Congestion management Technical Working Group
Working paper –Congestion zones

Purpose of paper

This paper seeks to progress design of the congestion zones model. It does so by examining the following areas:

1. **How do we calculate the level of transmission hosting capacity for the purposes of defining and classifying congestion zones?**
    a. How should areas of hosting capacity be defined? If boundaries are needed, how do we specify the boundaries of a congestion zone or REZ?
    b. How do we take into account the impact of diverse output profiles when determining where, and for how much generation capacity, transmission hosting capacity is available?
    c. How do we treat storage and load in calculating available network hosting capacity?
    d. How do we take into account network interdependencies when determining where, and for how much generation capacity, transmission hosting capacity is available?
2. **What information should accompany indicative hosting capacity to assist investors?**
3. **Governance of the process used to quantify transmission hosting capacity**
    a. In what form is hosting capacity information made available?
    b. Who is responsible for assessing hosting capacity?
    c. Is there a need for guidelines to describe the process to calculate hosting capacity, and if so, who prepares them?
    d. How often are these assessments updated?

Context

Defining areas of the network to reflect congestion/capacity for investors is required as a basis for calculating connection fees. For this reason, congestion zones and connection fees were presented in the May consultation paper as a combined model. However, there appears to be general consensus from stakeholders[1] that improving information for investors around congestion in locations in the network is a no-regrets reform. It would, on its own, still be an improvement on the status quo in terms of guiding new investors' locational investment decisions.

This paper seeks to develop the congestion zones model so that it can:

(a) Be applied as standalone reform, regardless of the investment timeframe model that is ultimately progressed by ESB, and
(b) Potentially inform development of the connection fee model.

Overview and aim of the congestion zone model

This model leverages a planning process to segregate the transmission system into zones that reflect the level of available hosting capacity for new generation. The purpose of this process would be to clearly signal to prospective investors which parts of the network are available for further development, which parts are reaching capacity, and those that are already full.[2]

[1] Submissions to the consultation paper and TWG feedback
[2] ESB, Transmission access reform consultation paper (May 2022), p 26.

The information generated by this process could be used to develop a set of locational signals that create incentives for generators, storage and demand side resources to connect in places that align with the broader development of the power system as set out in the ISP (as supplemented by government policy). Such an incentive can be, for example, connection fees that reflect the areas of capacity generated by the congestion zones process.

The information provided around congestion zones should assist proponents (and their consultants) to carry out their own detailed network access and market impact assessments for different areas in the network. This note seeks to identify the most valuable information for investors across existing resources and consider how it can be presented and built on, to establish a single source of information around network capacity across the NEM that is useful for investors in their siting decisions. It also seeks to identify a single set of parameters that can be used for assessing hosting capacity across the NEM.

1. How do we calculate the level of transmission hosting capacity for the purposes of defining and classifying congestion zones?

Electranet's "connection opportunities for" generation and load

ElectraNet's 2021 TAPR sets out the outcomes of ElectraNet's high-level assessment of 'the ability of the existing transmission network nodes and connection points to accommodate new generator connections.'[3] The results are high-level indications in MW of the generation and load capacity that can be connected at different connections points, categorised according to region:

Table 1: Indication of available capacity to connect generation and load on ElectraNet's network in 2024-45 (extract)

Connection point	Additional generation that could be connected (MW)				Additional load that could be connected (MW)
	Very low daytime demand Sunny and still	Medium demand Sunny and still	High winter demand Very windy, overcast	High summer demand Sunny at noon	Very high summer demand Low wind, early evening
Eyre Peninsula (132 kV)					
Cultana	250	275	175	125	100
Whyalla Central	150	175	175	125	20
Yadnarie	250	275	175	150	100
Port Lincoln Terminal	250	275	175	150	100
Wudinna	80	80	80	80	20
Mid North and Riverland (132 kV)					
Bungama	175	200	80	80	100
Port Pirie	100	100	80	80	20
Baroota	0	20	20	0	0
Brinkworth	275	275	60	200	125
Clare North	150	150	40	150	80

ElectraNet assessed the anticipated thermal ability of the network to accommodate additional generation for four different system conditions (see Table 4 below). ElectraNet's assessment

[3] ElectraNet, 2021 Transmission Annual Planning Report, p. 53.

captures the impact of generation that is committed to connect to the SA transmission network, as well as the capacity expansion once Project EnergyConnect is commissioned.

At each location, the output of the new generator was gradually increased while adjusting interconnector flows within their limits to maintain the supply-demand balance. The output of the new generator was increased until a voltage limitation or a thermal overload was observed, with single credible contingencies considered. The impact of existing run back schemes was also considered (where practicable). ElectraNet did not consider potential impacts on new or existing generators that could arise from any system strength limitations.[4]

Powerlink's Generation Capacity Guide

Similarly, Powerlink provides information for parties seeking connection to the transmission network in Queensland, including its Generation Capacity Guide (GCG). The current guide[5] broadly describes the current system strength environment and the opportunities for future investment in inverter-based generation. It also provides information on the local thermal capacity that may be available at different locations within Powerlink's network and the expected future utilisation of relevant major 'grid sections'. The GCG is published on Powerlink's website separate to the TAPR to facilitate updates to the GCG as required to make available the most up to date data for developers.

