PRE-DISPATCH PROCESS DESCRIPTION

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1. Introduction

1.1 Purpose of this Document

In accordance with clause 3.8.20(i) of the National Electricity Rules ('the Rules') AEMO (formerly NEMMCO) is required to fully document the operation of the Pre-dispatch process within the National Electricity Market ('NEM'), including the principles adopted in the design.

This document describes the current functional design of the Pre-dispatch process, including any assumptions and principles applied to the design. It does not discuss future design.

This document is aimed at market participants and members of the general public who wish to become familiar with all aspects of Pre-dispatch. The document will detail the following:

- = the NEM market pricing and dispatch model;
- = the Pre-dispatch process in the context of the NEM;
- = inputs required by Pre-dispatch from market participants and AEMO;
- = calculations performed within Pre-dispatch by the Scheduling, Pricing and Dispatch software module (known as the SPD algorithm); and
- = outputs produced by Pre-dispatch for market participants and AEMO.

This document is intended to complement the detailed IT specification provided by Cegelec ESCA entitled "Mathematical Modeling of the wholesale electricity market bid-clearing system - SPD: Scheduling, Pricing and Dispatch" Formulation v1.11.0.

For the purposes of discussion this document will use the term "Pre-dispatch" to only refer to the automatic process which runs the SPD algorithm. While the Manual Ancillary Services process (also referred to as ANSITT) can be considered part of the overall Pre-dispatch process as it provides manually-entered input to the automatic SPD process, this document does not discuss Manual Ancillary Services in any detail.

1.2 What is the purpose of Pre-dispatch?

The primary purpose of Pre-dispatch is to:

1. provide wholesale market participants with sufficient unit loading, unit ancillary service reserve and regional pricing information for them to make informed and timely business decisions relating to the operation of their dispatchable units.
2. provide the wholesale market operator (AEMO) with sufficient information to assist them in maintaining the power system in a reliable and secure operating state in accordance with the Rules obligation.

The above information is calculated by Pre-dispatch and published in the form of half-hourly (or trading interval) schedules of forecast unit loading, unit ancillary service response and regional market clearing prices (Spot Prices).

Pre-dispatch determines unit energy loading and unit ancillary service response levels by maximising the value of wholesale electricity market trading within each trading interval of the Pre-dispatch schedule. Maximum trading value is achieved by minimising the overall cost (as indicated by the offers and bids of dispatchable units) of jointly meeting forecast regional energy demand and ancillary service requirements, subject to various constraints on the operation of those dispatchable units. The linear programming solver module within the SPD algorithm performs these calculations.

1.3 Differences between Pre-dispatch & On-line Dispatch

1.3.1 On-Line Dispatch - Specific Models

This document does not describe the On-line Dispatch process nor the features or models specific to the On-line Dispatch process, which are:

- Fast Start unit commitment, decommitment and inflexibility profile;
- Unit Economic Participation Factor (EPF) calculation;
- Intervention Pricing calculation;
- Downloading of Unit dispatch targets to AGC.

Refer to AEMO's On-line Dispatch Process Description for details of these models.

1.3.2 Pre-dispatch - Specific Models

The following models are specific to the Pre-dispatch process only and are described in this document:

- Unit Daily Energy Constraints;
- Spot Price Sensitivities

1.4 References

- MMS Functional Specification - ABB ForStar
- Mathematical Modeling of the wholesale electricity market bid-clearing system - SPD: Scheduling, Pricing and Dispatch Formulation - Cegelec ESCA
- SPD PAS Module functional description - Cegelec ESCA [to be released]
- InfoServer Design Specification - ABB ForStar
- Spot Market Operations Timetable - AEMO
- IT Systems Business Cycle document - AEMO
- Manually Dispatched Ancillary Services (ANSITT) Process description - AEMO
- On-line Dispatch Process Description - AEMO [to be released]

2. National Electricity Market Model

This Section and Figure 1 below describe the NEM electrical model used by the SPD algorithm in the Pre-dispatch process.

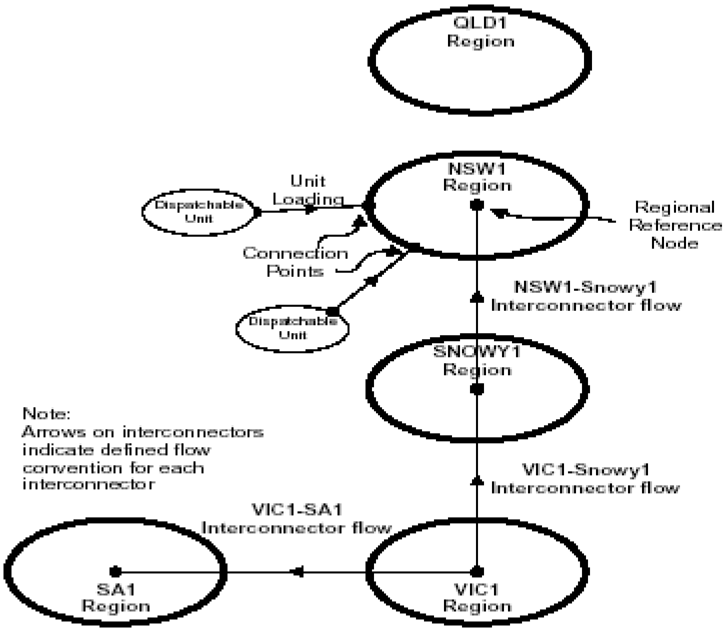


FIGURE 1 - NATIONAL ELECTRICITY MARKET - ELECTRICAL MODEL

2.1 Regions

A region is a specified part of the national transmission network which is used to convey electrical power from major generation centres to load centres. Regions and their regional boundaries are determined in accordance with Rules clause 3.5.1.

Each region is uniquely identified by a Region ID.

2.2 Connection Points & Regional Reference Node

A connection point is an agreed point of metered electrical supply either between a transmission network and a market participant or between a market participant and their customer.

Each region contains a number of connection points which are all electrically connected to that region's unique regional reference node within the transmission network.

Each connection point is identified by a unique Connection Point ID.

2.3 Dispatchable Units

A subset of the connection points within a region are assigned to individual dispatchable units. Dispatchable units are either net producers of electricity (dispatchable generating units, or *scheduled generating units* according to the Rules) or net consumers of electricity (dispatchable loads, or *scheduled loads* according to the Rules) that are registered to participate in the centralised dispatch and pricing processes operated by AEMO, including Pre-dispatch.

To account for network losses between each dispatchable unit and its associated regional reference node the local band prices within the dispatch bid/offer of each dispatchable unit are referred to the reference node using the intra-regional loss factor assigned to that dispatchable unit. Regional spot prices are then calculated by Pre-dispatch at the regional reference node.

Each dispatchable unit (including aggregated units) is identified by a unique Dispatchable Unit ID and is uniquely located at and associated with a Connection Point ID.

Note that in the SPD Formulation document:

- connection points are referred to as market nodes
- dispatchable units are referred to as traders

Also note that while the design of the current SPD algorithm permits a number of dispatchable units to be located at a single connection point, a one-to-one association between connection point (market node) and trader (dispatchable unit) is maintained to ensure that generic constraints are able to be applied to individual dispatchable units at the same physical location.

2.4 Dispatch Bids and Dispatch Offers

Dispatchable generating units submit dispatch offers to sell electrical energy to the market. Dispatchable loads submit dispatch offers to buy electrical energy from the market. Dispatch bids/offers are herein referred to as “bids”.

2.5 Interconnectors

An interconnector is a single or group of physical or logical transmission lines that electrically connect the regional reference nodes of two adjoining regions and transfer power between those regions. Interconnectors are referred to as inter-regional network according to the Rules.

The sign convention adopted in NEM for interconnector flow is away from the VIC1 region, as indicated in Figure 1 above.

Note that the design of the SPD algorithm does not currently accommodate mesh interconnections between regions (for example, the planned direct interconnection between NSW 1 and SA1 regions where there is an existing indirect interconnection via SNOWY1 and VIC1 regions).

Each interconnector is identified by a unique Interconnector ID.

3. Context of Pre-dispatch in NEM

Figure 2 below illustrates the Pre-dispatch process in the context of the overall National Electricity Market (NEM) process.

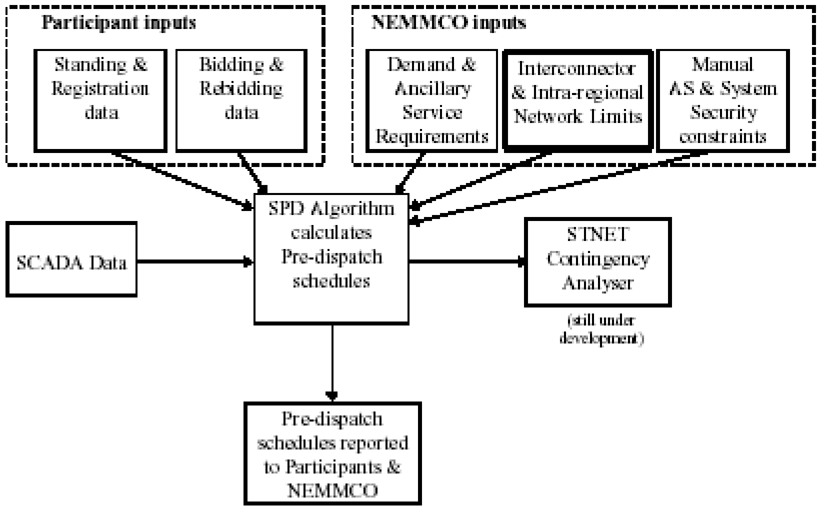


FIGURE 2- PRE-DISPATCH PROCESS IN THE NEM CONTEXT

The STNET application uses the inputs and outputs from the latest Pre-dispatch schedule to produce a future assessment of power system security on the occurrence of any credible contingency (loss of generation, load or network element) given the forecast unit and interconnector loadings. This forecasting tool will determine prospective network element overloads or voltage collapse conditions and identify any critical contingencies for any half¬hourly periods of the Pre-dispatch schedule.

4. Pre-dispatch Process

As indicated in Figure 2 above the ongoing integrity of the Pre-dispatch process relies upon the occurrence of a number of key activities:

1. Automatic Pre-dispatch process (using the SPD algorithm);
2. Unit dispatch bidding and re-bidding;
3. Regional Demand and AS Requirement forecasting;
4. Network constraint invoking;
5. Market reporting.

This Section firstly describes the automatic Pre-dispatch process cycle, the timing of the Pre-dispatch process and the period covered by the Pre-dispatch calculation. The subsidiary processes providing input to and taking output from the Pre-dispatch process are then described.

4.1 Automatic Pre-dispatch process

4.1.1 Pre-dispatch Process Cycle

As illustrated in Figure 3 below, the Pre-dispatch process operates as follows:

1. The Bid UpLoader process automatically uploads valid market participant dispatch bids/offer daily files into the central MMS database.
2. The central MMS Timer process automatically initiates the Pre-dispatch process on a cyclic basis every half-hour on the half-hour.
3. All the latest valid Pre-dispatch input data and unit dispatch bids/offers relevant to the current Pre-dispatch scheduling period is copied from the central MMS database into the SPD input data transfer tables. This includes Frequency Control Ancillary Services (FCAS) contract offer/re-offer data, which is translated into unit dispatch offers for each FCAS category.
4. The central MMS Pre-dispatch UpLoader process then triggers a number of parallel SPD calculations covering two base case calculations (from which only the first completed solution will be used) and a defined number of Pre-dispatch spot price sensitivity scenarios. Each SPD process is triggered from a Case ID sent by the MMS Pre-dispatch UpLoader. The SPD algorithm verifies the Case ID trigger against the Case ID passed in the input data transfer tables before proceeding to upload input data.
5. One SPD process captures initial conditions from the SCADA and writes these to the input data transfer tables. Once initial conditions are written all SPD processes are then released to read all data (including the SCADA initial conditions) from the input data transfer tables.
6. For each trading interval, the SPD algorithm firstly sets up various linear constraints based on the input data and SCADA initial conditions and then runs a linear programming-based optimisation to solve for that trading interval.
   This calculation is repeated for all trading intervals in turn over the current Predispatch scheduling period.
7. Each SPD process writes its solution to a solution text file. The full solution file of the first base case solution to complete is then automatically uploaded by the SPD UpLoader process into the SPD output data transfer tables. All of the spot price sensitivity scenario price-only solutions are made directly available to market participants in flat file format.
8. The central MMS Pre-dispatch DownLoader process, which continually polls for new solution data, detects a new Pre-dispatch base case solution in the SPD output data transfer tables and moves the solution data from the transfer tables into the central MMS database.
9. The central MMS Reporting process extracts data from the central MMS database and automatically creates and posts a series of text-based Pre-dispatch reports to each market participant and to AEMO.
10. Another automatic process replicates all Pre-dispatch input and solution data to the InfoServer replication database for access by market participants.

Further detail on the integration and timing of the above processes is provided in AEMO's Business Cycle document.

4.1.2 Process Timing

In accordance with the Spot Market timetable the Pre-dispatch process is automatically run by AEMO every half-hour on the half-hour to produce a Pre-dispatch schedule covering each trading interval of the current Pre-dispatch scheduling period.

Note that the Pre-dispatch calculation is only required under the Code to run at least every 3 hours.

4.1.3 Trading Interval and Trading Day

A trading interval represents a half-hourly period defined by the end time of the period. For example, trading interval 18:30 is the time period from 6:01 pm to 6:30pm.

