Demand Terms in EMMS Data Model

October 2019

Important notice

PURPOSE

AEMO has prepared this document to provide general information about regional demand definitions, as at the date of publication.

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VERSION RELEASE HISTORY

Version	Date	Author	Authorised by	Notes
12.0	31/10/2019	Electricity Market Monitoring	Brian Nelson	Modified terminology to incorporate five-minute settlement. Updated exceptions to definition of Operational Demand to exclude non-scheduled diesel generation in South Australia. Minor amendments.
11.0	09/01/2019	Electricity Market Monitoring	Brian Nelson	Updated template, weblinks, footnote and sections where native and operational demand are used.
10.0	03/09/2018	Operational Forecasting	Brian Nelson	Updated exceptions to definition of Operational Demand to include non-scheduled diesel generation in South Australia, following the re-classification of two SA Power Networks diesel facilities from scheduled to non-scheduled.
9.0	18/07/2018	Operational Forecasting	Jonathan Jorgensen	Updated exceptions to definition of Operational Demand to include a non-scheduled generator (Longreach Solar Farm)
8.0	04/06/2018	Operational Forecasting	Nathan White	Updated exceptions to definition of Operational Demand to include non-scheduled generators (Yaloak South Wind Farm and Hughenden Solar Farm).
7.0	06/09/2016	Market and System Change	Nathan White	Updated exceptions to definition of Operational Demand to exclude non-scheduled diesel generation in Tasmania following their de-registration.
6.0	18/05/2016	Market and System Change	Joe Spurio	Updated exceptions to definition of Operational Demand to include non-scheduled diesel generation in Tasmania.
5.0	28/09/2015	Market and System Change	Nathan White	Updated title to reflect full scope of this report. Include exceptions in the calculations of the key demands, add references to Rule clauses when applicable, modify EMMS Data Model, and other minor changes. Updated Table 2 to include omissions and rectify errors.
4.0	10/02/2012	Basilisa Choi	Brian Nelson	Major revamping to restructure the paper and include the key demands used by AEMO, in addition to the EMMS Data Model items.
3.0	23/12/2009	Market Operations and Performance		Initial creation – minor modifications were made to version 1.0 to add disclaimer and apply AEMO rebranding.

Introduction

Purpose and scope of this paper

This paper describes the composition, use and publication of the different types of demands and associated terms used in AEMO's Electricity Market Management Systems (EMMS) Data Model for National Electricity Market (NEM) participants or other interested parties. The particular focus of this paper is "as generated" demand, although other demands are defined.

Other organisations such as Network Service Providers or Jurisdictional Planning Bodies (JPBs) might have a different definition for the same terms or associated terminology discussed in this paper. This paper does not delve into the differences.

For definitional purposes, all references to "demand" in this paper equally apply to "consumption"[1].

Structure of the paper

The paper is structured as follows:

Section 1 introduces the three types of demand based on where they are measured in the electricity network. It also discusses the three key demands of Native, Operational and Scheduled related to "as generated" demand as used in the NEM.

Section 2 describes the "as generated" demand in the Electricity Market Management System (EMMS), by categorising them into their relevant electricity market processes.

Assumptions

The following assumptions are made for all demand definitions discussed in this paper.

- All demand definitions are on a regional basis[2].
- All demands can be expressed as either actual or forecast, unless explicitly stated.
- Scheduled loads mean normally-off scheduled loads[3]. There are currently no normally-on scheduled loads in the NEM.
- If the NEM registration classification of a unit differs from its EMMS classification, this paper only discusses the unit's EMMS classification[4].

Convention

EMMS field names are italicised. All key demands that are used throughout the paper have been bolded.

[1] For example, AEMO publications refer to both "operational demand" (electrical power, typically in MW) and "operational consumption" (electrical energy, typically in MWh), although the underlying compositional definition is the same. Refer to Operational Consumption and Demand document for more information on the differences between demand and consumption, at http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/planning/Use%20of%20Operational%20Consumption%20and%20Demand.ashx.

[2] Demand in a region that is met by generation within the region and the net interconnector imports into the region.

[3] Normally-on and normally-off scheduled loads are defined in clause 3.8.7(i) and (j) of the National Electricity Rules (NER).

[4] If a unit is registered as a non-scheduled generating unit but, as a condition of registration, the relevant Registered Participant must comply with some of the obligations of a Scheduled Generator, the unit may need to be treated as a scheduled generating unit in the central dispatch process. This paper refers to such a unit as a scheduled generating unit. For example, Yarwun is registered as a market non-scheduled generating unit but is dispatched as a scheduled generating unit with respect to its dispatch offers, targets and generation outputs. Accordingly, information about Yarwun is reported as scheduled generating unit information.

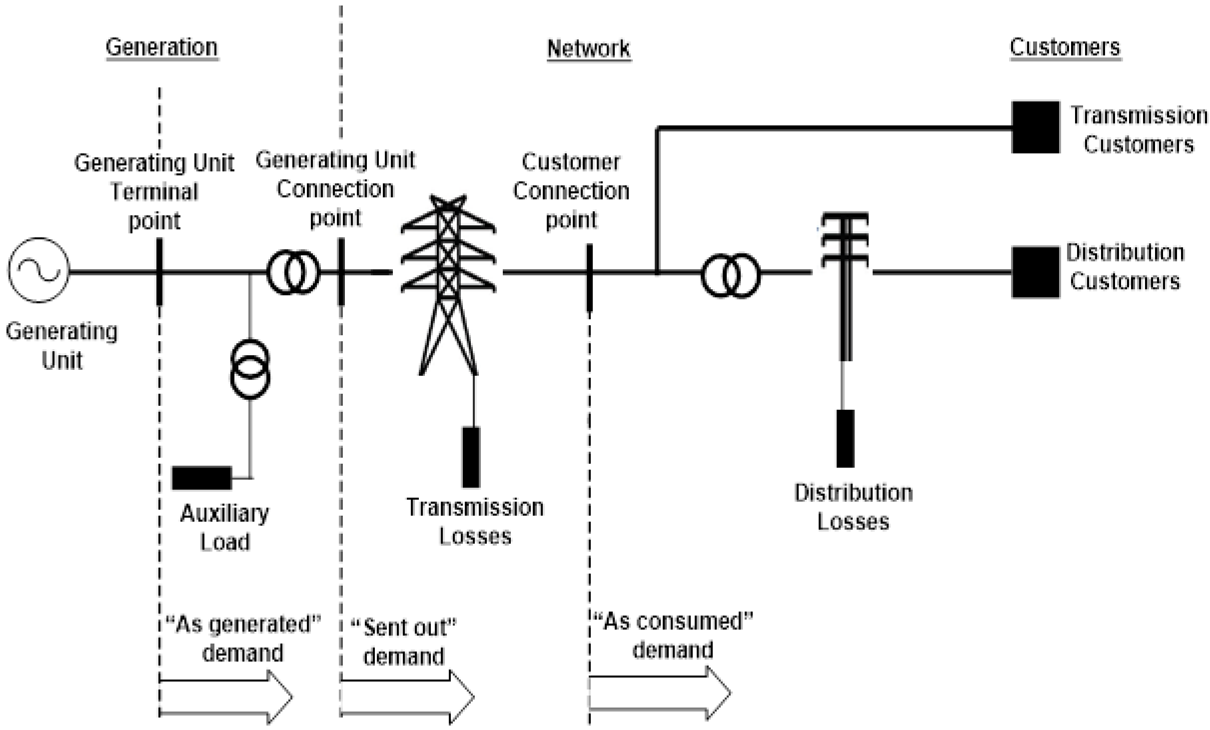
Contents

1. What is demand?

Demand is the electrical power requirement (in megawatts, or MW) of consumers in a region connected to the electricity network. As shown in Figure 1 below, based on the location of measurement in the electricity network, demand can be broadly classified into:

- "As generated" demand.
- "Sent out" demand.
- "As consumed" demand.

Figure 1 Electricity network topology



"As consumed" demand or "customer demand" is measured at each customer's connection point and represents the net electrical power consumed at that point. "As consumed" demand measures electricity power supplied to all customers (transmission and distribution) and therefore excludes generating unit auxiliary loads[5] and transmission losses.

