Constraint Formulation Guidelines

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Current version release details

Version	Effective date	Summary of changes
12	October 2023	Updated to new AEMO template, added 1 second FCAS services, included new terminology to meet the requirements of the National Electricity Amendment (Integrating energy storage systems into the NEM) Rule 2021 No. 13 (IESS Rule) which comes into effect on 3 June 2024, removed load relief values (moved to the Constraint Implementation Guidelines) and miscellaneous formatting fixes.

Note: There is a full version history at the end of this document.

1. Introduction

1.1. Purpose and scope

This is the Constraint Formulation Guidelines (CFG) made under National Electricity Rules (NER) 3.8.10(c) (Guidelines).

These Guidelines have effect only for the purposes set out in the NER. The NER and the National Electricity Law prevail over these Procedures to the extent of any inconsistency.

AEMO determines generation schedules and regional prices in the National Electricity Market (NEM) using a solver which finds the optimal solution to maximise the value of trade. The solution must satisfy linear constraint equations which are crafted to represent the physical restrictions necessary for secure and sustainable operation. This document sets out principles for translating these restrictions into (that is, formulating) constraint equations, grouped by type or purpose. It also covers the life cycle of constraint equations from business requirement identification through to notification of application in the operation of the NEM, and the process for applying and removing constraint equations from the dispatch process.

1.2. Definitions and interpretation

1.2.1. Glossary

Terms defined in the National Electricity Law and the NER have the same meanings in these Procedures unless otherwise specified in this clause.

Terms defined in the NER are intended to be identified in these Procedures by italicising them, but failure to italicise a defined term does not affect its meaning.

In addition, the words, phrases and abbreviations in the table below have the meanings set out opposite them when used in these Procedures.

Term	Definition
CIR	Congestion Information Resource – a consolidated source of information on AEMO's website relevant to the understanding and management of transmission network congestion.
Constraint equation	The mathematical representation that AEMO uses to manage power system limitations and FCAS requirements in NEMDE.
CVP factor	constraint violation penalty factor
DNSP	distribution network service provider
FCAS	frequency control ancillary service/s
LHS	Left Hand Side of a constraint equation. This consists of the variables that can be optimised by NEMDE. These terms include scheduled or semi-scheduled generators, scheduled loads, ancillary service loads, wholesale demand response units, bidirectional units, regulated Interconnectors, MNSPs or regional FCAS requirements.
Limit equation	A mathematical expression describing a limitation on a part of the transmission or distribution network. These are provided to AEMO by both TNSPs and DNSPs.
Mainland	The NEM regions: Queensland, New South Wales, Victoria and South Australia
MNSP	market network service provider

Term	Definition
MPC	Market Price Cap (previously called VoLL)
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
PASA	projected assessment of system adequacy
RHS	Right Hand Side of a constraint equation. The RHS is pre-calculated and presented to the solver as a constant; these terms cannot be optimised by NEMDE.
SCADA	Supervisory Control And Data Acquisition. Information such as line flows and generator outputs are delivered via SCADA.
System Normal	The configuration of the power system where: • All transmission elements are in service; or • The network is operating in its normal network configuration.
TNSP	transmission network service provider

1.2.2. Interpretation

These Procedures are subject to the principles of interpretation set out in Schedule 2 of the National Electricity Law.

1.3. Related documents

Title	Location
SO_OP3705 – Dispatch	https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3705---dispatch.pdf?la=en
Constraint Naming Guidelines	https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2016/constraint-naming-guidelines.pdf
Confidence Levels, Offsets & Operating Margins	https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2016/confidence_levels_offsets_and_operating_margins.pdf
Reliability Panel Frequency Operating Standards	https://www.aemc.gov.au/markets-reviews-advice/review-of-the-frequency-operating-standard
Market Managemenht System (MMS) Data Model	https://www.aemo.com.au/energy-systems/market-it-systems/nem-guides/wholesale-it-systems-software
Constraint Formulation Guidelines consultation	http://www.aemo.com.au/Consultations/National-Electricity-Market/Closed/Constraints-Formulation-Guidelines-Consultation

2. General principles of constraint equations

Constraint equation formulation is important to market participants such as generators and dispatchable loads because the formulation determines the influence or variation in output from that which might be expected from a consideration of offer prices alone.

When a generator is bound by a constraint equation to provide an output at a higher level, it is said to be constrained on and may be forced to generate energy at a power level which is more costly than the market return it receives for that energy. Conversely, when a generator is bound to reduce its output through the action of a constraint equation, it is said to be constrained off, and it may be unable to obtain a potentially high market return by increasing its energy production.

In some situations, generators and interconnectors can be in direct competition with each other to provide energy through a network constraint.

The constraint equation decides the optimal balance of supply from the various contributors, while providing a high degree of confidence that that the network limit is not violated.

2.1. Constraint Formulation Guidelines update process

The CFG are amended where necessary by AEMO in accordance with the Rules consultation procedures. Amendments may be required to address:

- The circumstances in which AEMO will use alternative network constraint formulations in dispatch (section 2.8);
- The process by which AEMO will identify or be advised of a requirement to create or modify a constraint equation, including the methodology to be used in determining network constraint equation terms and coefficients and the means by which AEMO will obtain and disseminate information to scheduled generators, semi-scheduled generators and market participants;
- The methodology for selecting the form of a network constraint equation, including the location of terms on each side of the equation;
- The process for implementing, invoking and revoking network constraint equations and the dissemination of information to scheduled generators, semi-scheduled generators and market participants (sections 8.1 and 3.3); and
- AEMO's policy in respect of the management of settlement residues by intervening in the central dispatch process and the process of that intervention.