Similar to ElectraNet's approach, Powerlink calculated each connection point's thermal capacity by iteratively applying increasing levels of generation to the connection point (balanced by changing power flows on the Queensland to New South Wales Interconnector) and performing contingency analysis. The thermal limit of a connection point was assessed as being reached when a rating breach was identified within the local network.

Table 2: Indicative connection point supportable generation capacities by zone

Zone	Voltage Level (kV)	Thermally supportable generation (MW)	Includes the substations
Far North	275	300-500	Chalumbin, Walkamin
	132	150-250	Chalumbin, Edmonton, Innisfail, Turkinje
Ross	275	800+	Ross
	132	150-400	Cardwell, Clare South, Ingham South, Tully, Yabulu South
North	275	800+	Nebo, Strathmore
	132	50-200	Alligator Creek, Bowen North, Collinsville North, Kemmis, Mackay, Moranbah, Newlands, Peak Downs, Pioneer Valley, Proserpine, Strathmore
Central West	275	200-800	Bouldercombe, Broadsound, Calvale, Lilyvale, Stanwell, Raglan
	132	100-300	Blackwater, Bouldercombe, Lilyvale, Bluff, Dysart

[4] ElectraNet, 2021 Transmission Annual Planning Report, p. 52.

[5] Current as at 31 July 2020: See https://www.powerlink.com.au/sites/default/files/2020-10/Generation%20Capacity%20Guide%20-%20August%202020.pdf

Powerlink's analysis is based on the existing and committed transmission network arrangements, as well as recent generator commitments.

The TAR team's preliminary thinking is that a similar approach be used to identify indicative hosting capacity for congestion zones, being to:

- Iteratively apply increasing levels of generation to a connection point or in a certain location, while adjusting interconnector flows within their limits, until a voltage or a thermal overload is observed
- Capture existing and committed transmission network arrangements
- Capture existing and committed generation
- Consider the impact of existing runback schemes
- Perform the assessment under *system normal* and *single credible contingency* conditions

The output will be an indicative maximum generation capacity that could be connected at each connection point, or in each zone, without breaching existing line and transformer ratings. Our initial thinking is that for each zone, there should be four indicative values to represent the supportable capacity under different weather and demand scenarios (discussed below).

Does TWG support this approach to calculating transmission hosting capacity? Does it have any feedback on the recommended approach or alternative approaches for consideration?

a. How should areas of hosting capacity be defined? If boundaries are needed, how do we specify the boundaries of a congestion zone or REZ?

Physical impacts

In the examples discussed above, ElectraNet and Powerlink assessed the capacity of the network to support new generation based on physical impacts. The output of the modelled new generator, at each connection point or in each zone, was increased until a voltage limitation or a thermal overload was observed.[6] ElectraNet determined the capacity to support new generation at each connection point, while Powerlink reflected the thermally supportable generation capacity according to "zones" (see Table 2 above).

For its capacity outlook modelling[7], AEMO disaggregates the existing five (pricing) regions of the NEM into sub-regions to reflect current and emerging intra-regional transmission limitations.[8] This facilitates AEMO's consideration of congestion between major load centres, given how it can be influenced by generation between regional reference nodes. The approach disaggregates some regions into one or more sub-regions, configured to identify major electrical subsystems within the electricity transmission network that allow free-flowing energy between transmission elements. Where key flow paths are identified that may materially constrain the transmission system from delivering energy between locations, this alternative sub-regional approach splits these areas from each other, to better identify the capacity of the intra-regional transmission system and the value of

[6] ElectraNet, Transmission Annual Planning Report 2021, p. 52; Powerlink, Generation Capacity Guide, August 2020, p. 5.

[7] As part of the ISP, AEMO undertakes capacity outlook modelling, which is 'the core process to explore how the energy system would develop in each ISP scenario, and to determine candidate development paths from which the optimal development path is selected': See AEMO, ISP Methodology 2021, p. 8.

[8] AEMO, ISP Methodology 2021, p. 12

potential augmentations. A 10-sub-region structure is therefore applied to improve the granularity of optimisations that were previously assessed across five regions.[9]

Table 34 NEM regions, ISP sub-regions, reference nodes and REZs

NEM region	ISP sub-region	Reference node	REZs
Queensland	Central and North Queensland (CNQ)	Ross 275 kilovolts (kV)	Q1, Q2, Q3, Q4, Q5 and Q6
	Gladstone Grid (GG)	Calliope River 275 kV	-
	Southern Queensland (SQ)	**South Pine 275 kV**	Q7, Q8 and Q9
New South Wales	Northern New South Wales (NNSW)	Armidale 330 kV	N1 and N2
	Central New South Wales (CNSW)	Wellington 330 kV	N3
	South NSW (SNSW)	Canberra 330 kV	N4, N5, N6, N7 and N8
	Sydney, Newcastle, Wollongong (SNW)	**Sydney West 330 kV**	-
Victoria	Victoria (VIC)	**Thomastown 66 kV**	V1, V2, V3, V4, V5 and V6
South Australia	South Australia (SA)	**Torrens Island 66 kV**	S1, S2, S3, S4, S5, S6, S7, S8 and S9
Tasmania	Tasmania (TAS)	**Georgetown 220 kV**	T1, T2 and T3

*Bold reference nodes are those used for whole of region modelling, for example in the ESOO. In such studies, all regional loads are represented at the regional reference nodes.

