Appendix 2. Indicator definitions and methodology

June 2024

Appendix to the 2024 Enhanced Locational Information Report

Important notice

Purpose

This report has been published to implement the Energy Security Board (ESB) 'enhanced information' transmission access reforms. The report is intended to support more informed investment and decision-making processes in the National Electricity Market, by collating public metrics and indicators that represent important locational characteristics of the power system. This report includes only publicly available information from existing AEMO, industry, and stakeholder publications.

AEMO publishes this *Enhanced Locational Information (ELI) Report* pursuant to its functions in section 49(2)(c) of the National Electricity Law. This publication is generally based on information available to AEMO as at 30 April 2024, unless otherwise indicated.

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AEMO has made reasonable efforts to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances.

Modelling work performed as part of preparing this publication inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material.

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Version control

Version	Release date	Changes
1.0	07/06/2024	Initial release.

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Contents

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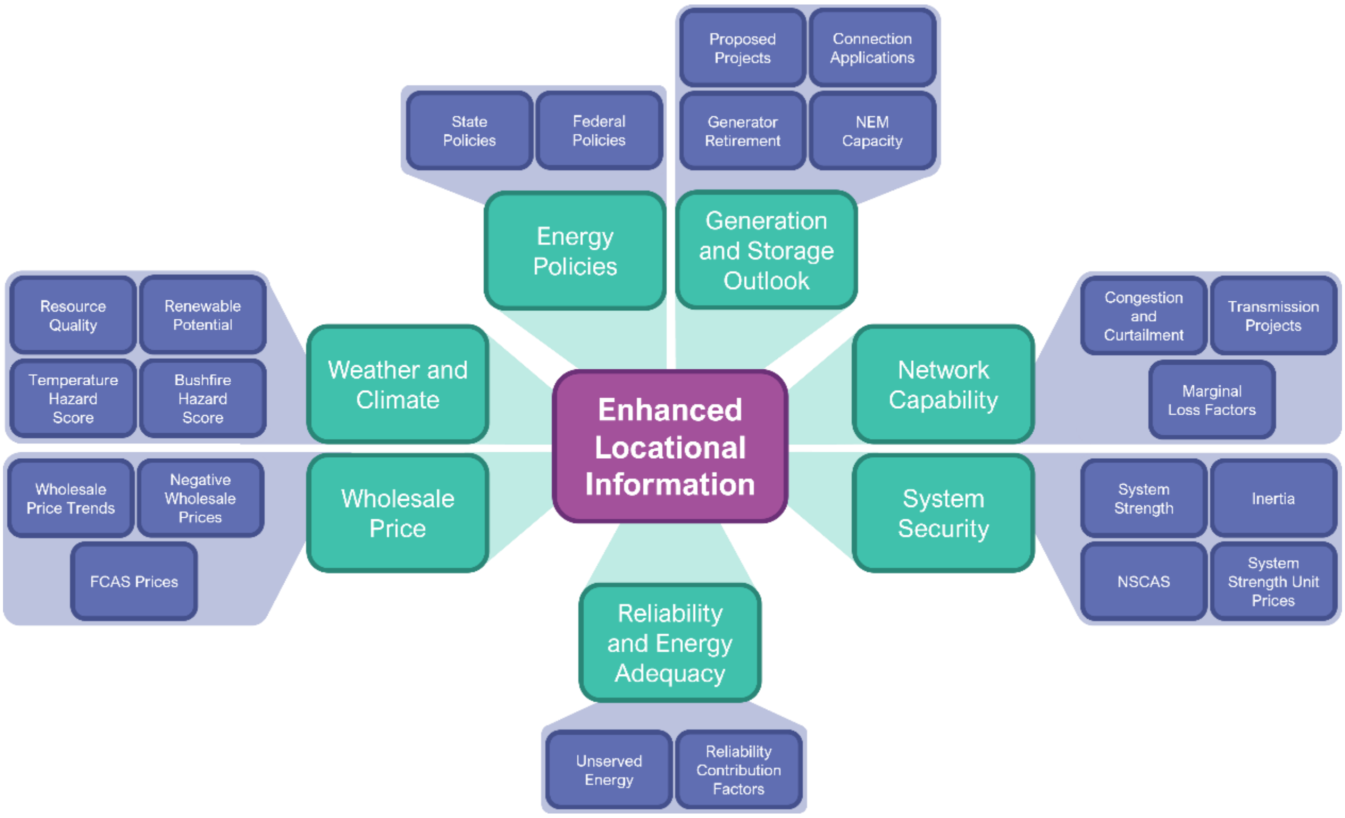
A2.1 Scope of content