AEMO will act on all reasonable requests to initiate a change to the CFG so that the amendment may be resolved by a final determination in accordance with those consultation procedures. If the proposed amendment is found to have merit through the consultation process then an amended version of these guidelines will be issued as part of that final determination.

2.2. Components of constraint equations

Constraint equations that are input into the market solver, the NEM Dispatch Engine (NEMDE), are formulated such that they can be separated into the following:

- Left Hand Side (LHS).
- Operator.
- Right Hand Side (RHS).

The LHS of constraint equations consists of controllable variables and their respective multiplying factors (or coefficients). Only linear combinations of the controllable variables are allowed, since NEMDE is based on linear programming optimisation. The controllable variables can contain a mixture of interconnector flow, market network service providers (MNSPs), scheduled/semi-scheduled generator output, scheduled loads, ancillary service loads, wholesale demand response units, bidirectional units, and regional frequency control ancillary services (FCAS). The multiplying factors may be either positive or negative values. These controllable variables are optimised by NEMDE.

The operator of constraint equations can be either “equal to” (=), “less than equal to” (≤) or “greater than equal to” (≥). It simply equates the LHS and RHS components. Typically network type constraint equations will have the “less than equal to” operator, while FCAS type constraint equations will have the “greater than equal to” operator.

The RHS of a constraint equation can be either a single value (static RHS) or a calculation based on multiple variables (dynamic RHS). The dynamic RHS can be made up of various inputs with either linear or non-linear calculations. The RHS can include any of the following variables:

- SCADA values.
- Current MW of scheduled, semi-scheduled generators, scheduled loads or bidirectional units.
- Estimated load reduction below a baseline load for wholesale demand response units.
- Region or sub-regional demand.
- Interconnector flow (regulated or MNSP).
- Transmission equipment rating.
- Generator or equipment status.
- Constant.

Before solving the dispatch run, NEMDE will calculate the RHS based on the current values of each of the terms.

2.3. Constraint sets

Constraint equations that apply under the same set of power system conditions – either for system normal or plant outage conditions – are grouped into constraint sets. Constraint sets contain one or more constraint equations and also include a description about the constraint set.

AEMO uses constraint sets to efficiently activate/deactivate constraint equations as described in section 8.1.

2.4. Types of power system limitations

Each constraint equation represents a particular type of power system limitation or requirement. Constraint equations can also exist for specific configurations of the power system, such as system normal or plant outages.

These power system limitations may include:

- Network:
  - Thermal – for managing the power flow on a transmission element so that it does not exceed a rating (either continuous or short-term) under normal conditions or following a credible contingency.

- Voltage stability – for managing transmission voltages so that they remain at acceptable levels after a credible contingency
- Transient stability – for managing network flows to ensure the continued synchronism of all generators on the power system following a credible contingency.
- Oscillatory stability – for managing network flows to ensure the damping of power system oscillations is adequate following a credible contingency.
- Network control schemes – the modelling of generator control schemes or reactive control devices on generator output.

- Frequency standards – maintain the frequency within the Reliability Panel standards by dispatching FCAS.
- Other (for more details see section 6):
  - Managing negative residues.
  - Rate of change (interconnector(s), generator(s)).
  - Non-conformance.
  - Network Support Agreement.
  - Unit zero.
  - Discretionary limit on individual or groups of scheduled/semi-scheduled generators, scheduled loads, ancillary service loads, wholesale demand response units, bidirectional units, MNSPs or interconnector(s).

2.5. How factors are determined

The coefficients for a constraint equation can be determined by several methods.

For constraint equations representing a flow across a network element (whether a single element or a group), the coefficients are determined by running a load flow application.

When coefficients are calculated for scheduled and semi-scheduled generators, scheduled loads, ancillary service loads, wholesale demand response units, bidirectional units, MNSPs and interconnectors, this is done relative to a single bus (known as a swing bus). In the NEM the swing bus is set to the regional reference node (RRN) where the network limitation exists, or for lines crossing regional boundaries it is the region on the sending end. Since the calculation is relative to the RRN any generators on that bus will have a coefficient of zero.

Interconnector coefficients are used to represent the overall contribution from the neighbouring region's generators. Where the neighbouring region's generators or interconnectors with remote regions have a larger contribution than the neighbouring region's interconnector, their coefficient reflects their contribution above the interconnector contribution. This most often occurs when neighbouring region generators and remote interconnectors are located electrically close to the boundary with the neighbouring region (for example, Murraylink and Southern Hydro generators can appear in constraint equations for limitations in southern New South Wales).

Coefficients can also be determined by running multiple studies for various power system conditions and then performing regression analysis. This is typically done by the transmission network service providers (TNSPs) for stability type limits, and when AEMO receives this limit advice due diligence is performed (see section 3.2).

If the constraint as provided by the TNSP is not oriented as per the Rules requirement 3.9.2 (d), AEMO re-orientates these constraints to ensure appropriate market pricing, provided that the re-oriented version is consistent with the technical envelope as defined by the original version.

In cases where the network service provider has determined the generating unit(s) at the RRN impact on the actual limit, these generating units may appear on the LHS of the constraint equation if power system studies indicate that it is necessary to ensure power system security.

Usage of each approach is covered in section 4.1.