"Sent out" demand is measured at each generating unit's connection point and represents the net electrical power output from the generating unit excluding its auxiliary load. "Sent out" demand therefore comprises:

- "As consumed" demand.
- All electricity transmission losses incurred in delivering the net generating unit output to the bulk electricity customer connection points.

"As generated" demand is measured at each generating unit's terminal point and represents the gross electrical power output from the generating unit. "As generated" demand therefore comprises:

[5] Load used to run a power station. This may include supplies to operate the coal mine as well.

- "Sent out" demand.
- The electrical power supplied to all auxiliary loads required to operate the relevant generating unit at its "as generated" output.

All demands discussed in this paper from this point are "As generated" demands.

AEMO performs a number of functions and processes that require different types of generating units or loads to be included in the demand calculations. These functional and operational requirements have led AEMO to produce various types of demands defined by composition. In essence, there are three key demands. They are:

- Native demand.
- Operational demand.
- Scheduled demand.

Table 1 provides an overview of the composition of native demand, operational demand, and scheduled demand.

- "Local generation" means power supplied from generators located in the relevant region.
- "Imported generation" means the net power supplied to the relevant region at its inter-regional boundaries.
- "Local scheduled loads" means power consumed by scheduled loads located in the relevant region.

Table 1 Native demand, operational demand and scheduled demand – composition

Generation source	Local generation					Imported generation	Local scheduled loads
Key demands	Scheduled and semi-scheduled generation	Non-scheduled wind/solar generation		Non-scheduled non-wind/non-solar generation	Exempt generation	Interconnector import including losses	
		Generation < 30MW	Generation ≥ 30MW				
Native demand	✓	✓	✓	✓	✓	✓	×
Operational demand	✓	×	✓	×	×	✓	×
Scheduled demand	✓	×	×	×	×	✓	✓

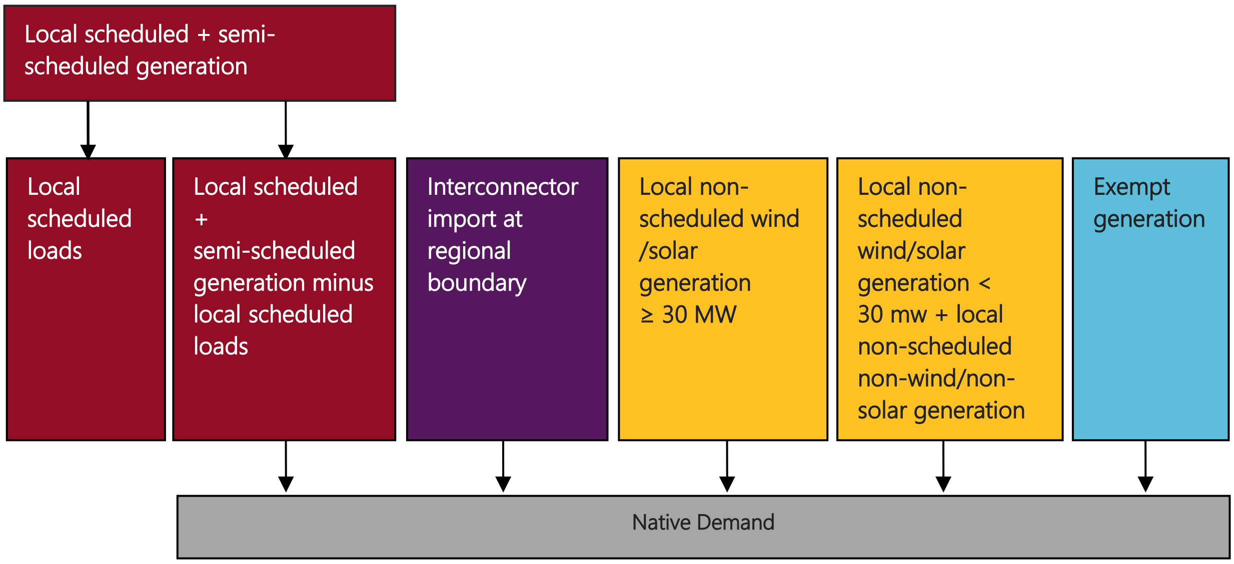
The three key demands and the exceptions in calculating these demands are discussed in detail in the following sections.

1.1 Native demand

Native demand in a region is demand that is met by local scheduled, semi-scheduled, non-scheduled[6], and exempt generation[7], and by generation imports to the region, excluding the demand of local scheduled loads[8]. Native demand only includes generation for which AEMO and the JPBs receive sufficient information.[9]

Figure 2 below shows the composition of native demand.

Figure 2 Native demand



Where native demand is used

Native demand is used as follows.

The 10% and 50% POE seasonal maximum native demand forecasts are used to derive the daily 10% and 50% POE forecast demand to be used for reliability assessment in Medium Term Projected Assessment of System Adequacy (MT PASA[10]). This is discussed in detail in Section 2.2.2.

1.2 Operational demand

Operational demand in a region is demand that is met by local scheduled generation, semi-scheduled generation and non-scheduled wind/solar generation of aggregate capacity ≥ 30 MW, and by generation imports to the region, excluding the demand of local scheduled loads. Operational demand differs from native demand in that it generally excludes demand met by non-scheduled wind/solar generation of aggregate capacity < 30 MW, non-scheduled non-wind/non-solar generation and exempt generation.

The exceptions which are included in the operational demand definition are:

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[6] This includes all non-scheduled generating units with aggregate capacity greater than 1 MW for which AEMO and JPBs have sufficient data.

[7] Exempt generation refers to generation that is exempt from registration, under Chapter 2 of the NER and in accordance with the "Guide to NEM generator classification and exemption" issued by AEMO: http://www.aemo.com.au/About-the-Industry/Registration/How-to-Register/Application-Forms-and-Supporting-Documentation/NEM-Generator-Exemption. Typically, this includes generation with a capacity less than 5 MW, or less than 30 MW provided it exports less than 20 GWh in any 12-month period.

[8] A market load classified in accordance to Chapter 2 of the NER as a scheduled load. A market customer submits dispatch bids in relation to scheduled loads.

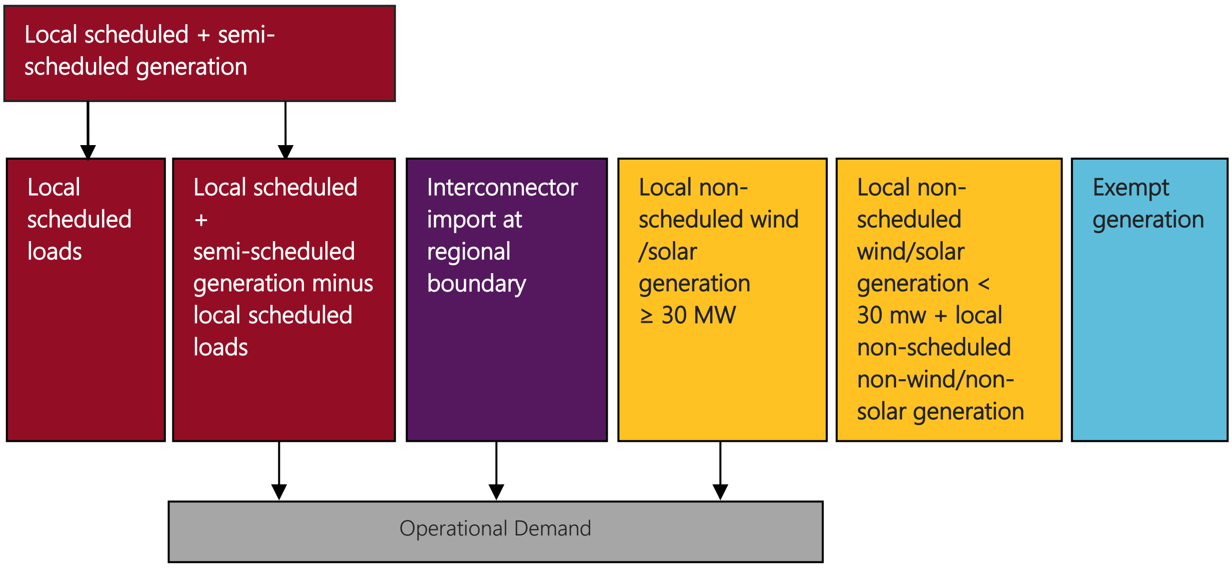
[9] Native demand does not include the demand met by behind-the-meter generation (e.g. rooftop PV, battery storage). Therefore, native demand reflects the impact of behind-the-meter generation (for example higher rooftop PV generation will result in lower midday native demand).