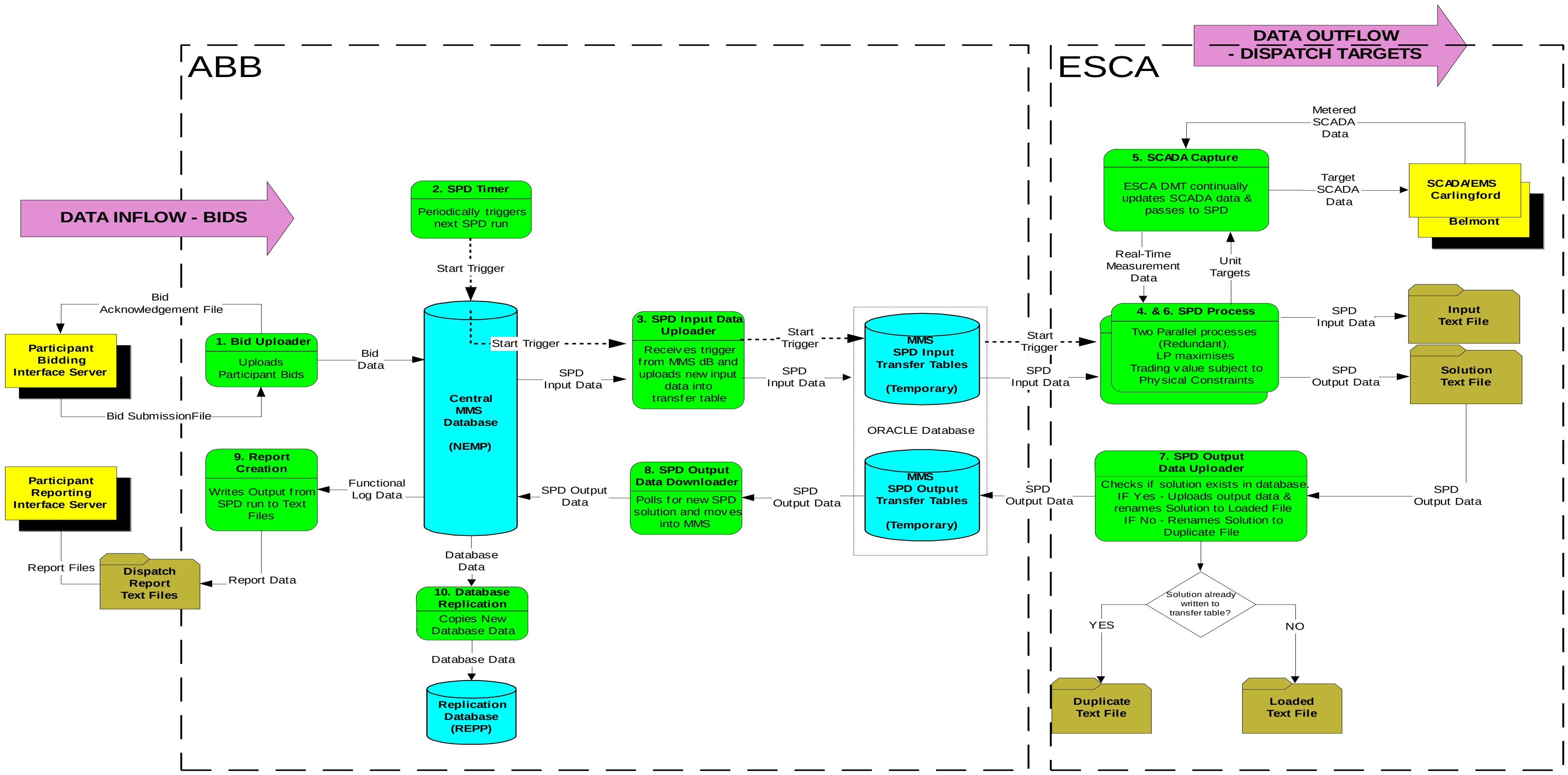
A trading day is defined as the time period from 04:01am to 04:00am the next calendar day. The trading day comprises 48 trading intervals commencing from trading interval 04:30.

Note that all time references are in Eastern Standard Time (EST).

4.1.4 Pre-dispatch Scheduling Period

The Pre-dispatch calculation produces schedule information covering the period from the currently dispatched trading interval up to and including the last trading interval of the last trading day for which the submission of energy bid band prices has closed.

FIGURE 3 - AUTOMATIC PRE-DISPATCH PROCESS - CYCLE DESCRIPTION



4.2 Unit Dispatch Bidding and Re-bidding

4.2.1 Bidding

Market participants with energy dispatchable units are required according to the Rules to submit valid acknowledged daily files of energy bid data for those units for input to Pre-dispatch.

On the initiation of the Pre-dispatch process, the latest daily file versions of valid unit energy bid and FCAS contract offer/re-offer data relevant to the current Pre-dispatch scheduling period is read from the central MMS database and then written to the SPD input data transfer tables for loading and processing by the SPD algorithm. If no valid daily energy bid file has been received for a unit, data from the unit's latest valid default bid file is used. If no valid FCAS contract re-offer file has been received for a unit, the latest relevant FCAS contract details are used.

The Pre-dispatch close-off time for energy bid band price data is 12.30pm on the day before the actual trading day to which that price data applies. FCAS Band price data is standing-type data as tendered in the relevant FCAS contract.

4.2.2 Re-Bidding

With the exception of Band Price, market participants are permitted to re-bid all other energy bid data and ancillary services dispatch re-offer data up to the actual time of dispatch.

Any energy bid data relating to the current Pre-dispatch scheduling period but submitted after the 12:30pm close-off time will be considered a re-bid and will require submission of a re-bid reason.

After the Pre-dispatch process commences data relating to the current Pre-dispatch scheduling period which is subsequently re-bid and validated during that process run will not be used until the next run of the Pre-dispatch process. Note that the capturing of bid and re-bid data for input to the Pre-dispatch process commences at the nominal half-hourly start time for the Pre-dispatch run.

4.3 Regional Demand & Ancillary Service Reqt forecasting

AEMO is required to initially submit prior to the 12:30pm close-off time and then regularly review the half-hourly energy demand forecasts for each region over the current Pre-dispatch scheduling period. These demand forecasts are issued via the POMMS (Pool Operators Interface to the Market Management System).

AEMO are also required to initially submit half-hourly ancillary service requirement forecasts for each region and for each category of ancillary service via the POMMS interface, although these requirements are reasonably static and are therefore not reviewed as often as energy demand forecasts.

4.4 Network Constraint invoking

AEMO is required to impose certain limits on the transfer of electrical power over network elements in order to protect those network elements from thermal damage due to overload or to avoid power system instability and possible shutdown following an electrical fault at a critical location. Network transfer limits are input to the Pre-dispatch calculation in the form of generic constraint equations for which certain limits are identified as being dynamically calculated during the Pre-dispatch run (refer to Sections 5.4.5 and 6.7.1 for more details).

AEMO initially sets up a library of network constraint sets, with each set representing a certain network configuration or loading condition scenario. Each network constraint set comprises one or more generic constraint equations which each define the transfer limit on either an interconnector or an intra-regional network element.

AEMO invokes individual network constraint sets for those trading intervals where the selected network scenario applies and where network transfers are likely to be affected by the transfer limits represented in those scenarios. Network constraint sets are invoked and revoked via the POMMS.

4.5 Market Reporting

As soon as the Pre-dispatch process completes both confidential and public market information relating to the latest Pre-dispatch scheduling period is made available.

Confidential market information is defined by the Rules as that set of information which is specific to a market participant and which is made available only to that market participant prior to the end of the trading day to which it relates.

Public market information is also defined by the Rules as that set of information which is either of an aggregate generic nature (for example, regional spot price, regional demand, interconnector loadings) or has now passed into history (including previously-confidential market information). All Pre-dispatch market information relevant to a specific trading day becomes available to the general public after the end of that trading day.

Market information is made available to market participants by:

- direct issue as text-based flat file reports copied to the relevant market participant's interface server Report directories for viewing through their desired interface; and
- indirect extraction from the InfoServer market information database by the market participant running the appropriate database query.

The general public will also be able to extract available market information from the InfoServer database via the Internet by running the appropriate database query within a Web browser.

AEMO also have access to additional region-level aggregate market information directly from the central MMS database using the POMMS Reporting interface to assist them in managing power system security and reliability.

5. Pre-dispatch Inputs

As discussed in the previous section, inputs used by the Pre-dispatch SPD algorithm can be categorised by the nature and source of the data, as follows:

From market participants

- Unit Registration data
- Unit Energy Dispatch Bid/Offer data
- Unit Governor FCAS Dispatch Offer data
- Unit Load Shedding FCAS Dispatch Offer data
- Unit AGC FCAS Dispatch Offer data
- Unit Manual Ancillary Services Dispatch Offer data

From the SCADA database

- Unit data
- Region data
- Interconnector data

From AEMO

- Pre-dispatch Configuration data
- SPD Configuration data
- Region Demand & FCAS Requirements data
- Network constraints data
- System Security constraints data

The following Sections describe these inputs.

5.1 Market Participant Data

5.1.1 Unit Registration Data

Unit Registration data is standing-type data that is initially submitted by the market participant and subsequently authorised by AEMO as part of the dispatchable unit registration process for participation in energy and/or ancillary services dispatch.

5.1.1.1 Dispatchable Unit Type

A dispatchable unit is registered as either a generating unit (net producer of electricity) or a load (net consumer of electricity) for the purposes of energy and/or ancillary services dispatch.

5.1.1.2 Normal Loading Status

Indicates whether a dispatchable unit which is a load (as defined above) is to be treated by Pre-dispatch as either normally-on or normally-off.

The SPD algorithm subtracts the total bid Energy Availability of all normally-on dispatchable loads located within a region from the historically-based Forecast Demand for that region.

5.1.1.3 Load Shedding Participation Factor

The Load Shedding Participation Factor is set to one (1) for all loads that are contracted to provide Load Shedding response to meet the FCAS 6 Second and 60 Second Raise Requirements and are dispatchable in the energy market. This ensures that the scheduled FCAS Raise response from those loads is limited by its scheduled energy consumption.

This Factor is set to zero for Load Shedding-contracted loads that are not energy-market dispatchable.

5.1.2 Unit Energy Dispatch Bid/Offer Data

Unit energy dispatch bid/offer data is price band and MW loading constraint information relating to a market participant's dispatchable unit(s) which is submitted by that market participant to AEMO in a daily file of pre-defined format. This data is used in Pre-dispatch to forecast the MW loading on the specified dispatchable unit at the end of each half-hourly trading interval of the specified trading day.

Note that all energy dispatch bid/offer for a specific trading interval is considered to apply over the whole trading interval.

5.1.2.1 Energy Bands

The total maximum capacity registered for a dispatchable unit must be submitted by the market participant in that unit's daily energy dispatch bid/offer in the form of ten price bands (herein called Energy Bands).

Each Energy Band associates a block or quantity of electrical power output (for a generating unit) or electrical power consumption (for a load) at the unit's local connection point with a local price for the dispatch of that block or quantity of electricity.

An Energy Band Offer for a generating unit represents the minimum price (Band Price) that the market participant is prepared to receive before increasing the electrical output of that generating unit by up to the maximum amount offered in that Energy Band for that trading interval (Band Quantity).

An Energy Band Bid for a load represents the maximum price (Band Price) that the market participant is willing to pay before decreasing the electrical consumption of that load by up to the maximum amount bid in that band for that trading interval (Band Quantity).

Band Prices (in $/MW) are trading day quantities which cannot be re-bid. Band Quantities (in MW) are re-biddable trading interval quantities and must be submitted for each trading interval of the trading day. Note that Band Prices for dispatchable loads must be greater than or equal to $zero under Rules clause 3.8.7(h), whereas there is no such price floor applied to Band Prices for dispatchable generating units.

The sum of the ten Band Quantities submitted for a dispatchable unit must be greater than or equal to the total maximum capacity of that unit. A Band Price must be assigned to each of the ten Energy Bands and must monotonically increase from Band 1 to Band 10, although not every Energy Band requires a non-zero Band Quantity.

Figure 4 below illustrates a sample Energy Band Offer for a dispatchable load.

5.1.2.2 Energy Availability

The specified maximum electrical output from a generating unit or maximum electrical consumption by a load that can be dispatched in the specified trading interval.

Energy Availability (in MW) is a re-biddable trading interval quantity which is optionally submitted by a market participant whenever the participant intends to constrain the unit's dispatch to below its maximum capacity.

5.1.2.3 Energy Ramp Rates

The specified maximum rate at which the electrical output from a generating unit or the electrical consumption by a load may increase (Ramp Up Rate) or decrease (Ramp Down Rate) within a trading interval.

Energy Ramp Up and Ramp Down Rates (in MW/minute) are re-biddable trading interval quantities which must be submitted for each trading interval of the trading day.

5.1.2.4 Daily Energy Limit

The specified maximum total energy output from a generating unit or maximum total energy consumption by a load that is available for scheduling by Pre-dispatch over the specified trading day.

This type of limit typically applies to generating plant such as hydro electric power stations which cannot generally operate at its maximum capacity indefinitely as their stored water supplies will be completely depleted.

The unit Daily Energy Limit (in MWh) is a re-biddable trading day quantity which is optionally submitted by a market participant in their dispatch bid/offer. Whenever a market participant enters a Daily Energy Limit on a dispatchable unit that unit is also identified to the SPD algorithm as Daily Energy Constrained.

A null entry for the Daily Energy Limit means there is no energy constraint on the unit and the Daily Energy Constrained status is reset.

5.1.2.5 Fixed Loading

A specified level of electrical output required from a nominated generating unit or a specified level of electrical consumption required by the nominated load for the specified trading interval. Unit Fixed Loading (in MW) is a re-biddable trading interval quantity which is optionally submitted (with a reason) by a market participant whenever the participant intends to constrain the unit's loading to a certain level other than that which would otherwise be determined by the SPD algorithm. A null Fixed Loading entry means there is no constraint.

The dispatch bid\offer of a dispatchable unit dispatched to a fixed loading cannot be used to set spot price for affected trading intervals.

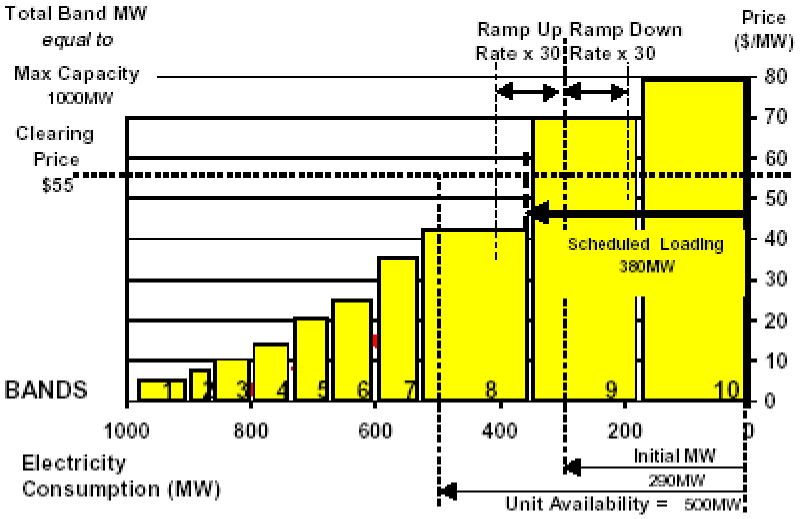


FIGURE 4- SAMPLE ENERGY DISPATCH BID FOR A SCHEDULED LOAD

5.1.2.6 Energy Dispatch Bid - worked example

The following is a worked example explaining how the dispatch bid for a dispatchable load is used in Pre-dispatch process. For the example, assume that the scheduled load 'X' belongs to a region 'R'.

Assume that the maximum capacity registered for load 'X' = 1000MW. The sum of Band Quantities in all 10 Energy Bands must therefore equal 1000MW.

The dispatch bid submitted for load X has:

Bands 1 to 8

Band 9

Band 10 Energy Availability Ramp Up Rate Ramp Down Rate

: 620 MW priced below $50/MW

: 190 MW at $70/MW

: 190 MW at $80/MW

: 500 MW

: 3 MW/min

: 3 MW/min

Initial MW consumption of load ‘X’ = 290MW (which equals the previous trading interval’s scheduled consumption or, for the first trading interval only, the current metered consumption).