2.6. LHS and RHS material considerations

2.6.1. LHS coefficients

There is a practical limitation to the size of the coefficients used on the LHS of a constraint equation. When the coefficient is small, there is a risk that NEMDE may choose to violate the constraint equation in preference to dispatching high priced offers. To avoid this, no LHS terms (whether scheduled, semi-scheduled generator(s), scheduled loads, wholesale demand response unit(s), bidirectional unit(s) or interconnectors) will have a coefficient less than 0.07[1].

The following procedure is applied to ensure no coefficients less than 0.07 are on the LHS:

- All constraint equations with LHS coefficients less than 0.07 are normalised (by multiplying both the LHS and RHS so the absolute value of the largest LHS coefficient is 1).
- Any remaining LHS terms with coefficients less than 0.07 are moved onto the RHS.

For FCAS constraint equations, all Region LHS coefficients are 1. Additionally, where there is a region FCAS LHS term for either Lower 5 minute or Raise 5 minute services, there will also be a Lower Regulation or Raise Regulation term with a matching factor (see section 5.4).

2.6.2. Restrictions on moving terms to the LHS

Normally, if a scheduled generating unit appears in a limit equation it would be moved to the LHS of the constraint equation. However, this can only occur if the scheduled or semi-scheduled entity has been defined as a dispatchable megawatt (MW) quantity with no other mathematical operations upon it (such as a square of the generation, a maximum of a group of generators or the online status of a generating unit).

Only in cases where AEMO has determined there is a power system security or market benefit would AEMO use various methods to move these generation terms to the LHS (as long as the coefficient on the generation term satisfies the size rule in section 2.6.1). These methods include linearizing the squared terms of the limit equation and moving each generator in a maximum calculation into a separate constraint equation.

Generating units are also not normally moved to the LHS of FCAS constraint equations; see section 5.9 for more information.

[1] See Constraints Formulation Guidelines – Final Determination for an explanation of how this factor is determined, at http://www.aemo.com.au/Consultations/National-Electricity-Market/Closed/Constraints-Formulation-Guidelines-Consultation.

2.6.3. RHS scaling factor thresholds

As described in section 2.6.1, constraint equations are scaled. AEMO has determined that the maximum allowable scaling factor to be applied is 30. Additionally, the actual scaling on an individual LHS term (that is, the scaling factor divided by the term's co-efficient) is to be limited to a maximum value of 200. This will avoid issues of forcing large ramping of LHS terms, such as inter-regional flows (up or down) to relieve the limit by a small amount.

2.7. Fully co-optimised formulation

As per NER clause 3.8.10 (b), AEMO uses the fully co-optimised constraint formulation to represent network constraint equations. This allows AEMO to control all the variables that can be determined through the central dispatch process.

Having more control variables on the LHS will allow NEMDE more flexibility, or degrees of freedom, to find the optimal solution. For a given constraint equation, increasing the number of LHS terms will increase the number of possible feasible solutions which satisfy the constraint equation. Therefore, NEMDE has more options to find the optimal solution by comparing the economic impact of these feasible solutions.

However, some variables, due to the small size of their coefficients, may be excepted where control of these variables would not be practical or enhance the security of the power system. These thresholds are discussed in section 2.6.

2.8. Alternative formulation

AEMO may use an alternative formulation in situations where the fully co-optimised constraint formulation does not provide appropriate control of the power system, as per NER 3.8.10 (e).

If AEMO determines that an alternative constraint formulation is required, the "Process for Developing Alternative Formulations" will be followed, as described in section 7.

The only alternative constraint formulations currently used by AEMO in its dispatch process are to represent Network Support Agreements, explained in section 6.2. TNSPs and distribution network service providers (DNSPs) may hold agreements with scheduled/semi-scheduled generators, scheduled loads, wholesale demand response units or bidirectional units to assist with system security and with managing constraint equations. Where applicable, AEMO will apply constraint equations to reflect the Network Support Agreement between the service providers and the generators, so that the market dispatch is consistent with operation under those agreements.

FCAS constraint equations are discussed in section 5, and other types of constraints are listed in section 6 of this document, in accordance with AEMO's disclosure requirement under NER clause 3.8.10 (c) (1).

2.9. Process to address concerns with constraint equations with small differences in the values of LHS coefficients

Any *NEM* Participant can raise concerns with AEMO about any constraint equations where it is felt that differences in the value of coefficients for LHS terms are so small that these differences are due more to measurement or other uncertainties in the development of these constraint equations than to actual differences in the network.

In such an application, the NEM Participant would have to:

- Identify the constraint equations of concern;
- Identify the coefficients within those constraint equations which are of concern ; and
- Provide prima -facie evidence as to why it believed the difference in these coefficients was not justified by the accuracy of their determination and that a benefit would arise from the removal of this difference.

AEMO, in response to such a request, would publish a report to the *NEM* that covers the following issues:

- Details of the request received;
- AEMO's assessment of the measurement errors of the coefficients of concern;
- A comparison between these assessed measurement errors and the current differences in the constraint equation values;
- A decision by AEMO as to whether or not the difference in these coefficients was justified by the accuracy of their determination, and if so, whether action is to be taken;
- If action is to be taken, an outline of the proposed changes to the constraint equations in question; and
- A request for comments within two weeks of date of publication.

AEMO would assess the comments received and then publish a final decision setting out:

- Whether or not a change will be made; and
- If a change is to be made:
  - Confirmed details for the change.
  - A timetable for the change to ensure at least 15 business days notice.

2.10. Constraint priority

2.10.1. Constraint violation penalty factors

The central dispatch algorithm uses a linear programming model to find the optimal dispatch solution, subject to a number of constraints. This optimal dispatch solution attempts to maximise the value of spot market trading, by minimising the total price of the dispatched resources while maintaining a secure operating system.