[10] MT PASA has a daily resolution and forecasts two years ahead. It is a PASA process.

- Yarwun (registered as non-scheduled generation but treated as scheduled generation in the EMMS).
- Mortons Lane wind farm, Yaloak South wind farm, Hughenden solar farm, Longreach solar farm (non-scheduled generation < 30 MW but due to power system security reasons AEMO is required to model in network constraints).

Figure 3 below shows the composition of operational demand.

Figure 3 Operational demand



Where operational demand is used

Operational demand is used as follows.

- For public reporting of electricity market and power system operation: for example, the maximum operational demand[11] records reported to the media for reporting on market and power system incidents.
- As a basis for calculating the forecast demand used in Pre-dispatch[12], Pre-dispatch Projected Assessment of System Adequacy (PD PASA[13]) and Short Term Projected Assessment of System Adequacy (ST PASA[14]) processes (discussed in Section 2.1.2 under Total Demand in Pre-dispatch and Section 2.2.1 for PD PASA and ST PASA).
- Actual values of operational demand to a half-hourly resolution, are published on the AEMO website[15] for all regions in the NEM.
- AEMO publishes 10%, 50% and 90% probability of exceedance[16] (POE) seasonal maximum[17] operational demand forecasts for three probable scenarios for summer and winter over a 20-year timeframe for all

[11] Also known as peak operational demand.

[12] Pre-dispatch has a 30-minute resolution and forecasts up to 40 hours ahead. It is a central dispatch process.

[13] PD PASA has a 30-minute resolution and forecasts up to 40 hours ahead. It is a PASA process.

[14] ST PASA has a 30-minute resolution and forecasts eight days ahead. It is a PASA process.

[15] Available under section "Operational Demand" at: http://www.aemo.com.au/Electricity/Data/Price-and-Demand/Operational-Demand-Data-Files.

[16] The 10%, 50%, and 90% POE demands are defined in Appendix A1.

[17] Maximum demand refers to the highest amount of electrical power delivered over a defined period (day, week, month, season or year).

NEM regions. These forecast are used for Integrated System Plan[18], Electricity Statement of Opportunities[19] and Energy Adequacy Assessment Projection[20].

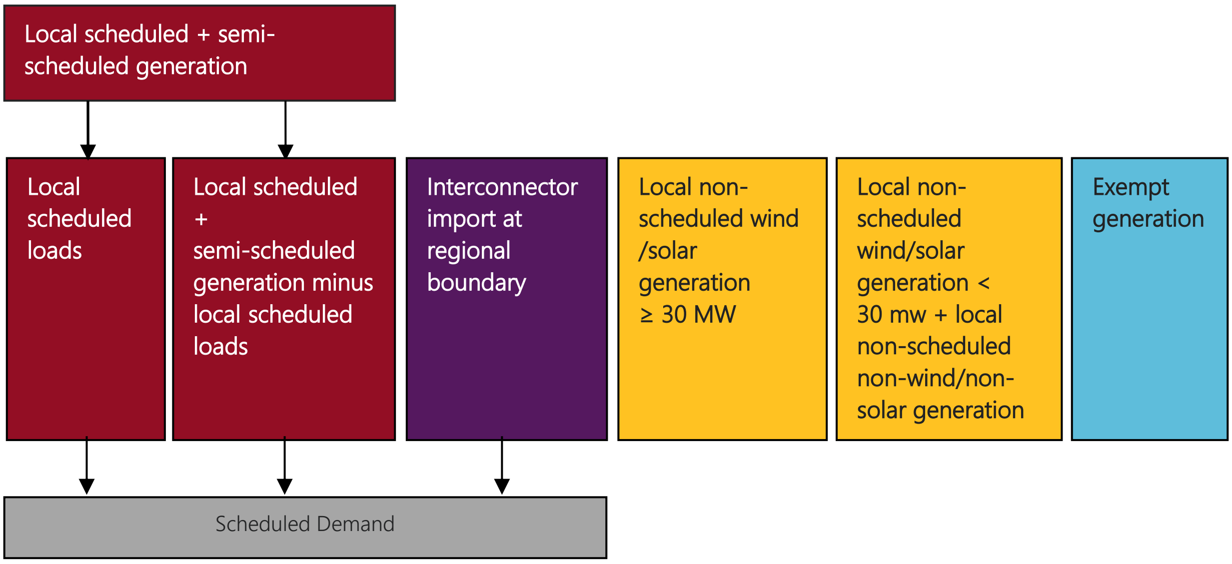
1.3 Scheduled demand

Scheduled demand in a region is demand that is met by local scheduled and semi-scheduled generation and by generation imports to the region. Scheduled demand differs from the other key demands in that it excludes the demand met by non-scheduled (wind/solar and non-wind/non-solar) generation and exempt generation, and includes the demand of local scheduled loads.

The exceptions are Tumut 3 pumps (registered as non-scheduled loads but treated as scheduled loads in the EMMS) which are included.

Figure 4 below shows the composition of scheduled demand.

Figure 4 Scheduled demand



Where scheduled demand is used

Scheduled demand is used as follows.

As a basis for calculating the forecast demand used in the central dispatch process to determine regional prices and dispatch targets for scheduled and semi-scheduled generating units and Market Network Service Providers (MNSPs).

Publication of scheduled demand values (*InitialSupply* and *ClearedSupply*) to the EMMS data model is discussed in Section 2.1.1.

Actual values of scheduled demand minus scheduled loads, to a half-hourly resolution, are published on the AEMO website[21] for all regions in the NEM.

[18] Integrated System Plan (ISP) at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

[19] NEM Electricity Statement of Opportunities (ESOO) at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

[20] Energy Adequacy Assessment Projection (EAAP) at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Energy-Adequacy-Assessment-Projection

[21] Available under section "Historical Demand" at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Market-Management-System-MMS/Generation-and-Load. This data will be discontinued from 1 July 2015.

2. Demand terms in EMMS data model

This section explains the components of the various demand-related terms published by AEMO that are part of the EMMS Data Model, and their inter-relationship. All the EMMS Data Model terms are defined using EMMS-specific field names.

The EMMS Data Model terms can be used to calculate the key demands discussed in Section 2.

Table 2 explains the components of the EMMS Data Model terms published by AEMO.

Appendix A2 lists the file names for each of the published EMMS Data Model terms in Table 2.