The 2024 ELI Report draws together a wide range of publicly available information on the power system[1], and overlays these indicators geographically to extract insights that may be relevant to informing better regulatory or investment decisions.

Figure 1 provides an overview of the categories and types of information considered in this report; further details on the associated inputs, assumptions, and data sources are presented in Appendix A1 and Appendix A2.

Figure 1 Overview of indicator types considered in the 2024 ELI Report



A2.1.1 Energy policies and commitments

State and federal governments are united in their efforts to decarbonise Australia, and most have committed to strong transition targets in recent years. These policies will shape the energy landscape and are an important consideration for new generation and storage projects.

Policy settings can change over time, and those included in the 2024 ELI Report are as they were understood on 1 April 2024.

[1] The 2024 ELI Report does not include data related to the sub-transmission or distribution networks.

A2.1.2 Network capability

Network capability indicators reflect the characteristics and limitations of the physical transmission network, which can directly impact on a proponent's ability to deliver energy to the system, and to access regional spot markets at times of attractive prices. They may also indicate opportunities for local firming or storage technologies able to time-shift excess energy to periods of higher network availability. These factors vary strongly by location, time of day, and surrounding system conditions. The 2024 ELI Report considers the following network indicators:

- **Network congestion** – AEMO uses constraint equations to mathematically model the physical limitations of the power system. The number of hours during which a particular constraint was binding and the marginal cost associated with the constraint are both used as indications of its severity and impact on nearby power flows.
- **Historical curtailment** – generator *curtailment* refers to any physical limitation that prevents available energy being delivered from a generator, other than for economic reasons. See Section A2.3 for more information.
- **Forecast curtailment** – this is an output of the Draft 2024 ISP modelling which considered both *economic spill* (where generators reduce output due to low market prices) and *transmission curtailment* (where generation is constrained down due to physical or operational limits).
- **Network augmentations** – this represents the timing and impact of network projects, based on stakeholder advice published on the Transmission Augmentation Information Page[2], coupled with outcomes from the Draft 2024 ISP. Projects are categorised as *committed and anticipated* when they are approved or underway, *actionable ISP projects* when the ISP indicates that work should continue or commence urgently, and *future ISP projects* when they are expected to become actionable over time.
- **Marginal loss factors (MLFs)** – the electrical resistance of conductors causes a percentage of the power flowing along them to be lost before it reaches a load. AEMO publishes MLFs annually to represent these losses as a scaling factor applied to generation or consumption at each network location[3]. The wholesale spot price seen by a generator at a particular location is the product of the MLF and the regional spot price.

A2.1.3 System security

System security needs reflect that a stable system requires more than a matched level of supply and demand. To ensure the system remains stable and secure, AEMO may act when required to ensure specific generators are in service, reduce the output of specific generators, or limit network transfers. This presents both a risk and an opportunity for proponents as existing sources of these services withdraw, and new providers are sought.

The 2024 ELI Report considers the locational requirements, availability, and emerging security shortfalls for system strength, inertia, and any network support and control ancillary services (NSCAS). Together these requirements ensure that all network protection and voltage control systems operate correctly, connected plant remain stable, the system can resist changes in frequency following a disturbance, and all power system safety and security standards are met.

[2] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

[3] AEMO, *Marginal Loss Factors: Financial Year 2024-25*, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/loss_factors_and_regional_boundaries/2024-25-financial-year/mlfs-for-the-2024-25-financial-year.pdf?la=en.