A dispatch solution will be feasible and secure only if all constraint equations are satisfied.

It may happen that a solution can only be obtained by violating a constraint equation(s). The solver decides which constraint equation(s) to violate, based on the constraint violation penalty (CVP) factor that is assigned to every type or class of constraint equation.

The CVP factor multiplied by the Market Price Cap (MPC) price represents the incremental cost (in $/megawatt hour (MWh)) imposed if the constraint equation is violated. Since NEMDE attempts to find the lowest cost solution, it will break the constraint equation with the lowest CVP factor first and add the cost of doing so to the overall cost of the solution.

Examples of constraint equation types include ramp rate, unit availability, FCAS requirements, and secure network limits.

CVP prices are assigned to each constraint equation type based on the following criteria:

- The higher the CVP price, the greater importance the solver associates with complying with the constraint equation.
- CVPs effectively assign an order of priority to violating constraint equations, with lower CVP constraint equations violated first to resolve dispatch conflicts.
- Sufficient grading exists between CVP prices of different constraint equation types (that is, step changes in CVPs should be sufficiently large) to ensure that the pre-defined priority order is maintained when determining the optimal dispatch solution.

For further information on constraint violation penalty factors, refer to the Schedule of Constraint Violation Penalty Factors[2] on AEMO's website.

As mentioned in the previous section, the overall cost of the solution increases when a constraint equation is violated in order to obtain a feasible dispatch solution. This increase is calculated as the product of the associated CVP, the MPC and the amount by which the constraint equation is violated.

Due to the constraint equation violation, the regional price calculated by NEMDE may be higher than the MPC. NEMDE will attempt to resolve the issue through a process known as the Automated Over-Constrained Dispatch re-run[3].

NEMDE will automatically relax the RHS of the violated constraint equation by the over-constrained amount plus 0.01 MW and re-run the solution. If the constraint equation is still violated to find a feasible solution, the RHS of the constraint equation is manually relaxed in increments of 0.01 MW until no violation occurs.

The resulting dispatch prices are published to the market.

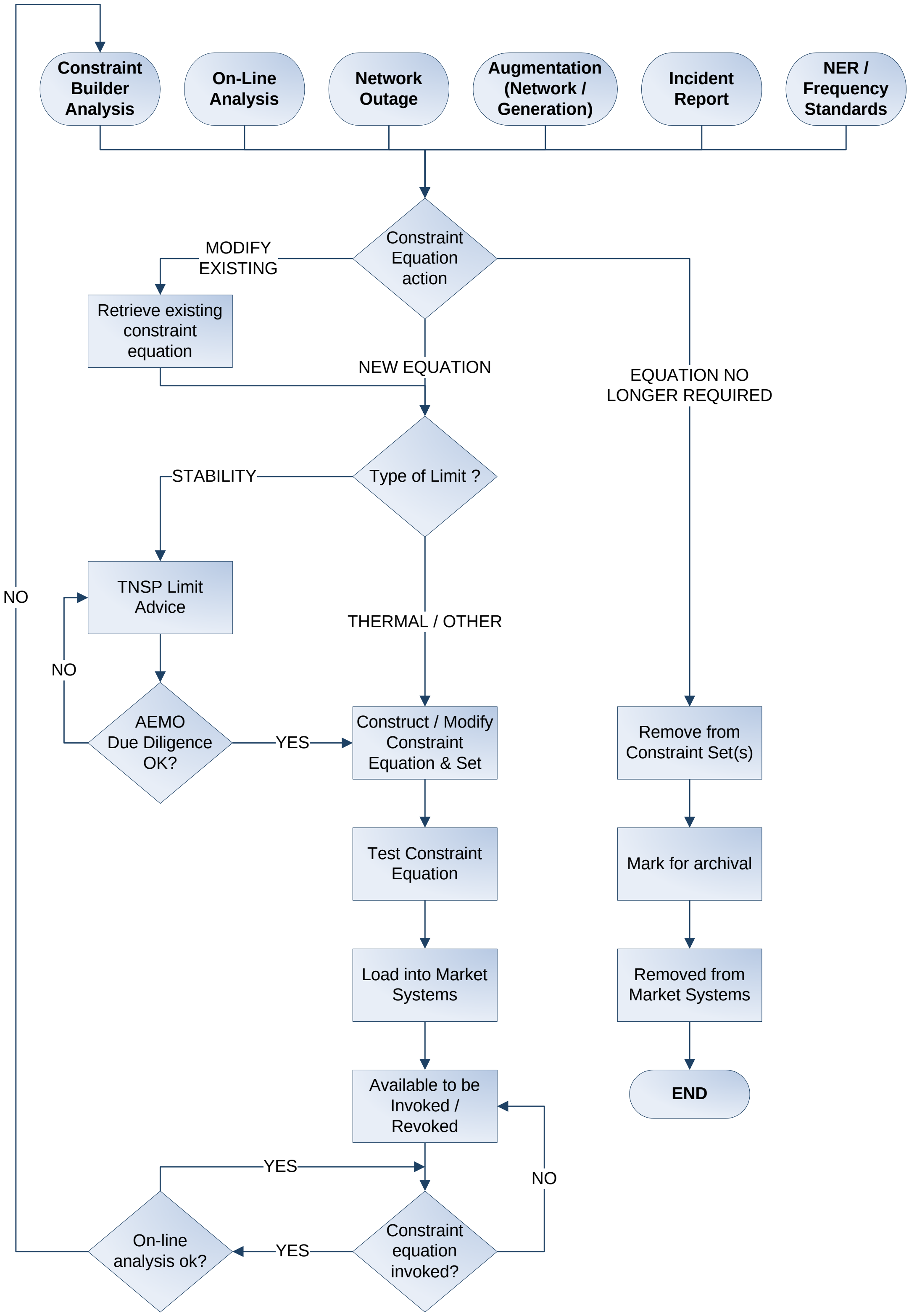
[2] At https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2016/schedule-of-constraint-violation-penalty-factors.pdf.