Table 2 Components of EMMS data model terms published by AEMO

EMMS data model term			Forecast type	Actual scheduled generation	Actual semi_scheduled generation	Actual non-scheduled (wind/solar >=30 MW)[A]	Actual non-scheduled (non-wind/\non-solar or wind/solar <=30	Exempt generation	Scheduled loads	Interconnector import at RRN	Allocated interconnector losses[B]	Aggregate dispatch error and forecast demand change
Package	**Table**	**Field**										
DISPATCH	DISPATCHREGIONSUM	CLEAREDSUPPLY	50% POE	✓	✓	×	×	×	✓	✓	✓	✓
DISPATCH	DISPATCHREGIONSUM	INITIALSUPPLY	Actual	✓	✓	×	×	×	✓	✓	✓	×
DISPATCH	DISPATCHREGIONSUM	TOTALDEMAND	50% POE	✓	✓	×	×	×	×	✓	×	✓
DISPATCH	DISPATCHREGIONSUM	DEMAND_AND_NONSCHEDGEN	50% POE	✓	✓	✓	✓	×	✓	✓	✓	✓
PRE_DISPATCH	PREDISPATCHREGIONSUM	CLEAREDSUPPLY	50% POE	✓	✓	×	×	×	✓	✓	✓	×
PRE_DISPATCH	PREDISPATCHREGIONSUM	INITIALSUPPLY	Actual	✓	✓	×	×	×	✓	✓	✓	×
PRE_DISPATCH	PREDISPATCHREGIONSUM	TOTALDEMAND	50% POE	✓	✓	×	×	×	×	✓	×	×
PRE_DISPATCH	PREDISPATCHREGIONSUM	DEMAND_AND_NONSCHEDGEN	50% POE	✓	✓	✓	×	×	✓	✓	✓	×
P5MIN[C]	P5MIN_REGIONSOLUTION	CLEAREDSUPPLY	50% POE	✓	✓	×	×	×	✓	✓	✓	✓[D]
P5MIN	P5MIN_REGIONSOLUTION	INITIALSUPPLY	Actual	✓	✓	×	×	×	✓	✓	✓	×
P5MIN	P5MIN_REGIONSOLUTION	TOTALDEMAND	50% POE	✓	✓	×	×	×	×	✓	×	✓[D]
P5MIN	P5MIN_REGIONSOLUTION	DEMAND_AND_NONSCHEDGEN	50% POE	✓	✓	✓	✓	×	✓	✓	✓	✓[D]
DEMAND_FORECASTS	PERDEMAND	RESDEMAND	50% POE	✓	✓	×	×	×	×	✓	✓	×
DEMAND_FORECASTS	PERDEMAND	DEMAND10PROBABILITY	10% POE	✓	✓	×	×	×	×	✓	✓	×

EMMS data model term			Forecast type	Actual scheduled generation	Actual semi_scheduled generation	Actual non-scheduled (wind/solar >=30 MW)[A]	Actual non-scheduled (non-wind/\non-solar or wind/solar <=30	Exempt generation	Scheduled loads	Interconnector import at RRN	Allocated interconnector losses[B]	Aggregate dispatch error and forecast demand change
Package	**Table**	**Field**										
DEMAND_FORECASTS	PERDEMAND	DEMAND90PROBABILITY	90% POE	✓	✓	×	×	×	×	✓	✓	×
PDPASA	PDPASA_REGIONSOLUTION	DEMAND50	50% POE	✓	✓	×	×	×	×	✓	✓	×
PDPASA	PDPASA_REGIONSOLUTION	DEMAND10	10% POE	✓	✓	×	×	×	×	✓	✓	×
PDPASA	PDPASA_REGIONSOLUTION	DEMAND90	90% POE	✓	✓	×	×	×	×	✓	✓	×
PDPASA	PDPASA_REGIONSOLUTION	DEMAND_AND_NONSCHEDGEN	50% POE	✓	✓	✓	×	×	×	✓	✓	×
STPASA_SOLUTION	STPASA_REGIONSOLUTION	DEMAND50	50% POE	✓	✓	×	×	×	×	✓	✓	×
PDPASA	PDPASA_REGIONSOLUTION	DEMAND50	50% POE	✓	✓	×	×	×	×	✓	✓	×
PDPASA	PDPASA_REGIONSOLUTION	DEMAND10	10% POE	✓	✓	×	×	×	×	✓	✓	×
PDPASA	PDPASA_REGIONSOLUTION	DEMAND90	90% POE	✓	✓	×	×	×	×	✓	✓	×
PDPASA	PDPASA_REGIONSOLUTION	DEMAND_AND_NONSCHEDGEN	50% POE	✓	✓	✓	×	×	×	✓	✓	×
STPASA_SOLUTION	STPASA_REGIONSOLUTION	DEMAND50	50% POE	✓	✓	×	×	×	×	✓	✓	×
STPASA_SOLUTION	STPASA_REGIONSOLUTION	DEMAND10	10% POE	✓	✓	×	×	×	×	✓	✓	×
STPASA_SOLUTION	STPASA_REGIONSOLUTION	DEMAND90	90% POE	✓	✓	×	×	×	×	✓	✓	×
STPASA_SOLUTION	STPASA_REGIONSOLUTION	DEMAND_AND_NONSCHEDGEN	50% POE	✓	✓	✓	×	×	×	✓	✓	×
MTPASA_SOLUTION	MTPASA_REGIONSOLUTION	DEMAND50	50% POE	✓	✓	×	×	×	×	✓	✓	×

EMMS data model term			Forecast type	Actual scheduled generation	Actual semi_scheduled generation	Actual non-scheduled (wind/solar >=30 MW)[A]	Actual non-scheduled (non-wind/\non-solar or wind/solar <=30	Exempt generation	Scheduled loads	Interconnector import at RRN	Allocated interconnector losses[B]	Aggregate dispatch error and forecast demand change
Package	**Table**	**Field**										
MTPASA_SOLUTION	MTPASA_REGIONSOLUTION	DEMAND10	10% POE	✓	✓	×	×	×	×	✓	✓	×
MTPASA_SOLUTION	MTPASA_REGIONSOLUTION	DEMAND_AND_NONSCHEDGEN	50% POE	✓	✓	✓	✓	×	×	✓	✓	×
TRADING_DATA[E]	TRADINGREGIONSUM	CLEAREDSUPPLY	50% POE	✓	✓	×	×	×	✓	✓	✓	✓
TRADING_DATA	TRADINGREGIONSUM	INITIALSUPPLY	Actual	✓	✓	×	×	×	✓	✓	✓	×
TRADING_DATA	TRADINGREGIONSUM	TOTALDEMAND	50% POE	✓	✓	×	×	×	×	✓	×	✓
TRADING_DATA	TRADINGREGIONSUM	DEMAND_AND_NONSCHEDGEN	50% POE	✓	✓	✓	✓	×	✓	✓	✓	✓

A. Exceptions are Mortons Lane wind farm, Yaloak South wind farm, Hughenden solar farm, and Longreach solar farm, all of which are included in this group as significant non-scheduled generation.
B. The MW losses incurred as a result of the flow across an interconnector can be proportionally allocated to the two regions connected by the interconnector using a pre-determined factor. This proportional allocation of the interconnector loss to a region is referred to as the region's allocated interconnector loss. It signifies the losses on the interconnector between the region boundary and the Regional Reference Node (RRN).
C. The package P5MIN contains data for 5MPD.
D. The 5MPD solver determines forecast demand changes for each interval, by applying the relevant historical average percentage demand change profile to the previous dispatch run's forecast total demand.
E. The package TRADING_DATA includes data for trading intervals. Data in the trading interval tables are averages of the data in the six dispatch intervals of the relevant trading interval.[22]

[22] The TRADINGREGIONSUM table will stop being populated from 1 July 2021, as stated in the EMMS Release Schedule and Technical Specification – 5MS Dispatch and Operations July 2019.

Forecast type

Forecast type	Description
Actual	Measured value aggregated from Supervisory Control and Data Acquisition (SCADA) based metering with substitution for bad data where available.
50% POE	Forecast value with a 50% probability of exceedance. Often referred to as the most probable forecast
10% POE	Forecast value with a 10% probability of exceedance.
90% POE	Forecast value with a 90% probability of exceedance.

The terms used in the central dispatch and Projected Assessment of System Adequacy (PASA) processes are discussed further in Sections 2.1 and 2.2 below.

