	10
TAS1	61.5	0	378.9	10	10
TAS1	62	0	379.5	10	10
TAS1	62.5	0	380.1	10	10
TAS1	63	0	380.5	10	10
TAS1	63.5	0	380.9	10	10
TAS1	64	0	381.7	10	10
TAS1	64.5	0	382.5	10	10
TAS1	65	0	383.4	10	10
TAS1	65.5	0	384.3	10	10
TAS1	66	0	384.15	10	10
TAS1	66.5	0	384	10	10
TAS1	67	0	384	10	10
TAS1	67.5	0	384	10	10
TAS1	68	0	384.1	10	10
TAS1	68.5	0	384.2	10	10
TAS1	69	0	384.75	10	10
TAS1	69.5	0	385.3	10	10
TAS1	70	0	385.3	10	10
TAS1	70.5	0	385.3	10	10
TAS1	71	0	385.25	10	10
TAS1	71.5	0	385.2	10	10
TAS1	72	0	385.2	10	10
VIC1	0.5	0	547.9	93	12
VIC1	1	0	648.1	93	12
VIC1	1.5	0	748.3	93	12
VIC1	2	0	817.4	93	12
VIC1	2.5	0	886.5	93	12
VIC1	3	0	935.85	93	12
VIC1	3.5	0	985.2	93	12
VIC1	4	0	1028.65	93	12

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
VIC1	4.5	0	1072.1	93	12
VIC1	5	0	1116.15	93	12
VIC1	5.5	0	1160.2	93	12
VIC1	6	0	1200.7	93	12
VIC1	6.5	0	1241.2	25	12
VIC1	7	0	1271.7	25	12
VIC1	7.5	0	1302.2	25	12
VIC1	8	0	1292.85	25	12
VIC1	8.5	0	1283.5	25	12
VIC1	9	0	1303	25	12
VIC1	9.5	0	1322.5	25	12
VIC1	10	0	1335.1	25	12
VIC1	10.5	0	1347.7	25	12
VIC1	11	0	1350.5	25	12
VIC1	11.5	0	1353.3	25	12
VIC1	12	0	1364.3	25	12
VIC1	12.5	0	1375.3	25	12
VIC1	13	0	1378.75	25	12
VIC1	13.5	0	1382.2	25	12
VIC1	14	0	1373.3	25	12
VIC1	14.5	0	1364.4	25	12
VIC1	15	0	1376.8	25	12
VIC1	15.5	0	1389.2	25	12
VIC1	16	0	1394.75	25	12
VIC1	16.5	0	1400.3	25	12
VIC1	17	0	1409.9	25	12
VIC1	17.5	0	1419.5	25	12
VIC1	18	0	1421	25	12
VIC1	18.5	0	1422.5	25	25
VIC1	19	0	1428.7	25	25
VIC1	19.5	0	1434.9	25	25
VIC1	20	0	1441.1	25	25
VIC1	20.5	0	1447.3	25	25
VIC1	21	0	1456.45	25	25
VIC1	21.5	0	1465.6	25	25
VIC1	22	0	1469.75	25	25
VIC1	22.5	0	1473.9	25	25

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
VIC1	23	0	1478.45	25	25
VIC1	23.5	0	1483	25	25
VIC1	24	0	1487.3	25	25
VIC1	24.5	0	1491.6	25	25
VIC1	25	0	1498	25	25
VIC1	25.5	0	1504.4	25	25
VIC1	26	0	1509.35	25	25
VIC1	26.5	0	1514.3	25	25
VIC1	27	0	1512.35	25	25
VIC1	27.5	0	1510.4	25	25
VIC1	28	0	1514.45	25	25
VIC1	28.5	0	1518.5	25	25
VIC1	29	0	1525.4	25	25
VIC1	29.5	0	1532.3	25	25
VIC1	30	0	1535.15	25	25
VIC1	30.5	0	1538	25	25
VIC1	31	0	1541.3	25	25
VIC1	31.5	0	1544.6	25	25
VIC1	32	0	1551	25	25
VIC1	32.5	0	1557.4	25	25
VIC1	33	0	1559.95	25	25
VIC1	33.5	0	1562.5	25	25
VIC1	34	0	1565.55	25	25
VIC1	34.5	0	1568.6	25	25
VIC1	35	0	1567.8	25	25
VIC1	35.5	0	1567	25	25
VIC1	36	0	1566.1	25	25
VIC1	36.5	0	1565.2	25	25
VIC1	37	0	1559.65	25	25
VIC1	37.5	0	1554.1	25	25
VIC1	38	0	1544.05	25	25
VIC1	38.5	0	1534	25	25
VIC1	39	0	1537.65	25	25
VIC1	39.5	0	1541.3	25	25
VIC1	40	0	1551.45	25	25
VIC1	40.5	0	1561.6	25	25
VIC1	41	0	1571.35	25	25