In this topology, the regional load and generation resources are appropriately split between the different sub-regions. Flow path transmission constraints are added to reflect the capability of the network. There is a trade-off when adding zones to this model. While additional zones provide more information, they increase the computational complexity of the PLEXOS model.

Does the TWG have any feedback on how granular congestion zones need to be to provide useful information to prospective market participants?

Financial impacts

Alternatively, it may be more useful for investors to assess the potential impact of their project on congestion if it can be defined according to physical or financial metrics. The TAR team's note on the connection fee option lists different approaches to assessing the impact of congestion. Defining congestion based on the impact of a proposed project (or multiple planned generation projects) may be a preferable approach if the Connection Fee model is ultimately adopted, to ensure consistency in information for investors.

b. How do we take into account the impact of diverse output profiles when determining where, and for how much generation capacity, transmission hosting capacity is available?

The capacities of thermally supportable generation reported in Powerlink's GCG are based on a single generation dispatch assumption, being a typical winter noon load and coincident output for the existing and committed scheduled and semi-scheduled generation projects (see Table 3 below). Powerlink notes that '[t]he thermally supportable generation at a connection point may be

[9] AEMO, 2021 Inputs, Assumptions and Scenarios Report, July 2021, p. 118.

substantially greater or lower with different generation patterns and load levels.'[10] The advantage of Powerlink's approach is simplicity, which potential investors may prefer.

Table 3: Base winter noon generation dispatch assumptions for Powerlink's Generation Capacity Guide

Zone/Interconnector	Generation sent out (MW)
Far North	203
Ross	429
North	375
Central West	907
Gladstone	942
Wide Bay	158
Surat	387
Bulli	1,272
South West	1,308
Moreton	18
Qld-NSW Interconnector Southerly Flow (swing)	840
Terranora Interconnector Southerly Flow	60

However, that the TAR team's initial thinking is that this assessment could be more useful to investors if it provides multiple indicative hosting capacity figures that reflect a pre-determined range of conditions. ElectraNet's assessment aims to reflect the impact on indicative hosting capacity of the diverse output profiles of generation connected to the network. Referring to Table 3 below, each scenario of ElectraNet's assessment assumed the varying output profiles of different generation types, corresponding to four different demand and weather conditions. For example, under a scenario of high summer demand, when it is sunny at noon, it is assumed a solar farm's output would be 0%, a wind farm's output at 90% capacity and a conventional generator's output at 5%.

[10] Powerlink, Generation Capacity Guide, August 2020, p. 5.

Table 4: System conditions considered in the assessment of the ability of the SA transmission system to accommodate additional generation

System condition	SA demand (MW)	SA system losses (MW)	Heywood interconnector flow (MW)	Project Energy-Connect flow (MW)	Conventional generator output (% of capacity)	Wind farm output (% of capacity)	Solar farm output (% of capacity)
High summer demand sunny at noon	2,500	170	490 (import)	740 (import)	5%	50%	95%
High winter demand very windy and overcast	2,000	140	100 (export)	190 (import)	5%	90%	0
Medium demand sunny and still	1,400	100	600 (import)	470 (import)	2%	5%	90%
Very low daytime demand sunny and still	0	30	230 (export)	260 (export)	2%	5%	95%

A static version of AEMO's inputs and assumptions for its ISP may be able to be derived for informing hosting capacity assessments. This may have the benefit of promoting consistency between (a) hosting capacity calculated for the purposes of congestion zones and (b) the ISP outcomes. Such consistency would allow investors to better compare the information from these two sources. AEMO applies the typical summer generation, in combination with the 10% POE peak derated generation capacities across the seasons[11], in a manner that reflects expected generator capabilities in the capacity outlook models. The definitions of these seasonal ratings and the temperature specifications are consistent with the ESOO, and described in the ESOO and Reliability Forecast Methodology Document[12]

- The winter capacity is used for all periods during winter ('Winter Reference')
- The 10% POE demand summer capacity is applied to the subset of hottest summer days, using the same approach outlined in the ESOO and Reliability Forecasting Methodology Document ('Summer Peak')
- For all other days in summer, the average of the typical summer and the winter rating is applied. This approach estimates the energy production capabilities of generators in summer, as opposed to focusing on the capacity available during peak periods which is more critical for unserved energy assessments ('Summer Typical').

[11] The typical summer capacity is used to represent the capacity that would be available under regular summer conditions, based on the 85th percentile of observed maximum daily temperatures for all reference years between December and March. Further details on this approach are available in the ESOO and Reliability Forecasting Methodology Document, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/esooand-reliability-forecast-methodology-document.pdf.

[12] Seasonal definitions reflect those specified in the 2020 ESOO; that is, summer ratings are applied between November to March and winter ratings between April to October.

These three categories could form the basis for the system conditions, including generator output profiles, that are assumed in a NEM-wide approach to calculating transmission hosting capacity in congestion zones.