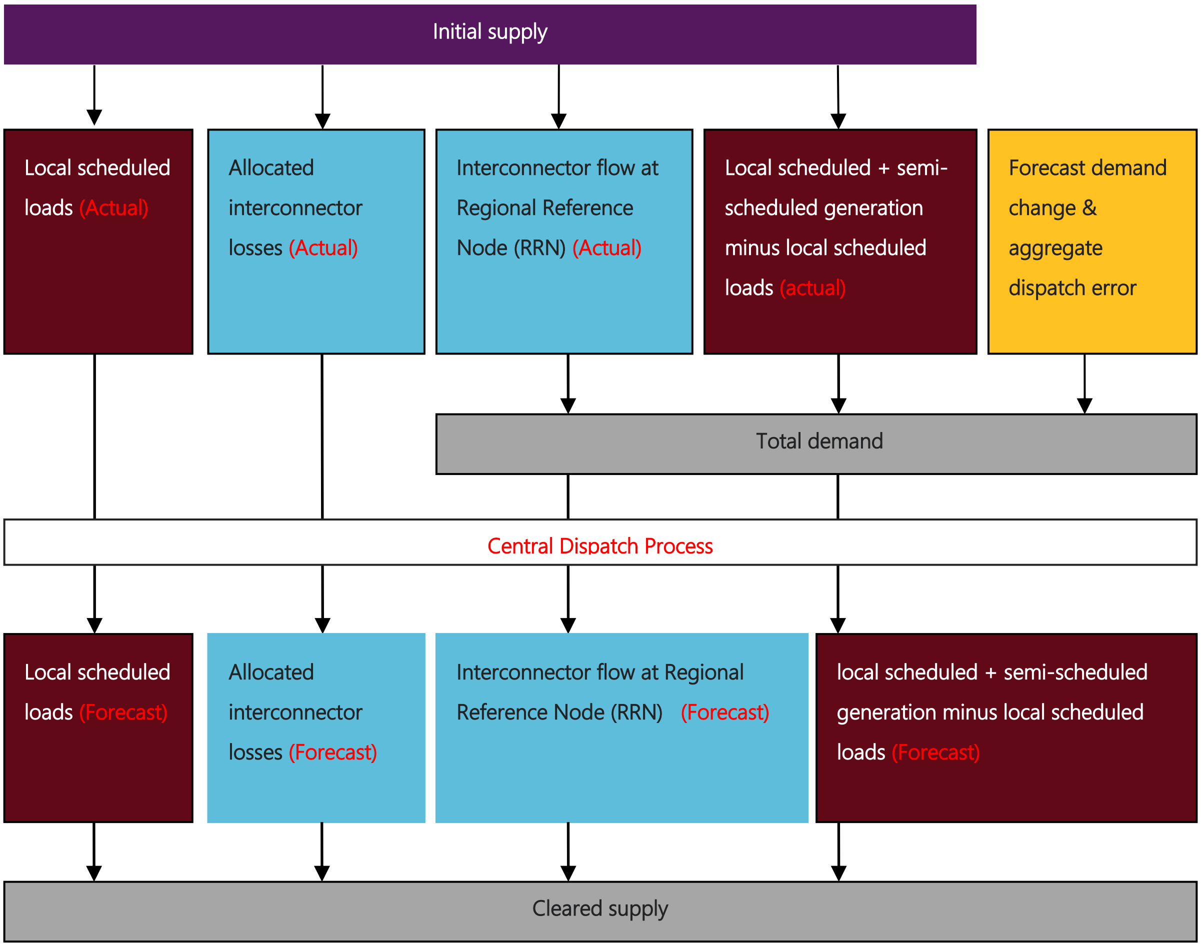
2.1 Demand Terms in EMMS Data Model used in the central dispatch process

The central dispatch process comprises Dispatch[23], Pre-dispatch, and Five-minute Pre-dispatch (5MPD[24]). The main EMMS Data Model demand terms used in the central dispatch process are[25]:

- Initial supply.
- Cleared supply.
- Total demand.

Figure 5 below provides an overview of the composition and relationship between Initial Supply, Cleared Supply and Total Demand in Dispatch.

Figure 5 Initial Supply, Cleared Supply and Total Demand



For 5MPD and Pre-dispatch, the composition and relationship between Initial Supply, Cleared Supply and Total Demand are similar in principle to those in Dispatch. Initial Supply, Cleared Supply and Total Demand

[23] Dispatch has a five-minute resolution and it forecasts five minutes ahead.

[24] 5MPD has a five-minute resolution and it forecasts one hour ahead.

[25] Table 2 also defines the demand term DEMAND_AND_NONSCHEDGEN, however it is not mentioned here as it is not used by the central dispatch process.

are discussed further in Sections 2.1.1 and 2.1.2. The relationship of Dispatched Generation to Total Demand and Cleared Supply is discussed in Section 2.1.3 using a Regional Energy Balance Equation.

2.1.1 Cleared Supply and Initial Supply

Initial Supply and Cleared Supply relate to Scheduled Demand. Initial Supply is actual Scheduled Demand measured or estimated at the beginning of an interval. Cleared Supply is forecast Scheduled Demand to be met at the end of the interval. Initial Supply is one of the inputs to the central dispatch process used to calculate Cleared Supply.

EMMS Relationships

The EMMS specific definitions for Initial Supply and Cleared Supply are given below.

Initial Supply is the sum, at the start of each interval, of generation from all scheduled and semi-scheduled generating units within the region plus the net interconnector flow[26] into the region (as measured at the inter-regional boundary[27]).

Cleared Supply is the sum of the dispatch targets for all scheduled and semi-scheduled generating units within the region plus the net target interconnector flow[28] into the region.

The formulae for calculation of *InitialSupply* and *ClearedSupply* using the EMMS field names (italicised) are provided in Table 3.

Table 3 Formula for InitialSupply and ClearedSupply

EMMS Field Name	Process	Formula
InitialSupply	Dispatch, Pre-dispatch, 5MPD	*InitialSupply* = Sum of *InitialMW* Over all Regional Scheduled and Semi-scheduled generating units + Net *MeteredMWFlow* into the Region Over all Interconnectors connected to the region
ClearedSupply	Dispatch, Pre-dispatch, 5MPD	*ClearedSupply* = Sum of *TotalCleared* Over all Regional Scheduled and Semi-scheduled generating units + Net *MWFlow* into the Region Over all Interconnectors connected to the region

In Dispatch, *InitialMW* and *MeteredMWFlow* are actual metered values (i.e. SCADA values). In Pre-dispatch and 5MPD, *InitialMW* and *MeteredMWFlow* are actual metered values only in the first interval and in subsequent intervals these values are based on the targets of the previous interval.

To obtain the data required for calculating *InitialSupply* and *ClearedSupply* using the formulae provided in Table 3, refer to Appendix A3 for information on relevant tables and field names in the EMMS Data Model.

Examples 1 and 2 in Appendix A4 compare manually calculated *InitialSupply* and *ClearedSupply* values using the formulae provided in Table 3 to the published values (calculated by the NEM systems) for a selected dispatch interval[29].

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[26] The net actual interconnector flow into the region, computed over all interconnectors connected to the region, is determined by deducting the exports out of the region from the imports into the region.

[27] Interconnector flow as measured at inter-regional boundary

= Interconnector flow at Regional Reference Node (RRN) + Allocated Interconnector Losses.

[28] The net target interconnector flow into the region, computed over all interconnectors connected to the region, is determined by deducting the export targets out of the region from the import targets into the region.

[29] The interval was chosen when a scheduled normally-off load was operating.

2.1.2 Total Demand

Total Demand is the underlying forecast demand at the Regional Reference Node (RRN) that is met by local scheduled and semi-scheduled generation and interconnector imports, excluding the demand of local scheduled loads and the allocated interconnector losses.

Total Demand is used for the regional price calculations in Dispatch, Pre-dispatch and 5MPD, and to determine dispatch targets for generating units.

EMMS Relationships

The EMMS specific definitions for Total Demand in Dispatch, Pre-dispatch, and 5MPD are discussed in this section.

In Dispatch and the first interval of 5MPD, Total Demand is calculated by:

- summing the actual generation values of all scheduled and semi-scheduled generating units within the region plus the net actual interconnector flow into the region
- minus scheduled loads and allocated interconnector losses
- plus the *DemandForecast*[30] and *AggregateDispatchError*[31].

The actual values are obtained from Supervisory Control And Data Acquisition (SCADA) telemetry.

For all subsequent intervals of 5MPD, the *AggregateDispatchError* (ADE)[28] is zero and the Total Demand is calculated by adding the forecast demand change[32] to the Total Demand of the previous interval.

In Pre-dispatch, Total Demand is computed from a 50% POE demand derived from a forecast Operational Demand calculated by AEMO's demand forecasting system (discussed in Section 2.2.1). To calculate the 50% POE demand in Pre-dispatch, the demand met by significant non-scheduled wind/solar generation (generally ≥ 30 MW) is deducted from the forecast Operational Demand. This 50% POE demand is referred to as *ResDemand* in the EMMS Data Model. The *ResDemand* is adjusted to remove the allocated interconnector losses to determine the Total Demand at the Regional Reference Node (RRN).