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
VIC1	41.5	0	1581.1	25	25
VIC1	42	0	1591.9	25	25
VIC1	42.5	0	1602.7	25	25
VIC1	43	0	1604.7	25	25
VIC1	43.5	0	1606.7	25	25
VIC1	44	0	1611.1	25	25
VIC1	44.5	0	1615.5	25	25
VIC1	45	0	1618.4	25	25
VIC1	45.5	0	1621.3	25	25
VIC1	46	0	1628.45	25	25
VIC1	46.5	0	1635.6	25	25
VIC1	47	0	1639.75	25	25
VIC1	47.5	0	1643.9	25	25
VIC1	48	0	1648.7	25	25
VIC1	48.5	0	1653.5	25	25
VIC1	49	0	1654	25	25
VIC1	49.5	0	1654.5	25	25
VIC1	50	0	1656.9	25	25
VIC1	50.5	0	1659.3	25	25
VIC1	51	0	1658.25	25	25
VIC1	51.5	0	1657.2	25	25
VIC1	52	0	1658.85	25	25
VIC1	52.5	0	1660.5	25	25
VIC1	53	0	1661.65	25	25
VIC1	53.5	0	1662.8	25	25
VIC1	54	0	1677	25	25
VIC1	54.5	0	1691.2	25	25
VIC1	55	0	1698.35	25	25
VIC1	55.5	0	1705.5	25	25
VIC1	56	0	1710.55	25	25
VIC1	56.5	0	1715.6	25	25
VIC1	57	0	1721.2	25	25
VIC1	57.5	0	1726.8	25	25
VIC1	58	0	1731.9	25	25
VIC1	58.5	0	1737	25	25
VIC1	59	0	1738.9	25	25
VIC1	59.5	0	1740.8	25	25

Region(s)	Forecasting Horizon (Hrs)	Lower reasonability limit	Upper reasonability limit	Delta lower reasonability limit	Delta raise reasonability limit
VIC1	60	0	1743.95	25	25
VIC1	60.5	0	1747.1	25	25
VIC1	61	0	1751.05	25	25
VIC1	61.5	0	1755	25	25
VIC1	62	0	1756.3	25	25
VIC1	62.5	0	1757.6	25	25
VIC1	63	0	1762.75	25	25
VIC1	63.5	0	1767.9	25	25
VIC1	64	0	1771.5	25	25
VIC1	64.5	0	1775.1	25	25
VIC1	65	0	1777.1	25	25
VIC1	65.5	0	1779.1	25	25
VIC1	66	0	1779.15	25	25
VIC1	66.5	0	1779.2	25	25
VIC1	67	0	1786.75	25	25
VIC1	67.5	0	1794.3	25	25
VIC1	68	0	1794	25	25
VIC1	68.5	0	1793.7	25	25
VIC1	69	0	1791.85	25	25
VIC1	69.5	0	1790	25	25
VIC1	70	0	1791.6	25	25
VIC1	70.5	0	1793.2	25	25
VIC1	71	0	1796.55	25	25
VIC1	71.5	0	1799.9	25	25
VIC1	72	0	1799.9	25	25

APPENDIX D. REFERENCES

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