A2.1.4 Reliability and energy adequacy

Reliability is a measure of the sufficiency of installed capacity to meet demand. A reliability shortfall occurs when the expected volume of unmet demand exceeds an annual threshold value[4]. The emergence of these shortfalls provides an indication of regions where supply scarcity may present an opportunity to invest.

While the ESOO presents AEMO's comprehensive projection of reliability, the 2024 ELI Report considers key indicators relating to demand, unserved energy, and locational reliability contribution factors indicating the projected effectiveness of new supplies to reduce unserved energy.

A2.1.5 Wholesale price indicators

Trends in wholesale energy and frequency control spot prices are likely to be significant considerations for proponent investment decisions. Proponents are likely to consider the generator curtailment and marginal loss factor metrics discussed earlier when considering potential sources and limits to revenue sufficiency in particular locations.

While AEMO's *Quarterly Energy Dynamics* report provides a deeper dive on pricing and market trends, the 2024 ELI Report extracts key high-level outcomes in average regional spot prices, and the growing prevalence of negative price periods in some regions.

A2.1.6 Generation and storage outlook

The Draft 2024 ISP forecasts that, by 2034-35, the NEM will need approximately 82 GW of utility-scale wind and solar, and 126 GW by 2049-50. Understanding where and when these capacity changes are forecast to occur, and the nature of potential competing or complementary projects, is an important consideration for choosing an optimal investment location or optimising other system services and network augmentations to deliver maximum benefits.

AEMO's ISP explores the nature, timing, and optimal development of the transmission system over the coming decades. The 2024 ELI Report leverages this work, and its associated inputs, to present locational indications of:

- The size and nature of existing, committed, and anticipated generation projects.
- The expected withdrawal timeline and impacts of existing generation closure.
- The long-term modelled outlook of generation and storage capacity in the NEM.

A2.1.7 Weather and climate

Renewable resource quality and other weather variables are key inputs into estimating likely generation availability for solar and wind generators. AEMO publishes this data as part of its *Inputs, Assumptions and Scenarios Report* (IASR), based on analysis of wind speed, solar irradiance, temperature, and historical generation and weather measurements. Availability of water has not been included in this report.

[4] The application of the interim reliability measure (specified in clause 3.9.3C(a1) of the NER to be 0.0006%) was extended to 30 June 2028 on 21 September 2023, in accordance with clause 11.132.2 of the National Electricity Rules. The reliability standard (specified in clause 3.9.3C(a) to be 0.002%) applies beyond this date.

A2.2 ELI scorecard criteria

The scorecards presented in the regional appendices (Appendix A3 to A7) summarise the key locational characteristics of each REZ. The following table explains the criteria presented in those scorecards.

<table>
<tr><th colspan="7">ELI report card details</th></tr>
<tr><td rowspan="3">REZ map</td><td colspan="6">Indicative generation is shown based on 22 December 2023 NEM generation maps[5]. Dark blue and purple icons correspond to existing and future generation, respectively. Future generation refers to generation in the application, pre-registration, or registration stages. Existing generation refers to generation in the commissioning or operational stages.</td></tr>
<tr><td>Wind</td><td>Solar</td><td>Hydro</td><td>Gas/Diesel</td><td>Coal</td><td>BESS</td></tr>
<tr><td colspan="6">The purple shading shows the indicative geographic area of onshore and offshore REZs. Network projects shown align with the Draft 2024 ISP optimal development path. Committed and anticipated projects are shown in grey, and actionable projects are shown in teal. The in-service timing of projects (advised by the proponents) are shown in brackets. Existing transmission infrastructure is coloured according to voltage level.</td></tr>
<tr><td>Network Transfer Capability</td><td colspan="6">Electricity networks have physical limits on their ability to transfer energy. Transfer capability across the transmission network is determined by assessments of thermal capacity, voltage stability, transient stability, oscillatory stability, and power system security/system strength. Transfer capability varies throughout the day with generation dispatch, load, weather conditions, and other factors also play a part.