The formulae for calculation of Total Demand using EMMS field names is provided in Table 4.

[30] The *Demand Forecast* is a 5-minute demand adjustment (Offset) that attempts to relate the demand at the beginning of a dispatch interval (*Initial Supply*) to the demand at the end (*Cleared Supply*) of the dispatch interval. From 1 July 2021 the National Electricity Amendment (Five Minute Settlement) Rule 2017 No.15 changes the definition of a dispatch interval to a trading interval, but it will still be five minutes long.

[31] *Aggregate Dispatch Error* is used by the NEMDE to account for non-conformance (from dispatch targets) of dispatched generating units that are not enabled for Regulation Frequency Control. The ADE is determined from within the NEM Energy Management System (EMS) and is passed to NEMDE prior to each dispatch run.

[32] The 5MPD solver determines forecast demand changes for each interval, by applying relevant historical average percentage demand change profile to the previous dispatch run's forecast total demand.

Table 4 Formulae for TotalDemand

EMMS Field Name	Process	Formula
TotalDemand	Dispatch	*TotalDemand* = Sum of *InitialMW* Over all Regional Scheduled and Semi-scheduled generating units - Sum of *InitialMW* Over all Regional Scheduled Loads + Net *MeteredMWFlow* into the Region Over all Interconnectors connected to the region - Total Allocated Interconnector Losses + *DemandForecast* + *AggregateDispatchError* (ADE) where Allocated Interconnector Losses = Sum (*MWLosses* x *FromRegionLossShare* [A]) Over all Interconnectors connected to the region
	5MPD	Same as Dispatch for first interval, then: $TotalDemand_{DI} = TotalDemand_{DI-1} + DemandForecast_{DI}$
	Pre-dispatch	*TotalDemand* = *ResDemand* – Allocated Interconnector Losses where Allocated Interconnector Losses = Sum (*MWLosses* x *FromRegionLossShare* [A]) Over all Interconnectors connected to the region The components of ResDemand are provided in Table 2.

A. *FromRegionLossShare* is a static factor (for each interconnector) that allocates the MW losses on the interconnector to the 2 regions that are connected by it. If the subject region is the notional FromRegion, *FromRegionLossShare* is used. If the subject region is the notional ToRegion, "1- *FromRegionLossShare*" should be used. For more information regarding the "*Treatment of Loss Factors*", please refer to the document on AEMO's website at: http://www.aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries/Treatment-of-Loss-Factors.

To obtain the data required for calculating Total Demand using the formulae provided in Table 4, refer to Appendix A3 for information on relevant tables and field names in the EMMS Data Model.

Example 3 in Appendix A4 compares manually calculated Total Demand value using the formulae provided in Table 4 to the published value (calculated by the NEM systems) for a selected dispatch interval.

2.1.3 Relationship between Dispatched Generation and EMMS Data Model terms in Regional Energy Balance Equation

A Regional Energy Balance Equation describes the relationship between Dispatched Generation, Total Demand and Cleared Supply. The Regional Energy Balance Equation is used in the central dispatch process by the NEM Dispatch Engine (NEMDE) to determine dispatch targets and regional prices.

The Regional Energy Balance Equation holds true for all intervals in Dispatch, Pre-dispatch and 5MPD if sufficient generation is dispatched to meet the demand. The equation using the EMMS terms (italicised) is given below.

DispatchableGeneration + Net Interconnector Targets (into the Region)

= *TotalDemand* + *DispatchedLoad* + Allocated Interconnector Losses

where:

Net Interconnector Targets

= Net *MWFlow* into the Region Over all Interconnectors connected to the region

Allocated Interconnector Losses

= Sum of (*MWLosses* x *FromRegionLossShare* [A])

In the central dispatch process, the TotalDemand value is determined before the optimisation process and the values for the other variables are decided during the optimisation process. The right-hand-side (RHS) of the equation equates ClearedSupply, which is the forecast Scheduled Demand at the end of a dispatch interval. The left-hand side (LHS) of the equation shows the total generation dispatched, including interconnector imports, to meet that Scheduled Demand.

To obtain the data required for the equation provided earlier, refer to Appendix A3 for information on the relevant tables and field names in the EMMS Data model.

Example 4 in Appendix A4 illustrates the relationship between Supply (i.e. LHS of the equation) and Total Demand in the Regional Energy Balance Equation for a selected dispatch interval.

2.2 Demand Terms in EMMS Data Model used in PASA processes

The PASA processes comprise Pre-dispatch PASA (PDPASA), Short term PASA (STPASA) and Medium term PASA (MTPASA).

The EMMS Data Model terms used in PDPASA and STPASA are:

- *Demand10*: a 10% POE demand (a high demand forecast),
- *Demand50*: a 50% POE demand (an average demand forecast) and
- *Demand90*: a 90% POE demand (a low demand forecast).

Although *Demand90* is published for PDPASA and STPASA, it is no longer used by the PDPASA and STPASA processes[33].

For MTPASA, AEMO publishes *Demand10* and *Demand50*.

The process for determining the POE demands used in PDPASA and STPASA is described in Section 2.2.1 and for MTPASA is described in Section 2.2.2.

2.2.1 Forecast PDPASA and STPASA demands

Process

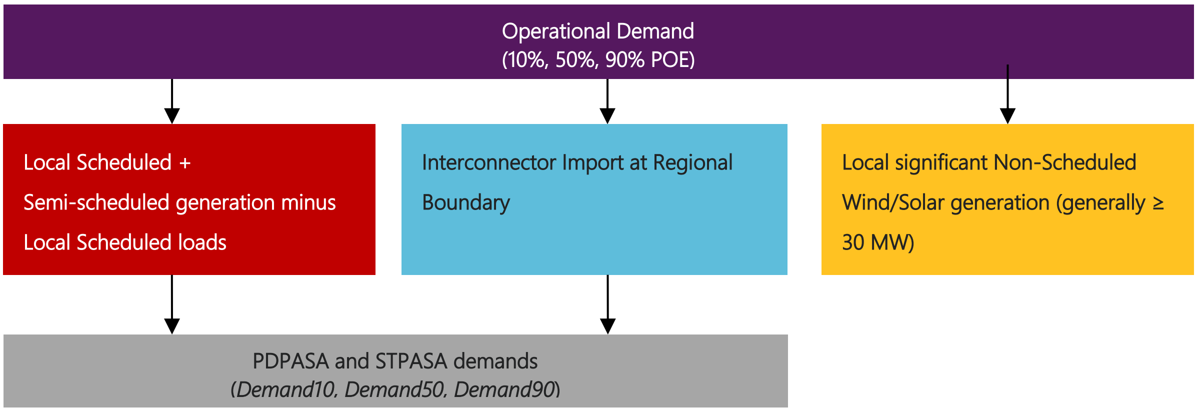
The POE demands used in PDPASA and STPASA are derived from a forecast Operational Demand, determined by AEMO's Demand Forecasting System (DFS) and the Australian Wind Energy Forecasting System (AWEFS)/ Australian Solar Energy Forecasting System (ASEFS). These POE demands are determined by deducting the demand component met by significant non-scheduled wind/solar generation (obtained from AWEFS/ASEFS forecasts[34]) from the forecast Operational Demand.

The composition of the POE demands for the PDPASA and STPASA processes is shown in Figure 6.

[33] AEMO is required to publish a 90% POE demand for STPASA under the NER.

[34] AWEFS/ASEFS provide outputs of wind/solar farm generation forecasts for multiple timeframes (Medium Term, Short Term and Pre-dispatch). Each of these timeframes use different inputs and prediction models to provide forecast outputs.