The SPD algorithm then determines the energy upper and lower limits within which load ‘X’ can be scheduled to consume:

Upper limit = minimum of (Ramp Up Limit, Energy Availability)

= minimum of (Initial MW + Ramp Up Rate x 30mins, Energy Availability)

= **380MW**

Lower limit = Initial MW - Ramp Down Rate x 30mins

= **200MW**

The SPD algorithm then performs an LP optimisation and determines the energy clearing price for region ‘R’:

Spot Price = **$55/MW**

As the price of Band 10 > Spot Price, it is fully scheduled with consumption=190MW As the price of Band 9> Spot Price, a further 190MW of consumption is scheduled.

At this stage the total consumption of Bands 9 and 10 = 380MW which is still within the upper and lower limits determined above. However, remaining Energy Bands are not dispatched at all, as their Band Prices are all below the Spot Price (that is, the market price was not low enough to justify consumption in those bands).

Therefore the final scheduled energy consumption of load ‘X’ = 380MW.

The SPD algorithm has scheduled an increase in the consumption of the load from zero MW, dispatching from the higher to the lower-priced Energy Bands until either the Spot Price falls below the price of the last band dispatched (as in this case) or is constrained to either its upper or lower operating limits.

5.1.3 Unit Governor FCAS Dispatch Offer Data

Governor FCAS dispatch offer data is FCAS response pricing and constraint information relating to a market participant’s Governor-contracted generating unit(s). This data is used in Pre-dispatch to forecast during each half-hourly trading interval of the specified trading day the amount of response required to be available from the specified generating unit’s Governor to supply one or more of the following FCAS Requirements (herein referred to as Governor services):

- FCAS 6 Second Raise
- FCAS 6 Second Lower
- FCAS 60 Second Raise
- FCAS 60 Second Lower

Governor FCAS dispatch offer data comprises standing-type data that is initially tendered by the market participant in their Governor contract. The availability of contracted Governor response for each of the Governor services can be subsequently re-offered by a market participant at any time prior to the start of the Pre-dispatch run. These re-offers are entered as starting-from records which are submitted to AEMO in a daily file of pre-defined format. At the start of each Pre-dispatch run, the current Governor contract offer and re-offer data is converted into trading interval-based FCAS 6 Second and 60 Second Raise and Lower Bands and response constraint data for input to Pre-dispatch.

5.1.3.1 Governor Capable status

Indicates that a generating unit is contracted to provide (during a certain trading interval) an automatic frequency control response using their turbine speed governing equipment.

The SPD algorithm will only schedule Governor response from generating units that are Governor Capable, have a non-zero bid Energy Availability and which are in-service (that is, have a non-zero dispatch target from the previous dispatch run).

5.1.3.2 Governor Maximum Response

AEMO may contract with a market participant to provide Governor responses (in MW) from a generating unit additional to minimum mandatory levels (as defined in Section 5.1.3.3 below) at the agreed contract prices for one or more of the defined Governor services.

The maximum amount of Governor response available from a generating unit is defined as a function of the level of energy output from that unit and the level of frequency deviation. In their Governor contract the market participant nominates for each Governor service two (2) piecewise linear droop characteristics representing governor response available from each of their contracted generating units. The first droop characteristic defines the maximum MW response as a two-piece function of both energy output and frequency deviation. The second droop characteristic defines the maximum MW response as a two-piece function of energy output only. Note that only the second droop characteristic is applied to Pre-dispatch calculations, with both characteristics used in Ancillary Services settlements.

Each two-piece characteristic comprises:

1. a pre-breakpoint maximum response amount which applies between zero energy dispatch and the contracted energy dispatch breakpoint and;
2. a maximum response amount which linearly decreases from the contracted maximum response amount in 1) above down to zero maximum response at the contracted energy dispatch level.

Figure 5 below shows the Governor 6 Second Raise maximum response characteristic, where:

R6Max = Raise6SecMax;

R6BP = Raise6SecBreakpoint;

$R6MN^{max}$ = Raise6SecCapacity.

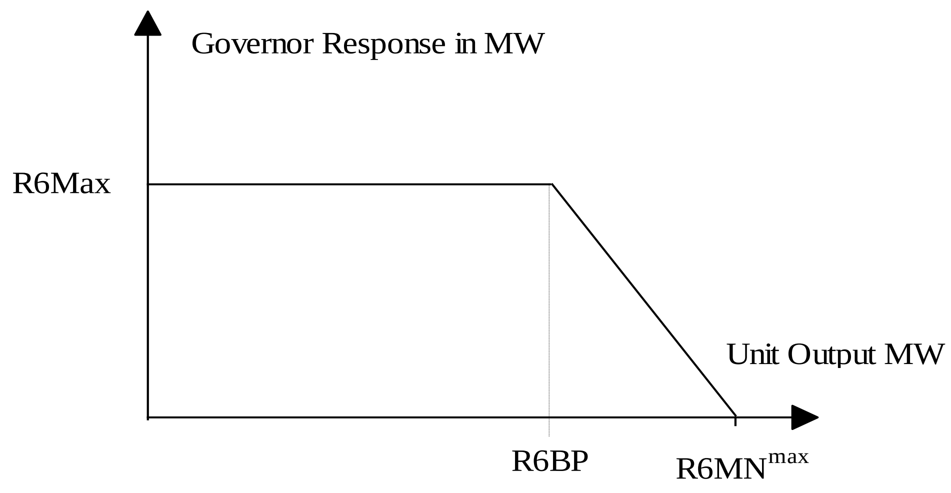


FIGURE 5 - CONTRACTED GOVERNOR 6 SECOND RAISE DROOP CHARACTERISTIC

Similar maximum response characteristics are provided for the other Governor services.

5.1.3.3 Governor Mandatory Response

According to the Rules all generating units must provide a certain minimum mandatory level of underfrequency and overfrequency Governor response within 60 Seconds.

For Pre-dispatch scheduling purposes it is assumed that the mandatory response levels are always fully available from all dispatchable generating units that are in-service (that is, with a non-zero dispatch target from the latest dispatch run). The mandatory response is summed for all generating units in each region and the total is then subtracted from the relevant FCAS 60 Second Raise or 60 Second Lower Requirement before the adjusted FCAS Requirement is passed to the SPD algorithm.

5.1.3.4 Governor Response Availabilities

Indicates whether or not the Governor Maximum Response is available from a generating unit in a particular trading interval, for each of the Governor services.

If the Governor response for a particular Governor services is notified by the market participant as available then both the contracted Governor Maximum Response function and a second FCAS Band for that Governor service is passed as input to the SPD algorithm. If the Governor Response is notified as unavailable or the last dispatch run's dispatch target is zero then these MW quantities are all passed as zero.

5.1.3.5 Governor Enabling Prices

The contracted prices (in $/MW) that the market participant is willing to accept in return for enabling the generating unit's turbine speed governing equipment to provide 6 Second and

60 Second Raise and Lower response above the above mandatory level relevant to each Governor service.

5.1.3.6 Governor FCAS Bands

Two FCAS Bands are passed to Pre-dispatch for each of the Governor services. However, the first FCAS Band, originally reserved for the mandatory governor response, will initially not be used.

If the Governor Response for a particular Governor service is notified as available, the Band Quantity for the second FCAS Band of that service is set to the contracted pre-breakpoint value of contracted Governor Maximum Response.

If the Governor Response for a particular Governor service is unavailable, the Band Quantities of all FCAS Bands for that service are all set to zero MW.

The Band Quantities determined above are passed as input to the SPD algorithm along with a Band Price (in $/MW) representing the Governor Enabling Price for the relevant service.

5.1.4 Unit Load Shedding FCAS Dispatch Offer Data (High Band)

Load Shedding FCAS dispatch offer data is FCAS response pricing and constraint information relating to a market participant's Load Shedding-contracted load(s). This data is used in Predispatch to forecast during each half-hourly trading interval of the specified trading day the amount of Load Shedding response required to be available from the specified load to supply both of the following FCAS Requirements (herein referred to as Load Shedding services):

- FCAS 6 Second Raise;
- FCAS 60 Second Raise.

Load Shedding FCAS dispatch offer data comprises standing-type data that is initially tendered by the market participant in their Load Shedding contract. The amount of Load Shedding Maximum Response can be subsequently re-offered by a market participant at any time prior to the start of the Pre-dispatch run. These re-offers are entered as starting-from records which are submitted by a market participant to AEMO in a daily file of pre-defined format. At the start of each Pre-dispatch run the current Load Shedding contract offer and re-offer data is converted into trading interval-based FCAS 5 Minute Raise Availability and FCAS Band information for input to Pre-dispatch.

5.1.4.1 Load Shedding Maximum Response

The contracted maximum amount (in MW) of FCAS Raise response that the load is able to provide within 60 Seconds by automatically shedding its load in response to a fall in power system frequency to within a defined underfrequency bandwidth (called the High Band).

If the contracted values of Load Shedding Maximum Response are not subsequently re-offered by the market participant then the Pre-dispatch is passed the contracted values by default in the calculation of Band Quantities for FCAS 6 Second and 60 Second Raise Bands.

Note that additional Load Shedding Maximum Response (Low Band) is contracted by AEMO for underfrequencies below the High Band threshold to cover major generation loss contingencies. This response is scheduled using the Manual Ancillary Services process.

5.1.4.2 Load Shedding Enabling Price

The contracted price (in $/MW) that the market participant is willing to accept in return for enabling the dispatchable load's automatic underfrequency Load Shedding facility.

5.1.4.3 Load Shedding FCAS Bands

A FCAS 6 Second Raise Band and a 60 Second Raise Band is automatically passed to Pre-dispatch for each dispatchable load contracted to provide Load Shedding ancillary service.

The Band Quantity in each FCAS Band is the maximum amount (in MW) of frequency control Raise response (as last notified by the market participant to AEMO in an ancillary services re-offer) that the dispatchable load can provide within 60 Seconds by automatically shedding its load in response to a fall in power system frequency to within a defined underfrequency bandwidth (called the High Band).

The Band Quantities determined above are passed as input to the SPD algorithm along with a Band Price (in $/MW) representing the Load Shedding Enabling Price.

5.1.5 Unit AGC FCAS Dispatch Offer Data

AGC FCAS dispatch offer data is FCAS response pricing and constraint information relating to a market participant's AGC-contracted generating unit(s). This data is used in Pre-dispatch to forecast during each half-hourly trading interval of the specified trading day the amount of AGC frequency regulating response required to be available from the specified generating unit to supply both of the following FCAS Requirements (herein referred to as AGC Regulating services):

- FCAS 5 Minute Raise;
- FCAS 5 Minute Lower.

AGC FCAS dispatch offer data comprises standing-type data that is initially tendered by the market participant in their AGC contract. The AGC Maximum Response Limits can be subsequently re-offered by a market participant at any time prior to the start of the Pre-dispatch run. These re-offers are entered as starting-from records which are submitted to AEMO in a daily file of pre-defined format. At the commencement of each Pre-dispatch run, the current AGC contract offer and re-offer data is converted into trading interval-based FCAS 5 Minute Raise and Lower Availability and FCAS Band information for input to Pre-dispatch.

Dispatchable loads do not participate in the scheduling of AGC Regulating services.

5.1.5.1 AGC Capable status

Indicates that a generating unit is contracted to provide [during a certain trading interval] automatic frequency regulating response using their Automatic Generation Control (AGC) equipment.

The SPD algorithm will only schedule frequency regulating response from generating units that are AGC Capable, have a non-zero bid Energy Availability and which are in-service (that is, have a non-zero dispatch target from the previous dispatch run).

5.1.5.2 AGC Maximum Response

The contracted maximum amounts of Frequency Raise and Lower regulating response (entered in MW/minute but converted to MW/5 minutes) that the generating unit is able to provide from its AGC equipment over a particular trading interval.

5.1.5.3 AGC Maximum Response Limits

For a particular trading interval the contracted maximum and minimum MW limits (herein referred to as AGC Upper and AGC Lower Limits) outside of which a generating unit is no longer considered able to provide any automatic 5 Minute Raise and Lower regulating response using its AGC equipment

If the contracted values of AGC Upper and Lower Limits are not subsequently re-offered by the market participant then the Pre-dispatch uses the contracted values by default in the calculation of 5-Minute Raise and Lower Band Quantities.

5.1.5.4 AGC Enabling Price

The contracted price (in $/MW) that the market participant is willing to accept in return for enabling a generating unit’s AGC equipment to provide the 5 Minute Raise and/or the 5 Minute Lower responses.

5.1.5.5 AGC FCAS Bands

An FCAS 5 Minute Raise Band and an FCAS 5 Minute Lower Band is automatically passed to Pre-dispatch for each dispatchable generating unit contracted to provide AGC regulating services.

The Band Quantity for the 5 Minute Raise service is calculated as the minimum of the contracted AGC Maximum Raise Response, and (for the first trading interval only of each Predispatch schedule) the minimum of the AGC Upper Limit and the bid unit Energy Availability *less* the latest unit energy dispatch target.

The Band Quantity for the 5 Minute Lower service is calculated as the minimum of the contracted AGC Maximum Lower Response, and (for the first trading interval only of each Predispatch schedule) the [minimum of the bid unit Energy Availability and the] latest unit energy dispatch target *less* the AGC Lower Limit.

The Band Quantities determined above are passed as input to the SPD algorithm along with a Band Price (in $/MW) representing the AGC Enabling Price.

5.1.6 Unit Manual Ancillary Services Contract Dispatch Offer Data

The following Ancillary Services contracts are not scheduled using the SPD algorithm but are scheduled using a Manual Ancillary Services process:

- Rapid Generator Unit Loading (RGUL);
- Load Shedding (Low Band);
- Reactive Support;
- Rapid Generator Unit Unloading (RGUU);
- System Restart.

AEMO notify market participants to enable the above Ancillary Services by manually issuing a dispatch instruction through the NEMNet.

5.1.6.1 RGUL Capable status

Indicates to the SPD algorithm that a generating unit can provide automatic FCAS 5-Minute Raise response in a certain trading interval using their automatic unit start-up equipment.

Note that in the initial stages of the NEM that Unit RGUL response will not be co-optimised in the SPD algorithm but will be manually dispatched using the Manual Ancillary Services process.

5.1.6.2 RGUL Maximum Response

The contracted maximum amounts of RGUL 5 Minute Raise response (in MW) that a generating unit is able to provide over 5 Minutes under its RGUL contract.

5.1.6.3 RGUL Enabling Prices

The contracted price (in $/MW) for enabling a generating unit’s RGUL facility to provide a FCAS 5 Minute Raise response.

5.1.6.4 Load Shedding Maximum Response (Low Band)

The contracted maximum amounts of 6 Second and 60 Second Raise response (in MW) that a load is able to automatically provide in a particular trading interval using its Load Shedding equipment.

If the contracted values of Load Shedding Maximum Response are not subsequently re-offered by the market participant then the Manual Ancillary Services process uses the contracted values by default.