[3] https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2016/over-constrained-dispatch-rerun-process.pdf

3. Constraint equation lifecycle

3.1. Lifecycle from limits to constraint equations

Figure 1 Constraint equation lifecycle



3.2. How AEMO receives information

TNSPs are responsible for supplying AEMO with information on the limitations of their part of the transmission network. Similarly, DNSPs are responsible for the distribution network limitations. This information, or limit advice, can take the form of equations (known as limit equations), a transmission element rating, or a maximum flow on a group (or cut-set) of transmission elements. Limit advice is supplied for both system normal and outage of one or more transmission elements.

Limit advice is most often supplied when there are changes to the capability of the power system, such as new/retired generation, new/retired transmission, the addition of control schemes or for transmission / generation outages. AEMO continually monitors the performance of constraint equations as indicated in the constraint equation lifecycle flow diagram (Figure 1 above). AEMO may request updated limit advice from the TNSP if it believes an existing limit advice is no longer effective.

Upon receiving limit advice from TNSPs, AEMO performs due diligence (see Figure 1) to ensure the advice is reasonable and that the power system remains in a stable operation state following the credible contingency indicated in the limit advice. Due diligence is a check only and is not used to recalculate the limit.

TNSPs and DNSPs supply both limit equations and rating information to common mailboxes at AEMO.

AEMO receives information about scheduled and semi-scheduled generators, scheduled loads, ancillary service loads, wholesale demand response units and bidirectional units via the registration process (NER 2.2.1) and the generator performance standards (NER Schedule 5.2).

3.3. Publication of constraint information to participants

3.3.1. Constraint Library

The Constraint Library is published through AEMO's market systems via participant data feeds and the AEMO website. The data is consistent with the AEMO-supported Market Management System (MMS) Data Model.

The MMS Data Model is a logical data model provided and supported by AEMO for participants operating in the wholesale electricity market.

The constraint library contains information about all the constraint equations that are maintained by AEMO office staff. The key MMS data model tables that contain information about the library are listed below.

Table 1 Constraint Library in MMS data model

MMS data model table name	Content
SPDCONNECTIONPOINTCONSTRAINT	LHS terms for dispatchable units and loads (Connection Points)
SPDINTERCONNECTORCONSTRAINT	LHS terms for interconnectors and market network service providers
SPDREGIONCONSTRAINT	LHS terms for aggregated regional FCAS
GENCONDATA	Description of a constraint equation, Static RHS, mathematical operator
GENERICCONSTRAINTRHS	Constraint equation RHS terms

MMS data model table name	Content
GENERICEQUATIONDESC	Description of a Generic Equation
GENERICEQUATIONRHS	Generic Equation RHS terms
GENCONSETTRK	Description of a Constraint Set
GENCONSET	Links Constraint Equations to Constraint Sets
EMSMASTER	Links the ID used on the constraint equation RHS with a value in AEMO's EMS. Also includes a description of the ID.

3.3.2. Information on constraint equation results

Dispatch information on constraint equations is also available from AEMO's market systems. The key MMS data model tables that provide constraint results are listed below.

Table 2 Dispatch information in MMS data model

MMS data model table name	Content
DISPATCHCONSTRAINT	RHS value, marginal cost and violation degree
DISPATCH_CONSTRAINT_FCAS_OCD	Revised FCAS constraint marginal cost for OCD intervals
DISPATCHBLOCKEDCONSTRAINT	List of constraint equations blocked in a dispatch run
DISPATCHINTERCONNECTORRES	Import and Export limits for constraint equations
GENCONSETINVOKE	Period(s) when a constraint set is invoked

AEMO can remove, or block, constraint equation(s) that are part of a currently invoked constraint set, without removing the constraint equation(s) from the constraint set.

For further information on blocking constraint equation(s) refer to the Dispatch Operating Procedure (SO_OP3705) on AEMO's website.

3.3.3. Congestion Information Resource

AEMO is required to publish the Congestion Information Resource (CIR) as per NER 11.30.2 (Interim CIR) and 3.7A (First and subsequent CIRs). The CIR is available on the AEMO website and it includes the CFG. Other constraint-related information in the CIR includes reporting of interconnector quarterly performance and mis-pricing information of connection points in the NEM.

4. Network constraints

4.1. General formulation principles

Network constraint equations are used by AEMO to manage flows across one or more transmission elements (either transformers or transmission lines) by dispatching generation, loads or interconnectors in the energy market.

As described in section 3.2, TNSPs and DNSPs provide AEMO with limit equations and/or transmission element ratings. Where only thermal ratings have been supplied, AEMO will formulate a feedback constraint equation (see section 4.2).

For limit equations defined in terms of existing market quantities (such as interconnectors), AEMO will rearrange the LHS and RHS of these to comply with both the fully co-optimised formulation (see section 2.7) and LHS co-efficient (section 2.6) rules. Only those limit equation terms which are specified as dispatchable MW quantities can be moved onto the LHS (see section 2.6.2 on restrictions for moving terms to the LHS).