Alternatively, investors may prefer that the transmission hosting capacity values be presented on a technology-specific basis. For example, the indicative hosting capacity value could be presented as "X MW of wind hosting capacity, Y MW of solar hosting capacity and Z MW dispatchable".

Does TWG support hosting capacity assessments providing investors with multiple figures of static capacity under a selection of pre-determined operating circumstances? Alternatively, should we consider whether the information can be presented in terms of technology-specific values?

If so, does TWG support the use of seasonal conditions? Does the TWG have feedback on the seasonal conditions we should be relying on to reflect diverse output profiles, including how many scenarios should be established?

Alternatively, would TWG prefer to understand the percentage of time they can expect to be constrained or forego revenue as a result of congestion? If so, is TWG aware of existing resources that can be used as a basis for this assessment?

c. How do we treat storage and load in calculating available network hosting capacity?

If the assessment of hosting capacity is undertaken for multiple scenarios (or system conditions), as is the case with ElectraNet's assessment, it will be necessary to determine the assumptions for load and storage under each scenario.

The TAR team's preliminary thinking is that each TNSP is best placed to determine the demand assumption under each seasonal scenario for their assessment. However, the TNSP should ensure its assumption is consistent with the ISP inputs and assumptions (if relevant/appropriate) and that demand assumptions be consistent with the most recent NEM Electricity Statement of Opportunities (ESOO).

We welcome the TWG's views on how best to determine how storage should be treated for hosting capacity assessments. Specifically, what should be the assumed storage behaviour in each system scenario. Given the business models for grid scale batteries and pumped hydro are still evolving, or can be wide-ranging, this assumption may be trickier to settle. Key questions include whether:

- under each scenario, grid scale batteries and pumped hydro should be treated differently. This may be appropriate given the operation of pumped hydro is reliant on rainfall.
- In areas or periods of congestion, storage in different areas of the network will be incentivised to draw from the grid to alleviate constraints – this will depend on the operational access reform model that is implemented, and may have broader implications for the other scenario assumptions.

Does the TWG have any feedback on how load and storage should be captured in the assessment of hosting capacity?

d. How do we take into account network interdependencies when determining where, and for how much generation capacity, transmission hosting capacity is available?

The transmission network is a highly meshed system, and the flow of electricity is influenced by generation and system services across multiple locations. There is a question of how modelling of indicative hosting capacity at each connection point or in each zone should take into account the impact of broader network constraints, both intra-regional and inter-regional.

The thermally supportable generation capacity identified in Powerlink's assessment only relates to constraints on the local network around each connection point, including the network adjacent to the connection point and between the connection point and the main transmission system. Powerlink did not assess whether multiple generators in a region are likely to result in congestion on the backbone transmission network. [13]

In undertaking its assessment, ElectraNet considered the range of demand, generation and interconnector operating conditions set out in Table 4 above to determine the indicative maximum generation capacity that could be connected without breaching existing line and transformer ratings, under *system normal* and *single credible contingency* conditions.[14] For some system conditions that are not included in Table 4 above, such as times of very high wind generation output with moderate to low demand, the total dispatch of SA generation could be constrained by the capacity of the interconnectors to export electricity from SA. In determining the indicative hosting capacity, ElectraNet did not consider the potential impact of constraints in Victoria and New South Wales, or elsewhere in the NEM. It also notes that it did not consider 'any impact of co-optimised dispatch for generators connected on interconnector flowpaths'.[15]

As such, Powerlink and ElectraNet's hosting capacity figures should be read as reflecting capacity in one location *or* in another location, and *not* as the cumulative hosting capacity when combined.

For its capacity outlook modelling, AEMO has identified notional transfer limits between sub-regions (Figure 34 above) represented at the time of 'Summer Peak', 'Summer Typical', and 'Winter Reference' in the importing sub-region. These notional transfer limits are presented in the table below. The forward direction of flow is typically in the north or west direction and is consistent with the flow path name.

[13] Powerlink, Generation Capacity Guide, August 2020, p. 5.
[14] This assessment is limited to a few operating conditions and does not attempt to define the amount and value of constraints that could be experienced at any particular location; see ElectraNet 2021 TAPR, p. 53.
[15] ElectraNet, 2021 TAPR, p. 56.

Table 37 Notional transfer capabilities between sub-regions

Flow path (forward power flow direction)	Forward direction capability (MW)			Reverse direction capability (MW)		
	Summer Peak	Typical Summer	Winter Reference	Summer Peak	Typical Summer	Winter Reference
CNQ – GG [A]	700	700	1,050	750	750	1,100
SQ – CNQ	700	700	1,000	2,100	2,100	2,100
NNSW – SQ (“QNI”) [B]	685	745	745	1,205	1,165	1,170
NNSW – SQ (“Terranora”)	0	50	50	130	150	200
CNSW – NNSW	910	910	910	930	930	1,025
CNSW – SNW	7,525 (6,125[C])	7,525 (6,125[C])	7,625 (6,225)[D]	6,125[D]	6,125[D]	6,125[D]
SNSW – CNSW	2,700	2,700	2,950	2,320	2,320	2,590
VIC – SNSW [E]	870	1,000	1,000	400	400	400
SNSW – SA	800	800	800	800	800	800
VIC – SA (“Heywood”) [F]	650	650	650	650	650	650
SNSW – SA & VIC – SA combined	1,300	1,300	1,300	1,450	1,450	1,450
VIC – SA (Murraylink)	220	220	220	100	200	200
TAS – VIC	478	478	478	478	478	478

Note: Forward and reverse directions are as referred in the first column of this table.