5.1.6.5 Load Shedding Enabling Price (Low Band)

The contracted price (in $/MW) for enabling a load’s Load Shedding equipment to provide a 6 Second and 60 Second Raise response.

5.1.6.6 Reactive Support Availability & Availability Price

The contracted maximum available Reactive Support (converted into the active power equivalent, in MW) that a generating unit is able to provide at the contracted price (in $/MW) in order to maintain local power system voltage within defined bounds.

5.1.6.7 RGUU Maximum Response & Enabling Price

The contracted maximum amount of Rapid Generating Unit Unloading (in MW) that a generating unit is able to automatically provide at the contracted price (in $/MW) in response to a defined major overfrequency event which would otherwise result in power system instability.

5.1.6.8 System Restart Availability & Availability Price

The contracted maximum amount of System Restart generation capacity (in MW) that a generating unit is able to supply a “black” power system within a defined period of time at the contracted price (in $/MW).

5.2 SCADA Measurand Data

Every SCADA value captured from SCADA requires a unique SCADA Measurand name.

For each dispatchable unit, this is the defined prefix of the SCADA database analogs representing the current metered values of Unit Loading, energy market Ramp Rates and AGC Status.

For each interconnector, the defined name of the SCADA database analog representing the current metered value of Interconnector flow.

The specific analog type names used in the NEM SCADA database are automatically appended by the SPD DMT interface to the NEM SCADA database.

For each generic constraint dynamic RHS, there are a series of SCADA measurands which are associated with the SPD RHS calculation by uniquely mapping them to SPD RHS term identifiers.

5.3 SCADA Captured Data 5.3.1 Unit data

The following Unit data is captured by the SPD process from the NEM SCADA database and is applied to the first trading interval calculation only of the current Pre-dispatch scheduling period.   Note that the SCADA used by the SPD algorithm can be up to 60 Seconds old, as the SPD capture cycle is not synchronised with the original data capture.

5.3.1.1 Initial Metered Unit Loading

The current metered value (in MW) of Unit electrical output (for a generating unit) or electrical consumption (for a load) automatically captured from the NEM SCADA database used as the starting point for the calculation of dispatchable unit loading at the end of the first trading interval only of each Pre-dispatch schedule.

If the SCADA quantity is unavailable or its value is reported by SCADA as “bad” quality then the SPD algorithm uses by default the input value passed from the MMS (which is the unit dispatch target calculated from the latest on-line Dispatch run).

5.3.1.2 Energy Market Ramp Rates

These are the maximum energy market Ramp Up Rates and Ramp Down Rates (in MW/minute) that can be achieved by a dispatchable unit as reported from the NEM SCADA database. These quantities are either derived from the Unit’s AGC system or have been manually selected by the unit operator and transmitted to the NEM SCADA database.

If the SCADA quantity is unavailable or its value is reported by SCADA as “bad” quality then the SPD algorithm only uses the relevant Ramp Up and Ramp Down Rates submitted in the energy market dispatch bid/offer.

5.3.1.3 Initial AGC Status

The current status of the dispatchable generating unit’s AGC system, where 0=AGC OFF and 1=AGC ON.

If the SCADA quantity is unavailable or its value is reported by SCADA as “bad” quality then the SPD algorithm uses by default [the last “good” unit AGC Status captured from the NEM SCADA database.

5.3.2 Region data

The calculated regional Aggregate Dispatch Error and Forecast Demand Change referred to below are applied to the adjustment of AEMO's half-hourly forecast of regional energy demand. This adjustment is made to metered Demand for both On-line Dispatch and for the first half-hour only of each Pre-dispatch run. Note that no such adjustment is made to regional energy demand in the subsequent half-hours of the Pre-dispatch schedule.

5.3.2.1 Aggregate Dispatch Error

A unit Dispatch Error is automatically calculated within AEMO’s Energy Management System (EMS) for each dispatchable unit. This is equal to the Unit dispatch target last downloaded to the SCADA database *less* the Initial Metered Unit Loading captured from the SCADA. An Aggregate Dispatch Error is then calculated by EMS for each region, equaling the sum of unit Dispatch Errors for all units in the region that are not currently selected to an AGC frequency regulating mode.

5.3.2.2 Forecast Demand Change

The amount (in MW) by which the current value of metered regional Energy Demand is forecast to change over the 5 minute period of the last dispatch interval.

These values are automatically calculated by the EMS for each region using a regional Neural Network model, which essentially applies weights to each of a series of historical 5 Minute metered demand changes in order to derive a forecast demand change.

5.3.3 Network data

5.3.3.1 Initial Metered Interconnector Flow

The current metered value (in MW) of interconnector flow captured from the NEM SCADA database.

If the SCADA quantity is unavailable or its value is reported by SCADA as “bad” quality then the SPD algorithm uses by default the interconnector flow target calculated in the latest run of the on-line Dispatch process.

5.4 AEMO Data

5.4.1 Pre-dispatch Configuration data

5.4.1.1 VoLL

Value of Lost Load (in $/MW). This is the price cap for the spot price calculated by the SPD algorithm.

5.4.1.2 Constraint Violation Penalty Weights

The SPD algorithm permits the violation or relaxation of a constraint limit based upon its violation price relative to other constraints. A number of these violation prices are passed as input to SPD algorithm as default violation penalty weights which represent multiples of VoLL.

For each type of constraint, and for all invoked generic constraints, the SPD algorithm initially multiplies the relevant violation penalty weight by VoLL to derive the violation penalty price (in $/MW), which is then used in the SPD co-optimisation calculation.

The following constraints violations are passed to the SPD algorithm as default penalty weights:

- Deficit/Surplus Unit Ramp Rate;
- Deficit Connection Point (Unit) Capacity ;
- Deficit Interconnector Flow;
- Surplus Interconnector Flow;
- Deficit/Surplus Generic Constraint;
- Deficit Region Generation;
- Surplus Region Generation;
- Deficit Region Raise 6 Second;
- Deficit Region Raise 60 Second;
- Deficit Region Raise 5 Minute;
- Deficit Region Lower 6 Second;
- Deficit Region Lower 60 Second;
- Deficit Region Lower 5 Minute;
- Breaking of Price-Tied Energy Bands;
- Real-Time Dispatch Anchor (used in on-line Dispatch only).

The violation penalty prices of the Deficit Region FCAS Locally-sourced Requirement automatically default to their associated Deficit Region FCAS Requirement constraints listed above. The violation penalty prices of the following Unit constraints automatically default to the Deficit Connection Point (Unit) Capacity:

Deficit Unit Daily Energy;

Deficit Unit Total Band Offer MW;

Deficit Unit FCAS 6 Second Raise;

Deficit Unit FCAS 60 Second Raise;

Deficit Unit FCAS 5 Minute Raise;

Deficit Unit Governor FCAS 6 Second Raise;

Deficit Unit Governor FCAS 60 Second Raise;

Deficit Unit Governor FCAS 6 Second Lower;

Deficit Unit Governor FCAS 60 Second Lower.

The violation penalty prices for Deficit/Surplus Unit Fast Start Profile MW (which is used in Online Dispatch only) is set internally within the SPD algorithm.

Also note that there are no violation penalties associated with Deficit Unit FCAS 6 Second Lower, 60 Second Lower or 5 Minute Lower services as the amounts of scheduled response for these services are directly related to the scheduled energy consumption (for dispatchable loads) and a constraint conflict with Lower response is therefore unlikely to arise.

Refer to the SPD Formulation document for further details.

5.4.1.3 Spot Price Sensitivity Scenarios

A number of pre-defined Spot Price Sensitivity scenarios are calculated in each run of the Predispatch process. Each scenario calculation requires a separate run of the SPD algorithm. The results of these scenario calculations provide details of the expected sensitivity of the Spot Price in a trading interval to a step change in the Forecast Demand of a region(s) occurring in that trading interval and applied from the first trading interval of the Pre-dispatch schedule onwards.

Each scenario is associated with a pre-defined set of regional Forecast Demand offsets (positive or negative, in MW). For a particular scenario, the Forecast Demand offset for each region is added to the Forecast Demand for that region, with the resulting series of modified Demands applied as inputs to the scenario calculation.

5.4.2 SPD Configuration data

5.4.2.1 Static and Dynamic Data Sequence

StaticDataSequence and Dynamic Data Sequence are numbers which change whenever static-type or dynamic-type input data to the SPD algorithm has changed. If the SPD algorithm detects that the sequence number for a certain type of data has changed since the last Predispatch run then all the SPD input data of that type will be read by the SPD algorithm.

Static data items are defined by AEMO as inputs to the SPD algorithm that do not change often, and currently include:

- Region ID
- Interconnector ID
- Connection Point ID/Trader ID
- SCADA Measurand Names

Dynamic data items are all other SPD input items.

5.4.2.2 Updated Initial Conditions

A flag used internally by the SPD algorithm which is set by a single SPD process after all SCADA input data has been captured by that SPD process and written to the common input Transfer Tables so that the input Transfer Tables can be released for reading by all other SPD processes for that Pre-dispatch run. This ensures that the multiple SPD processes comprising Pre-dispatch (two base cases and a defined number of Pre-dispatch Spot Price sensitivities) all use the same initial values captured from the NEM SCADA database. This flag is initially reset before each new Pre-dispatch run.

5.4.2.3 Version

Version number of the SPD transfer table, which SPD algorithm uses to verify compatibility against the version number of its LP module.

5.4.3 Region Configuration data

5.4.3.1 Scaling Factor

For each region, a value between 0 and 1 used by the SPD algorithm to scale down the amount of FCAS Requirement that is either manually specified for a region or automatically calculated by the SPD algorithm. This factor applies to the FCAS Requirement of all six FCAS categories.

The Scaling Factor for all regions will, by default, be set to one (1).

5.4.3.2 Unit Risk Setting Factor

For each dispatchable generating unit, a value between 0 and 1 used by the SPD algorithm to scale down the amount which that generating unit's scheduled energy + FCAS response contributes towards the SPD's calculation of the largest single generation loss in each region. A Risk Setting Factor of one (1) signifies that the total scheduled energy + FCAS response for a particular unit for a particular FCAS category is eligible to set the FCAS Requirement for a region if it is the highest value for all units in that region AND the Generator Risk model is enabled (see Section 5.4.4 below).

The Risk Setting Factor values for all units will be set to zero for the start of NEM.

5.4.4 Region Demand & FCAS Requirements

AEMO determines and enters half-hourly forecasts of regional energy demand and regional FCAS Requirements for each of the following six FCAS categories:

- 6 Second Raise
- 60 Second Raise
- 6 Second Lower
- 60 Second Lower
- 5 Minute Raise
- 5 Minute Lower

While the SPD algorithm can optionally automatically calculate the regional FCAS Requirements for the 6 Second, 60 Second services using the SPD Generator Risk model, this feature will not be used and all of these requirements will be manually entered by AEMO.

5.4.4.1 Forecast Demand

The most probable (50% probability of exceedance) energy demand in a region (in MW) for a particular trading interval. These forecasts are based upon half-hourly historical metering records of as-generated Demand, which are assumed to include the electricity consumption by normally-on dispatchable loads and which also include interconnector flow losses.

5.4.4.2 FCAS Raise Requirements

The minimum total FCAS Raise response (in MW) required to be available to a region in a trading interval for each of the FCAS Raise services. FCAS response is held on dispatchable generating units and dispatchable loads scheduled to provide Raise response under their relevant FCAS contract.

The FCAS 6 Second and 60 Second Raise Requirements for each region are determined to cover at all times the sudden credible loss of the largest single generation input to that region and to arrest the decline in power system frequency within 6 Seconds and 60 Seconds of the contingency, in accordance with the Reliability Panel's power system frequency standard.

The FCAS 5 Minute Raise Regulating Requirement for each region is determined to cover at all times the fluctuations in frequency resulting from predictable increases in regional energy demand above forecast.

Note that a separate FCAS 5 Minute Raise Contingency Requirement is also defined for postcontingency frequency restoration. This requirement is met by using the Manual Ancillary Services process.

5.4.4.3 FCAS Raise Locally-sourced Requirements

The minimum total FCAS Raise response (in MW) required to be available to a region in a trading interval **from local sources only** within that region for each of the FCAS Lower services.

In keeping with the principle of economic allocation of capacity reserve between regions this Local Requirement is generally not defined (and local shares = zero MW) unless there is a credible risk that the interconnection between regions itself represents the largest single contingent loss of generation input to a region, in which case the Local Requirement for that region may be set to the import limit on that interconnector.

5.4.4.4 FCAS Lower Requirements

The minimum total FCAS Lower response (in MW) required to be available to a region in a trading interval for each of the FCAS Lower services.   FCAS Lower response is held on dispatchable generating units by virtue of their scheduled generation.

The FCAS 6 Second and 60 Second Lower Requirements for each region are determined to cover at all times the sudden credible loss of the largest single load on that region and to arrest an increase in power system frequency within 6 Seconds and 60 Seconds of the contingency, also in accordance with the Reliability Panel’s power system frequency standard.

The FCAS 5 Minute Lower Regulating Requirement for each region is determined to cover at all times the fluctuations in frequency resulting from predictable decreases in regional energy demand below forecast.

Similar to the FCAS 5 Minute Lower Contingency Requirement, the FCAS 5 Minute Lower Contingency Requirement for post-contingency frequency restoration is met using the Manual Ancillary Services process.

5.4.4.5 FCAS Lower Locally-sourced Requirements

The minimum total generation reduction reserve (in MW) required to be available to a region in a trading interval **from local sources only** within that region for each of the FCAS Lower services.

In keeping with the principle of economic allocation of capacity reserve between regions this locally-sourced Requirement is generally not defined (and local shares = zero MW) unless there is a credible risk that the interconnection between regions itself represents the largest single contingent loss of load on a region, in which case the locally-sourced Requirement for that region may be set to the export limit on that interconnector.

5.4.5 Generic Constraints

Limits on the operation of dispatchable units and interconnectors in the power system are implemented in the SPD algorithm using generic constraints.   For example, flow on an interconnector can be expressed as a linear combination of various quantities such as regional demand, generation configuration and network outages. This flow can be constrained to be less than, equal to or greater than a certain limit.

Network transfer limits are input to the SPD algorithm in the form of generic constraint equations, comprising a set of LHS variable terms (scheduled quantities in SPD), an inequality operator and a RHS fixed value which represents the limit being applied.

Generic constraints are set up by AEMO and used in Pre-dispatch to represent limits on scheduled unit energy loading, interconnector flow and intra-regional network flow in a trading interval. Every generic constraint equation passed as input to the SPD algorithm comprises the following:

- = Constraint ID
- = Constraint Variables
- = Constraint Variable Factors • = Constraint Operator
- = RHS Type
- = RHS
- = Constraint Type
- = Violation Weight
- = Intervention Status

5.4.5.1 Constraint ID

The unique name assigned to a generic constraint equation and used to associate the various components of the generic constraint equation. This name is also used to associate these components with a dynamically calculated RHS value captured from the NEM SCADA database.