REZ transmission limits represent the maximum generation that can be dispatched at any point in time within a REZ, reflecting the transfer capability of the shared transmission network, and taking into account any local load. For more information, refer to Section 2.3.4 of the ISP Methodology[6]. Transmission limits are also modelled along flow paths between sub-regions which can have implications for the REZ transmission limit, as flows along the flow path from generation outside the REZ compete with generation within the REZ. For more information on the ISP sub-regions, refer to Section 3.10 of the 2023 Inputs, Assumptions and Scenarios Report[7].</td></tr>
<tr><td>Generation Hosting capacity or access rights</td><td colspan="6">Hosting capacity reflects how much generation capacity can connect to the network without experiencing significant reductions in available energy generation due to technical limitations of the network. Total hosting capacity includes existing and new capacity. Spare hosting capacity is the available capacity for new generation to connect. This is equal to total hosting capacity less existing generation capacity.

Network transfer capability is typically one of the inputs considered when calculating hosting capacity. Refer to Section A2.4 for further detail on hosting capacity calculation.</td></tr>
<tr><td colspan="7">Resource metrics</td></tr>
<tr><td rowspan="6">Resource quality</td><td colspan="6">Resource quality for solar is the average capacity factor based on 11 reference years:</td></tr>
<tr><td>≥30%</td><td>≥28%</td><td>≥26%</td><td>≥24%</td><td>≥22%</td><td><22%</td></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D</td><td>E</td><td>F</td></tr>
<tr><td colspan="6">Resource quality for wind is the average capacity factor based on 11 reference years:</td></tr>
<tr><td>≥45%</td><td>≥40%</td><td>≥35%</td><td>≥30%</td><td colspan="2"><30%</td></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D</td><td colspan="2">E</td></tr>
<tr><td>Renewable potential</td><td colspan="6">Renewable potential outlines possible REZ size in MW based on the geographical size and resource quality in the REZ. Resource limits were derived by AEMO based on 2018 DNV-GL report, ISP workshops, consultation with TNSPs and jurisdictions, and written feedback to the 2018 ISP, 2022 ISP and Draft 2023 IASR.</td></tr>
</table>

[5] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/nem-generation-maps.

[6] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

[7] At https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf?la=en.

Climate hazard		
Temperature score	The REZ temperature score is based on the projected once in 10-year maximum temperatures for the years 2030 and 2050[8]. Temperature scores for offshore REZs consider the area on land that is expected to connect.	
	Score	**Description**
	A	Between 28°C and 38°C
	B	Between 30°C and 44°C
	C	Between 32°C and 48°C
	D	Between 34°C and 50°C
	E	Between 44°C and 52°C
Bushfire score	The REZ bushfire score is based on the projection of annual average FFDI "high" fire danger days around the years 2030 and 2050 and the probability of large bushfires occurring (a dominant input). Bushfire scores for offshore REZs consider the area on land that is expected to connect[9].	
	Score	**Description**
	A	Model projections associate less than half the days of a year with high fire danger days and a probability of zero large fires in 20 years.
	B	Model projections associate less than half the days of a year with high fire danger days and a probability of one large fire in 20 years.
	C	Model projections associate more than half the days of a year with high fire danger days and a probability of one large fire in 20 years.
	D	Model projections associate more than half the days of a year with high fire danger days and a probability of between one and four large fires in 20 years.
	E	Model projections associate more than half the days of a year with high fire danger days and a probability of one large fire in three years.
Marginal Loss Factors		
Marginal Loss Factor	The financial year 2024-25 NEM intra-regional loss factors, commonly referred to as marginal loss factors (MLFs)[10]. The MLFs for operational VRE generators within each REZ are given, according to voltage and technology type. Where there are multiple generators of the same voltage and technology type, the MLF is given as a range to encompass all relevant generators.	
Congestion and curtailment		
Congestion information	Refer to Section A2.3.3**Error! Reference source not found.**.	
Historical VRE curtailment	Refer to Section A2.3.1. Generators are considered within each REZ per the ISP mapping for modelling[11].	
VRE curtailment and economic offloading - ISP forecast	Curtailment happens when VRE generation reduces output due to transmission network congestion. Economic offloading happens when VRE generation is dispatched below its maximum availability due to market prices. Both are represented as a percentage of VRE. The VRE curtailment and economic offloading was calculated based on the Draft 2024 ISP DLT zonal network model representation and rounded to nearest 1%.	