A. CNQ-GG limits are heavily influenced by the amount of generation in northern and central Queensland, particularly at Gladstone. The provided transfer limit is a representation with typical generation output from Stanwell and Calvale and reduced generation at Gladstone. This limit will be further reviewed with hourly simulation results.
B. QNI Minor is a committed project and is included in the transfer capability.
C. The CNSW to SNW transfer limit is reduced to 6,125 MW in the absence of Eraring or Vales Point generation.
D. Power is not expected to frequently flow from SNW to CNSW since the major load centre is SNW. For DLT modelling, a transfer limit of 6,125 MW is assumed for this limit, and will be reviewed if it becomes material.
E. VNI Minor is a committed project and is included in the transfer capability.
F. The Heywood interconnector currently operates at 600 MW forward capability and 550 MW reverse capability. AEMO and ElectraNet are working to release the transfer capability to its designed capability of 650 MW in both directions.

To identify transfer limits for each seasonal condition, AEMO gathers input data from asset owners, for example network ratings for various ambient temperature conditions, any runback schemes or SPSs. AEMO also gathers historical operational data for the network. AEMO then consults with the local TNSPs to understand potential limiting factors and either AEMO or the TNSP undertakes power system analysis to evaluate the impact of each of the limiting factors on the transfer capacity. This includes:

a. A mixture of thermal capacity, voltage stability, transient stability, oscillatory stability, and power system security/system strength assessments, depending on the sub-region, and
b. Testing worst-case conditions and typical conditions, and a selection of appropriate demand and generator dispatch conditions.

AEMO selects the most binding transfer limit. For example, if there is a transient stability issue which limits flow between sub-regions to a particular MW value, but that value is higher than the MW flow value for the voltage stability limit for that sub-region, then the voltage stability limit will be used to set the transfer capability.[16]

Should the hosting capacity assessment be based on all types of constraints, and not just thermal, even though this may result in more conservative figures?

Does the TWG support relying on the notional transfer capabilities for interconnectors identified by AEMO through its ISP process?

2. What information should accompany indicative hosting capacity values to assist investors?

To support investors' consideration of the risks for their project's proposed output at a certain location, we recommend the following information accompany the indicative hosting capacity values.

We seek the TWG's feedback on the below information, as well as any other information investors would value alongside indicative hosting capacity.

Overlay hosting capacity with (historical and forecast) constraint information

Indicative hosting capacity could then be accompanied by both historical and forecast constraints corresponding to each location/zone. The NER Clause 5.12.2(c)(3) requires TNSPs to report the forecast of constraints and inability to meet network performance requirements. This reporting must at least include:

(i) a description of the constraints and their causes;
(ii) the timing and likelihood of the constraints;
(iii) a brief discussion of the types of planned future projects that may address the constraints over the next 5 years, if such projects are required; and
(iv) sufficient information to enable an understanding of the constraints and how such forecasts were developed;

This information can help investors (and stakeholders more broadly) understand how close the power flows in the network are to capacity limits or, vice versa, how much load (e.g. storage) is needed to alleviate congestion in a zone. It identifies the transmission elements where flows have been at, or close to, the limits. Capacity could be limited due to the power flows reaching:

- The maximum rating of a single transmission element, such as a transmission line or a transformer;
- The combined capacity of a group of transmission elements, such as several parallel transmission lines constituting inter regional links; and
- The limits set by system wide considerations such as voltage, transient or oscillatory stability.

Further, transparency around the cause of transmission limits – i.e. whether it is based on a thermal constraint or a voltage constraint – can help investors determine whether they are willing to fund a a solution alleviate the constraint.

[16] AEMO, ISP Methodology 2021, pp. 16-17.

By way of example, TransGrid's 2021 TAPR provided details of transmission constraints for the previous 12 month period (1 March 2020 – 28 February 2021).[17]

Table A5.1: Constraints operating at the capability limit

Rank	Constraint ID	Total duration (dd:hh:mm)	Type	Impact	Reason
1	V^^N_NIL_1	33:11:40	Voltage Stability	Vic - NSW Interconnector + Generators	Avoid voltage collapse around Murray for loss of all APD potlines
2	N_X_MBTE2_B	31:15:35	Unit Zero	Terranora Interconnector	Lower limit on Directlink, two cables out
3	N^N-LS_SVC	26:10:40	Voltage Stability	Terranora Interconnector	Avoid voltage collapse on trip of Armidale to Coffs Harbour (87), Lismore SVC out
4	N_X_MBTE_3B	21:08:45	Unit Zero	Terranora Interconnector	No flow on Directlink, all three cables out

In their TAPRs, TNSPs also provide information around emerging and future constraints. For example, in its 2021 TAPR, ElectraNet highlighted the limitations that could bind looking forward, based on a 10-year forecast of generator expansion. The information notes the forecast binding hours and potential mitigating projects.