5.4.5.2 Constraint Variables

There are three types of generic constraint variables:

- = constraints on total regional unit loading
- = constraints on interconnector flow
- = constraints on dispatchable unit loading

5.4.5.3 Constraint Variable Factors

The static coefficient applied to each the constraint variables on the LHS of a generic constraint equation.

A value of zero means that the constraint variable is not part of the constraint equation.

5.4.5.4 Constraint Operator

Defines whether the calculated value of the variable terms on the LHS of a generic constraint equation are required to be:

- = less than or equal to;
- = equal to; or

- = greater than or equal to the associated RHS limit value.

5.4.5.5 RHS Type

Defines for a particular generic constraint whether the RHS limit to be used by the SPD algorithm is the static RHS value passed from the MMS database or the dynamic RHS value calculated by the SPD PAS algorithm.

5.4.5.6 RHS

This is a fixed limit value assigned to a generic constraint equation against which the calculated value of the variable terms on the LHS of that generic constraint is assessed.

5.4.5.7 Constraint Type

Identifies the purpose of the generic constraint equation:

- = Unit Fixed Loading limit applied by a market participant;
- = Unit Energy Loading limit applied by AEMO to a non-complying Unit;
- = Unit Energy Loading limit applied to secure additional Ancillary Service response from that Unit;
- = Interconnector flow limit
- = Intra-regional network flow limit

5.4.5.8 Violation Weight

The constraint violation penalty weight used in the SPD algorithm to determine the relative priorities for resolving conflicting constraints.

5.4.5.9 Intervention Status

AEMO assigns an “Intervened” status to a generic constraint if that constraint is invoked to ensure that the power system remains in a reliable operating state. “Intervened” generic constraints are used by On-Line Dispatch only to trigger the calculation of Intervention Prices.

5.4.6 Interconnector Flow model

5.4.6.1 Interconnector Flow Convention

Each interconnector has a defined flow convention, with positive interconnector flows out of the defined “From Region” region into the “To Region” region.

5.4.6.2 Interconnector Energy Flow Limits

The limits on the scheduled flow of energy over an interconnector (in MW), defined for each direction of flow.

AEMO intends to use generic constraints to impose energy import and export limits on interconnector flow. These limits will usually more restrictive than the corresponding static Import and Export Limits defined below.

For the purposes of identifying the relative priorities of Limit violation, AEMO has identified two classes of interconnector limit:

- = Stability Limits, used to represent system security and plant safety type limits. Relaxing these constraints would represent a threat to system security or equipment safety, and therefore involuntary load shedding may be used in order to remain within these higher-priority limits.
- = Thermal Limits, used to represent limits which can be exceeded for a specified time interval - that is, all available dispatchable generation and demand options would be utilised before violating this constraint, but involuntary load shedding would not be undertaken to remain within these lower-priority limits.

5.4.6.3 Interconnector {Energy+FCAS Support} Flow Limits

The limits on the scheduled flow of {energy *plus* FCAS support} over an interconnector (in MW), defined for each direction of flow. FCAS support is the amount of scheduled FCAS response provided by regions other than the FCAS Case region (refer Section 6.6.4).

Energy *plus* FCAS support interconnector limits are passed to the SPD algorithm as the relatively static Interconnector Import Limits and Export Limits.

5.4.6.4 Interconnector 6 Second & 60 Second Overload Factors

The factors defined for each interconnector (normally less than unity) which the SPD algorithm uses to scale up the relevant Import and Export Limits (as defined above) to provide short-term interconnector flow overload capabilities for the scheduling of {energy *plus* FCAS 6 Second Raise/Lower support} and {energy *plus* FCAS 60 Second Raise/Lower support} flows respectively.

AEMO intends to use the static Import and Export Limits for limiting the amount of scheduled {energy *plus* FCAS support} interconnector flow. Therefore the 6 Second and 60 Second Overload Factors will normally be set to zero.

5.4.6.5 Outage Deration Factor

The factor used to derate the static interconnector Export and Import Limits (Section 5.4.6.3 above) during an interconnector outage. This factor will normally be set to zero, as generic constraints will be used to impose interconnector limits.

5.4.7 Interconnector Flow Losses model

5.4.7.1 Flow Segments & Segment Breakpoints

The electrical I^2R losses incurred by an interconnector is a non-linear function of flow across that interconnector. The losses characteristic for each interconnector is modeled in the SPD algorithm by a pre-defined series of ordered flow segments, with each segment identified by a unique flow segment ID and associated with an interconnector flow breakpoint (in MW).

Flow Breakpoints are used in the calculation of loss factors for each interconnector flow segment.

5.4.7.2 Maximum MW In and Maximum MW Out

The interconnector import limit (MaxMWIn) and export limit (MaxMWOut) (in MW) which define the outer bounds of interconnector flow which apply to the piece-wise linear flow segment loss model.

5.4.7.3 Loss Constant

The constant value used in the calculation of flow segment loss factors for an interconnector.

5.4.7.4 Loss Flow Coefficient

The coefficient applied to the average of adjacent flow segment MW breakpoints for each flow segment and used in the calculation of the flow segment loss factors for an interconnector. A Loss Flow Coefficient is defined for each interconnector involved in the losses calculation.

5.4.7.5 Demand Coefficient

The coefficient applied to the Total Demand of the associated region and used in the calculation of the flow segment loss factors for an interconnector. A Demand Coefficient is defined for each region involved in the losses calculation.

5.4.7.6 Interconnector Loss Share Factor

The percentage of total scheduled interconnector flow losses to be allocated by the SPD algorithm to the region defined as the “From Region” for that interconnector. The remaining losses are allocated by the SPD algorithm to the defined “To Region” region.

5.4.7.7 Non-Physical Loss Flow Range

For each interconnector, the defined bandwidth of interconnector flow around the value of interconnector flow scheduled in the previous trading interval (or the Initial Metered Interconnector Flow for the first trading interval of each Pre-dispatch schedule). On detection of non-physical interconnector flow losses for any interconnector (see Section 5.4.7.8 below), the interconnector flow calculated in the second pass of the SPD algorithm is bounded to be within this bandwidth.

The Non-Physical Loss Flow Range is defined so as to limit the error resulting from the use of a single flow segment in the NPL model while not unduly restricting any scheduled change in interconnector flow over the trading interval.

5.4.7.8 Non-Physical Loss Threshold

A second pass of the SPD algorithm is triggered whenever, for any interconnector, the absolute losses error (in MW) between the SPD-calculated value of interconnector losses and the theoretical value of losses (based upon an ordered reconstitution of segment flows up to the scheduled interconnector flow) is greater than or equal to a defined minimum losses error threshold.

The default Non-Physical Loss Threshold is 1.

5.4.8 Intra-regional Network Flow model

AEMO will invoke a set of generic constraints to limit the scheduled energy flow over intra-regional network elements.

The particular generic constraint set invoked will depend upon the prevailing system conditions (such as a prior transmission line outage). When the scheduled energy flow reaches the flow limit applied by the generic constraint, the generic constraint becomes binding. Note that the SPD algorithm will not schedule FCAS support flow on intra-regional network elements.

5.4.9 Unit Ancillary Services Constraints

Unit Ancillary Services constraints are generic constraints invoked by AEMO for a particular trading interval in order to limit the scheduled energy loading of a dispatchable unit so that additional ancillary service response can be provided by that unit.

Ancillary Services constraints are only used in scheduling Ancillary Services that are not automatically co-optimised by the SPD algorithm but rather are recommended by the Manual Ancillary Services process.

6. Pre-dispatch Calculation

6.1 Over view

The complete Pre-dispatch process calculation is performed as two separate but parallel processes - the co-optimised Pre-dispatch which uses the SPD algorithm (simply referred to in this document as Pre-dispatch) and the Manual Ancillary Services process.

Sections 6.2 onwards only details the co-optimised Pre-dispatch calculation. Refer to the AEMO document “Manually Dispatch Ancillary Services process description“ for a more detailed description of the Manual Ancillary Services process.

6.1.1 Co-optimised Pre-dispatch

The calculation of scheduled unit loading and pricing information is performed by the Scheduling, Pricing and Dispatch (SPD) algorithm. The Pre-dispatch SPD algorithm consecutively solves a series of constrained joint energy/FCAS response co-optimisation problems (also called the objective function) for each individual trading interval of the Pre-dispatch scheduling period using classical linear programming (LP) techniques. Constraint models are used to represent the various operating characteristics of dispatchable units and their interaction with the electricity network. These constraint models are converted into the form of linear constraints suitable for input to an LP optimisation. Where constraints are binding in the solution for a trading interval these constraints will report a marginal price, which indicates the opportunity cost of relaxing that constraint.

6.1.2 Manual Ancillary Services process

A separate Manual Ancillary Services process ANSITT (which operates in parallel with the cooptimised Pre-dispatch process) provides advisory Unit Ancillary Services response and

Unit loading constraint schedules covering the requirements for the following non co-optimised Ancillary Services:

- = Major contingency FCAS 5 Minute services (supplied under AGC and RGUL contracts);
- = Major contingency FCAS 6 Second & 60 Second services (supplied under Governor and Load Shedding contracts) - the requirements defined for this service are additional to the minor contingency requirement met by co-optimised Pre-dispatch;
- = Network Loading Control services (supplied under AGC and RGUL contracts);
- = Stability Control service (supplied under RGUU contracts); and
- = Voltage Control service (supplied under Reactive Support contracts)

Where the Manual Ancillary Services process advises that the scheduled energy loading on a dispatchable unit needs to be constrained in order to provide additional Ancillary Service response, these constraints are then manually invoked by AEMO as generic constraints in Pre-dispatch for use by the SPD algorithm.

6.2 Constraint models

The constraint models applied in Pre-dispatch are:

Unit Loading constraint models

- = Unit Ramp Rate constraints
- = Unit Daily Energy constraints
- = Unit FCAS Raise Capacity constraints
- = Unit FCAS Lower Capacity constraints
- = Unit Joint Energy and FCAS Raise Capacity constraints
- = Unit Joint Energy and FCAS Lower Capacity constraints
- = Energy Band Price Tie-breaking constraints

Energy Demand/Supply Balance models

- Regional Forecast Demand Adjustment
- Regional Energy Bid/Offer Clearing
- Inter-regional Energy Trading
- Regional Energy Pricing

System Security models

- = Regional FCAS Requirement
- = Regional FCAS Offer Clearing
- = Inter-regional FCAS Trading
- = Regional FCAS Pricing

Network Flow models

- = Interconnector Flow constraints
- = Interconnector Flow Losses
- = Interconnector Flow Non-Physical Losses

- = Intra-regional Flow constraints

A brief description of the Pre-dispatch objective function and the above constraint models is presented in this section. For a more detailed mathematical explanation of each model refer to the SPD Formulation document.

6.3 Objective Function

This model seeks to maximise the value of the market by minimising the cost of generation subject to constraints. The mathematical formulation uses the sum of the dispatched band MW multiplied by the band price plus any violation penalties.

In accordance with clause 3.8.1(b) of the Code the Pre-dispatch calculation aims to maximise the overall value of spot market trading for each trading interval of the Pre-dispatch scheduling period. The value of spot market trading is defined as:

dispatched load x energy dispatch bid band price (for dispatchable loads)

less

dispatched generation x energy dispatch offer band price (for dispatchable generating units)

less, for each of the six FCAS categories…

dispatched FCAS response x FCAS dispatch offer band price (for FCAS-contracted units)

subject to the following constraints:

- = unit dispatch offer and dispatch bid constraints;
- = unit availability constraints;
- = regional energy demand constraints;
- = intra-regional network constraints and intra-regional losses;
- = inter-regional network constraints and inter-regional losses;
- = current levels of dispatched Unit generation and load;
- = ancillary services requirements; and
- = energy band price tie-breaking constraints.

The following Figure 6 illustrates in simple terms how the SPD algorithm uses unit dispatch bid/offer Band Prices and the forecast of Regional Energy Demand to calculate the optimal Unit energy dispatch and market clearing price for energy, at the point where total Region Energy Demand matches total scheduled Supply to the region.

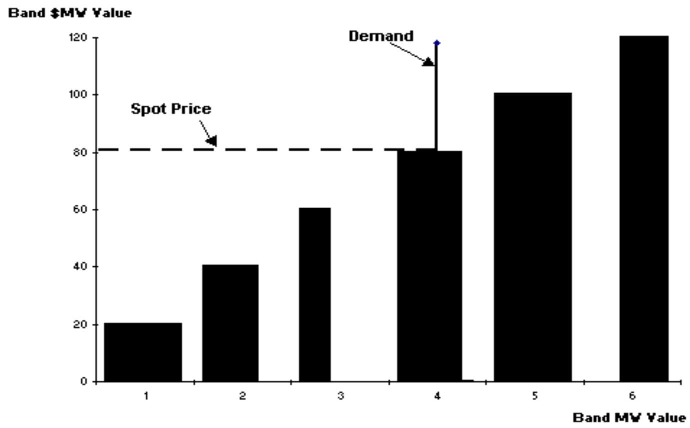


FIGURE 6- ENERGY DEMAND/SUPPLY BALANCE

6.4 Unit Loading constraint models

6.4.1 Unit Loading

Scheduled unit loading is the sum of scheduled Band loadings for that unit, as illustrated in **Error! Reference source not found.** below:

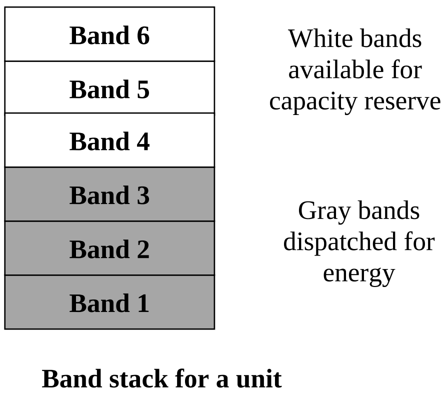


FIGURE 7- CALCULATION OF SCHEDULED UNIT LOADING

6.4.2 Unit Ramp Rate constraints

Unit Ramp Up Rates and Ramp Down Rates are passed as input to the SPD algorithm from the dispatch bid/offers of all dispatchable units and are then converted into respective upper and lower constraints on the loading (output of a generating unit or consumption by a load) that each unit can be dispatched to by the end of a trading interval. These constraint calculations are based on the initial unit loading at the start of a trading interval (which is the scheduled unit loading calculated for the previous trading interval or, for the first trading interval only, the current SCADA unit loading) and the maximum amount by which that initial loading can change over that trading interval as indicated by the relevant Unit Ramp Rate.

The upper bound is the initial consumption at the start of a dispatch or trading interval *plus* the maximum amount by which that initial consumption can increase over the interval, as indicated by the ramp up rate multiplied by the number of minutes in the interval.

The lower bound is the initial consumption at the start of a dispatch or trading interval *less* the maximum amount by which that initial consumption can decrease over the interval, as indicated by the ramp down rate multiplied by the number of minutes in the interval.