[8] This data was provided by the Commonwealth Scientific and Industrial Research Organisation (CSIRO) for 2030 and 2050.

[9] A "high" fire danger day is defined as any day where the Forest Fire Danger Index (FFDI) is greater than 12.

[10] MLFs from https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/loss_factors_and_regional_boundaries/2024-25-financial-year/mlfs-for-the-2024-25-financial-year.pdf?la=en.

[11] See AEMO, 2023 *IASR Assumptions Workbook*, September 2023, *Summary Mapping* tab, at https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-iasr-assumptions-workbook.xlsx?la=en.

ISP forecast	
Scenario	The Draft 2024 ISP involves long-term market simulations of different scenarios. *Step Change* is the ISP's most likely scenario, and is used for the ELI report.
Existing, committed, and anticipated generation	The existing, committed and anticipated generation as of 21/11/2023, based on the October 2023 Generation information page published by AEMO, consistent with the Draft 2024 ISP. This metric includes some data not used as an input to ISP modelling.
Projected variable generation	Long-term market simulations of projected variable energy outlook for utility-scale solar and wind generation at different times intervals across all scenarios. All VRE projections are based on the optimal development path and is in addition to existing, committed and anticipated generation. All values are rounded to the nearest 50 MW.
Transmission limit	The limit represents the network limit for the total VRE within a REZ. REZ expansion options are generally linearised, that is, they are not discrete options[12].
Anticipated and Actionable Transmission Projects	Relevant committed and anticipated projects, or actionable ISP projects, as according to Appendix A5. Network Investments of the Draft 2024 ISP[13]. The timings given are the in-service dates, as informed by the relevant proponents.

[12] See Section 2.4.6 of the ISP Methodology, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

[13] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2024-isp-consultation/appendices/a5-network-investments.pdf?la=en.

A2.3 Curtailment and congestion methodology

A2.3.1 Historical curtailment methodology

For historical curtailment data, this report uses the term "curtailment" in the same sense it is used in AEMO's *Quarterly Energy Dynamics* reports[14]. In this context, curtailment refers to any limitation on the output of a generator other than due to "economic offloading".

Economic offloading refers to a generator being dispatched below its maximum availability, because some or all of its output was bid into price bands greater than the regional reference price, that is, it was undercut by competitors offering their output at a lower price.

Curtailment therefore refers to energy from a generator not being dispatched, even though it was bid at or below the regional reference price, because of some other limitation (for example a network constraint).

Definitions and calculation methods are recorded in Table 1 below.

Table 1 Definitions of terms relevant to generator curtailment

Term	Definition	Calculation method
[Economic offloading + curtailment]	The difference between generator availability and total cleared dispatch	Calculated from market data[A] for each dispatch interval in calendar year 2023, for each generator dispatchable unit identifier (DUID), specifically: 1. Generator maximum availability[B]. 2. Generator total cleared dispatch.
Economic offloading	The generator availability in bid price bands above the regional reference price adjusted for MLF	Calculated from market data[A] for each dispatch interval in calendar year 2023, for each generator DUID, specifically: 1. Generator maximum availability. 2. Generator total cleared dispatch. 3. Generator bid price and availability bands. 4. Regional reference price. 5. Generator MLF.
Curtailment	The remainder after economic offloading is subtracted from [Economic offloading + Curtailment]	Arithmetic calculation: Curtailment = [Economic offloading + Curtailment] – Economic offloading

A. At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/market-data-nemweb.

B. This is read from the 'Availability' field in the 'DISPATCHLOAD' EMMS table. For Semi-scheduled units, this is the lower of MAXAVAIL bid availability and Unconstrained Intermittent Generation Forecast (UIGF) value.

This calculation of curtailment does not capture every aspect of network-related generation limitation. For example, it does not capture:

1. Instances of generators reducing offered availability to zero because a transmission outage would constrain their output to (or near) zero.
2. Instances where generators limit the number of inverters online due to system strength constraints, causing the maximum availability value in market systems to be lower than the true maximum availability of the wind/sun resource.