For limit equations defined for a cut-set which is not a market interconnector, AEMO will determine a translation into market quantities (one such method is using a feedback equation – see section 4.2) and then rearrange LHS and RHS quantities similarly to limit equations defined in terms of market quantities.

Constraint equations generally have an operating margin applied as per the Confidence Levels, Offsets & Operating Margins policy[4].

4.2. Feedback constraint equations

Feedback constraint equations allow the dispatchable units and interconnector(s) on the LHS to move by the MW available (or headroom) between the limit and the flow across the line or cut-set. These constraint equations rely on the use of actual measurements of the LHS variables and the line flow(s).

a x Generator 1

- b x Generator 2

+ c x Interconnector ≤

[Limit

– Flow across line(s)

] x Scaling

+ a x Generator 1 (current value)

- b x Generator 2 (current value)

+ c x Interconnector (current value)

The limit can be either a transmission element rating or the calculation of a stability limit.

5. FCAS constraints

AEMO uses constraint equations to procure FCAS to ensure that when an event occurs on the power system (such as loss of the largest generator or loss of an interconnector and subsequent islanding of a region), frequency is maintained within the frequency operating standards (FOS) as specified by the Reliability Panel.

Constraint equations specify the total FCAS enablement to be dispatched for each FCAS for one region or a group of regions. In this way, constraint equations can be formulated to represent the requirements for the whole NEM (global requirements) or for local requirements for one or more regions.

[4] https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2016/confidence_levels_offsets_and_operating_margins.pdf

FCAS requirements can be calculated using the contingency size, demands (in the form of load relief – see section 5.2) and inertia.

5.1. Types of FCAS

AEMO procures FCAS for each of the two Regulation and eight Contingency FCAS markets:

- Raise and Lower Regulation.
- Raise and Lower 5 minute.
- Raise and Lower 60 second.
- Raise and Lower 6 second.
- Raise and Lower 1 second[5].

5.2. Load relief

When there is an increase or decrease in frequency, there is a corresponding change in energy demand. This effect, called load relief, is an integral element of the Contingency FCAS constraint equations. The change in demand is always in a direction that tends to alleviate the frequency deviation; that is, for a reduction in frequency, the load relief is negative (decrease in demand), which tends to alleviate the falling frequency.

The load relief value can be different for the Mainland regions and Tasmania, and can change over time (due to the underlying load changes). It is normally measured as a change in demand for a y 1% change in frequency (0.5 hertz (Hz)).

5.3. General formulation

FCAS Requirement Region 1 (Service xx) + ... +

FCAS Requirement Region n (Service xx) ≥ RHS

where the Service is the same for all regions and is one of the 10 Raise or Lower services.

5.4. 5 minute services co-optimised with Regulation

The 5 minute and Regulation services are both delivered in the 5 minute timeframe, so the amount of Regulation enabled is subtracted from the 5 minute service that would otherwise be required.

This is implemented in the constraint equations by including the Regulation on the LHS.

FCAS Requirement Region(s) (Lower or Raise 5 min Service)

+ FCAS Requirement Region(s) (Lower or Raise Regulation Service) ≥ RHS

A number of the standards can be satisfied in 10 minutes instead of 5. In these cases, 2x the regulation is subtracted.

[5] The new market for the 1 second services will start in October 2023.

However, since NEMDE requires that the LHS factors in FCAS constraint equations are 1, these are implemented so that the first 5 minutes of dispatched regulation is on the LHS and the second 5 minutes is on the RHS as a constant term:

FCAS Requirement Region(s) (Lower or Raise 5 min Service)

+ FCAS Requirement Region(s) (Lower or Raise Regulation Service) ≥

RHS – Regulation Requirement in the 2nd 5 mins (Constant)

where the constant term is the current minimum regulation requirement for the region(s) on the LHS e.g. Mainland = 130 MW, Tasmania = 50 MW.

5.5. Risk of region(s) separating

Where there is a credible risk of separation between two regions (either from a plant outage or a reclassification of multiple line loss as a credible contingency), the interconnector flow that is at risk is co-optimised with the FCAS requirements.

Raise FCAS Requirement for Region(s) on one side of the interconnector at risk

- Interconnector at risk flow into those regions ≥

+ Load added to the regions on separation

- Load removed from the regions on separation

- Load relief from these regions

Lower FCAS Requirement for Region(s) on one side of the interconnector at risk

- Interconnector at risk flow out of those regions ≥

- Load added to the regions on separation

+ Load removed from the regions on separation

- Load relief from these regions

There are two constraint equations for each service. One constraint equation is for the region(s) on one side of the interconnector, the other for the regions on the other side. The load relief excludes the load that becomes physically disconnected, and includes load that becomes physically connected, post-separation.

5.6. Separation not aligned with a regional boundary

Separation points that do not align with the market defined regional boundary can leave scheduled or semi-scheduled generators, scheduled loads, ancillary service loads, wholesale demand response units or bidirectional units disconnected from the RRN of their parent region.

Since FCAS is dispatched on a regional basis, and there is no way to tell NEMDE these units are or will be electrically connected to a different region, the FCAS services for the generating unit(s) are set to zero. This prevents these units from contributing towards meeting the regional requirement.

FCAS Requirement Generator (Service) ≤ 0

5.7. Units disconnected due to loss of a transmission element

Similarly to section 5.6, if multiple generating units will be disconnected from the power system on a single contingent event, and their capacity exceeds the capacity of the single largest generating unit in the region or group of regions, those generating units at risk will be excluded from supplying FCAS.

This is done by either setting the contingency FCAS services to zero or removing the contribution of those units from the FCAS requirements for the contingency. The second method is used where AEMO has identified scenarios with multiple credible contingencies, where it is impractical or impossible to exclude all these units from providing FCAS.