The Unit Ramp Rate constraint model is therefore inter-temporal by nature, as the unit upper and lower loading constraints calculated for a particular trading interval depend upon the scheduled unit loading calculated in the previous trading interval.

6.4.3 Unit Daily Energy constraint

Unit Daily Energy Limits are used by market participants in Pre-dispatch to limit the total amount of energy (energy generated for a generating unit or energy consumed by a load) that can be scheduled on their energy-constrained units from the start of the trading day onwards. Note that energy-constrained units are not subject to this limit in On-line Dispatch.

For each energy-constrained unit the initial Daily Energy Remaining in each trading day covered in the Pre-dispatch scheduling period is firstly calculated and then passed as input to the SPD algorithm as “Energy Available”. The Daily Energy Remaining for the current trading day is the sum of all the 5-minute values of scheduled Unit Loading calculated in each run of On-line Dispatch, commencing with the value calculated for the dispatch interval ended 0405hrs and ending with the value for the latest dispatch interval run prior to the start of the Pre-dispatch run. The Daily Energy Remaining for the next trading day is simply the Daily Energy Limit value as bid.

After the SPD algorithm commences, the initial value of Daily Energy Remaining for the trading interval is converted into an upper constraint on the loading that the unit can be dispatched to by the end of that trading interval. After that trading interval solves the initial value of Daily Energy Remaining for each unit is reduced by the energy scheduled in that trading interval for that unit, with the updated values of Daily Energy Remaining passed as initial values for the next trading interval calculation.

Once the Daily Energy Limit has been reached the unit upper loading constraint is effectively set to zero for the remaining trading intervals of that trading day.

Note that the Unit Daily Energy constraint model is inter-temporal by nature, as the unit upper loading constraint calculated for a particular trading interval depends upon SPD’s calculation of the cumulative energy dispatched from that unit for all previous trading intervals of the trading day.

Also note that energy-constrained units with no further energy available can still contribute FCAS response. However, units that have bid a zero Energy Availability cannot contribute any FCAS response as their FCAS Band Quantities are all set to zero MW.

6.4.4 Unit FCAS Raise Capacity constraint

For each contracted dispatchable generating unit, the scheduled FCAS Raise response for each of the Governor services is limited to the corresponding value of pre-breakpoint Governor Maximum Raise Response (input to the SPD algorithm as Raise6SecMax and Raise60SecMax). The Raise60SecMax value is adjusted to be net of the dispatchable generating unit's mandatory governor response. For the AGC Regulating service the scheduled FCAS Raise response is limited to the AGC Maximum Raise Response (input as Raise5MinMax).

For each dispatchable load, the scheduled FCAS Raise response for each of the Load Shedding services is limited to the minimum of Load Shedding Maximum Raise Response (input as Raise5MinMax) and the scheduled load energy consumption.

6.4.5 Unit FCAS Lower Capacity constraints

For each contracted dispatchable generating unit, the scheduled FCAS Lower response for each of the Governor services is limited to the minimum of the corresponding values of pre-breakpoint Governor Maximum Lower Response (input to the SPD algorithm as Lower6SecMax and Lower60SecMax) and the scheduled unit energy generation. The Lower60SecMax value is adjusted to be net of the dispatchable generating unit's mandatory governor response.

For each contracted dispatchable generating unit, the scheduled FCAS Lower response for the AGC Regulating service is limited to the minimum of AGC Maximum Lower Response (input as Lower5MinMax) and the scheduled unit energy generation.

6.4.6 Unit Joint Energy and FCAS Raise Capacity constraints

This model considers the practical limitations of a dispatchable unit's maximum generating capacity. For each dispatchable generating unit, there are two joint energy/FCAS response constraints considered by Pre-dispatch:

- = Energy versus FCAS Raise Capacity; and
- = Energy versus Governor Droop Raise Capacity

6.4.6.1 Joint Energy/FCAS Raise Capacity

The sum of the scheduled energy loading and the scheduled FCAS response must be less than or equal to the FCAS Capacity of that unit.

FCAS Capacity is set to the Governor contract values of Raise6Capacity and Raise6Capacity for the 6 Second and 60 Second Raise services. For the 5 Minute Raise service the Maximum FCAS Capacity is assumed to be the bid unit Energy Availability.

6.4.6.2 Joint Energy/Governor Droop Raise Capacity

The sum of the scheduled energy loading and the scheduled FCAS response must be less than or equal to the Governor Droop Raise Capacity of that unit for each of the FCAS 6 Second and 60 Second Raise services.

Governor Droop Capacity for each service is a slope constraint equal to:

RaiseMax x (RaiseCapacity - Scheduled Energy)

(RaiseCapacity - RaiseBreakpoint)

6.4.7 Unit Joint Energy and FCAS Lower Capacity constraints

This model imposes limits of a dispatchable generating unit's current generation level.

For each dispatchable generating unit, there is a joint energy/FCAS response constraint considered by Pre-dispatch relating to Governor Droop Lower Capacity

6.4.7.1 Joint Energy/Governor Droop Capacity

The sum of the scheduled energy loading and the scheduled FCAS response must be less than or equal to the Governor Droop Lower Capacity of that unit for each of the FCAS 6 Second and 60 Second Lower services.

Governor Droop Lower Capacity for each service is a slope constraint of similar format to the Governor Droop Raise Capacity:

$$\text{LowerMax} \quad \times \quad \frac{(\text{LowerCapacity} - \text{Scheduled Energy})}{(\text{LowerCapacity} - \text{LowerBreakpoint})}$$

6.4.8 Energy Band Price Tie-breaking constraints

Where two or more units have Energy Bands with the same Band Price when referred to the regional reference node and the SPD algorithm requires additional loading from those Bands, the Band Price-tie model calculates the sharing of that additional load between those Bands. This is done by applying to each Band the calculated ratio of the individual Band MW available to the total MW available from both the price-tied Bands.

As an example, two units each have a Band with a Band Price of $10/MW. One Band can provide 200MW and the other 300MW at this price. Only a further 300MW is needed to meet Demand. The SPD algorithm will use a pro-rata formulation to calculate what percentage 200MW is of the total available (200/500=40%). The unit with 200MW available will provide 40% of the total needed. The unit with 300MW available will provide the remaining 60%.

Note that there are limitations to this model. The Bands must be Energy Bands (no tie-breaking rules applied to price-tied FCAS Bands), must belong to units in the same region and the rules apply to either all generating unit bands or to all load bands. Note also that as the violation penalty associated with the Band Price-tie model is very small, the Price-tie MW sharing will effectively be over-ridden by any conflicting constraint, including Ramp Rate constraints or a binding joint energy/FCAS response limit.

It is assumed that the Price-tie model only applies where there are explicit price-tied Energy Bands, and do not apply where:

- = a joint energy/FCAS dispatch offer considered together may be effectively priced-tied with other offers after accounting for opportunity costs;
  or
- = Bands are price-tied only after taking into account inter-regional losses

6.5 Demand/Supply Balance models

6.5.1 Non-dispatchable Demand calculation

Prior to commencing the SPD calculation for a particular trading interval the half-hourly energy Forecast Demand provided by AEMO for each region is initially adjusted by the SPD algorithm to remove:

- = the calculated interconnector electrical losses between the region's boundary and its regional reference node; and
- = the total Unit Energy Availability of all normally-on dispatchable units in the region, as submitted in their dispatch bids.

The historically-based Pre-dispatch Forecast Demand provided by AEMO is assumed to include a normally-on dispatchable load component. The above initial adjustments are therefore necessary in every trading interval in order to determine the amount of non-dispatchable regional energy demand at the regional reference node. The SPD algorithm then schedules dispatchable generation and load to meet this Non-dispatchable demand and sets energy clearing prices based upon this demand.

For the first trading interval only, both the regional Aggregate Dispatch Error and the Demand Forecast Change is addedd to the above Pre-dispatch Forecast Demand.

The resulting calculation of Non-dispatchable Demand is then reported back by the Pre-dispatch SPD algorithm as Total Demand.

6.5.2 Regional Energy Bid/Offer Clearing

6.5.2.1 Band Price Referral

Intra-regional network electrical losses between each dispatchable unit's connection point and its associated regional reference node is modeled by a static loss factor. For each dispatchable unit the Band Prices submitted in the daily dispatch bid/offer file are divided by the unit's associated connection point loss factor before being passed as input to the SPD algorithm.

6.5.3 Inter-Regional Energy Trading

While there is no explicit link between the amount of interconnector losses and dollar value of those losses, an indirect link does exist. Owing to the energy Demand/Supply balance constraint (scheduled Generation = scheduled Load *plus* Interconnector losses) any losses incurred on interconnectors have to be supplied from generating units, which incurs a generation cost in the LP objective function.

As the SPD algorithm aims to minimise cost and to maximise the value of the LP objective function, interconnector losses (and therefore interconnector flow) therefore tend to be reduced owing to this indirect association with generation costs, balanced against the relative benefit from increasing inter-regional energy trading (and interconnector flow)

6.5.4 Energy Pricing

The energy clearing price is set from the marginal cost of supplying a further MW of energy.

As the Bands of dispatchable units (including loads) can be marginally or partially dispatched, these Bands are able to set the market price for an interval.

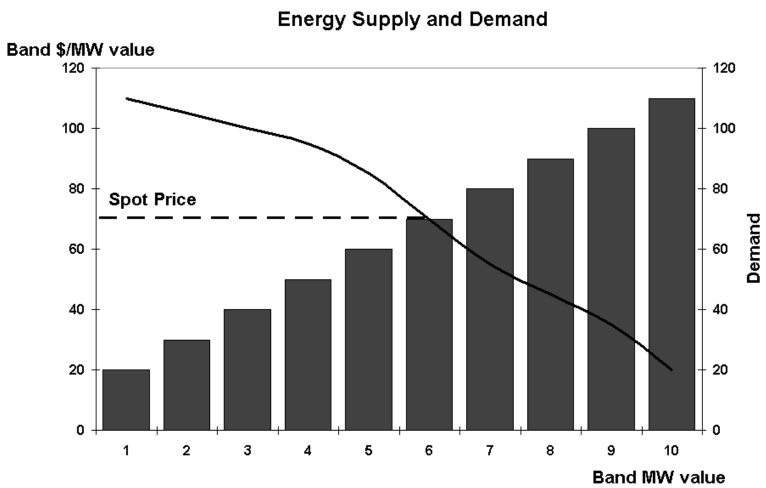
The following exceptions relating to the calculation of market prices should be noted:

- = Market price may not correspond to any single referred Band Price where the marginal cost of supply is represented by the combined cost of varying the scheduled loading of a number of units which are jointly subject to a constraint.

- = Similarly, the market price may not correspond to any single referred Band Price where the marginal cost of supply is represented by a binding interconnector flow limit which is defined as a function of interconnector flow on a number of interconnectors.

- = Where the scheduled interconnector flow coincides with a flow segment bound, the resulting interconnector loss factor lies arbitrarily between the loss factors determined for the two adjoining flow segments. In these cases the market participant cannot reliably predict the relative market prices between the two adjoining regions.

- = Where regional energy demand is exactly cleared on the boundary between two energy bands in the merit order, the resulting market price cannot be reliably predicted, and may be the price of either the fully-loaded Band or the fully-unloaded Band.



The solid line represents increasing demand for energy. Each bar represents a Energy Band. Where the energy supply and demand curves intersect, an energy clearing price or

Spot Price is determined. Using this information market participants can reconcile at which Band the Spot Price will occur and bid accordingly.

The above Figure does not take into account the effects of any implicit or generic constraints on unit scheduled energy loading. Consider Figure 8 below.

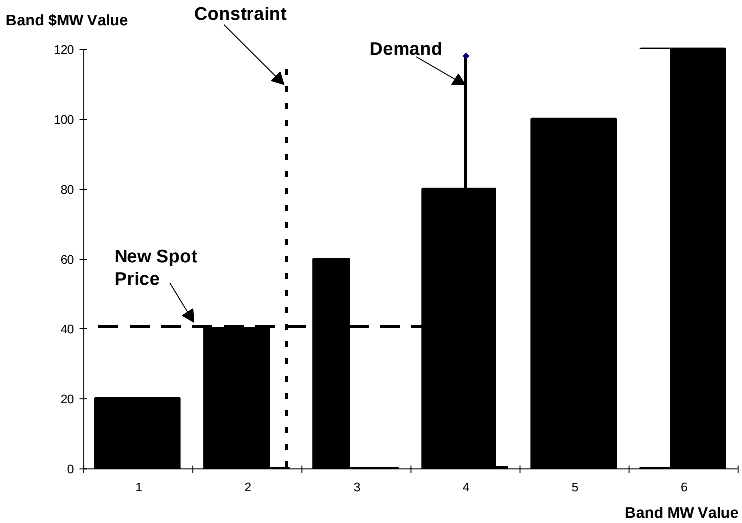


FIGURE 8- EFFECT OF A BINDING CONSTRAINT ON SPOT PRICE

A binding constraint on a particular dispatchable generating unit which results in that unit being loaded to a higher level than it would have otherwise been economically loaded to will generally result in the spot price being set by a lower-priced unit rather than by that unit. Conversely, a binding constraint on a particular dispatchable generating unit which results in that unit being loaded to a lower level than it would have otherwise been economically loaded to will generally result in the spot price being set by a higher-priced unit rather than by that unit.

6.6 System Security models

6.6.1 Regional FCAS Requirement

These requirements are determined by the Reliability Panel based on covering the largest single credible contingency across the interconnected regions. The SPD Generation Risk model described below will not be used initially, with all regional FCAS Requirements entered manually.

As the FCAS Requirement defined for each region is based upon covering at all times a single contingent loss of generation and load within each of the interconnected networks (Southern regions and Queensland region), then the FCAS Requirement of all regions does not need to be satisfied concurrently.

Note that this differs from the requirement that Energy Demand in all regions must be concurrently met.

6.6.1.1 Generation Risk Model

Each dispatchable generating unit is assigned a Unit Risk Factor. The SPD Generation Risk model defines the FCAS Raise Requirement in a region as the largest single credible loss of scheduled (generation + FCAS response) supplied to that region, such as would occur on the failure of the largest generating unit.

6.6.1.2 Interconnector Risk

Interconnector import may at times represent the largest single credible loss of scheduled (energy + FCAS support) supplied into a region. In this case if all interconnection were lost with neighbouring regions then the total regional FCAS Requirement would need to be provided from sources local to that region. As the SPD algorithm does not directly model Interconnector Risk, AEMO will then manually enter a locally-sourced regional FCAS Requirement equal to the regional FCAS Requirement.

6.6.2 Regional FCAS Requirement adjustments

As discussed in Section 5.1.3.3 above, the regional FCAS Requirements for each of the 60 Second Raise and Lower services is reduced by the total mandatory governor response assumed to be available to that region from in-service dispatchable generating units.