Figure 6 10%, 50%, and 90% POE demands in PDPASA and STPASA



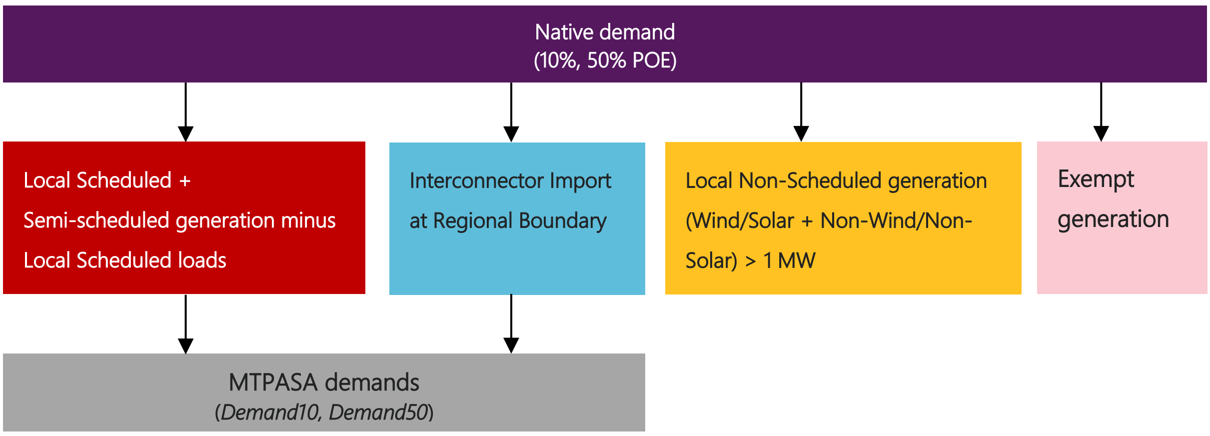
2.2.2 Forecast MTPASA Demands

Process

The POE demands used in MTPASA are derived from the forecast seasonal maximum Native Demands published in the NEFR. To determine the MTPASA *Demand10* and *Demand50*, AEMO prepares 10% and 50% POE daily maximum Native Demand forecasts for each region based on the respective medium economic growth 10% and 50% POE seasonal maximum Native Demand forecasts published in NEFR. The daily maximum Native Demand forecasts are determined by multiplying the seasonal maximum Native Demand forecasts with pre-determined factors corresponding to seasons, days of the week and public holidays. The MTPASA *Demand10* and *Demand50* are then calculated by subtracting the forecast demand met by non-scheduled and exempt generation from the forecast daily 10% and 50% POE maximum Native Demand. The forecast demand met by non-scheduled generation is the sum of the forecast non-scheduled wind/solar generation obtained from AWEFS/ASEFS and the forecast non-scheduled non-wind/solar generation published in NEFR.

The composition of the POE demands used in the MTPASA process is shown in Figure 7 below.

Figure 7 10% and 50% POE demands in MTPASA



A1. Probability of exceedance demands

The probability of exceedance (POE) demand is the probability or the likelihood the forecast would be met or exceeded. The three main types of POE demands are:

- 10% POE Demand.
- 50% POE Demand.
- 90% POE Demand.

They are used in the various processes within AEMO to determine a realistic range of power system and market outcomes.

50% POE demand

A 50% probability of exceedance (POE) demand, also known as *Demand50*, implies there is a 50% probability of the forecast being met or exceeded.

10% POE demand

The 10% probability of exceedance (POE) demand is the value that 10% of the actual demand values are expected to be above and 90% of the actual demand values are expected to be below.

90% POE demand

The 90% probability of exceedance (POE) demand is the value that 90% of the actual demand values are expected to be above and 10% of the actual demand values are expected to be below.

A2. Website publication information

The data listed in Table 2 is published to the EMMS Data Model via comma-delimited (csv) files. The comma-delimited files are published to the AEMO website at http://www.aemo.com.au/Electricity/Data/Market-Management-System-MMS .

Table 5 below provides the file name for each EMMS Data model table.

Table 5 List of files publishing EMMS Data model related to demand data

Business Process	EMMS Data Model Package	EMMS Data Model Table	File name
Dispatch	DISPATCH	DISPATCHREGIONSUM	PUBLIC_DISPATCHIS_<#CASE_DATETIME>*.ZIP
Dispatch	TRADING_DATA	TRADINGREGIONSUM	PUBLIC_TRADINGIS_<#CASE_DATETIME>*.ZIP
5MPD	P5MIN	P5MIN_REGIONSOLUTION	PUBLIC_P5MIN_<#CASE_DATETIME>*.ZIP
Pre-dispatch	PRE_DISPATCH	PREDISPATCHREGIONSUM	PUBLIC_PREDISPATCHIS_<#CASE_DATETIME>*.ZIP
PDPASA	PDPASA	PDPASA_REGIONSOLUTION	PUBLIC_PDPASA_<#CASE_DATETIME>*.ZIP
STPASA	STPASA_SOLUTION	STPASA_REGIONSOLUTION	PUBLIC_STPASA_<#CASE_DATETIME>*.ZIP
MTPASA	MTPASA_SOLUTION	MTPASA_REGIONSOLUTION	PUBLIC_MTPASA_<#CASE_DATETIME>*.ZIP

Operational Demand (Actual and Forecast) is published as part of the November 2014 EMMS data model release[35].

Table 6 List of files publishing EMMS Data model related to demand data

EMMS Data Model Package	EMMS Data Model Table	File name
DEMAND_FORECASTS	DEMANDOPERATIONALACTUAL	PUBLIC_ACTUAL_OPERATIONAL_DEMAND_HH_<#CASE_DATETIME>*.ZIP
DEMAND_FORECASTS	DEMANDOPERATIONALFORECAST	PUBLIC_FORECAST_OPERATIONAL_DEMAND_HH_<#CASE_DATETIME>*.ZIP

[35] The published Operational Demand (Actual and Forecast) csv files can be found at http://www.aemo.com.au/Electricity/Data/Price-and-Demand/Operational-Demand-Data-Files/.

A3. EMMS table/ field names for obtaining data for computing EMMS terms

Only the fields that are not covered in Table 2 and introduced as inputs to the equations in Section 2.1 are covered in below. Table 7 provides the MMS Data Model table and field names.

Table 7 EMMS Data Model

Description	Table in EMMS Data Model	*EMMS Field Name*
Actual generation of Scheduled and Semi-scheduled generating units	For Dispatch: DISPATCHLOAD For Pre-dispatch: PREDISPATCHLOAD For 5MPD: P5MIN_UNITSOLUTION	*INITIALMW*
Actual interconnector flow at regional boundary	For Dispatch: DISPATCHINTERCONNECTORRES For Pre-dispatch: PREDISPATCHINTERCONNECTORRES For 5MPD: P5MIN_INTERCONNECTORSOLN	*METEREDMWFLOW*
Targets for Scheduled and Semi-scheduled generating units	For Dispatch: DISPATCHLOAD For Pre-dispatch: PREDISPATCHLOAD For 5MPD: P5MIN_UNITSOLUTION	*TOTALCLEARED*
Target for Interconnector flow at regional boundary	For Dispatch: DISPATCHINTERCONNECTORRES For Pre-dispatch: PREDISPATCHINTERCONNECTORRES For 5MPD: P5MIN_INTERCONNECTORSOLN	*MWFLOW*
Interconnector MW Losses	For Dispatch: DISPATCHINTERCONNECTORRES For 5MPD: P5MIN_INTERCONNECTORSOLN For Pre-dispatch: PREDISPATCHINTERCONNECTORRES	*MWLOSSES*
From Region Loss Share	INTERCONNECTORCONSTRAINT	*FROMREGIONLOSSSHARE*
Demand Forecast, ADE	For Dispatch: DISPATCHREGIONSUM For 5MPD: P5MIN_REGIONSOLUTION	*DEMANDFORECAST, AGGREGATEDISPATCHERROR*
Dispatched Generation (Sum of dispatched Scheduled and Semi-scheduled generation)	DISPATCHREGIONSUM	*DISPATCHABLEGENERATION*
Dispatched Loads (Sum of dispatched Scheduled loads)	DISPATCHREGIONSUM	*DISPATCHEDLOAD*

A4. Examples

The EMMS terms and formulae introduced in Section 2.1 are explained using a selected dispatch interval below. The selected interval is the dispatch interval ending 0310 hrs on 11 July 2010 and the selected region is NSW. This particular dispatch interval and region were selected because the amount of the scheduled load dispatched in NSW was non-zero for the interval.

The relevant EMMS data for the selected dispatch interval is provided in Table 8.