[14] At https://aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed.

3. Instances where generators are subjected to hold-points during commissioning, causing the maximum availability value in market systems to be lower than the true maximum availability of the wind/sun resource.
4. Network constraints driving regional prices below zero, leading to some generators not being dispatched.

A2.3.2 Forecast curtailment terminology

In addition to historical curtailment data, this report includes forecasts of VRE curtailment and economic offloading for each REZ from 2025 to 2027, based on analysis completed for the Draft 2024 ISP. Note that the Draft 2024 ISP uses slightly different terminology to describe curtailment than that used in AEMO's *Quarterly Energy Dynamics* and in this report. Table 2 maps the curtailment forecast terminology used in the Draft 2024 ISP to that used in this report.

Table 2 Mapping of curtailment forecast terminology used in Draft 2024 ISP to 2024 ELI report

Draft 2024 ISP terminology	2024 ELI Report terminology
Transmission curtailment	Curtailment
Economic spill	Economic offloading

A2.3.3 Congestion methodology

Congestion thresholds

Constraints recorded in the congestion tables (in the NEM region appendices), and lines highlighted in the congestion maps[15] of this report, have been included based on meeting any of the thresholds recorded in Table 3.

Table 3 Thresholds for inclusion of constraints in congestion tables, and lines in congestion maps

Threshold	Binding hours	Binding Impact ($)	Map colour
1	20	50,000	Yellow
2	100	100,000	Red
3	250	500,000	Crimson
4	750	1,000,000	Black

Inclusions and exclusions

Constraint information analysed came from the NEM Constraint Report 2023 summary data[16], which summarises constraint statistics for calendar year 2023.

Constraints analysed were limited to those meeting the following criteria:

1. Type = NIL (i.e. Outage constraints were excluded), AND

[15] The locational information for transmission lines used in the congestion maps was downloaded from the Digital Atlas of Australia. This includes transmission and sub-transmission lines down to 110 kV, and in some instances down to 66 kV. Available at https://digital.atlas.gov.au/datasets/digitalatlas::electricity-transmission-lines/explore.

[16] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams.

2. Limit Type = Thermal, OR Transient Stability, OR Voltage Stability, OR Oscillatory Stability, OR System Strength[17].

Lines have been highlighted in the congestion maps on the basis of being either a monitored or tripped line in a constraint that meets a threshold in Table 3. Where a line met both a binding hours and a binding impact threshold, the colour applying to the higher of the two thresholds was used on the map. Lines appearing in multiple constraints were also accounted for (the binding hours and binding impact were summed across all constraints the line featured in as a monitored or tripped element).

Many stability constraints cannot be simply mapped onto particular lines, therefore most stability constraints that meet a threshold in Table 3 are not represented in the congestion maps (they are, however, all recorded in the congestion tables). Stability constraints are represented on congestion maps if:

1. The constraint includes a monitored or tripped line on the right hand side of the constraint, so it functions effectively the same as a thermal constraint, OR
2. The constraint consists of a hard numerical limit on a particular line or lines.

Congestion on transformers is not shown on congestion maps, but is recorded in congestion tables.

Binding impact

Binding constraint equations affect electricity market pricing. The binding impact is used to distinguish the severity of different binding constraint equations.

The binding impact of a constraint is derived by summarising the marginal value for each dispatch interval (DI) from the marginal constraint cost (MCC) re-run[18] over the period considered. The marginal value is a mathematical term for the binding impact arising from relaxing the RHS of a binding constraint by one MW. As the market clears each DI, the binding impact is measured in $/MW/DI.

The binding impact in $/MW/DI is a relative comparison and a helpful way to analyse congestion issues. It can be converted to $/MWh by dividing the binding impact by 12 (as there are 12 DIs per hour). This value of congestion is still only a proxy (and always an upper bound) of the value per MW of congestion over the period calculated; any change to the limits (RHS) may cause other constraints to bind almost immediately after.

[17] Analysed constraints were limited to these types as they are generally more location specific and therefore more informative about where congestion is most and least prevalent on the network, compared to other types of constraints.