6.6.3 Regional FCAS Offer Clearing

FCAS Band Quantities and Band Prices for each FCAS category (derived from Ancillary Services contract offers and re-offers) are co-optimised along with all Energy Band Quantities and Band Prices in order to satisfy both Demand and FCAS Requirements in all regions subject to various constraints.

FCAS Cases

As the regional FCAS Requirement is non-coincident, the SPD algorithm schedules enough total FCAS response from units in all regions to cover the FCAS Requirement of each single region taken in turn (each of these scheduling studies is referred to as an FCAS Case).

Each FCAS Case study determines the FCAS response targets for all dispatchable units for each of the six FCAS categories.

6.6.3.1 FCAS Raise response

Capacity Reserve is the aggregate ability of all generating units to rapidly increase output (or loads to rapidly reduce consumption) in an emergency due to a sudden loss of the largest single generation into the power system. Sufficient capacity reserve (in the form of scheduled Governor and Load Shedding FCAS response) is achieved by maintaining a margin of generation below the FCAS capacity (for generating units) or consumption above zero (for loads).

6.6.3.2 FCAS Lower response

Load Rejection Reserve is the aggregate ability of all generating units actually in-service to rapidly reduce output in an emergency due to a sudden loss of the largest single load on the power system. Sufficient load rejection reserve (in the form of scheduled Governor FCAS response) is achieved by maintaining a margin of generation above the total self dispatch levels for all dispatchable generating units.

6.6.4 Inter-regional FCAS Trading

The inter-regional FCAS trading model looks at the possibility of regional FCAS Requirements being met by other regions through the scheduling of inter-regional FCAS response (also called FCAS support).

As regional FCAS Requirements are non-coincident, Interconnector FCAS support flows can be scheduled in both directions at once so that regions can support each other. FCAS support flow does not have to be dedicated to one direction only.

For any region other than the region with the FCAS Requirement (the Case region), the total FCAS response scheduled from units in non-Case regions must be exported out of those regions (which have no FCAS Requirement under this Case) into the Case region as FCAS support.

The SPD algorithm then relates the net FCAS support available from non-Case regions with the remaining interconnector capacity, which in turn affects the net energy flow scheduled on all connected interconnectors. The SPD algorithm considers the defined static Interconnector Export and Import Limits, subtracts what is scheduled for energy flow and uses the remaining interconnector capacity for scheduling of FCAS support.

6.6.5 FCAS Pricing

The FCAS clearing price is set from the marginal cost of supplying a further MW of FCAS response.

As the FCAS Bands of dispatchable units (including loads) can be marginally or partially dispatched, these Bands are able to set the FCAS Price for an interval.

6.7 Network Flow constraint models

6.7.1 Interconnector Flow Limits

Generic constraints will be set and adjusted to reflect the pre-contingent limits of interconnectors. These pre-contingent limits are based on consideration of a single credible contingency event (for example, the loss of the largest generator), and as such there is inherently a post contingency'overload' capacity built into the limit. The pre-contingent generic constraints will therefore always be at least one contingency value *less* than the absolute limits.

The SPD algorithm will recruit FCAS support over interconnectors up to the value of the static Export Limit or Import Limit (refer Section 5.4.6.3), which may at times exceed the energy-only interconnector limit plus one contingency. For this reason, it has been decided to limit the co-optimised FCAS Requirement to consideration of single contingency events only.

Additional FCAS Requirement to cover double contingency events (which the Reliability Panel requires be met under the power system frequency standards) will be dispatched manually.

Note that the interconnector flow limits and a number of intra-regional network flow limits are calculated dynamically by the SPD PAS algorithm based upon the previous trading interval's scheduled units loadings and interconnector flows or, for the first Pre-dispatch trading interval only, based upon metered initial conditions captured from the NEM SCADA database. Note that all interconnector flow limits are reported back to market participants.

6.7.2 Interconnector Flow Losses

The interconnector loss factor equation comprises a constant, a term dependent on interconnector flow, and terms dependent on forecast regional demands. Given the forecast of regional demands for a particular trading interval it is possible to define the interconnector loss factor as a linear function of interconnector flow alone. Internally, the SPD algorithm translates these loss factors into marginal losses.

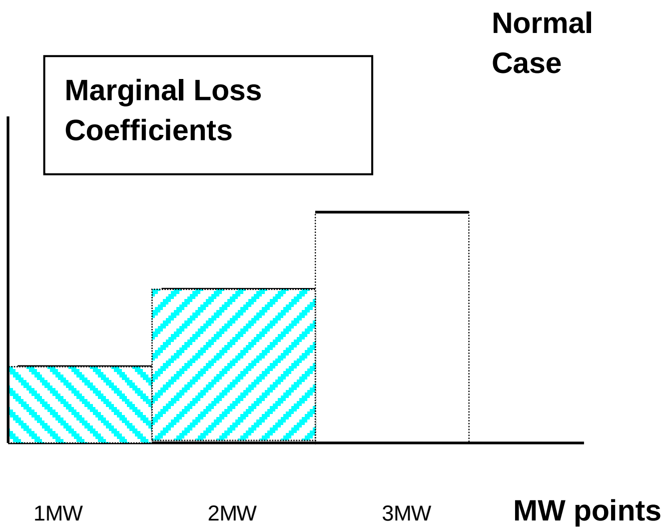
Conventionally, quadratic losses would be defined as the integral of marginal losses with respect to flow, possibly with a constant loss added. As there should be no losses associated with an interconnector if there is no flow on that interconnector, the constant is assumed to be zero.

As an LP cannot implement a quadratic loss function without employing iteration, the SPD algorithm instead employs a piece-wise linearisation of the loss function. This means that marginal losses are converted to constants associated with each of a number of user-defined interconnector flow segments, with a separate flow variable defined for each flow segment. The constant marginal loss used corresponds to the average of the continuous marginal losses at the two ends of the flow segment.

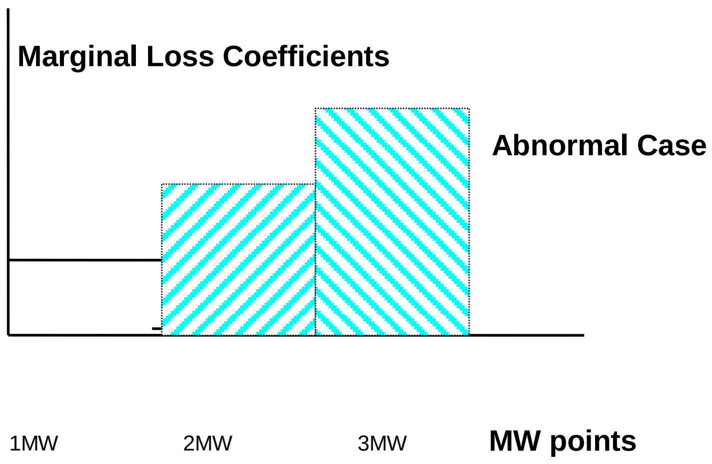
The segmentation of interconnector flows into flow segments means that it is possible for the LP solution to schedule an interconnector flow which coincides with the end of a flow segment. In this case a decrease in flow will produce a change in losses reflecting the marginal losses on the current flow segment, while an increase in flow will produce a change reflecting the marginal losses on the next flow segment. Such an outcome occurs because the higher marginal losses on the next flow segment are too great to justify dispatching flow in that flow segment. In this case it is cheaper to import power from the receiving region than it is to export power from the sending region.

6.7.3 Interconnector Flow Non-Physical Losses (NPL)

Under normal conditions, the SPD algorithm will correctly calculate interconnector flow losses. For this formulation to employ the appropriate flow segments, the objective function minimises interconnector losses, consistent with the overall objective of dispatching at maximum overall trading benefit based on the bids and offers of market participants. This is the case when the Spot Price is positive. When the Spot Price becomes zero there is no cost associated with flow losses and the objective function is indifferent to the level of losses. However, when the Spot Price becomes negative (that is, an Excess Generation Price), the value of the objective function can be improved by maximising losses, incorrectly favouring the use of higher marginal loss flow segments ahead of the lower marginal loss flow segments (refer to Figures below).



Assume that scheduled interconnector flow = 2MW. Under positive pricing situations, interconnector losses are correctly calculated by the SPD algorithm as illustrated above.



Under abnormal negative pricing (excess generation) situations (refer Figure above) the scheduled segment flow corresponding to the lowest-loss flow segment is zero, while the scheduled segment flow corresponding to the highest-loss flow segment is non-zero. In this case these calculated electrical losses are not physically realisable and the scheduled interconnector energy flows are therefore incorrect.

The non-physical losses (NPL) model counters this effect by performing a second run of the SPD algorithm for each trading interval in which NPL are detected. In the second SPD run the scheduled interconnector flow is constrained to within a single flow segment. This flow segment is bounded by the scheduled interconnector flow from the previous trading interval (or the initial metered interconnector flow, for the first trading interval only of each Pre-dispatch schedule) *plus/minus* a Non-Physical Loss Flow Range defined for the interconnector. The single flow segment loss factor corresponds to the loss factor determined for scheduled interconnector flow from the previous trading interval. The interconnector loss offset is also adjusted.

Note that the NPL model does not apply to inter-regional FCAS trading as it is assumed that FCAS trading does not incur electrical losses.

Also note that on detection of a NPL condition on one interconnector, the NPL model is then applied to all interconnectors.

6.8 Constraint Violation

Where a set of imposed constraints cannot be satisfied concurrently, the SPD algorithm may fail to solve unless one or more of the conflicting lower priority constraints are permitted to be relaxed (violated) to the required degree.

Section 5.4.1.2 above details the types of constraints for which constraint violation is permitted. The SPD LP objective function includes constraint violation variable terms for these constraints. Generally the lower the penalty price the lower is the priority for satisfying that constraint over a conflicting higher-priced constraint and the more readily that constraint will be violated first, as the overall violation cost is minimised in the LP objective function.

Note that as the Energy Ramp Rate violation penalty passed as input to the SPD algorithm is defined in $/MW, the effective penalty price is converted into $/MW/hour and will therefore differ between Pre-dispatch and On-line Dispatch owing to the length of the intervals concerned. For Pre-dispatch:

Effective Ramp Rate penalty price = Input Ramp Rate penalty price / 2

This also applies to the Daily Energy Constraint violation penalty price passed to SPD , which is converted into $/MWh :

Effective DEC penalty price = Input DEC penalty price x 2

7. Pre-dispatch Outputs

Pre-dispatch information is released to the market in two stages:

- = Output results calculated from each run of the Pre-dispatch process are released after that Pre-dispatch run. Pre-dispatch data of an aggregate nature (both inputs and outputs) is published to the whole market, with data relating to a specific market participant only published to that participant; and
- = All Pre-dispatch data (both input and output) is published to the whole market after the end of the trading day to which that data applies.

Pre-dispatch input data has already been described in Section 5.

The following Section describes all output data determined from Pre-dispatch, categorised into either Unit-based data or aggregate data, as follows:

Unit data

- = Unit Energy dispatch data
- = Unit Ancillary Services dispatch data

Aggregate data

- = Pre-dispatch solution data
- = Regional data
- = Network data

7.1 Unit data

7.1.1 Unit Energy dispatch data

The trading interval data in this Section is calculated by Pre-dispatch for each dispatchable unit.

7.1.1.1 Total Cleared

The scheduled Unit loading (in MW) cleared for a dispatchable unit in a trading interval.

For a dispatchable generating unit, this value is the forecast electrical output of the unit on an as-generated basis. For a normally-on or normally-off dispatchable load, this value represents the forecast electrical consumption.

These targets are confidentially reported to the relevant market participant in electronically-transmitted text files updated after every Pre-dispatch run.

Note the SPD algorithm employs linear programming techniques to solve. Therefore, the scheduled loadings for both dispatchable generating units and loads are, by nature, continuous rather than quantised values.

This means that for dispatchable units that typically exhibit a quantised loading response (such as a pump) it is more relevant to bid so that the dispatch process would be unlikely to schedule partial loading in any energy bands of that unit. This can be achieved, for example, through pricing bands sufficiently away from the likely market clearing price.

7.1.1.2 Initial MW

The value of Initial Unit Metered Loading actually used by the SPD algorithm (refer Section 5.3.1.1) for calculations in the first trading interval of each Pre-dispatch schedule.

7.1.1.3 Energy Market Ramp Rates

The bid energy market Ramp Up Rate and Ramp Down Rate submitted in the dispatch bid/offer for each Unit for a particular trading interval. For the first trading interval only of each Pre-dispatch schedule, this value is the most restrictive of the bid energy market Ramp Rate and the telemetered energy market Ramp Rate captured from the NEM SCADA database (if that value exists and is of "good" quality).

7.1.2 Unit Ancillary Services dispatch data

The following data is confidentially reported to the relevant market participant in electronicallytransmitted text files updated after every Pre-dispatch run.

7.1.2.1 FCAS Raise Response

For a trading interval, the scheduled amount of Raise response (in MW) forecast to be required from the dispatchable unit for the relevant FCAS 6 Second Raise, 60 Second Raise and/or 5 Minute Raise service.

7.1.2.2 FCAS Lower Response

For a trading interval, the scheduled amount of Lower response (in MW) forecast to be required from the dispatchable unit for the relevant FCAS 6 Second Lower, 60 Second Lower and/or 5 Minute Lower service.

7.1.2.3 FCAS Response Marginal Value

For a trading interval and each FCAS category, the marginal value or shadow price (in $/MW) of a dispatchable unit's FCAS response constraint,. This value will be non-zero only if the constraint on the unit's ability to provide an FCAS response is binding.

7.1.2.4 FCAS Response Violation Degree

For a trading interval and each FCAS category, the amount (in MW) by which a dispatchable unit's FCAS response constraint is violated by a conflicting higher-priority constraint. The marginal value of the violated constraint will reflect the violation penalty price of the conflicting higher-priority constraint.

7.1.2.5 AGC Status

The AGC Status actually used by the SPD algorithm (refer Section 5.3.1.3) for calculations in the first trading interval of each Pre-dispatch schedule.

7.1.2.6 Ancillary Service Constraints

All manually-invoked constraints applied specifically to a single unit alone in order to limit its scheduled energy loading for the purpose of providing a specific Ancillary Service.

7.1.2.7 Ancillary Service Constraint Binding Status

For each manually-invoked Ancillary Service constraint, whether or not the Ancillary Service constraint is binding in the solution.

7.2 Aggregate Data

7.2.1 Pre-dispatch solution data

7.2.1.1 Solution Status

This is the status of the latest Pre-dispatch solution, where;

0 = Successful (Normal) solution, with no constraints violated;

or

1 = Abnormal solution, where any constraint has been violated;

or

-X = SPD LP Solver Failure, where X is the offset from the first trading interval to the first trading interval for which the SPD algorithm has failed to solve.

Note that no SPD outputs are reported back to the MMS if the SPD LP Solver fails.

7.2.1.2 Solution Complete

Indicates that all the Pre-dispatch solution data has been successfully written for this Pre-dispatch run, where 1 = Success and 0= Failure.