Limitation	Timing indication	Affected corridor	Forecast average binding hours (hrs/year) [22]		Potential mitigating project(s)
			2021-22 to 2030-31	2021-22 to 2040-41	
Loss of Templers West 275/132 kV transformer overloads Para 275/132 kV transformer	After 2023	Robertstown – Adelaide	853	1025	Install second Templers West 275/132 kV transformer
Loss of Robertstown 275/132 kV transformer overloads Waterloo – Waterloo East 132 kV	After 2023	Robertstown – Adelaide	300	845	Increase capacity of the Robertstown to Adelaide transmission corridor
Loss of Robertstown – Para 275 kV overloads Waterloo East – Waterloo 132 kV	After 2023	Robertstown – Adelaide	119	473	Increase capacity of the Robertstown to Adelaide transmission corridor
Loss of one 275 kV circuit between Davenport and Cultana overloads the other 275 kV circuit	After 2022	Davenport – Cultana	66	90	Remove plant rating limitations on the Davenport – Cultana 275 kV corridor

Overlay with planned network augmentation

As with Powerlink and ElectraNet's assessments, the TAR team's preliminary thinking is that the calculation of existing transmission hosting capacity capture existing and committed transmission network arrangements, including committed expansions or augmentations.

However, feedback from the TWG is that investors would value information around possible future network changes, including those identified in AEMO's Integrated System Plan. Network augmentations or expansions may alter the level of supportable generation in a given location.

The TAR team's preliminary thinking is that indicative transmission hosting capacity values are overlayed with information about anticipated transmission projects. These should include ISP projects, as well as incremental upgrades/augmentations set out in TNSPs' TAPRs and Network Capability Incentive Parameter Action Plans (NCIPAPs). Such projects could be network or non-

[17] Transgrid, Transmission Annual Planning Report 2021, p. 149.

network augmentations and could be regulated or non-regulated assets. This information should also reflect state-based transmission planning, such as the 2021 Infrastructure Investment Objectives Report[18], which AEMO Services publishes in its capacity as the NSW Consumer Trustee under the Electricity Infrastructure Investment Act 2020 (NSW).

Information about the planned projects should be provided according to the location or zone that it relates to, with details about the justification of the project and indicative timing. It will also be necessary to determine a standard measure for investors to understand the likelihood of the project going ahead. For example, for the purposes of AEMO's ISP modelling, 'anticipated transmission projects' are 'transmission augmentations that are not yet committed but are highly likely to proceed and could become committed soon.'[19] The projects must be in the process of meeting *three of the five* committed project criteria[20], which are as follows:

1. The proponent has obtained all required planning consents, construction approvals and licenses, including completion and acceptance of any necessary environmental impact statement.
2. Construction has either commenced or a firm commencement date has been set.
3. The proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for the purposes of construction.
4. Contracts for supply and construction of the major components of the necessary plant and equipment (such as transmission towers, conductors, terminal station equipment) have been finalised and executed, including any provisions for cancellation payments.
5. Necessary financing arrangements, including any debt plans, have been finalised and contracts executed.

For the purposes of congestion zones, any projects that do not meet three of the five above criteria could then be flagged as 'potential projects'.