This is not done for the loss of the largest unit, because it is not possible to apply this principle universally due to the aggregation of some units in the NEM into a single unit (for example, Gordon Power Station in Tasmania). Additionally, AEMO has determined that there is little power system security or market benefit considering the cost of general implementation.

5.8. Basslink

Unlike other interconnectors that are generally capable of transferring FCAS under all conditions, Basslink is prevented by its control system from transfer of FCAS services beyond its upper and lower transfer limits. This requires the headroom between Basslink flow and Basslink limit (that is, the amount of megawatts that Basslink can contribute in a frequency event) to be considered when formulating FCAS constraint equations.

Additionally, Basslink has a No-Go zone between approximately -50 MW and +50 MW and is deemed to be unable to transfer FCAS services while flow is within this range.

Therefore, Basslink is considered to be unresponsive to frequency if any of the following are met:

- The Basslink dispatch target from the previous dispatch run is at the boundary or within the No-Go zone.
- The Basslink frequency controller is not operational.
- The Basslink measured power flow at the start of the dispatch interval is within the range ±50 MW.
- The Basslink measured power flow is equal to or greater than the bid availability.

To allow for cases when Basslink is unable or restricted in the amount of FCAS it can transfer for *NEM* regulation and global contingency events, five groups of constraint equations exist:

- Global requirements – when Basslink is unconstrained for FCAS.
- Local requirements for the Mainland regions – when Basslink is in the No-Go zone:

Raise FCAS Requirement for Mainland Regions ≥

Size of Generator Event on Mainland regions

- Load Relief from Mainland regions

- Local requirements for Tasmania – when Basslink is in the No-Go zone:

  Lower FCAS Requirement in Tasmania ≥

  EMS Calc for Tasmanian Load Event

- Basslink flow co-optimised with Mainland local requirements – when Basslink is able to transfer FCAS but is limited by its transfer limits or the no-go zone:

  Raise FCAS Requirement for Mainland Regions

  – Basslink flow ≥

  Size of Generator Event on Mainland regions

  - Load Relief from Mainland regions

  + 50 (if Basslink < -50)

  - Basslink Max Bid Availability (Tasmania to Victoria) (if Basslink > 50)

- Basslink flow co-optimised with Tasmanian local requirements – when Basslink is able to transfer FCAS but is limited by its transfer limits or the no-go zone:

  Lower FCAS Requirement in Tasmania

  - Basslink flow ≥

  EMS Calc for Tasmanian Load Event

  + 50 (if Basslink < -50)

  - Basslink Max Bid Availability (Tasmania to Victoria) (if Basslink > 50)

Similarly, for local contingency events there are three groups of constraint equations:

- Global requirements.
- Local requirements – when Basslink is in the No-Go zone.
- Basslink flow co-optimised with local requirements – when Basslink is able to transfer FCAS but is limited by its transfer limits or the No-Go zone.

5.9. Moving generating units at risk to the LHS

Normally, the critical generating unit with the largest power output will not be moved to the LHS of FCAS constraint equations. It is impractical (or impossible in Tasmania with the three Gordon units aggregated) to do this, and there is little market benefit in terms of improved optimisation of FCAS dispatch with energy dispatch.

However, for network contingency situations where there is a large amount of generation at risk (> 1.5x largest regional generating unit), AEMO will determine, on a case by case basis, whether moving generating units at risk to the LHS is appropriate, taking into account considerations such as the risk of power system security violations due to the FCAS requirement exceeding the FCAS availability.

For example, consider the case of a 400 MW power station of three units with one double-circuit connection to the transmission system, in a region where the FCAS raise requirement is typically 130 MW, and the maximum FCAS raise service available in the region is 250 MW. When the double-circuit connection is reclassified as a credible contingency, or one circuit is out of service on a prior outage, system security requires that the generation from the power station must be limited to no more than 250 MW (ignoring load relief, inertia and demand effects for simplicity). If the power station were dispatched above 250 MW, there would be insufficient raise FCAS to cover the generation lost through the credible contingency. This situation is best managed dynamically by moving the generation risk to the LHS of the relevant FCAS raise constraint equations, so the power station generation can be co-optimised with the raise FCAS capability. This avoids introducing and continually updating discretionary constraints to limit the power station generation.

6. Other types of constraint equations

6.1. Non-conformance

Non-conformance is a condition where a dispatched unit (a scheduled generating unit, constrained off semi-scheduled generator, scheduled network service or scheduled load) fails to follow a dispatch target.

AEMO applies a non-conformance constraint equation when a defined threshold is exceeded (refer to Dispatch Operating Procedure (SO_OP3705) on AEMO's website for more information). The RHS of the non-conformance constraint equation is set to the last telemetered value of generation, consumption or transfer, that is, the initial value for the new dispatch interval. The non-conformance constraint equation will remain in place until the participant advises AEMO that they are capable of following dispatch instructions.

Non-conformance constraint equations operate to ensure that dispatch of all other scheduled units is consistent with the operation of scheduled and semi-scheduled generators that are temporarily unable to follow dispatch instructions. The general form is:

Generator target = last telemetered value

Non-conformance constraints are not classified as network constraint equations.

6.2. Network Support Agreements

TNSPs and DNSPs may hold agreements with generating units to assist with system security and to help manage contingencies and binding constraint equations, as an alternative to network augmentation.