Table 8 EMMS Data for Dispatch Interval ending 0310 hrs on 11 July 2010

EMMS Field Names	EMMS recorded values	EMMS Field Names	EMMS recorded values
MeteredMWFlow (QNI)	-1002.84	*InitialMW* (Generation)	5339.73
MeteredMWFlow (Terranora)	-136.19	*TotalCleared* (Loads)	195
MeteredMWFlow (VIC-NSW)	612.64	*TotalCleared* (Generation)	5309.32
MWLosses (QNI)	57.95	*TotalDemand*	6801.76
MWLosses (Terranora)	3.5	*DemandForecast*	-22.51
MWLosses (VIC-NSW)	28.12	*DispatchableGeneration*	5309.32
MWFlow (QNI)	-983.61	*NetInterchange*	-1687.44
MWFlow (Terranora)	-137	*ClearedSupply*	7041.37
MWFlow (VIC-NSW)	611.44	*InitialSupply*	7091.41
InitialMW (Loads)	221.26	*AggregateDispatchError* (ADE)	0

Examples 1, 2, and 3 below demonstrate how *InitialSupply*, *ClearedSupply*, and *TotalDemand* can be achieved using the formulae provided in Section 2.1. The manually calculated values using the formulae are then compared against the system calculated values, which are published to the EMMS Data Model. Example 4 demonstrates that the regional energy balance equation holds true for the selected dispatch interval.

Example 1

The table below provides the published EMMS data (refer to Table 8) and manually calculated values for *Initial Supply* using the formula in Section 2.1.

Date	Published EMMS Data				Manually Calculated Data		
	Initial Supply	***Metered MW Flow (QNI)***	***Metered MW Flow (Terranora)***	***Metered MW Flow (VIC-NSW)***	**Net Initial MW (EMMS data summated)**	**Net Import to NSW (EMMS data summated)**	***Initial Supply* (from the formula)**
11/07/2010 03:10	7091.41	-1002.84 [A]	-136.19	612.64	5339.73	1751.67 [B]	7091.40

A. A flow of -1002.84 MW on NSW1-QLD1 means an import of +1002.84 MW into NSW on that interconnector. The +ve or –ve sign represents the direction of flow on the interconnector with northerly flow being +ve and southerly flow being –ve.
B. Net Import into NSW = +1002.84 (NSW1-QLD1) + 136.19 (N-Q-MNSP1) + 612.64 (VIC1-NSW1) = 1751.67 MW.

The Net *InitialMW* value was determined by summing the individual generating unit *InitialMW* (SCADA) values for all scheduled and semi-scheduled generators in NSW. Net Import into NSW was calculated by extracting the *MeteredMWFlow* (SCADA) values for QNI (NSW1-QLD1), Terranora (N-Q-MNSP1) and Victoria to NSW (VIC1-NSW1) Interconnectors and subtracting the exports out of the region from imports into the region. A minor discrepancy between the dispatch value and calculated value exists possibly due to rounding errors.

Example 2: Cleared Supply in Dispatch

The table below provides the published EMMS data (refer to Table 8) and manually calculated values for *Cleared Supply* using the formula in Section 2.1.

Date	Published EMMS Data					Manually Calculated Data	
	Cleared Supply	**Net *Total Cleared (Total Dispatch targets)***	***MW Flow (NSW-QLD)***	***MW Flow (Terranora)***	***MW Flow (VIC-NSW)***	**Net Import Target into NSW (EMMS data summated)**	***Cleared Supply* (from the formula)**
11/07/2010 03:10	7041.37	5309.32	-983.61 [A]	-137.00	611.44	1732.05 [B]	7041.37

A. A flow of -983.61 MW on NSW1-QLD1 is the same as an import of +983.61 MW into NSW on that interconnector.
B. Net Import into NSW = +983.61 (NSW1-QLD1) + 137 (N-Q-MNSP1) + 611.44 (VIC1-NSW1) = 1732.05 MW.

The Net *TotalCleared* value is the same as the published *DispatchableGeneration* value in the EMMS Data Model. This value can also be determined by summing the individual generating unit dispatch targets (i.e. *TotalCleared*) for all scheduled and semi-scheduled generators in NSW. Net Import Target into NSW is calculated by extracting the *MWFlow* values for QNI (NSW1-QLD1), Terranora (N-Q-MNSP1) and Victoria to NSW (VIC1-NSW1) Interconnectors and subtracting the exports out of the region from imports into the region.

Example 3: Total Demand in Dispatch

The table below provides the published EMMS data (refer to Table 8) and manually calculated values for *Total Demand* using the formula in Section 2.1.

Date	Published EMMS Data			Manually Calculated Data				
	Total Demand	**Demand Forecast**	**ADE**	**Net Load *Initial MW* (EMMS data summated)**	**Net Generation *Initial MW* (EMMS data summated)**	**Net Allocation Interconnector Losses (EMMS data calculated)**	**Net Import into NSW (EMMS data)**	***Total Demand* (from the formula)**
11/07/2010 03:10	6801.76	-22.51	0	221.26	5339.73	44.61 [A]	1750	6801.35

A. Net Interconnector Loss allocated to NSW
= 3.5 (MW Loss on N-Q-MNSP) * 0.65 (Loss Factor Allocation to NSW on N-Q-MNSP) +
57.95 (MW Loss on NSW-QLD) * 0.42 (Loss Factor Allocation to NSW on NSW-QLD)+
28.12 (MW Loss on VIC-NSW) * 0.64 (Loss Factor Allocation to NSW on VIC-NSW).

The Net Generation *InitialMW* value is determined by summing the individual generating unit *InitialMW* values for all scheduled and semi-scheduled generators in the NSW region. The Net Load *InitialMW* value is determined by summing the individual scheduled load *InitialMW* values. The interconnector flow values (*MeteredMWFlow*) are extracted for QNI (NSW1-QLD1), Terranora (N-Q-MNSP1) and Victoria to NSW (VIC1-

NSW1) Interconnectors and net import calculated by subtracting the exports out of the region from imports into the region.

The discrepancy between the manually calculated *Total Demand* value and the dispatch value (determined by NEMDE) is due to a subtlety involving the interconnector loss calculated. The *TotalCleared* interconnector losses (from which the Allocated Interconnector Losses are determined) are calculated from interconnector target flow instead of *InitialMW* flow. The latter of these values is not reported by NEMDE. As NEMDE actually uses the estimated losses at the beginning of the dispatch interval to determine *Total Demand*, the manual calculation is only an approximation of the NEMDE calculation, and is a source of some of the result discrepancy.

Example 4: Regional Energy Balance Equation in Dispatch

The Regional Energy Balance Equation is provided below. The RHS of the equation equates *ClearedSupply*.

DispatchableGeneration + Net Interconnector Targets (into the Region)

= *TotalDemand* + Net Dispatchable Load + Allocated Interconnector Losses

The Regional Energy Balance in the NSW region for the selected dispatch interval is shown below.

Dispatchable Generation	5309.32
Target Interconnector Flow	1732.05
Balance on LHS	7041.37

=

Total Demand	6801.35
Dispatchable Load	195
Interconnector losses	44.61
Balance on RHS	7041.37

Dispatchable Generation, *Total Demand*, *MW Flow*, *Initial MW* for Scheduled Loads and *MW Losses* values are extracted from the respective tables in the EMMS Data Model.

Glossary

Term	Definition
5MPD	Five-minute Pre-dispatch
ADE	Aggregate Dispatch Error
ASEFS	Australian Solar Energy Forecasting System
AWEFS	Australian Wind Energy Forecasting System
EMMS	Electricity Market Management System
ESOO	Electricity Statement of Opportunities
JPB	Jurisdictional Planning Body
LHS	Left-hand side
MNSP	Market Network Service Provider
MTPASA	Medium Term Projected Assessment of System Adequacy
MW	Megawatt
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
PDPASA	Pre-dispatch Projected Assessment of System Adequacy
POE	Probability of Exceedance
QNI	Queensland to New South Wales Interconnector
RHS	Right-hand side
RRN	Regional Reference Node
SCADA	Supervisory Control and Data Acquisition
STPASA	Short Term Projected Assessment of System Adequacy