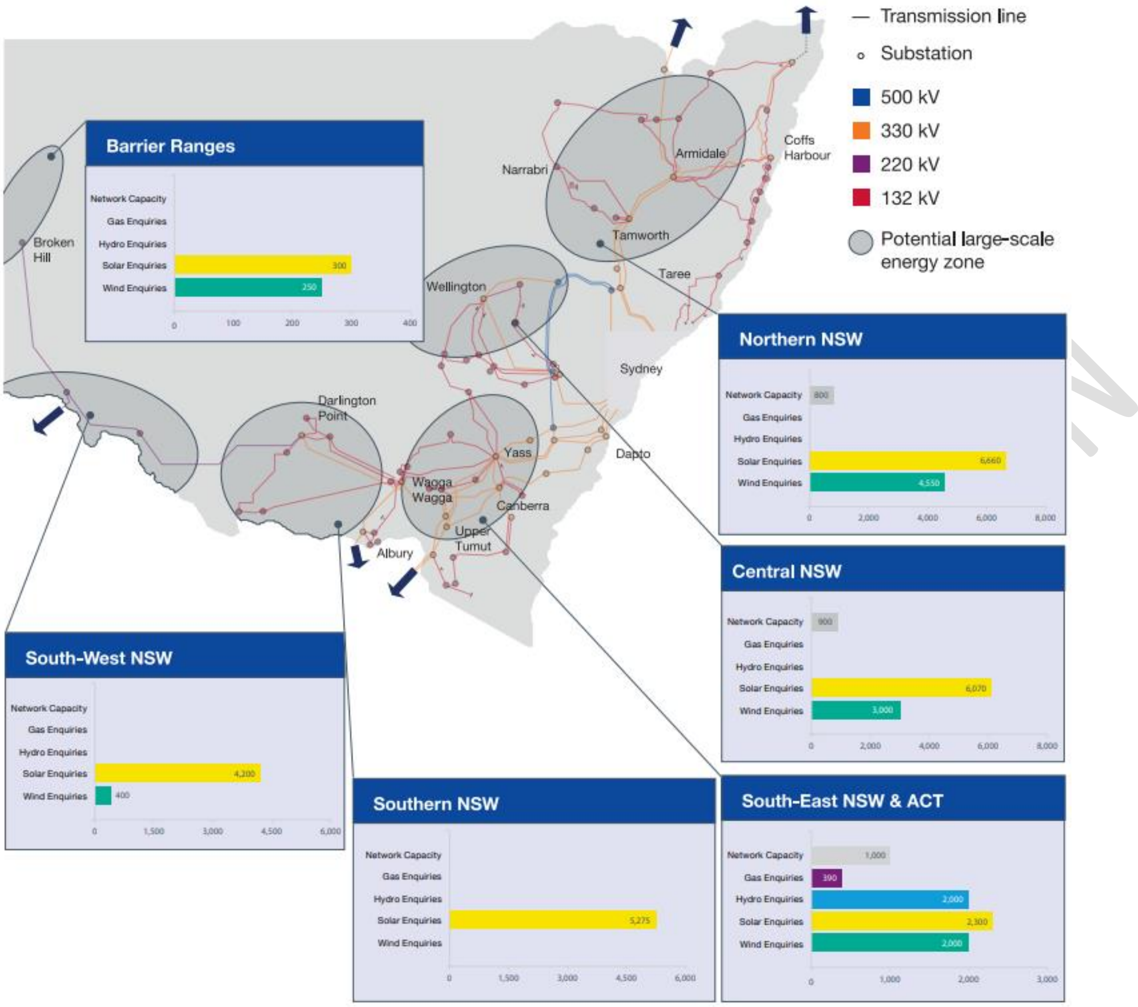
New connections and withdrawals

Investors may also find it useful to understand the cumulative capacity of generation for which connection enquiries have already been received for a given location/zone.

TransGrid's older TAPRs indicated existing hosting capacity (Transgrid did not provide detail on how it calculated this).[21] What may be useful to draw from, however, was that the hosting capacity for each region was provided alongside information about the current generation connection enquiries Transgrid had received for that location.

[18] AEMO Services as Consumer Trustee, 2021 Infrastructure Investment Objectives Report, December 2021.
[19] AEMO, Inputs Assumptions and Scenarios Report 2021, p. 126.
[20] The definition of committed projects comes from the AER's RIT-T instrument, as required by the AER's CBA Guidelines.
[21] TransGrid's more recent TAPRs indicate it does not have any spare hosting capacity on its network.

Figure 27 – Current generation connection enquiries to TransGrid network and available capacity



Equally, investors should have visibility of planned generation withdrawal, including indicative timing. This information was provided in ElectraNet's 2021 TAPR.[22] In capturing such information for congestion zones, it will again be important that it is consistent with forecast generator closures in AEMO's ISP, to avoid conflicting information confusing potential investors.

3. Governance of the process used to quantify transmission hosting capacity

a. In what form is hosting capacity information made available?

It is important that indicative hosting capacity for all locations/zones across the NEM, and overlayed information around constraints and future network developments, are all contained in one place. This is to facilitate investors' ability to evaluate potential facility sites that span across different jurisdictions.

The TAR team's preliminary thinking is that a central portal (interactive map) be developed, which would provide the indicative MW of existing transmission hosting capacity for each zone across the NEM. The portal could be based on existing interactive mapping tools, such as AEMO's interactive

[22] See chapter 5.1.

map.[23] In 2021, Powerlink introduced a geographical interactive mapping tool to complement the information contained in its TAPR templates. This provides perspective and context on potential network developments over the 10-year outlook period.[24] Similarly, Ausgrid has introduced its DTPAR Mapping Portal.[25]

The TAR team's preliminary thinking is that the indicative MW value of hosting capacity at each connection point/in each zone be used to develop a high-level traffic light system that lays over the map, to clarify the signal for investors considering multiple sites across the NEM. NEOEN suggested a traffic light system to guide generator investments.[26] However, the traffic light signals in their proposed model would indicate whether a proposed project, if connected in a certain location, would cause congestion. Under the recommended traffic light system here, the signals would demonstrate illustratively the areas in the network with more hosting capacity relative to other areas. It would then be for the investor to consider the implications of the indicative hosting capacity and associated information for their proposed project output.

A traffic light system would require a standard set of indicator values, along the lines of:

- Green light: 200MW+ indicative hosting capacity
- Yellow light: 50MW – 200MW indicative hosting capacity
- Red light: 0MW – 50MW indicative hosting capacity

If multiple hosting capacity values are provided to reflect varying dispatch conditions on the broader network, the values provided under different system conditions may span different traffic light signals (e.g. yellow light for high summer demand and green light for low daytime demand). Where this is the case, multiple traffic light signals could appear with an indication of the corresponding system conditions.

It is envisaged that investors would be able to click on each connection point or zone to access the overlayed information discussed above, including forecast constraints and future transmission augmentations for that specific location. As is the case with Ausgrid's DTPAR, investors (and their consultants) accessing the portal should be able to download a system limitation templates/workbooks with the details of historical and forecast constraints, including the type of constraint, affected lines and the time that the constraints were binding.[27]

AEMO's Connections Simulation Tool

At the TWG investment sub-group meeting on 28 July, the ESB took an action to consider whether AEMO's Connections Simulation Tool (CST) or a variation is suitable to use as a basis for congestion zones. The aim would be to build on this with information that stakeholders consider would be useful.