The TNSP or DNSP registers the generating unit with AEMO and specifies that the generating unit may be periodically used to provide a network support function and will not be eligible to set spot prices when constrained on. Where applicable, AEMO will apply constraint equations to reflect the relevant Network Support Agreement .

Network support constraint equations operate to control network flows of the transmission elements using the generating units identified in the respective agreements. The general form is:

Generator target ≥ Generator initial value + network flow – network limit

There is no co-optimisation of these network equations, because they apply only to the generators subject to the agreement. Accordingly, the resulting equations are classed as an alternative formulation.

6.3. Unit Zero constraints

Unit Zero constraint equations are applied when scheduled or semi-scheduled generators, scheduled loads, ancillary service loads, wholesale demand response units or bidirectional units are unable to generate, but are not bid in as unavailable. This may be the case when a generating unit is connected to a transmission element or group of transmission elements that are removed from service. For performance reasons, NEM Participants may choose not to bid the unit as unavailable for dispatch, since it is technically able to generate.

AEMO enters a constraint equation into NEMDE to constrain this generator to zero for dispatch purposes.

Unit zero constraint equations are also applied when a generating unit has tripped and the offers are not updated. The general form is:

Generator output ≤ 0

Bidirectional units can have both positive and negative flows so two constraint equations are required:

Generator output ≤ 0

Generator output ≥ 0

Unit Zero constraints are not classified as network constraint equations.

7. Process for developing alternative formulations

If AEMO determines that an alternative formulation is required, AEMO will publish a report that details the following:

- The problem and reasons why the fully co-optimised formulation cannot be used; and
- Details of the new constraint equation(s).

Once the above is completed and the constraint equation(s) implemented, AEMO will consult on the addition to the CFG, as outlined in section 2.1.

8. Application of constraints

8.1. Process of invoking and revoking constraints

The process of invoking (or activating) and revoking (or deactivating) is not done on individual constraint equations but is instead done via constraint sets.

Constraint sets are invoked to represent the current or future configuration of the power system in NEMDE. This can include no outages (or system normal), one or multiple transmission elements out of service, reclassification of loss of multiple transmission elements as a credible contingency, and separation of two regions.

System normal constraint sets are, in general, invoked all the time unless a transmission element outage increases a power system limit.

8.2. Ramping of network constraints

AEMO applies ramping constraint equations to avoid large shifts in power flows and potential price spikes. Two constraint equations for each limit are created – a hard and a soft ramping constraint equation.

The soft and hard constraint equations will have the same LHS formulation and ramp to the same final RHS value. As such, if the original constraint equation is of an alternative formulation, then the ramping constraint equations will also be an alternative formulation. The final RHS value is derived from the pre-dispatch RHS value. The soft constraint equation will ramp faster than the hard constraint equation so it can achieve the final RHS value in fewer dispatch intervals.

Consequently, the soft constraint equation has a small CVP which is determined by the marginal value of its outage constraint equation in pre-dispatch. The CVP for a hard constraint equation will be set as the same for a normal network constraint equation.

8.3. Use of discretionary and quick constraints

It is not practical for AEMO to maintain a library of constraint sets and constraint equations for every possible permutation of power system configurations (although it endeavours where possible to create them for planned outages). Instead, AEMO has created a library of simple constraint equations and sets for limiting groups of generating units and/or interconnectors to predefined values (known as discretionary constraints). Additionally, there is an application available to AEMO’s control room staff to quickly create and invoke custom constraint equations (quick constraints).

These discretionary and quick constraint equations can be used to maintain power system security in cases where there are no existing constraint equations, where AEMO’s Constraint Automation cannot create the required constraint equations, or where the existing ones are not working correctly.

Appendix A. Rule reference to CFG section

Table 3 Rule Reference to CFG Section

Rule Ref	Description	CFG Section #
3.8.10(b)	Obligation to use fully co-optimised network constraint formulation	2.7
3.8.10(c)(1)	Circumstances in which alternative network constraint formulations will be used in dispatch	2.8
3.8.10(c)(2)	Process to identify requirement to create or modify a network constraint equation	3.1, 3.2
3.8.10(c)(2)(i)	Methodology for determining terms and coefficients	2.5, 2.6, 3.2
3.8.10(c)(2)(ii)	Means of obtaining from and disseminating to Participants information	3.2, 3.3
3.8.10(c)(3)	Methodology in selecting the form of equation (including location of terms on each side of equation)	2.6, 2.7
3.8.10(c)(4)	Process for implementing, invoking and revoking equations including choice of alternative vs fully co-optimised formulations and dissemination of information in respect of this process	7, 8.1
3.8.10(c)(5)	Policy in respect of negative settlement residue constraint management	System Operations Operating Procedure 3705
3.8.10(e)(1)	Identification of types of network constraints for which AEMO may use an alternative formulation	2.8
3.8.10(f)	Represent constraints in a form that can be reviewed after the trading interval	3.3

Version release history

Version	Effective date	Summary of changes
11	24 October 2021	Updated to latest AEMO template, corrected URLs and formatting adjustments. Added Wholesale Demand Response units.
10.1	5 December 2013	Republication of version 10, with hyperlinks and AEMO responsible department updated.
10	6 July 2010	Added AEMO disclaimer, fixes to several section references which appeared as 0.
9	12 May 2010	Complete revision to align with the Congestion Management Review NER changes, renamed document from Constraint Formulation Policy to Constraint Formulation Guidelines to align with NER, revisions based on CFG consultation.
8	1 July 2005	Correct a typographical error in Section 3.
7	29 June 2005	Included additional details to clarify certain issues in response to feedback from Participants.
6	24 June 2005	First version issued publicly.