[18] The MCC re-run relaxes any violating constraint equations and constraint equations with a marginal value equal to the constraint equation's violation penalty factor (CVP) x market price cap (MPC). The calculation caps the marginal value in each DI at the MPC value valid on that date. MPC is increased annually on 1 July.

A2.4 Notes on hosting capacity

Hosting capacity is used to describe a complex intersection of technical limitations and commercial considerations regarding the network and generators which connect to it.

In general, hosting capacity is a term, usually defined in MW, which reflects how much generation capacity can connect to the network without suffering unreasonable reduction in energy generation due to technical limitations of the network. Spare hosting capacity is the available capacity for new generation to connect. Total hosting capacity includes both existing and new capacity. What technical limits are included, how those technical limits are included, and what constitutes an unreasonable reduction, varies with the context. Hence, hosting capacity figures often vary even when referring to the same REZ.

There is some merit in developing a universal hosting capacity calculation methodology, but is not realistic to state a single hosting capacity value that allows proponents to make informed decisions, unless they are also provided with information which allows them to understand the inputs and the methodology applied. Typically, hosting capacity methodologies involve one or more of the following aspects:

- The transfer capability of the network.
- The acceptable level of network curtailment.
- The type of generation mix (for example, wind, PV, storage) present.
- The available level of system strength.

As these aspects often involve subjective judgement, or multiple possible representations/simplifications, hosting capacity calculations can vary even with the same methodology. These aspects are discussed below.

The transfer capability of the network

This represents the technical capability of the network to transfer energy. It is often represented as a static value in planning assessment, but in reality will change depending on prevailing conditions, such as type of generation online, ambient temperature, demand, and interconnector flows. How these factors fold up into a single value can result in significant differences.

The physical location of where and how the transfer capability is defined also plays a large role. For example, the network within a REZ may not be the factor limiting generation output; it could be a constraint elsewhere in the network (such as an interconnector) which limits generation output.

Likewise, within a REZ network, the hosting capacity is not homogenous. Parts of the REZ may be a strong backbone and have a high transfer capability, but other parts of the REZ are more remote and connected by a weaker part of the network.

The transfer capability must also take into account the requirement to maintain a secure power system. For example, the transfer capability is often not the summation of the line ratings connecting a location to the rest of the network, as that level of transfer would mean that following the loss of a line the remaining lines would not be operating within ratings.

The acceptable level of network curtailment

Building sufficient network capacity so a generator is never curtailed due to network is not economically prudent. Typically, there is an acceptable level of network curtailment which allows the generator to recover its construction and operating costs, and strikes a balance between cost of upgrading the network and the reduction in generation capability.

There is no universal optimal value, as it depends on a range of things including commercial costs, generation mix, market conditions, network capability and cost to upgrade the network.

Conceptually, the more network curtailment is acceptable, the more hosting capacity a REZ will have. The ISP, with its whole of system optimisation, generally forecasts network curtailment in the range of 10%. The New South Wales REZ access rights have target levels of network curtailment in the 5% range.

Additionally, a different source of curtailment – economic curtailment – often has a larger impact than network curtailment. Put simply, economic curtailment occurs when it is more economically prudent to overbuild wind and solar to ensure good energy yield on cloudy/low wind days but forgo some energy on very sunny/windy days. Economic curtailment tends in the ISP to be higher than network curtailment, in the range of 15%[19].

The type of generation mix

Sometimes hosting capacity is defined with a simple MW value. It is possible that more generation can be hosted if the generation tends to produce power at different times. For example, wind and solar generate at different times, so they are rarely competing with each and causing congestion. Likewise, a BESS is likely to generate (discharge) at times of low wind and solar.

Additionally, storage such as BESS can increase the hosting capacity of a REZ, as it can store the generation within a REZ, avoiding network congestion and decreasing the amount of network curtailment.

[19] See Section A4.3 of AEMO's Draft 2024 ISP Appendix 4 System Operability, December 2023, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2024-isp-consultation/appendices/a4-system-operability.pdf?la=en.