AEMO is currently developing the CST to allow proponents (and their consultants) to run studies against a four-state PSCAD model. The model reflects the current state, rather than a forward-looking representation, of the network. The primary use of the CST will be for proponents to conduct

[23] https://www.aemo.com.au/aemo/apps/visualisations/map.html
[24] See https://www.powerlink.com.au/reports/transmission-annual-planning-report-2021#resource-sections
[25] See https://dtapr.ausgrid.com.au/
[26] As suggested by NEOEN: See Neoen, Submission to Transmission Access Reform Project Initiation Paper January 2022, p. 6.
[27] Ausgrid's DTPAR Mapping Portal allows systems limitation template to be downloaded.

connections studies on plant models to increase model quality and investigate specific anomalies. This will aim to reduce the iterations required for acceptable connection applications.[28] The tool is an optional fee-for-use service.

ESB staff do not consider the CST is an appropriate basis for the form of information needed for congestion zones. The CST is a PSCAD plant model set up in a simulation tool so that connection proponents can run PSCAD studies for their proposed plant and fine tune their models.

Does TWG support using existing interactive mapping tools as a basis for developing a NEM-wide central portal of information for investors?

Does TWG see value in overlaying indicative hosting capacity values with a traffic light signal system? If so, does TWG have feedback on the above proposed indicator values?

Is there another form for congestion zone information that ESB staff should consider?

b. Who is responsible for assessing hosting capacity?

The TAR team's preliminary thinking is that Primary TNSPs be responsible for assessing hosting capacity for their respective transmission networks. Each TNSP has the best understanding of its own network, including the state of existing assets, local conditions, upcoming network augmentations and submitted connection enquiries. They are therefore considered to be best placed to assess the hosting capacity on their network. The information from this assessment should be consistent with TNSPs' advice to AEMO under its joint planning responsibilities for the ISP process.[29]

The TAR team's preliminary thinking is that AEMO have the responsibility for administering the central information portal, with the input of TNSPs.

Does TWG agree that TNSPs should be responsible for assessing transmission hosting capacity?

Does TWG agree that AEMO should administer the central portal?

c. Is there a need for guidelines to describe the process to calculate hosting capacity, and if so, who prepares them?

To ensure TNSPs are consistent in their approaches to forecasting congestion in their respective jurisdictions, the TAR team's preliminary thinking is that guidelines be developed which describe the methodology for assessing the indicative hosting capacity of the transmission network. The TAR team's preliminary thinking is that AEMO develop and administer these guidelines, similar to how it must develop reliability forecast guidelines and an ISP methodology under the actionable ISP framework.[30] As the central system planner, AEMO would be best placed to set the assessment approach that all TNSPs are expected to follow. If stakeholders consider there would be value in developing best practice principles for undertaking this assessment, these could be developed in consultation with stakeholders to include in the NER or in guidance developed by the AER (similar to the role of the Forecasting Best Practice Guidelines).

[28] AEMO, Presentation – Industry Working Group Session 2, Slide 8.
[29] AEMO, Inputs, Assumptions and Scenarios Report 2021, p. 124.
[30] Under NER clause 4A.B.4, AEMO's reliability forecast guidelines must explain how it will implement the AER's Forecasting Best Practice Guidelines in preparing a reliability forecast.

The inputs and assumptions for each periodic assessment of the transmission hosting capacity should then be consistent with the inputs and assumptions of the latest ISP (albeit with simplifications). This is important to ensure the indicative hosting capacity is somewhat consistent with the ISP outcomes.

Does TWG agree with the need for guidelines to describe the methodology for assessing indicative hosting capacity, to ensure consistent approaches across jurisdictions? If so, does TWG agree that AEMO is best-placed to develop these guidelines?
Does the TWG consider there is value in identifying best practice principles for this process?

d. How often are these assessments updated?

In considering how often transmission hosting capacity should be assessed, there is a trade-off between investors' need for up-to-date information and the time needed by TNSPs to undertake the assessment.

If aligning this assessment with the biennial ISP process – namely to use consistent inputs and assumptions – then this implies the assessment of transmission hosting capacity should also be undertaken every second year. Misalignment between the two processes risks confusion around which information the TNSP should be relying on in assessing hosting capacity.

Alternatively, it could be left up to the discretion of each TNSP as to how often it will update the indicative hosting capacity values on the central portal. There is arguably an incentive for TNSPs to update this information where the hosting capacity has increased, in order to maximise unregulated connections to their network. However, there would be no such incentive where the hosting capacity has decreased. To address the latter, there could be an explicit requirement in the NER for TNSPs to ensure this information remains accurate. However, this may be difficult to enforce in practice.

For this reason, the TAR team's preliminary thinking is that the NER stipulate how often TNSPs must assess the indictive hosting capacity of the network. ESB staff intend to consult with TNSPs to better understand how long an assessment of indicative hosting capacity would feasibly take, to inform its recommendations.

Does the TWG agree that the NER should stipulate how often the TNSP must assess the hosting capacity of its network?

Does the TWG have views on how often this assessment should be conducted?