7.2.2 Region data

The trading interval data in this Section is calculated by Pre-dispatch for each region.

7.2.2.1 Spot Price

The energy clearing price (in $/MW) at the reference node of each region for a trading interval, being the marginal value (or shadow price) of the energy demand/supply balance constraint.

If this clearing price is positive then the trading interval is not an excess generation trading interval. Under the Code the Spot Price equals the clearing price and the Excess Generation Price is set to $zero.

7.2.2.2 Excess Generation Price

If this clearing price defined in Section 7.2.2.1 above is negative, then the trading interval is an excess generation trading interval. Under the Code the Spot Price is set to $zero and the Excess Generation Price equals the clearing price.

Note that the total MW amount of excess generation in a region (which equals the total scheduled generating unit loading below self-dispatch level) is not explicitly reported by Pre-dispatch.

7.2.2.3 Spot and Excess Generation Sensitivity Prices

These are the regional Spot Prices and Excess Generation Prices calculated for each of the series of 28 Pre-dispatch Spot Price sensitivity scenarios.

7.2.2.4 Total Demand

The forecast non-dispatchable energy demand initially calculated by the SPD algorithm for a region (refer Section 6.5.1) and applied as a fixed value in the Energy Demand/Supply balance constraint for the calculation of dispatch and pricing by the SPD algorithm.

7.2.2.5 Daily Energy Requirement

The total daily Energy Demand forecast for a region, calculated as the sum of Energy Demands for all trading intervals over the relevant trading day.

7.2.2.6 Short-Term Capacity Reserve Requirement

The minimum Short-term Capacity Reserve Requirement (in MW) defined for a region. These are the same requirements provided as input to the Short-Term PASA process.

7.2.2.7 Short-Term Capacity Requirement

The minimum short-term Capacity Requirement defined for a region, being the sum of the most probable Region Demand and the Short-term Capacity Reserve Requirement for that region.

This value is determined from the Short-Term PASA process running over the Pre-dispatch scheduling period. AEMO refers to this value in making intervention decisions within the Pre-dispatch schedule time-frame.

7.2.2.8 Energy-unconstrained Short-Term Capacity

The total Short-term Capacity available to a region, making no allowance for binding Daily Energy Limits on energy-constrained units. Determined from the Short-Term PASA process running over the Pre-dispatch scheduling period.

7.2.2.9 Energy-constrained Short-Term Capacity

The total Short-term Capacity available to a region, being the total bid Unit Availability of all dispatchable units in that region after allowing for binding Daily Energy Limits on energy-constrained units. Determined from the Short-Term PASA process running over the Pre-dispatch scheduling period.

AEMO refers to this value in making intervention decisions within the Pre-Dispatch schedule time-frame.

7.2.2.10 Energy-constrained Short-Term Capacity Surplus

The total surplus of Energy-constrained Short-Term Capacity available to a region over its Short-term Capacity Reserve Requirement. Also considers dispatchable loads approved for reserve calculations. Determined from the Short-Term PASA process running over the Pre-dispatch scheduling period.

This is defined in the Code as the amount of surplus or unused generating capacity available in a trading interval, assessed as being in excess of the Short-term Capacity required to meet the current forecast Energy plus Capacity Reserve requirement, taking into account the known or historical levels of demand management.

Insufficient reserve of this type may lead to a declaration of a Low Reserve or Lack of Reserve condition (LRC, LOR1, LOR2 or LOR3) and a possible market intervention by AEMO.

Low Reserve and Lack of Reserve definitions are:

• =	LRC	- Reserve level is below the Short-term Capacity intervention trigger as defined by the Reliability Panel;
• =	LOR1	- Reserve level in a region is below the sum of the largest and second largest contingencies;
• =	LOR2	- Reserve in a region is below the largest contingency;
• =	LOR3	- Involuntary load shedding is required due to an actual or forecast supply shortage. Region Spot Price is set to $VoLL.

7.2.2.11 Dispatchable Generation

The total scheduled energy generation (in MW) from all dispatchable generating units belonging to a region for a particular trading interval.

7.2.2.12 Dispatchable Load

The total scheduled energy consumption (in MW) from all dispatchable loads belonging to a region for a particular trading interval.

7.2.2.13 Deficit/Surplus Generation

The total amount (in MW) of deficit generation (if negative) or surplus generation (if positive) in a region.

Surplus generation in a region is calculated as the amount by which the total scheduled generation supplied to a region exceeds the energy demanded by that region. If this amount is negative then the region is suffering deficit generation, where the total scheduled generation supplied falls short of the energy demanded in that region. Surplus generation may result from insufficient aggregate Energy Ramp Down Rate capability or load rejection reserve being held on dispatchable generating units to meet the falling Demand in the region.

7.2.2.14 Net Interchange

The total scheduled Interconnector energy flow exported out of a region over all interconnectors connected with that region for a particular trading interval

7.2.2.15 FCAS Dispatch

The total amount of FCAS response (in MW) scheduled to supply a region's FCAS Requirement, for each FCAS category.

7.2.2.16 FCAS Local Dispatch

The total amount of scheduled FCAS response (in MW) which is sourced locally to a region, for each FCAS category.

7.2.2.17 FCAS Requirement

As input to the SPD algorithm, the minimum amount of FCAS response (in MW) required by a region, for each FCAS category.

7.2.2.18 FCAS Local Requirement

As input to the SPD algorithm, the minimum amount of the total FCAS Requirement for a region which must be locally sourced from within that region, for each FCAS category.

7.2.2.19 FCAS Import

The net import (in MW) of scheduled FCAS support (positive = import, negative = export) with neighbouring regions, for each FCAS category.

7.2.2.20 FCAS Clearing Prices

The clearing prices (in $/MW) for meeting the FCAS Requirement in a particular trading interval, for each FCAS category. Note that these prices are indicative only and are not used in the settlement of Ancillary Services.

There are three types of FCAS Prices defined:

- = Requirement FCAS Price
- = Locally-supplied FCAS Price
- = Supply FCAS Price

7.2.2.21 Aggregate Dispatch Error

The value of Aggregate Dispatch Error which is applied in the adjustment of each region's Forecast Demand for the first trading interval only of each Pre-dispatch schedule.

7.2.2.22 Forecast Demand Change

The value of Demand Forecast Change which is applied in the adjustment of each region's Forecast Demand for the first trading interval only of each Pre-dispatch schedule.

7.2.3 Network data

The trading interval data in this Section is calculated by Pre-dispatch for each interconnector for each trading interval.

7.2.3.1 Interconnector Flow

The scheduled interconnector power transfer at the inter-regional boundary (in MW) out of the region defined as that interconnector's FromRegion.

Negative interconnector flow values refer to net power transfers into the defined FromRegion.

7.2.3.2 Interconnector Metered MW Flow

The value of Initial Interconnector Metered Flow (in MW) actually used by the SPD algorithm (refer Section 5.3.3.1) for calculations in the first trading interval of each Pre-dispatch schedule.

7.2.3.3 Interconnector Flow Limits

The Interconnector Export & Import power transfer limit for each interconnector.

For each interconnector, the net Interconnector power transfer (in MW) at the inter-regional boundary exported from the defined FromRegion. Positive values are exported from the FromRegion.

Equations describing constraint on interconnector Export and Import power transfer for each interconnector. Equation takes the form of a generic constraint, similar to intra-regional network constraints.

7.2.3.4 Interconnector Flow Limit Status

Whether or not interconnector power transfer limit is binding in the Pre-Dispatch solution.

7.2.3.5 Marginal Value

The marginal value (shadow price) of the interconnector (energy + FCAS support) flow limit (in \$/MW), which is non-zero if that limit has been reached and is binding. The non-zero value represents the net cost of exceeding the (energy + FCAS support) flow limit by 1 MW.

7.2.3.6 Violation Degree

The degree of violation (non-zero only if the constraint is violated)

7.2.3.7 Interconnector Flow Losses

The calculated value (in MW) of scheduled Interconnector Flow electrical losses.

7.2.3.8 Interconnector Flow Loss Factor

The marginal Loss Factor associated with the scheduled Interconnector Flow, as used in the Pre-dispatch solution to determine interconnector flow losses. Spot Prices calculated between regions connected by an interconnector with unconstrained flow are related via this Loss Factor.

7.2.3.9 Intra-regional Network Flow Limit

A listing of all intra-regional network constraints that have been invoked for the Pre-Dispatch solution.

7.2.3.10 Intra-regional Network Flow Limit Status

Whether or not the intra-regional network constraint invoked for a trading interval is binding in the Pre-Dispatch solution for that trading interval, for each intra-regional network constraint.

An intra-regional network limit is binding if the marginal value (shadow price, in $/MW) for the associated generic constraint is non-zero. Note that if the intra-regional network limit is relaxed in the Pre-dispatch solution in order to satisfy a conflicting higher priority constraint(s) then the violation degree (in MW) of its associated generic constraint is non-zero (representing the amount by which the limit is relaxed) and its marginal value will reflect the violation penalty price associated with the higher priority constraint(s).

APPENDIX 1

Table 1 - Explicit SPD Constraint Violation Types

	VIOLATION VARIABLES	SPD FORMULATION EQUATION	FROM MMS?	VIOLATION PENALTY DEFAULT	VIOLATION PENALTY WEIGHT	VIOLATION PENALTY PRICE $/MW
1.	*DeficitTraderRampRateNote 1*	*(8.1), (8.2), (8.4), (8.5)*	YES		120	600,000
2.	*SurplusTraderRampRate*Note2	*(8.1), (8.2), (8.4), (8.5)*	YES		120	600,000
3.	*DeficitTraderProfileMW*	*(9.1.1), (9.1.2), (9.3.1)*	NO	Internal only	80	400,000
4.	*SurplusTraderProfileMW*	*(9.1.2), (9.2.1), (9.3.1)*	NO	Internal only	80	400,000
5.	*DeficitTraderEnergyCapacity*	*(4.7.1), (4.7.2), (5.1.1.5)*	YES		70	350,000
6.	*DeficitTraderEnergy*Note3	*(11.1),* (11.3)	NO	Defaults to Trader Energy	70	350,000
7.	*DeficitTraderEnergy+5MinRaise CapacityNote 4*	*(5.1.1.5)*	NO	Defaults to Trader Energy	70	350,000
8.	*DeficitTraderOfferMW*	*(4.6.4), (4.6.5), (8.3), (8.6)*	NO	Defaults to Trader Energy Capacity	60	300,000
9.	*SurplusInterconnectorCapacity*	(4.2.3-1), (14.2.1-1)	YES		50	250,000
10.	*DeficitInterconnectorCapacity*	(4.2.3-2), (14.2.1-2)	YES		50	250,000

	VIOLATION VARIABLES	SPD FORMULATION EQUATION	FROM MMS?	VIOLATION PENALTY DEFAULT	VIOLATION PENALTY WEIGHT	VIOLATION PENALTY PRICE $/MW
11.	*DeficitTraderEnergy+6SRaise Capacity*	*(5.1.1.1)*	NO	Defaults to Trader Energy	50	250,000
12.	*DeficitTraderEnergy+60SRaise Capacity*	*(5.1.1.3)*	NO	Defaults to Trader Energy	50	250,000
13.	*DeficitTraderGovR6*	*(5.3.1-2)*	NO	Defaults to Trader Energy	50	250,000
14.	*DeficitTraderGovL6*	*(5.3.2-2)*	NO	Defaults to Trader Energy	50	250,000
15.	*DeficitTraderGovR60*	*(5.3.3-2)*	NO	Defaults to Trader Energy	50	250,000
16.	*DeficitTraderGovL60*	*(4.3.4-2)*	NO	Defaults to Trader Energy	50	250,000
17.	*DeficitRegionGen*	*(4.5.1)*	YES		30	150,000
18.	*SurplusGenericConstraint* *DeficitGenericConstraint*	*(4.6.1), (4.6.2)*	YES		20	100,000
19.	*SurplusRegionGen*	*(4.5.1)*	YES		10	50,000
20.	*LocDeficitRegionL6*	(6.1.2.1-1)	NO	Defaults to Deficit RegionL6	8	40,000
21.	*DeficitRegionL6*	(6.1.2.1-2)	YES		8	40,000
22.	*LocDeficitRegionL60*	(6.1.2.2-1)	NO	Defaults to Deficit RegionL60	7	35,000

	VIOLATION VARIABLES	SPD FORMULATION EQUATION	FROM MMS?	VIOLATION PENALTY DEFAULT	VIOLATION PENALTY WEIGHT	VIOLATION PENALTY PRICE $/MW
23.	*DeficitRegionL60*	(6.1.2.2-2)	YES		7	35,000
24.	*LocDeficitRegionL5*	(6.1.2.3-1)	NO	Defaults to Deficit RegionL5	6	30,000
25.	*DeficitRegionL5*	(6.1.2.3-2)	YES		6	30,000
26.	*LocDeficitR6*	(6.1.1.1-1)	NO	Defaults to Deficit RegionR6	5	25,000
27.	*DeficitRegionR6*	(6.1.1.1-2)	YES		5	25,000
28.	*LocDeficitRegionR60*	(6.1.1.2-1)	NO	Defaults to Deficit RegionR60	4	20,000
29.	*DeficitRegionR60*	(6.1.1.2-2)	YES		4	20,000
30.	*LocDeficitRegionR5*	(6.1.1.3-1)	NO	Defaults to Deficit RegionR5	3	15,000
31.	*DeficitRegionR5*	(6.1.1.3-2)	YES		3	15,000
32.	*EPFAnchor*		YES			10^{-4}
33.	*TBSlack1, TBSlack2*	(10.1)	YES			10^{-5}

TABLE 2 - Generic Constraint Violation Types

	CONSTRAINT VIOLATION TYPE	SOURCE	REQUIRED VIOLATION WEIGHT	VIOLATION PRICE $/MW	COMMENT
1.	Participant-entered Unit Fixed Loading	Bids	100	500,000	Constraint prefixed by $ Violation penalty is automatically assigned by the MMS
2.	AEMO-entered Unit Fixed Loading	POMMS Quick Constraint	90	450,000	Constraint prefixed by # Used on non-complying units
3.	AEMO-entered Unit Intervention constraint	POMMS Quick Constraint	90	450,000	
4.	AEMO-entered Unit Ancillary Service constraint	POMMS Quick Constraint	50	250,000	Same violation penalty as Unit FCAS violation
5.	Network limits: High priority	POMMS standard Generic Constraint	40	200,000	Constraint Naming prefix convention is used
6.	Network limits: Low priority	POMMS standard Generic Constraint	20	100,000	Constraint Naming prefix convention is used

Note 1
PDS divides DeficitTraderRampRate by 2. RTD divides it by 12
Note 2
PDS divides SurplusTraderRampRate by 2. RTD divides it by 12
Note 3
PDS multiplies DeficitEnergy by 2
Note 4
DeficitTraderEnergy+5MinRaiseCapacity is not a separate constraint violation in SPD